entergy

Courtney R. Nicholson
Vice President – Regulatory and Public Affairs
Entergy New Orleans, LLC
504-670-3680 | cnicho2@entergy.com
1600 Perdido Street, New Orleans, LA 70112

November 21, 2022

VIA ELECTRONIC MAIL ONLY
Ms. Lora W. Johnson, CMC, LMMC
Clerk of Council
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112

Re: Filing of the New Orleans Technical Reference Manual Version 6.0 (Resolutions R-15-140; R-18-228; UD-08-02, UD-17-03, UD-20-02)

Dear Ms. Johnson,

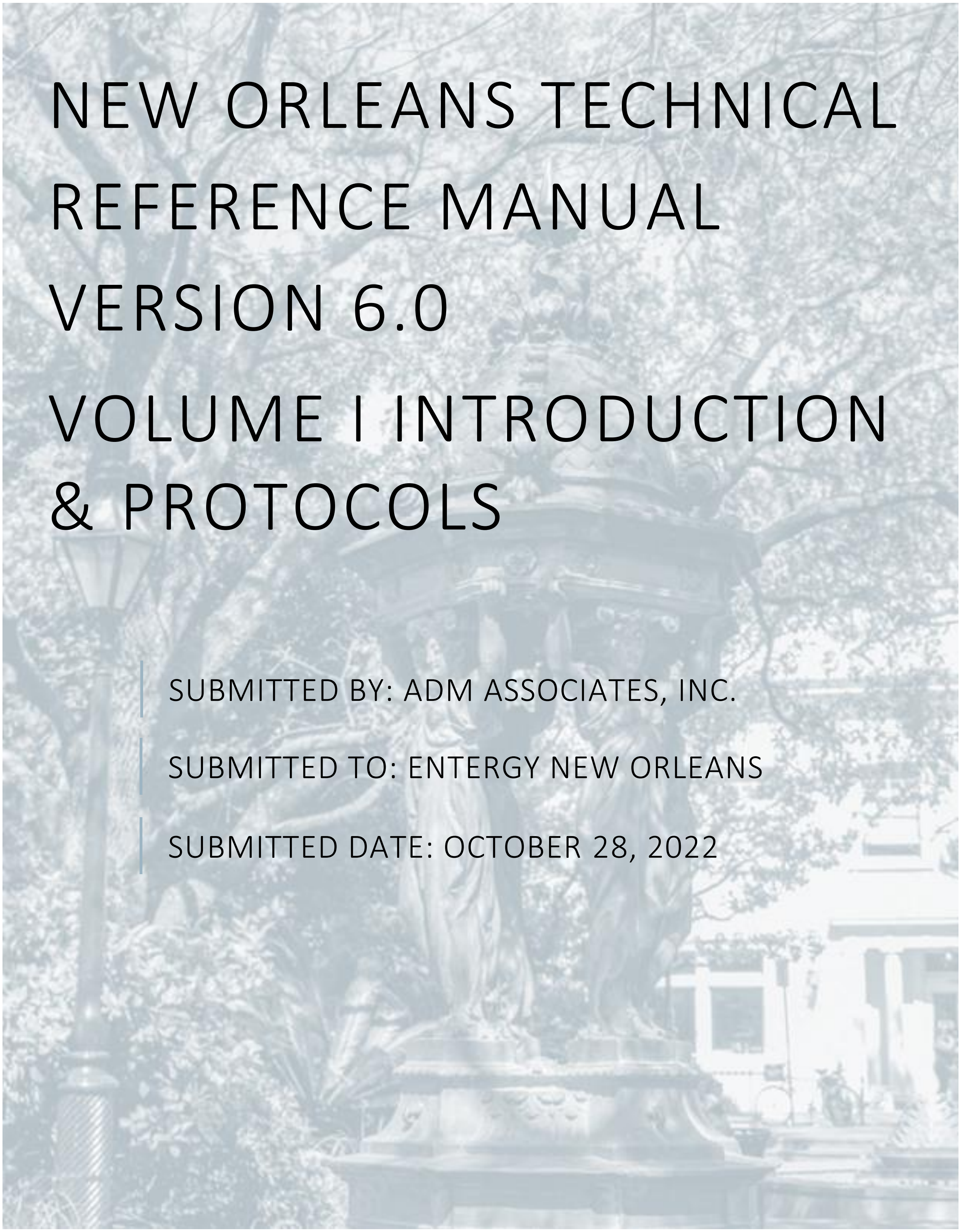
On April 9, 2015, the Council of the City of New Orleans ("Council") adopted Resolution R-15-140 that directed Entergy New Orleans, LLC ("ENO") to create a New Orleans Technical Reference Manual ("TRM"). On June 21, 2018, the Council adopted Resolution R-18-228 which approved the New Orleans TRM Version 1.0 and required updates to the TRM through biannual meetings. On November 22, 2021, ENO filed the TRM Version 5.0. On behalf of ADM Associates, ENO submits the attached New Orleans Technical Reference Manual Version 6.0. As a result of the remote operations of the Council's office related to Covid-19, ENO submits this filing electronically and will submit the original and requisite number of hard copies once the Council resumes normal operations, or as you direct. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

Should you have any questions regarding this filing, please contact my office at (504) 670-3680. Thank you for your assistance with this matter.

Sincerely,
Courtney R. Nicholson
Courtney R. Nicholson

Enclosures

cc: Official Service List UD-08-02, UD-17-03, UD-20-02 (via electronic mail)



NEW ORLEANS TECHNICAL REFERENCE MANUAL VERSION 6.0

VOLUME I INTRODUCTION & PROTOCOLS

SUBMITTED BY: ADM ASSOCIATES, INC.

SUBMITTED TO: ENTERGY NEW ORLEANS

SUBMITTED DATE: OCTOBER 28, 2022

ACKNOWLEDGEMENTS

ADM Associates, Inc. (ADM) would like to acknowledge the many talented individuals who contributed to this sixth version of the Technical Reference Manual for Program Year 13 (2023).

The Entergy New Orleans staff participated in ongoing evaluation deliverable reviews and discussions, attended regular meetings, and responded to follow-up questions, data requests and document requests. They are an ongoing partner in our evaluation efforts.

We also wish to thank the implementation firms: APTIM, Franklin Energy Services, Energy Wise Alliance, Green Coast Enterprises, Honeywell, and their staff for their insights and information.

Additionally, we would like the evaluation staff who supported the creation of this document.

ADM Staff

Richard Haley | Lead Residential Field Staff

John Coleman | Lead C&I Field Engineer I

Joe Marquez | Project Manager

Michael Nicholson, CMVP, CEM | Engineer II

Chris Johnson | Senior Analyst

Melissa Kosla | Senior Analyst

Zephaniah Davis | Senior Manager

Blake Heckendorn, PE | Senior Engineer

Melissa Culbertson | Director

Adam Thomas, PMP | Principal

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

ACRONYMS/ABBREVIATIONS

Table 1 Acronyms/Abbreviations

Acronym	Term
AC	Air Conditioner
AOH	Annual operating hours
APS	Advanced Power Strip
AR&R	Appliance Recycling & Replacement
BP	Behavioral Program
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CEE	Consortium for Energy Efficiency
CF	Coincidence factor
CFL	Compact fluorescent lamp (bulb)
CFM	Cubic feet per minute
CRE	Commercial Real Estate
DI	Direct install
DLC	Direct Load Control
DLC	Design Lights Consortium
EER	Energy efficiency ratio
EFLH	Equivalent full-load hours
EISA	Energy Independence and Security Act
EL	Efficiency loss
EM&V	Evaluation, Measurement, and Verification
ES	ENERGY STAR
EUL	Estimated Useful Life
GPM	Gallons per minute
HDD	Heating degree days
HID	High intensity discharge
HOU	Hours of Use
HP	Heat pump
HPwES	Home Performance with ENERGY STAR
HSPF	Heating seasonal performance factor
HVAC	Heating, Ventilation, and Air Conditioning
IEER	Integrated Energy Efficiency Ratio
IEF	Interactive Effects Factor
IPLV	Integrated part load value
IQW	Income Qualified Weatherization
ISR	In-Service Rate
kW	Kilowatt

Acronym	Term
kWh	Kilowatt-hour
LCDR	Large Commercial Demand Response
LCIS	Large Commercial & Industrial Solutions
LCA	Lifecycle Cost Adjustment
LED	Light Emitting Diode
M&V	Measurement and Verification
MFS	Multifamily Solutions
MW	Megawatt
MWh	Megawatt-hour
NC	New Construction
NTG	Net-to-Gross
PCT	Participant Cost Test
PFI	Publicly Funded Institutions
PY	Program Year
QA	Quality Assurance
QC	Quality Control
RCA	Refrigerant charge adjustment
RIM	Ratepayer Impact Measure
RLA	Retail Lighting and Appliances
ROB	Replace on Burnout
RR	Realization Rate
RUL	Remaining Useful Life
SCDR	Small Commercial Demand Response
SCIS	Small Commercial & Industrial Solutions
SEER	Seasonal Energy Efficiency Ratio
SK&E	School Kits and Education
TA	Trade Ally
TPI	Third-Party Implementer
TPE	Third-Party Evaluator
TRC	Total Resource Cost Test
TRM	Technical Reference Manual
UCT	Utility Cost Test
VFD	Variable Frequency Drive

SAVINGS TYPES

Table 2 Savings Types

Savings Types	Definition
Energy Savings (kWh)	The change in energy (kWh) consumption that results directly from program-related actions taken by participants in a program.
Demand Reductions (kW)	The time rate of energy flow. Demand usually refers to electric power measured in kW (equals kWh/h)
Expected / *Ex ante* Gross	The change in energy consumption and/or peak demand that results directly from program-related actions taken by participants in a program, regardless of why they participated.
Verified / *Ex post* Gross	Latin for “from something done afterward” gross savings. The energy and peak demand savings estimates reported by the evaluators after the gross impact evaluation and associated M&V efforts have been completed.
Net / *Ex post* Net	Verified / *ex post* gross savings multiplied by the net-to-gross (NTG) ratio. Changes in energy use that are attributable to a particular program. These changes may implicitly or explicitly include the effects of free-ridership, spillover, and induced market effects.
Annual Savings	Energy and demand savings expressed on an annual basis, or the amount of energy and/or peak demand a measure or program can be expected to save over the course of a typical year. The TRM provides algorithms and assumptions to calculate annual savings and are based on the sum of the annual savings estimates of installed measures or behavior change.
Lifetime Savings	Energy savings expressed in terms of the total expected savings over the useful life of the measure. Typically calculated by multiplying the annual savings of a measure by its EUL. The TRC Test uses savings from the full lifetime of a measure to calculate the cost-effectiveness of programs.

1. TRM PURPOSE AND SCOPE

ADM Associates, Inc. (ADM) is contracted as the Third-Party Evaluator (TPE) for New Orleans Energy Smart Programs administered by Entergy New Orleans (ENO) and their Third-Party Implementer (TPI) team. The purpose of the Technical Reference Manual (TRM) is to provide a single common reference document to estimate energy and peak demand savings from energy efficiency measures promoted by ENO. This document is a compilation of deemed savings values approved by the New Orleans City Council (City Council) and their Advisors for use in estimating savings for energy efficiency measures. The TRM is updated annually through a collaborative process between Stakeholders and the TPE, ADM. The data and methodologies in this document are to be used by program planners, administrators, implementers, and evaluators for forecasting, reporting, and evaluating energy and demand savings from energy efficiency measures installed in New Orleans.

The selection of measures for inclusion in this TRM was based on historical implementation rates of measures; identification of measures in other programs that may warrant inclusion; and an assessment of whether a measure is an appropriate candidate for deemed savings or if it warrants custom analysis. Some viable measures have been excluded from this TRM as they are more appropriate for custom analysis.

1.1 Deemed Savings / Unit Energy Savings (UES)

Deemed savings refers to an approach for estimating average or typical savings for efficiency measures installed in relatively homogenous markets with well-known building characteristics and usage schedules. Previous market research and building simulation tools have been used to develop estimates of “average” or deemed energy or peak savings per measure as a function of building type, capacity, weather, building schedules, and other input variables. Using this approach, program savings can be estimated by multiplying the number of measures installed by the deemed or estimated savings per measure based on previous research on the average operating schedules, baseline efficiencies, and thermal characteristics of buildings in each market.

The deemed savings approach provides reasonably accurate estimates of savings in mass markets where building operating conditions, system characteristics, and baseline efficiencies are relatively well-defined. This approach is not normally used to estimate savings in less homogenous and more site-specific applications, especially in non-residential facilities where the range of operating conditions and energy using processes is significant and can vary widely from one project to another for a similar measure. Developing energy savings estimates for these more complex facilities require the use of one or more of the International Performance Measurement and Verification Protocol (IPMVP) options that require some form of on-site measurement.

Deemed savings estimates require the development of engineering algorithms, tools, or models to estimate average savings as a function of one or more average inputs, including baseline usage, equipment efficiency levels, and building thermal characteristics. This document organizes the methods and sources used to develop these average and default values by measure category and sector and lays out the resulting savings per measure estimates in the form of savings values, algorithms, and/or calculation tools for energy efficiency measures offered by utility program administrators for claiming and reporting energy savings impacts to the City Council.

1.2 TRM Scope and Development Cycle

One of the primary objectives of the TRM is uniform application of savings methods and their assumptions. The TRM provides consistent savings estimates across programs and utility service territories, as well as estimating program-level cost-effectiveness. By establishing clear qualification criteria for the development of projected and claimed savings estimates, the TRM provides transparency of savings for all interested stakeholders.

The TRM document also provides guidance on the update frequency for key inputs and/or equations based on the vintage of the input parameters, as well as the EM&V team's assessment of the level of variability in likely savings estimates across the range of measure applications. The intent is to help participants in the energy efficiency market save money and time by providing a single source to guide savings estimates and equations.

Finally, the EM&V team provides clear criteria for deciding whether future efficient technologies or systems are good candidates to be included in the TRM as a deemed savings measure estimate or a deemed algorithm with stipulated or variable parameters. Changes to the TRM are driven by new technologies, code or baseline changes, a change in high impact measures (HIM) or a request from the implementation team.

The data and algorithms in the TRM are to be used for projecting program savings for the next year and reporting program savings for the previous year. The specific process for updating the TRM and related guidance is discussed in Section 2.10 *Protocol and Guidance for Updating the TRM*.

1.3 TRM Updates Between V5.0 and V6.0

For 2023, the Energy Smart Portfolio is in project year 13 and the TRM is well-established: All measures offered have TRM sections to support them and all major measures are based in primary New Orleans data collection. While there are two new measures to retrofit/NC measures, the TRM 6 focuses on updating existing measures to comply with a variety of new codes and regulations:

Energy Independence Security Act (EISA) – The first of two advances of lighting standards from EISA 2007 Regulations were phased in from January 2012 to January 2014 and dictated higher efficiency for General Service Lamps (GSLs). Phase II (known as the 'EISA backstop') takes effect on July 25, 2022, stipulating that all GSLs sold in the United States (US) must achieve a minimum efficacy of 45 lumens/watt. The ruling also significantly expands the definition of GSLs, extending the covered lumen range, base types, and shapes, while reducing the types of bulbs exempted. This has major implications for lighting nationwide, necessitating a near-complete revision of the Residential Lighting Efficiency chapter, the retirement of four existing residential lighting chapters and minor updates to the commercial lighting chapter and standard wattage table:

- Residential Lighting Efficiency
- ENERGY STAR® Omni-Directional LEDS (retired)
- ENERGY STAR Directional and Specialty LEDS (retired)
- ENERGY STAR Omni-Directional CLFs (retired)
- ENERGY STAR Specialty CFLs (retired)
- Commercial Lighting Efficiency
- Standard Wattage Table Appendix

ENERGY STAR – ENERGY STAR is a government-backed program who provide information on the energy consumption of products and devices using different standardized methods. The standards set by ENERGY STAR for consumer products and buildings are similar to other Department of Energy requirements in that criteria are revised and updated as newer technologies, processes and conditions are introduced. Seven measures will be subject to increased efficiency criteria during 2023, necessitating updates of those chapters:

- Residential Ceiling Fans
- Residential Refrigerators
- Residential Water Coolers
- Commercial Combination Ovens
- Commercial Convection Ovens
- Commercial Dishwashers
- Commercial Solid Door Refrigerators

International Energy Conservation Code (IECC) 2021 – The IECC is referred to as a model energy code because building codes are state or local laws; there is no national building energy code in the US. Regardless of when any state adopts a code, every three years, the IECC is updated to incorporate new building technologies and practices as they evolve over time and ensure that new homes and commercial buildings meet modern-day minimum levels of efficiency. For 2023, New Orleans will be adopting IECC 2021, having previously used IECC 2009. Seven measures in the TRM are affected by the change in code and have been updated accordingly:

- Residential Ceiling Insulation
- Residential Central Air Conditioner Replacement
- Residential Air Source Heat Pump Replacement
- Residential Ground Source Heat Pump Replacement
- Residential Ductless Heat Pump Replacement
- Commercial Packaged Terminal Air Conditioners and Heat Pumps
- Commercial Unitary and Split Air Conditioners and Heat Pumps

Seasonal Energy Efficiency Ratio 2 (SEER2) – The SEER measures air conditioning and heat pump cooling efficiency, which is calculated by the cooling output for a typical cooling season divided by the total electric energy input during the same time frame. The Department of Energy (DOE) is changing the way HVAC systems are tested. New M1 testing procedures are thorough, demanding a lower SEER2 equipment rating (with corresponding analogous test procedures for Energy Efficiency Ratio 2 (EER2) and Heating Season Performance Factor 2 (HSPF2). Effective January 1, 2023, cooling products will be subject to regional minimum efficiencies using the new system and prohibits the sale of units which do not meet the minimum criteria. Further, IECC 2021 uses the new rating system when stipulating new codes. The new rating system and standards required updating six TRM sections:

- Residential Central Air Conditioner Replacement
- Residential Air Source Heat Pump Replacement
- Residential Ground Source Heat Pump Replacement
- Residential Ductless Heat Pump Replacement
- Commercial Packaged Terminal Air Conditioners and Heat Pumps
- Commercial Unitary and Split Air Conditioners and Heat Pumps

Specifics of these updates, as well as additions and other changes to TRM sections are discussed in detail below.

1.4 New and Revised Measures

1.4.1 COMMERCIAL MEASURES

The non-residential updates are listed below.

- Refrigerator and Freezer Case Solid Doors (New) - This measure is retrofitting existing vertical, open, refrigerated display cases by adding and installing doors.
- Water Cooler Timers (New) - This measure involves installing a timer on an existing water cooler to shut down operation during unoccupied hours.
- Window Film (Update) – Savings for film applied to south-facing windows was developed for three heating types and added to existing east and west-facing values.
- Demand Control Ventilation (Update) – Building types and savings values for 'Small Office General' and 'Small Office Densely Occupied' were removed and replaced with 'Small Office (<30,000 ft^2)' and 'Large Office (≥30,000 ft^2) to better reflect the types of office buildings found in New Orleans.
- Variable Speed Drives (Update) – Building types and savings values for 'Small Office General' and 'Small Office Densely Occupied' were removed and replaced with 'Small Office (<30,000 ft^2)' and 'Large Office (≥30,000 ft^2) to better reflect the types of office buildings found in New Orleans.
- ENERGY STAR Combination Ovens (Update) – Updated to reflect ENERGY STAR 3.0 qualification criteria. Deemed savings updated.
- ENERGY STAR Convection Ovens (Update) – Updated to reflect ENERGY STAR 3.0 qualification criteria. Deemed savings updated.
- ENERGY STAR Commercial Dishwashers (Update) – Updated to reflect ENERGY STAR 3.0 qualification criteria. Deemed savings updated.
- ENERGY STAR Solid Door Refrigerators and Freezers (Update) – Updated to reflect ENERGY STAR 5.0 qualification criteria. Deemed savings updated.
- Air Conditioner and Heat Pump Tune-Up (Update) – Air Conditioner and Heat Pump tune-ups can involve multiple steps during the tune-up process, not all of which are necessary for every system. The revised chapter now allows for savings to be assigned to partial tune-ups, based on individual components of the tune-up.
- Packaged Terminal Air Conditioner and Heat Pump – Baseline and efficiency levels updated to reflect SEER2 and IECC 2021 requirements. Deemed savings tables updated.
- Unitary and Split System Air Conditioner and Heat Pump – Baseline and efficiency levels updated to reflect SEER2 and IECC 2021 requirements. Deemed savings tables updated.

1.4.2 RESIDENTIAL MEASURES

The residential updates are listed below.

- ENERGY STAR Ceiling Fans (Update) – Updated to reflect ENERGY STAR 4.0 qualification criteria. Deemed savings updated.
- ENERGY STAR Refrigerators (Update) – The savings algorithm has been updated and no longer includes the Site/Lab Factor (SLF).
- ENERGY STAR Water Coolers (Update) – Updated to reflect ENERGY STAR 3.0 qualification criteria. Deemed savings updated.

- Window Film (Update) – Eligibility wording has been revised to include south-facing windows.
- Central Air Conditioner Replacement (Update) – Baseline and efficiency levels updated to reflect SEER2 and IECC 2021 requirements. Deemed savings tables updated.
- Heat Pump Replacement (Update) – Baseline and efficiency levels updated to reflect SEER2 and IECC 2021 requirements. Deemed savings tables updated.
- Ground Source Heat Pump (Update) – Baseline and efficiency levels updated to reflect SEER2 and IECC 2021 requirements.
- Ductless Heat Pump (Update) – Baseline and efficiency levels updated to reflect SEER2 and IECC 2021 requirements.
- Central Air Conditioner and Heat Pump Tune-Up (Update) – Air Conditioner and Heat Pump tune-ups can involve multiple steps during the tune-up process, not all of which are necessary for every system. The revised chapter now allows for savings to be assigned to partial tune-ups, based on the individual components of the tune-up, and to which certain levels of the component are applied (such as the % of refrigerant charge adjust). Deemed savings values have been calculated and included for applications common in the Energy Smart portfolio.
- Ceiling Insulation (Update) – Baseline and efficiency levels updated to reflect SEER2 and IECC 2021 requirements. Baseline level of insulation updated with past three years' of Energy Smart program data. Deemed savings tables updated. A baseline has been provided for new construction projects.
- Air Infiltration (Update) – A baseline has been provided for new construction projects.

1.4.3 PROTOCOLS

Language in the Demand Response protocol has been changed to state that ENO participants in MISO but does not currently participate in the Demand Response market.

1.4.4 PRIMARY DATA COLLECTION

The following EM&V studies have been completed, allowing for incorporation of primary data into the TRM:

- Metering of residential air conditioning runtime, applied to AC replacement and duct sealing
- Field assessment of average SEER for air conditioning units in duct sealing projects
- Billing analysis to support reductions achieved from residential air conditioning tune-ups
- Measurement of residential domestic hot water (DHW) temperature setpoints, incorporated into DHW replacements and low flow devices
- Metering of residential lighting run-time
- Metering of commercial lighting run-time for the following facility types:
    - K-12 Education
    - Exterior Lighting (all commercial)
    - Food Preparation
    - Food Sales: Non-24 Hour Supermarket
    - Food Service: Fast Food
    - Food Service: Sit-down Restaurant
    - Health Care: In-Patient
    - Lodging: Common Areas
    - Lodging: Guest Rooms

- Multifamily: Common Area
- Religious Assembly/Worship
- Retail: Freestanding
- Warehouse: Non-Refrigerated

The data collected for these studies is summarized in Table 1-1 below.

Table 1-1 Parameters Validated with Primary Data Collection in New Orleans

Parameter	Measures Affected	Value	Sample Size
Residential Cooling Equivalent Full-load Hours	Duct Sealing, AC replacement, AC tune-up	1,637	68 homes
Residential Cooling Peak Coincidence Factor	Duct Sealing, AC replacement, AC tune-up	77%	68 homes
Residential Heating Equivalent Full-load Hours	Duct Sealing, Central AC and Heat Pump Tune-Up, Ductless Heat Pump, Ground Source Heat Pump and Heat Pump Replacement	HP: 396 ER: 600	295 homes
Lighting hours of use	CFLs, Specialty CFLs, Directional LEDs, Omnidirectional LEDs	2.38	40 homes, 355 loggers
Residential Lighting Peak Coincidence Factor	CFLs, Specialty CFLs, Directional LEDs, Omnidirectional LEDs	11.74%	40 homes, 355 loggers
Residential DHW Setpoint (deg. F)	Water Heater Replacement, Faucet Aerators, Low Flow Showerheads	122.24	37 homes
Residential AC Tune-Up Annual % Savings	AC Tune-Up	10.1%	260
Commercial Lighting Hours of Use	Commercial Lighting	Original values created for 10 facility types.	59 premises, 210 loggers
Commercial Lighting Peak Coincidence	Commercial Lighting	Original values created for 10 facility types.	59 premises, 210 loggers
Average Duct Sealing Leakage Reduction	Duct Sealing	SF: 471 MF: 443	SF: 4,939 MF: 325
Deemed Net-to-Gross Ratios	Residential: Duct Sealing Air Sealing AC/HP Tune-Up ENERGY STAR Window AC ENERGY STAR Refrigerator	Varies: Duct Sealing – 95% Air Infiltration – 95% AC/HP Tune-Up – 82% Window AC – 62% Refrigerator – 44%	Varies: Duct Sealing – 282 Air Infiltration – 78 AC/HP Tune-Up – 135 Window AC – 30 Refrigerator – 44
Deemed ISRs for Mailer kit Items	LED lighting, Faucet Aerators and Low-Flow Showerheads	LEDs: 71% Aerators: 45% Showerheads: 62%	4,572 participant responses

Primary data collection has continued during all PY evaluations, including PY12. After PY12 program close, the following data will be analyzed to either develop or refine important savings inputs:

- Results from the Residential PY12 Smart Thermostats M&V analysis will be used to update the Residential Smart Thermostat chapter, which has previously relied on the results of the PY8 pilot analysis.

- Results from the Commercial PY12 Smart Thermostats M&V analysis will be used to update the Commercial Smart Thermostat chapter, which has previously relied on deemed reductions from similar programs administered in other territories.

1.5 Incremental Costs

Incremental costs mean the difference between the cost of the efficient measure and the cost of the most relevant baseline measure that would have been installed (if any) in the absence of the efficiency program. Installation costs (material and labor) shall be included if there is a difference between the efficient measure and the baseline measure.

Note that the TRM includes at least one deemed incremental cost(s) as a default value(s) for most measures. However, consistent with previous versions, in instances where the TPA has better information on the true incremental cost of the measures (e.g., direct install programs), the TPA-specific incremental cost value should be used for the purposes of cost-effectiveness analysis.

Examples of incremental cost calculations include:

- The incremental cost for an efficient measure that is installed in new construction or is being purchased at the time of natural installation, investment, or replacement is the additional cost incurred to purchase an efficient measure over and above the cost of the baseline/standard (i.e., less efficient) measure (including any incremental installation, replacement, or O&M costs if those differ between the efficient measure and baseline measure).
- For a retrofit measure where the efficiency program caused the customer to update their existing equipment, facility, or processes (e.g., air sealing, insulation, tank wrap, controls), where the Customer would not have otherwise made a purchase, the appropriate baseline is zero expenditure, and the incremental cost is the full cost of the new retrofit Measure (including installation costs).
- For the early replacement of functioning equipment with a new efficient measure, where the customer would not have otherwise made a purchase for a number of years, the appropriate baseline is a dual baseline that begins as the existing equipment and shifts to the new standard equipment after the expected remaining useful life of the existing equipment ends. Thus, the incremental cost is the full cost of the new efficient measure (including installation costs) being purchased to replace a still-functioning equipment less the present value of the assumed deferred replacement cost (including installation costs) of replacing the existing equipment with a new baseline measure at the end of the existing equipment's life. This deferred credit may not be necessary when the lifetime of the measure is short, the costs are very low, the measure is highly cost-effective even without the deferred credit, or for other reasons (e.g., certain direct install measures, measures provided in kits to customers).
- For services, such as facility energy audits, energy assessments, and retro-commissioning, the incremental cost is the full cost of the services. Even if the service is performed entirely by a TPA, the full cost of the service charged by the TPA is the incremental cost, because this is assumed to be the cost of the service that would have been incurred by the customer if the customer were to have the service performed in the absence of the efficiency program. In some cases, this will be at the measure level; in others, it will be at the program level. Such costs should be included in measure-level cost-effectiveness calculations only

when they are inseparable from the efficiency improvements – i.e., when the provision of the service is what produces energy savings (e.g., retro-commissioning).

- For the early retirement of functioning equipment before its expected life is over (e.g., appliance recycling programs), the incremental costs are composed of the customer's value placed on their lost appliance, any customer transaction costs, and the pickup and recycling cost. The incremental costs include the actual cost of the pickup and recycling of the equipment because this is assumed to be the cost of recycling the equipment that would have been incurred by the customer if the customer were to recycle the equipment on their own in the absence of the efficiency program. The payment a TPA makes to the customer serves as a proxy for the value the customer places on their lost appliance and any customer transaction costs.

1.6 Simulation Modeling

The savings for some weather sensitive measures were developed via simulation modeling. The model software platforms included are as follows: eQuest©; BEopt™; EnergyGauge USA; and EnergyPlus™.

1.7 Weather

Various measures in the TRM refer to Typical Meteorological Year version 3 (TMY3) weather data. This data is publicly available from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB).

This data reflects the typical year of New Orleans weather based off historical data and is the common practice for projecting average annual savings of weather sensitive measures. Inputs from the TMY3 dataset for New Orleans included the following: temperature; humidity; wind speed and direction; cloud cover; and solar radiation.

1.8 Application of Values in this TRM

It is the intent to have the values in this TRM provide parameters to stipulate ex-post gross energy savings (kWh) and demand reduction (kW) estimates. The values in this TRM do not account for free-ridership, as that is a parameter that may vary based on a program delivery mechanism (for example, the free-ridership rates for residential lighting differ significantly between retail markdown in the Consumer Products versus direct install). The measurement of free-ridership and the application of net-to gross is discussed in detail Section 2.3.7 *Impact Protocol 4.0: Net-to-Gross Analysis*.

The values in this TRM will be used to verify *ex post* gross energy savings (kWh) and demand reductions (kW), except when specified otherwise in the EM&V Plan.

1.9 Future Studies

Each measure section includes a discussion of future studies suggested by the authors of this TRM. For many measures, no studies are recommended, and suggested updates include only updating when codes and standards affecting the specific measure change. The suggestion of future studies is focused on areas of high impact in the Energy Smart portfolio (such as duct sealing) and for the identification of potential future high impact measures (such as ductless mini-split HVAC systems and smart thermostats).

The studies detailed are suggestions on the part of the authors of the TRM and guidance and feedback on these issues is welcomed as part of the stakeholder advisory process.

The general guidelines that are provided for when a study is warranted are as follows (though occasionally subject to modification as specified in a measure-specific chapter):

- Measures should be flagged for further review if they exceed 1% of savings within the residential or non-residential portfolio. In such instances, it should be determined whether:
- Primary data has been collected in Energy Smart evaluations to support the deemed savings;
- The data is sufficiently recent to support its continued use; and
- If data collection to support a deemed savings revision is cost-effective or cost-feasible given the implementation and EM&V budgets for Energy Smart programs.
- Measures that are not over the high-impact threshold should be considered for impact or market assessment studies if:
- Stakeholders (the Council and their Advisors, ENO, Third-Party Administrators (TPA), interveners, the Third-party Evaluator (TPE), and/or other appropriate parties) conclude a measure is of strategic importance to future program implementation efforts; or
- A measure is high-impact within an important market sub-segment (such as low-income, multifamily, or municipal government).

1.10 Overall TRM Layout

This document is divided into separate documents for ease of use:

Volume 1

- Section 1: *TRM Purpose and Scope* covers the process for TRM updates and version rollouts, weather zones, peak demand definitions, TRM structure, and the format of the TRM measure overviews.
- Section 2: *Evaluation Protocols* contains guidance on the application of the TRM that have been reviewed and approved by the EM&V team.

Volume 2

- Section 1: *Residential Measures* contains the measure descriptions and deemed savings estimates and algorithms for measures installed in residential dwellings.
- Section 2: *Non-Residential Measures* contains the measure descriptions and deemed savings estimates and algorithms for measures installed in nonresidential businesses.

Volume 3

- Appendix 1: Engineering Inputs, Methods and Assumptions, and Prototypical Building Characteristics
- Appendix 2: Examples of Existing Baseline Methods for Settlement and Examples of Baseline Adjustments
- Appendix 3: Prior Work in DR M&V Methods
- Appendix 4: Information Sources and References

2. EVALUATION PROTOCOLS

This chapter describes the recommended EM&V Protocols that should be incorporated in process and impact evaluations of the programs pursuant to the Energy Smart Implementation Plan for 2023-2025 (Docket R-20-257 and UD-20-02).

2.1 Protocols Introduction

This section provides protocols for various activities related to performing Evaluation, Measurement, and Verification (EM&V) for the Energy Smart programs that ENO is offering to its residential, commercial, and industrial customers.

The first section introduces the Protocols and explains general principles and concepts, then following sections provide protocols for specific topics:

- 2.3 Protocols for Impact Evaluation
- 2.4 Protocols for Process Evaluations
- 2.5 Protocols for Evaluation of New Construction Projects
- 2.5 Protocols for Evaluation of Retrocommissioning Projects
- 2.7 Protocols for Evaluating Behavioral Programs
- 2.7 Protocols for Evaluating Demand Response Programs and Projects
- 2.8 Protocols and Guidance for Establishing Quality Assurance / Quality Control for Programs
- 2.9 Protocol and Guidance for Updating the TRM

2.2 Description of the Energy Smart Portfolio

Through Energy Smart programs, ENO offers energy efficiency programs to New Orleans residents and businesses. Any residential, commercial, or industrial Entergy New Orleans electric customer is eligible to participate. The NO TRM V6.0 will be applied to the PY13, or 2023 and is active from January 01, 2023, going forward. The table below outlines the portfolio of programs[1] offered in PY13.

[1] Per the filing of Entergy New Orleans, LLC's Energy Smart Program Application for Approval of the Implementation Plan for Program Years 13-15 (Docket Nos. UD-20-02 and UD-08-02). This Plan has not yet been approved; these are subject to change.

Table 2-1 PY13 Portfolio of Programs

Program Name	Sector	Type
Home Performance with ENERGY STAR	Residential	EE
Income Qualified Weatherization	Residential	EE
Multifamily Solutions	Residential	EE
A/C Solutions	Residential	EE
Retail Lighting and Appliances	Residential	EE
School Kits and Education	Residential	EE
Appliance Recycling & Replacement Pilot	Residential	EE
Behavioral	Residential	Behavioral
EasyCool - Bring Your Own Thermostat	Residential	DLC/DR
Peak Time Rebate Pilot	Residential	DLC/DR
Electric Vehicle Bring Your Own Charger Pilot	Residential	DLC/DR
Small C&I Solutions	C&I	EE
Large C&I Solutions	C&I	EE
Publicly Funded Institutions	C&I	EE
C&I Construction Solutions	C&I	EE
Large Commercial Automated Demand Response	C&I	DLC/DR

2.2.1 PURPOSE OF EVALUATION

As defined by the American Evaluation Association, evaluation of an offering involves "assessing the strengths and weaknesses of programs, policies, personnel, products and organizations to improve their effectiveness." The role of evaluation is two-fold:

- Quantify Results: Document, measure and estimate the energy and demand savings of an offering to determine how well it has achieved its goals and managed its budget.
- Gain Understanding: Determine why certain effects occurred (or didn't occur) and identify ways to improve and refine current and future offerings; also, to help select future offerings (NAPEE 2007).

Figure 2-1 below provides a visual representation of the role of evaluation activities during the lifecycle of a typical program. As the figure shows, program evaluation should be viewed as an ongoing process that provides information regarding changes in direction and adjustments to goals and objectives over time.

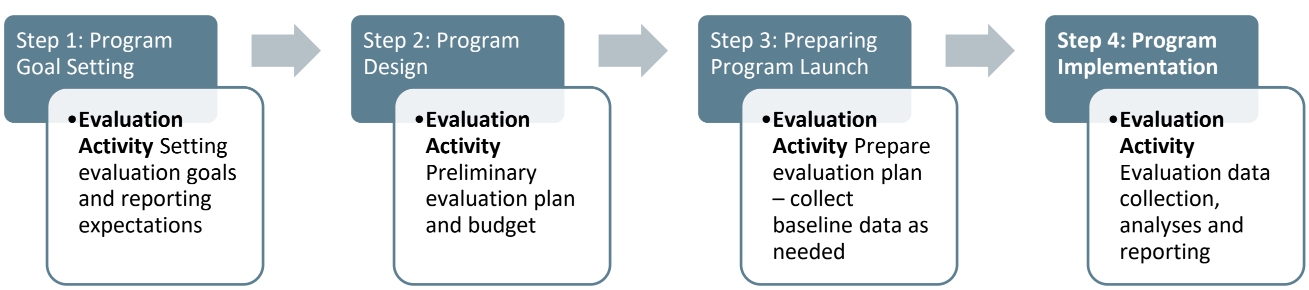


Figure 2-1 High-Level Evaluation Activities in Program Implementation Cycle (NAPEE, 2007)

2.2.2 PURPOSE OF EM&V PROTOCOLS PRESENTED IN THIS VOLUME

The protocols are intended to provide a common framework and set of reference points for conducting cost-effective evaluations. Protocols describe the types of information that must be collected to conduct a comprehensive examination of the overall effectiveness, the recommended frequency for conducting these evaluations, and the key metrics that must be reported during these evaluation activities.

2.3 Protocols for Impact Evaluation

This chapter provides guidance and protocols pertaining to impact evaluation activities for measures and projects that are not included on the list of prescriptive measures for Energy Smart programs. Protocols are presented as follows:

- Impact Protocol 1.0: Impact Evaluation Timing
- Impact Protocol 2.0: Level of Rigor for Impact Evaluations
- Impact Protocol 3.0: Evaluation of Savings for Non-prescriptive Measures or Projects
- Impact Protocol 3.1: Evaluation Approach for 100% Custom Measures
- Impact Protocol 3.2: Impact Evaluation of Non-Prescriptive Measures Whose Savings May Be Treated as Prescriptive
- Impact Protocol 3.3: Impact Evaluation of Information-Based Programs
- Impact Protocol 4.0: Net-to-Gross Analysis

2.3.1 IMPACT PROTOCOL 1.0: IMPACT EVALUATION TIMING

The decision regarding the appropriate time frame for impact evaluation has two components:

- When and over what period of time the evaluation effort will take place?
- What is the level of detail or “granularity” required for the evaluation analyses?

2.3.1.1 Evaluation Occurs When and over What Period of Time?

A standard evaluation begins before program implementation begins to collect important baseline data and then continues for some time after the program is completed to analyze persistence of savings and other program elements.

The actual timing of evaluation efforts influenced by several factors, including:

- What will be the period of analyses (i.e., how many years)?
- Will persistence of savings be determined, and if so, how?
- What is the timing for policy decisions and evaluation planning?
- What is the need for early feedback for program implementers?
- Where is the program in its lifecycle?
- What are the evaluation data collection time lags?
- What are the other regulatory and/or management oversight requirements to be addressed in this evaluation?
- What information or data are needed to update specific energy and demand savings from the measure, and to quantify life estimates?

- What is the timing and format required for the reporting process? Is a single, final program report needed, or are more frequent reports required?

In general, program evaluations are conducted with a three-year plan. Process evaluations are usually conducted at the end of the first year of program operations and at the conclusion of the program period. Impact evaluations may be conducted annually or at the conclusion of Program Years 2 and 3, and generally free ridership and spillover no more frequently than once every three years provided there are sufficient data to determine energy savings estimates and adjustments and no significant changes in a program design. The timing for the EM&V activities should be specified in EM&V plans for the programs to be evaluated.

2.3.1.2 What Level of Detail is Required?

This relates to whether 15-minute, hourly, monthly, seasonal, or annual data collection and savings reporting are necessary. The granularity decision is based how the information will be used for evaluation purposes. Annual savings data provide an overview of program benefits. More detailed data are usually required for both cost-effectiveness analyses and resource planning purposes.

If demand savings are to be calculated, the choice of definition (e.g., annual average, peak summer, coincident peak, etc.) is related to time granularity. When evaluating energy or demand savings, it is important to properly define the project boundaries (i.e., what equipment, systems, or facilities will be included in the analyses). Ideally, all primary effects (the intended savings) and secondary effects (unintended positive or negative effects), and all direct (at the project site) and indirect (at other sites) will be captured in the evaluation. The decision concerns whether savings will be evaluated for specific pieces of equipment. For example, the “boundary” may include motor savings or light bulb savings estimates, the end-use system (e.g., the HVAC system or the lighting system), the entire facility, or the entire energy supply and distribution system (Modified NAPEE, 2007).

The EM&V plan for each program should stipulate the confidence and precision levels necessary to provide for a robust EM&V analysis of the savings estimates and describe the sampling strategy that will be used. Sampling strategies will vary by program and across the program portfolio. The sampling strategy for a particular program should therefore be fully described in the EM&V plan for that program.

2.3.2 IMPACT PROTOCOL 2.0: LEVEL OF RIGOR FOR IMPACT EVALUATIONS

Impact evaluation of gross savings can be performed under different levels of rigor, depending on available evaluation resources, uncertainty in expected savings, magnitude of expected savings, program budget, and other criteria.

The level of effort necessary to assess savings impacts is driven by the equipment type and data collection needs. The International Performance Measurement and Verification Protocol (IPMVP) is an important and widely used guidance document that provides guidelines about the “level of effort” required to document energy efficiency savings. The IPMVP presents various M&V options, summarized in Table 2-2, that help guide savings verification methods and levels of effort.

Table 2-2 IPMVP M&V Options

IPMVP Option	Measure Performance Characteristics	Data Required
Option A: Engineering calculations using spot or short-term measurements and/or historical data	Constant performance	Verified installation Nameplate or stipulated performance parameters Spot measurements Runtime hour measurements
Option B: Engineering calculations using metered data	Constant or variable performance	Verified installation Nameplate or stipulated performance parameters End-use metered data
Option C: Analysis of utility meter (or sub-meter) data using techniques from simple comparison to multivariate regression analysis	Variable performance	Verified installation Utility metered or end-use metered data Engineering estimate of savings input into SAE model
Option D: Calibrated energy simulation / modeling; calibrated with hourly or monthly utility billing data and / or end-use metering	Variable performance	Verified installation Sport measurements, runtime hour monitoring, and/or end-use metering to prepare inputs into models Utility billing records, end-use metering, or other indices to calibrate modeling

In the California Energy Efficiency Evaluation Protocols, IPMVP M&V options are used to identify two levels of rigor for evaluation of gross energy savings.

- Basic rigor level, which is consistent with IPMVP Option A (or, in some cases, Option C).
- Enhanced rigor level, which is consistent with IPMVP Options B or D (or, in some cases, Option A).

The levels of rigor for evaluating impacts of a program can be assigned by using this correspondence between IPMVP M&V options and levels of rigor by determining which IPMVP option should be applied to assess savings for measures or projects in a program. For example, Lawrence Berkeley National Laboratory (LBNL) maintains a webpage on its Measurement & Verification portal that allows use of interactive tools to identify the IPMVP option that is best suited to evaluating savings for a particular project. (See http://mnv.lbl.gov/interactive/ipmvp-1a-2.) This tool can be used to assign an IPMVP Option and corresponding level of rigor (basic, enhanced) to measures or projects included in a program.

The LBNL application (which is adapted from IPMVP 2012 Volume 1) identifies an appropriate M&V option based on responses to questions about the energy conservation measure/project that's being considered for evaluation. Items of information needed include the following:

- Claimed kWh / kW
- Count of measures in the projects
- Count of installed measures
- Descriptions of any equipment changed or of new equipment installed
- Interactive effects between measures
- Percentage of savings vs. baseline

For Energy Smart programs, there are prescriptive and non-prescriptive measures. Prescriptive measures are explicitly listed as such in program materials. Non-prescriptive measures are those that are not included on the list of prescriptive measures for the Energy Smart programs. Within the set of non-prescriptive measures, a distinction can be made between 100% custom measures and measures where deemed calculation methods might be used but data need to be collected or developed to be put into the calculation algorithms.

This distinction is shown in Table 2-3. For Prescriptive Measures that are included on the list of prescriptive measures, savings are deemed. (These deemed savings values are provided in the current Technical Reference Manual.) Protocols for assessing savings for Non-Prescriptive and 100% Custom Measures are discussed in Section 2.3.4 Impact Protocol 3.1: Custom Measures Evaluation.

Table 2-3 Spectrum of Measures: 100% Prescriptive to 100% Custom[2]

Types	100% Prescriptive	Non-Prescriptive		100% Custom
	Exclusive Source	**Primary Source**	**Used as a Source**	**May be used as a Source**
Deemed Calculation(s)	No	Yes	Yes	No, unless custom measure EM&V protocols are included
Deemed Variables or Factors	No	Mix of site-/project-specific and deemed data	None or minimal	None or minimal
Site- or Project-Specific Variables or Factors	No	Mix of site-/project-specific and deemed data	Exclusively or mostly	Exclusively or mostly
Deemed Savings Values	Fully deemed savings values	Partially deemed savings values	No, savings determined per deemed calculations, resulting in site/ project specific savings	No, savings determined per project/measure analyses and data collection, resulting in site/project specific savings
EM&V Method	Deemed savings	M&V Option A	M&V Option B, C, or D	M&V Options B, C, or D (e.g., for individual building projects) or control group methods (e.g., for residential projects)

2.3.3 IMPACT PROTOCOL 3.0: EVALUATION OF NON-PRESCRIPTIVE MEASURES

As discussed in Section 2.3.2 Impact Protocol 2.0: Level of Rigor for Impact Evaluations, levels of rigor with which savings for non-prescriptive and custom measures are assessed are determined depends on the methods chosen for the analysis of savings. Protocols pertaining to the choice of methods are presented in this section. In general, documentation information is used to determine (1) what methods of savings analysis to use and (2) specifications of assumptions and sources for these specifications. Protocols are provided for the following:

- 100% custom measures
- Non-prescriptive measures that are not 100% custom
- Measures promoted through mass market programs

[2] Carroll 2013, as adapted and presented in SEE Action Guide for States: Guidance on Establishing and Maintaining Technical Reference Manuals for Energy Efficiency Measures

2.3.4 IMPACT PROTOCOL 3.1: CUSTOM MEASURES EVALUATION

Types of measures that can be 100% custom include (1) measures or projects that site-specific but that are considered too complex or unique to be included in the list of standard measures provided in the TRM or (2) measures that may involve metered data, but that require additional assumptions to arrive at a 'typical' level of savings as opposed to an exact measurement.

Most measures in this category are custom measures installed in both retrofit and new construction situations in C&I facilities. In general, these custom measures are more complex measures that require site-specific information and detailed calculations to estimate energy and demand savings. These measures do not comply with a prescriptive calculation approach or may benefit from having more detailed savings analysis.

Because custom measures are often unique, their savings are evaluated using a site-specific M&V approach, with more reliance placed on using site-specific engineering analysis and end-use metering as methods to estimate savings. The site-specific approach involves (1) selecting a representative sample of custom projects or measures that participated in a program; (2) determining the savings for each project or measure in the sample, usually by using one or more of M&V Options defined in the IPMVP; and (3) applying the results of estimating the savings for the sample projects or measures to the entire population in the program. Further information on the EM&V methods recommended for custom measures in provided in Table 2-4. Methods to determine gross savings for 100% custom measures depend on the type of measure and the end use affected (e.g., lighting, HVAC, industrial process).

Table 2-4 Summary of Recommended EM&V Methods for 100% Custom Measures[3]

Characteristic	Approach	Additional Comments
Program Tracking	Initial gross estimates of energy and demand savings and initial net impacts as applicable. Measure description with, as applicable, unit quantities, sizes/ capacities, baseline and installed efficiencies, and operating hours.	Any additional parameters that could be useful for quality control or for evaluation design, such as sampling that are described in the EM&V plan.
Recommended M&V Method	On-site inspections with partial (Option A) or complete (Options B,C,D) measurements on a census or sample of program participants. Site visits with short-term metering is the most appropriate approach for C&I Custom measures. A detailed engineering spreadsheet model can be used to capture the dynamics and interactions on an hourly basis. Data collected from Energy Management Systems (EMS) may also provide cost-effective information and should be included in EM&V plans if available.	Metering methods often include time-of-use loggers, interval kW recorders, and spot power measurements.
Alternative M&V Method	If the Custom measure involves significant HVAC equipment and/or controls, calibrated simulation modeling (Option D) offers a viable alternative for capturing measure dynamics and interaction.	Metering can be used to calibrate the model. Such metering may include whole premise interval kW recorders with some end-use metering.

[3] NEEP EM&V Protocols, 2010

Evaluating savings impacts for custom measures or projects requires that baseline conditions be defined. The baseline reflects the conditions, including energy consumption, that were occurring before the installation of the measure. Baseline definitions consist of site-specific issues and broader, policy-oriented considerations.

- Site-specific issues include the characteristics of equipment in place before an efficiency measure is implemented as well as how and when the affected equipment or systems are operated. When defining the baseline, it is also important to consider where in the life cycle of the existing equipment or systems the new equipment was installed. The options are:
  - Early replacement of equipment that had not reached the end of its useful life;
  - Failed equipment replacement, with new energy efficient equipment installed; or
  - New construction.

For each option, there are two generic approaches to defining baselines.

- Project-Specific Baseline. With the project-specific procedure (used with all or a sample of the projects in a program), the baseline is defined by a specific technology or practice that would have been pursued, at the site of individual projects, if the program had not been implemented. For energy efficiency programs, the baseline is established by:
  - Assessing the existing equipment's energy consumption rate, based on measurements or historical data;
  - Completing an inventory of pre-retrofit equipment; or
  - Comparing to a control group's energy equipment (used where no standard exists or when the project is an "early replacement," i.e., implemented prior to equipment failure).

  The most widely accepted method, and recommended for these EM&V Protocols, is to define the baseline by determining what technologies the new equipment replaces. That is, the baseline is related to actual historical base year energy consumption or demand and carried forward to future years (NAPEE, 2007).

- Performance Standard Baseline. For the Performance Standard Baseline approach, a performance standard is developed that provides an estimate of baseline energy and demand for all the projects in a program. The assumption is that any project activity will produce additional savings if it has a "lower" baseline than the performance standard baseline. Performance standards are sometimes referred to as "multi-project baselines" because they can be used to estimate baseline savings for multiple project activities of the same type.

  Under the performance standard procedure, baseline energy and demand are estimated by calculating an average (or better-than-average) consumption rate (or efficiency) for a blend of alternative technologies or practices. These standards are used in large-scale retrofit (early replacement) programs when the range of equipment being replaced and how it is operated cannot be individually determined. This would be the case, for example, in a residential compact fluorescent lamp (CFL) incentive program, where the types of lamps being replaced and the number of hours they operate cannot be determined for each home. Instead, studies are used to determine typical conditions. Another common use of performance standards is to define a baseline as the minimum efficiency standard for a piece of equipment as defined by a law, code, or standard industry practice. This is commonly used for new construction or equipment that replaces failed equipment (NAPEE, 2007).

This approach is especially important when it is difficult to determine baselines, such as in new construction programs since no comparison period exists. However, the concepts of project and performance standard baseline definitions can still be used in these circumstances. The industry-accepted methods of defining new construction baselines are based on:

- Specifications of buildings that would have been built or equipment installed, without the influence of the program, at the specific site of each construction project. This might be evaluated by standard practice evaluation or building plans and specifications that were prepared prior to the program being launched.
- Existing building codes and/or equipment standards; and
- Performance of equipment, buildings, etc., in a comparison group of similar program non-participants.

Because custom projects or measures are usually site-specific, site visits are generally required to collect appropriate information to analyze savings. This includes collecting information on the quantity, sizing, servicing, and scheduling for HVAC, lighting, refrigeration, motors, process, and other equipment. Information may also be collected on the capabilities of control systems (e.g., whether centralized or distributed, capabilities for control monitoring, automation possibilities, and expansion possibilities).

2.3.5 IMPACT PROTOCOL 3.2: IMPACT EVALUATION OF NON-PRESCRIPTIVE MEASURES WHOSE SAVINGS MAY BE TREATED AS PRESCRIPTIVE

Energy Smart programs may include non-prescriptive measures that are not 100% custom measures. Savings for these measures are not deemed. However, savings can be assessed using savings calculation algorithms with stipulated and “open variables”. Examples of open variables include the following:

- Capacity of an AC unit
- Change in connected load
- Square footage of insulation
- Hours of operation of a facility or of a specific electric end-use
- Horsepower of a fan or pump motor

Essentially, the savings calculation algorithms can be considered deemed, but the algorithms require customer-specific input for open variables to calculate the energy and demand savings. With customer-specific information used for open variables, savings values for the same measure can differ across customers.

Information on open variables can be collected from program participants or through site visits. For some open variables, a default value may have to be used when data for the open variable cannot be collected. For example, an average value can be provided that can be considered the default value for input to the algorithm and that can be used when customer-specific information is not available.

Some issues that should be considered in evaluating savings for non-prescriptive measures include the following.

- Algorithms and definitions of terms should be reviewed to verify that accepted industry standards are being used to reasonably estimate savings. This review should be used to ensure that the deemed methodologies for calculating savings are clearly defined and can be implemented practically and effectively.
- High-impact measures should be identified for review and clarifications or modifications.
- Low-impact measures with unrealistic and inaccurate savings values should be reviewed. This review can be done periodically to adjust the level of EM&V rigor based on market adoption.
- For nonresidential measures, consider establishing energy impact thresholds by measure type in the TRM, above which customer-specific data collection is required for open variables. The intent of this is to reduce the overall uncertainty of portfolio savings estimates by increasing the accuracy of project-level savings estimates for extremely high-impact measure installations.
- When to use default values for open variables in the *ex ante* and/or *ex post* savings calculations should be determined considering the savings impact and the uncertainty associated with the measure. Default values for open variables can be used if customer-specific or program-specific information is unreliable or cannot be easily obtained. The default values are appropriate for low-impact and low-uncertainty measures (e.g., lighting retrofits in a small business facility). In contrast, customer-specific values are appropriate for high-impact and high-uncertainty measures, (e.g., HVAC or lighting retrofits in universities or hospitals that have diverse facilities) and where those types of projects represent a significant share of program savings for a year.
- For key open variables where default values are provided that are based on evaluations completed in other jurisdictions or taken from industry or other associations, the literature supporting use of the default values should be reviewed and assessed. This may include reviewing the population from which source data were used for deriving the default values and providing recommendations as to what populations or technologies the derived default values can be applied.

Because customer-specific data for open variables are collected and used to estimate savings, there will be a variety of savings values for the same measure. Customer-specific or program-specific data for the *ex ante* and/or *ex post* savings calculations should be used for as many open variables as possible to improve the accuracy of estimated savings. Site-specific data or information should be used for measures with important variations in one or more input values (e.g., delta watts, efficiency level, equipment capacity, operating hours). Customer-specific data can come directly from measure application forms, be collected during the application process, or collected through site visits.

To guide the customer-specific data collection, measures can be grouped into various end-use categories (e.g., lighting, HVAC, motors & VFDs) and kWh savings thresholds established for each end-use category level that can be used to determine whether customer-specific information should be used for estimating *ex ante* and/or *ex post* savings. If a project involves multiple measures or types of technology that fall under the same end-use category, the savings for all those measures/technology types should be grouped together to determine if the project falls below or above a particular threshold.

2.3.6 IMPACT PROTOCOL 3.3: IMPACT EVALUATION OF INFORMATION-BASED PROGRAMS

Through the Energy Scorecard program, ENO provides information to customers that they can use to adjust their use of electricity. The protocol provided here is intended to give guidance on evaluating the impacts of this and other information-based programs that might be used to provide information to customers.

There are several evaluation approaches that can be used to determine the savings impacts of an information-based program that provides customers with information that they can use to voluntarily take actions to adjust their energy. The approaches differ in their ability to produce accurate and robust results and are therefore discussed in descending order of desirability. Because of differences in performance, Option 1 is the preferred approach. Option 2 should be used only when Option 1 is infeasible. Option 3 should only be used when both Option 1 and Option 2 are infeasible.

If available, interval meter data should be used to estimate load impacts. Where advanced metering infrastructure (AMI) data is not available for all participants, estimates based on a sample of metered homes may be used.

The three options for estimation of impacts from information-based programs are as follows.

- Option 1 uses an analysis based on an experimental design that makes appropriate use of random assignment so that the reference load is estimated using a representative control group of program participants. The most common type of design satisfying this criterion is a randomized control trial (RCT), but other designs may also be used. An evaluation contractor can select a specific design, based on their professional experience.
- Option 2 uses a comparison group analysis where the loads of a group of non-participating customers that are similar to participating homes with respect to observable characteristics (e.g. electricity consumption) are used to estimate the reference load. Because there is a variety of matching techniques that are available, an evaluation contractor can choose the technique used to select the comparison group based on their professional judgment. Difference-in-differences estimators should be used in the analysis to control for any differences that may remain after matching.
- Option 3 is a 'within-subjects' analysis where the reference energy use of participating customers is estimated using data on their energy use during a period before their participation in the information-based program began.

The analysis for all three options can be accomplished through regression analysis that relates energy use to weather conditions (particularly temperature) and other variables that influence usage. Panel regression modeling is the recommended technique.

2.3.7 IMPACT PROTOCOL 4.0: NET-TO-GROSS ANALYSIS

NTG analysis is directed at quantifying those savings attributable to a program. This protocol presents general definitions and methods that can be employed as part of a sound NTG analysis.

There are five approaches commonly used for determining NTG.

- Self-Reporting Surveys: From participants and non-participants without independent verification;

- Enhanced Self-Reporting Surveys: Self-reporting surveys are combined with interviews and independent documentation review and analysis. They may also include analysis of market-based sales data;
- Econometric Methods: Statistical models are used to compare participant and non-participant energy and demand patterns. These models often include survey inputs and other non-program-related factors such as weather and energy costs (rates);
- Deemed: NTG is estimated using information available from evaluation of similar programs; and
- Stipulated: The stipulation of NTG may be used when the expense and uncertainty of the results are considered significant barriers (NAPEE, 2007). Use of stipulated values is not recommended if they yield results that are uncertain and/or costly; instead, the Protocol will support the usage of literature reviews.

These approaches for assessing the energy savings attributable to a program are based on determining NTGRs that have two main components: free ridership and spillover.

- Free ridership refers to program participants who received an incentive but would have installed the same efficiency measure on their own had the program not been offered. This includes partial free riders, defined as customers who, at some point, would have installed the measure anyway, but the program persuaded them to install it sooner or customers who would have installed the measure anyway, but the program persuaded them to install more efficient equipment and/or more equipment. For the purposes of EM&V activities, participants who would have installed the equipment within one year will be considered full free riders; participants who would have installed the equipment later than one year will not be considered to be free riders (thus no partial free riders will be allowed).
  Free ridership is the share of gross program savings that is generally the savings accounted for in program records and then adjusted for the naturally occurring adoption; the free ridership rate is based on actions participants “would have taken anyway” (i.e., actions that were not induced by the program). Each energy efficiency program covers a range of energy efficiency measures and is designed to move the overall market for energy efficiency forward. However, it is likely that some participants would have wanted to install some high efficiency measures (possibly a subset of those installed under the program) even if they had not participated in the program or been influenced by the program in any way.
- Spillover refers to energy savings that are due to the influence of a program but are not counted in program records. For example, a customer installs a set of efficiency measures in one of his/her buildings. These measures were promoted (and incented) under a DSM program. The customer then decides to install the same measures at another site, where there is no program incentive. In this case, the program had an influence on the market beyond the energy savings in this customer’s first building. Spillover can be broken out in three categories:
  - *Participant Internal Spillover* represents energy savings from additional measures implemented by participants at participating sites not included in the program but directly attributable to the influence of the program.
  - *Participant External Spillover* represents energy savings from measures taken by participants at non-participating sites not included in the program but directly attributable to the influence of the program.
  - *Non-Participant Spillover* represents energy savings from measures that were taken by non-participating customers but are directly attributable to the influence of the program.

Spillover adds to a program's measured savings by incorporating indirect (i.e., not incented) savings and effects that the program has had on the market above and beyond the directly incented or directly induced program measures.

Total spillover is a combination of several factors that may influence non-reported actions to be taken at the project site itself (inside spillover) or at other sites by the participating customer (outside spillover). Each type of spillover is meant to capture a different aspect of the energy savings caused by the program, but not included in program records. Because a primary goal of most DSM programs is to transform markets through a variety of strategies – including education, promotion, and increasing awareness of the benefits of energy efficiency – one would expect spillover to occur to some extent in the market.

The overall NTG is meant to account for both the net savings at participating projects and spillover savings that result from the program (but are not included in program records). When the gross program savings multiplies the NTG ratio, the result is an estimate of energy savings that are attributable to the program (i.e., savings that would not have occurred without the program). The basic equation is:

$$NTG = 1 - \text{Free ridership} + \text{Spillover}$$

The underlying concept inherent in the application of the NTG formula is that only savings caused by the program should be included in the final net program savings estimate, but this estimate should include all savings caused by the program (i.e., the net program savings should account for free ridership and include spillover).

2.3.7.1 Estimating Free Ridership: Survey Techniques

Data to assess free ridership should be gathered through a series of survey questions asked of end-use customers and trade allies who participated in the program. Free ridership can be evaluated by asking direct questions, aimed at obtaining respondent estimates of the appropriate free ridership rate that should be applied to them, and by supporting, or influencing questions used to verify whether the direct responses are consistent with participants' views of the program's influence.

The direct free ridership questions ask respondents to estimate the share of measures that would have been incorporated at high efficiency if not for the technical and financial assistance of the program. The questions also ask respondents to estimate the likelihood that they would have incorporated measures "of the same high level of efficiency" if not for the technical and financial assistance of the program. This flexibility in how respondents conceptualize and convey their views on free ridership will allow respondents to provide their most informed response, thus improving the accuracy of the free-ridership estimates.

The "program influence" questions clarify the role that program interventions (e.g., financial incentives and technical assistance) played in decision-making and provide supporting information on free ridership. Responses to these questions are analyzed for each respondent and used to identify whether the direct responses on free ridership are consistent with how each respondent rated the "influence" of the program.

These results will then be compared to free ridership estimates based on on-site inspections/audits, and/or estimates derived from similar surveys completed in other jurisdictions.

2.3.7.2 Estimating Spillover: Survey Techniques

The basic method for assessing participant (inside and outside) spillover employs a three-step approach to determine the following:

1. Whether spillover exists at all. These are yes/no questions that ask, for example, whether the respondent incorporated energy efficiency measures or designs that were not recorded in program records. Questions relate to extra measures installed at the project site (inside spillover) and to measures installed in non-program projects (outside spillover).
2. Extent of the spillover. These questions request information about the number or share of projects/jobs/facilities into which additional measures or technologies are installed (these questions are not asked for inside spillover because the value is simply the one project on which the interviewee focuses).
3. Amount of savings per spillover project. These questions ask respondents to estimate the energy savings associated with the non-recorded measures relative to the savings from the participating project itself.

The outcome of these inquiries is an estimate of the share of those non-recorded savings that can be attributed to the influence of the program.

2.3.7.3 Timing of Data Collection for Free Ridership vs. Spillover

Where possible, a staggered data collection approach should be used to collect information in support of NTG analysis. The rationale for this approach is that free ridership and spillover data are best collected at different points in time.

Free ridership data are most accurate when collected as closely as possible to the point in time when the participation decision is made. Doing so helps to ensure accurate participant recall of motivating factors and relative program influence while also producing other benefits, including near-term feedback for program staff regarding program influence effects.

Conversely, spillover data are considered most accurate when collected sometime after the participating project has been completed. Allowing a reasonable amount of time to pass before asking participants about spillover effects ensures that participants have sufficient time to: a) install the incented equipment, b) experience its operating parameters and costs, and c) then decide whether to install additional energy efficiency measures at the project site or some other location independent of any program support or financial incentive (Johnson et al., 2010).

2.3.7.4 Hierarchical Approaches for Determining When to Update NTG Values

A decision tree with several steps can be used to determine the timing for updating attribution analysis. The framework for updating net savings follows the hierarchical approach presented visually in Figure 2-2 Each step in the decision is discussed in the following paragraphs.

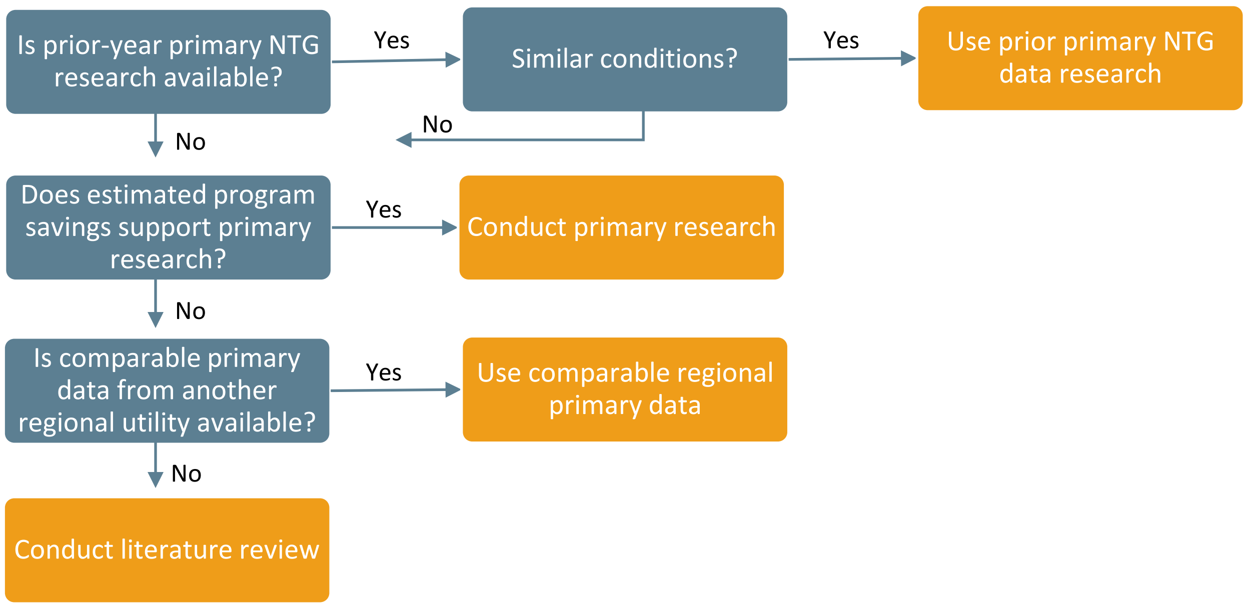


Figure 2-2 Decision Tree for Timing and Selection of NTG Research

Has NTG research been conducted on the same program in a prior year? The first step to determining whether primary NTG research should be conducted in a given program year is to assess whether primary data collected for the same program are available from a prior year. If prior data are available, it should be determined whether the prior values are applicable in the current year. There are at least two overarching components of this decision.

- First, determine if the current program is similar to the program in which the primary data was collected: Is the mix of measures the same? Is the contribution to savings for each measure similar? Are the incentive levels comparable? Is (are) the delivery method(s) similar?
- Second, determine if the market conditions are similar to the time period in which the prior data were collected: Has there been a substantial change in incremental cost for the efficient measures? Has there been a substantial change in the supply or availability of the efficient measures? Has there been a substantial change in the market share of efficient measures (i.e., the ratio of efficient measures sold to total comparable standard and efficiency measures)? Are the local or federal codes and standards the same as when the prior NTG values were estimated?

If the program and market conditions are comparable to the time period(s) in which the prior primary NTG research was conducted, these prior values can be considered applicable to the current program year.

- If prior year primary data are not available or are determined not to be applicable due to changes to either program or market conditions. The TPE should then determine whether estimated savings from the program support primary research. In general, programs that represent at least 5-10 percent of the portfolio estimated savings in any given year should use NTG ratios that are estimated via primary data research for that specific program.
- If prior year data for the program are not available or applicable, and the program savings does not support primary data collection. The evaluation should then consider if NTG values derived from Arkansas-

based comparable programs are available. A comparable program is defined as one that is similar in terms of program maturity, incentive levels, delivery mechanism, and measure types. Ideally, NTG values derived in the same program year would be used, but values from prior years may also be used if the comparability conditions are met.

- For existing and new programs that do not meet any of the above specifications. A literature review may be undertaken to locate a similar program (or programs) that has (or have) an established NTG value(s). This approach requires that the research be well documented. A program may be identified as similar if it meets the following conditions:
- Program similarity: maturity, incentive levels, delivery mechanism, and measure types are similar; and
- Market similarity: demographic, household, and business characteristics are similar (or as similar as possible) to those for New Orleans.

With this hierarchical approach, evaluation resources can be directed towards programs that could benefit most from primary research, thus avoiding unnecessarily repeating NTG research every year for the same programs. However, to prevent NTG values from being repeated too many years and becoming potentially “stale”, NTG values for programs that meet the contribution to savings threshold should be updated at least via primary research at least once during every three-year program cycle.

The steps along this decision tree should be clearly presented and discussed as part of program evaluation plans.

Evaluations using trade ally responses should be collected for programs where the trade allies play a key role in the installation decision. The evaluation work plan should present a discussion of the representation from the trade ally respondents. If use of information supplied by trade allies is applicable, evaluation plans should include details regarding how trade ally responses will be integrated with customer survey responses to determine overall program attribution.

EM&V reports should include robust reporting related to NTG research, methods, and findings. To ensure consistency and transparency, the report should include the following information regarding NTG analyses.

- Summary of each programs NTG source. For example, a table could show which programs received updated NTG research versus those where NTG analysis used previous values, deemed values, or secondary research.
- Discussion of rationale for use of previous estimate or literature review. EM&V reports should cite evidence that the delivery, incentives, measures, and program design were unchanged.
- If unique NTG values are assigned to distinct program components, then each component should be reported with gross and net savings contributions. Where different program components (e.g., measures) have different NTG values, savings for each program component should be presented along with the respective NTG values.

It is recommended that an appendix be included in the report that details NTG approach and methods. This appendix should include the following:

- High-level discussion of approach and methods. A methods section should detail the overarching NTG approach across programs, especially if the same algorithms and logic are used across multiple programs.

- Detailed discussion of logic (including questions, full battery of survey question). Complete survey battery logic, flow-charts, and comprehensive details of the program NTG approach should be included in the appendix.
- Discussion of program-specific logic in each section. If individual program NTG research includes customized logic that is distinct from the overall approach included in the methods section, then the differences in approach should be reported within each individual program section.

2.4 Protocols for Process Evaluations

This protocol provides guidance regarding scope and timing for process evaluation of a programs. A process evaluation involves examining the process of implementing a program and determining whether the program is operating as planned. The goal of a process evaluation is to recommend ways to improve processes to increase a program's effectiveness. A process evaluation focus on determining the overall effectiveness of program delivery, identifying opportunities for program improvements, and assessing key program metrics, including participation rates, market barriers, and overall program operations.

2.4.1 PROCESS PROTOCOL 1.0: PROCESS EVALUATION DETERMINATION

Two major criteria can be applied to determine if a process evaluation of a program is needed.

- The first criterion is to determine if it is time for a process evaluation;
- The second criterion is to determine if there is a need for a process evaluation.

Table 2-5 addresses the first criterion, setting out conditions for determining what timing is appropriate for conducting a process evaluation.

Table 2-5 Determining Appropriate Timing to Conduct a Process Evaluation

1. No Previous Process Evaluation: If a program has not had a comprehensive process evaluation, conducting a process evaluation should be considered.
2.New and Innovative Components: If a program has new or innovative components that have not been evaluated previously, then a process evaluation should be considered for assessing their level of success in the current program and their applicability for use in other programs.
3. New Vendor or Contractor: If a program is a continuing or ongoing program but is now being implemented, in whole or in part, by a different vendor than in the previous program cycle, then a process evaluation should be considered to determine if the new vendor is effectively implementing the program.
If any of these criteria are met, it is time to conduct a process evaluation.
If none of these criteria are met, proceed to Table 2-6 (Step 2) in the Process Evaluation Decision Map.

Figure 2-3 provides a flow chart for determining whether it is time to perform a process evaluation of a program.

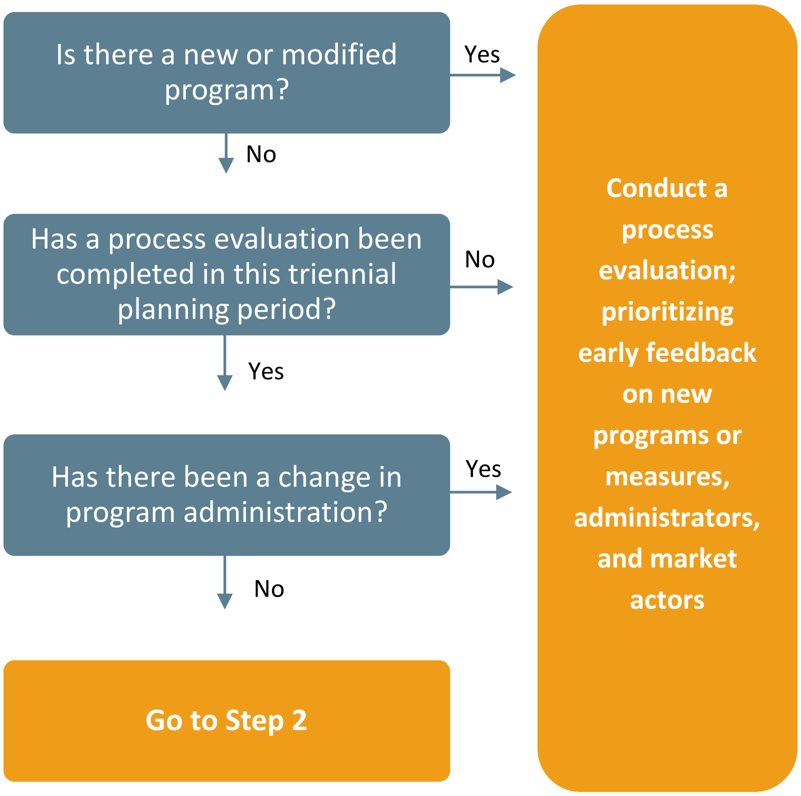


Figure 2-3 Determining Timing for a Process Evaluation

Process evaluations may be used to diagnose areas where a program is not performing as expected. Conditions to consider are outlined in the table below.

Table 2-6 Determining Appropriate Conditions to Conduct a Process Evaluation

Conditions appropriate to conducting a process evaluation may include the following:
1. Impact Problems: Are program impacts lower or slower than expected?
2. Informational/Educational Objectives: Are the educational or informational goals not meeting program goals?
3. Participation Barriers: Are the participation rates lower or slower than expected?
4. Operational Challenges: Are the program's operational or management structure slow to get up and running or not meeting program administrative needs?
5. Cost-Effectiveness: Is the program's cost-effectiveness less than expected?
6. Negative Feedback: Do participants report problems with the program or low rates of satisfaction?
7. Market Effects: Is the program producing the intended market effects?
If any of the criteria is met, a process evaluation is needed to identify ways to address and correct these operational issues.
If none of these criteria is met in either Step 1 or Step 2, then a process evaluation is not needed at this time.
Re-evaluate the need for a process evaluation at the end of the program year.

Figure 2-4 defines the method to identifying problems in program administration that may warrant a process evaluation.

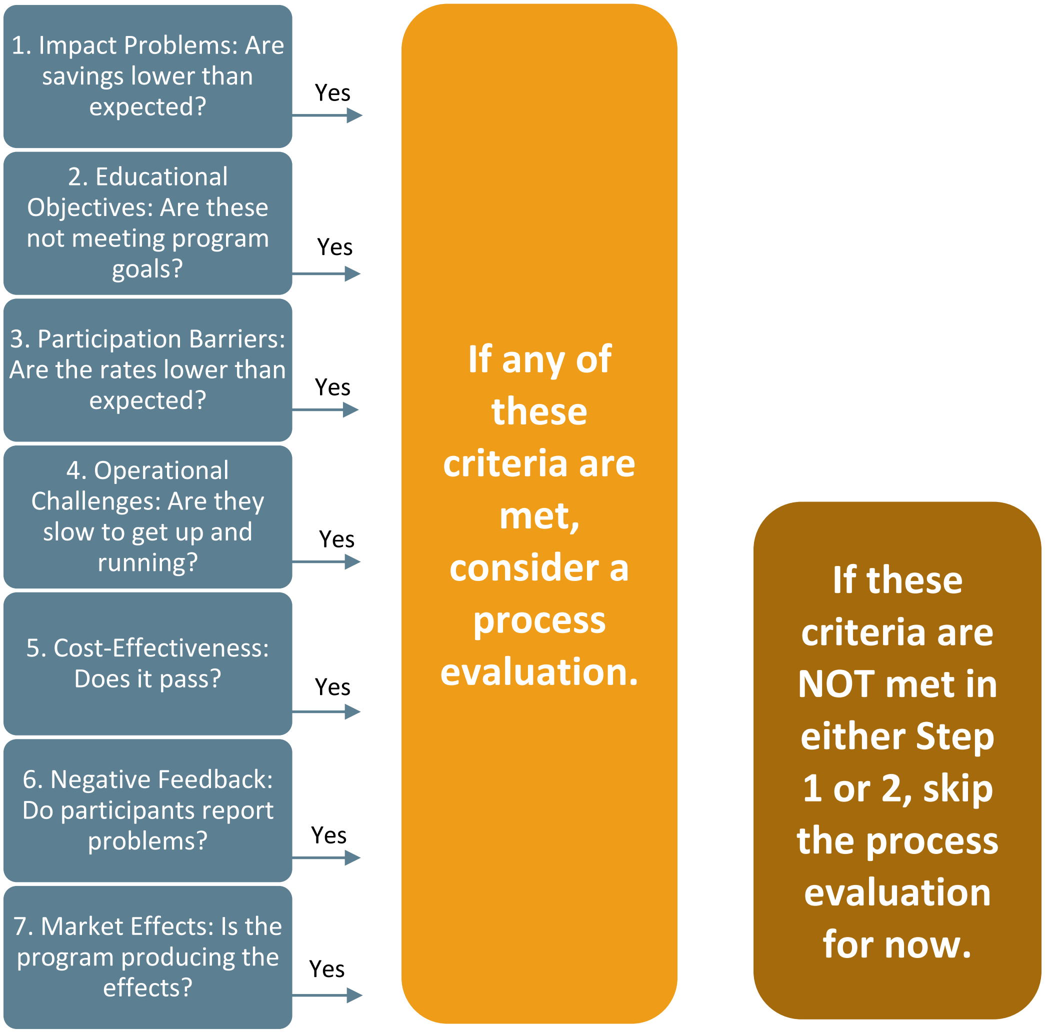


Figure 2-4 Determining Need to Conduct a Process Evaluation

Throughout an evaluation cycle, limited or focused process evaluation activities (e.g., review of program database, interviews of staff) may be used to determine interim progress for a program. Findings from focused process evaluation activities serve several purposes.

- Provide a progress report for each recommendation for program improvement made in previously conducted evaluations. For each evaluation recommendation, the report should indicate whether the recommendation has been accepted and implemented, rejected, or is still under consideration. If the recommendation is rejected, an explanation of the reason for rejection should be provided. If a recommendation is still under consideration, then an explanation should be provided for the steps underway to reach an implementation decision for that recommendation, which should include:
- Identify progress made towards achieving program objectives; and
- Identify any issues that may need to be explored more fully in future program evaluations.

2.4.2 PROCESS PROTOCOL 2.0: PLANNING PROCESS EVALUATION

This protocol provides guidance on the key issues that should be addressed in planning process evaluation activities. Aspects of program operations to address any deficiencies identified in Figure 2-4.

Three tables are provided that outline the key researchable issues that should be addressed in a process evaluation.

- Table 2-7 provides a general outline of the key elements that should be included in a process evaluation plan.
- Table 2-8 provides more detailed information regarding the key areas for investigation that need to be addressed in a process evaluation.
- Table 2-9 identifies those topic areas that should be covered in all process evaluations, those areas that should be investigated when the program is experiencing specific operational issues or challenges, and those areas that are most applicable to new programs or pilot programs.

Table 2-7 Recommended Elements of a Process Evaluation Plan[4]

Element	Description
Introduction	Description of the program or portfolio under investigation; specific characteristics of the energy organization providing the program including current marketing, educational or outreach activities and delivery channels
Process Evaluation Methodology	Process evaluation objectives, researchable issues, and a description of how specific evaluation tactics will address the key researchable issues including the proposed sampling methodology for program/third-party staff, key stakeholders, trade allies/vendors, and customers. The sampling methodology should be clearly explained with specific targets of completed surveys or interviews clearly described in the EM&V Plan.
Timeline	Summarized by key tasks identifying the length of the process evaluation and key dates for completion of major milestones
Budget	Costs of conducting the process evaluation by specific tasks and deliverables

[4] California Evaluation Protocols, 2006

Table 2-8 Recommended Areas of Investigation in a Process Evaluation

Program Design ▪ Program mission, vision and goal setting and goal setting process ▪ Assessment or development of program and market operations theories ▪ Program design and design characteristics, and program design process ▪ Use of new or best practices	**Additional Guidance** ▪ This area is especially important to address in first-year evaluations and evaluations of pilot programs.
Program Administration ▪ Program management process ▪ Program staffing allocation and requirements ▪ Management and staff skill and training needs ▪ Program tracking information and information support systems ▪ Reporting and relationship between effective tracking and management, including operational and financial management	**Additional Guidance** ▪ This area should be covered in all process evaluations, but it is especially important to address in those evaluations where operational or administrative deficiencies exist.
Program Implementation and Delivery ▪ Description and assessment of program implementation and delivery process ▪ Program marketing, outreaching, and targeting activities ▪ Quality control methods or operational issues ▪ Program management and management's operational practices ▪ Program delivery systems, components, and implementation practices ▪ Program targeting, marketing and outreach efforts ▪ Program goal attainment and goal-associated implementation processes and results ▪ Program timing, timelines, and time-sensitive accomplishments	**Additional Guidance** ▪ This is critical to gathering the information necessary to assess the program's operational flow. ▪ These are areas that should be addressed if program is not meeting its participation goals or if the program is under-performing. ▪ All marketing and outreach materials should be reviewed and assessed as part of document review task. ▪ These areas should be addressed in all process evaluations but are especially important if the program is under- performing regarding savings or participation rates.

Table 2-9 Recommended Areas of Investigation in a Process Evaluation

Areas of Investigation	Additional Guidance
▪ Documentation of program tracking methods and reporting formats	▪ This is a key element of the review of the program database and the TPE should request copies of the program records or extracts along with the data dictionary.
▪ Customer interaction and satisfaction (both overall satisfaction and satisfaction with key program components, including satisfaction with key customer- product-provider relationships and support services) ▪ Customer or participant's energy efficiency or load reduction needs and ability of program to deliver on those needs ▪ Market allies' interaction and satisfaction with program ▪ Reasons for low level of market effects and spillover ▪ Intended or unanticipated market effects	▪ These topics should be investigated in customer surveys and should be a priority if the program is experiencing negative feedback or lower-than-expected participation rates or energy savings.

2.4.3 PROCESS PROTOCOL 3.0: PROCESS EVALUATION REPORT AND RECOMMENDATIONS

The suggested reporting requirements for a process evaluation report are given in Table 2-10..

Table 2-10 Suggested Reporting Requirements for Process Evaluation Report[5]

Suggested Reporting Requirement	Description
1. Detailed Program Description	Process evaluation report should present a detailed operational description of the program that focuses on program components being evaluated. The use of a program flow model is highly recommended. Report should provide sufficient detail so that a reader can understand program operations and likely results of recommended program changes.
2. Program Theory	Process evaluation report should include a presentation of the program theory. If the program theory is not available or cannot be provided in time for the evaluation report due date, a summary program theory built from the evaluation team's program knowledge may be included instead. However, it should be complete enough for a reader to understand the context for program recommendations. It does not need to be a finely detailed program theory or logic model.
3. Support for Recommended Program Changes	All recommendations need to be adequately supported. Each recommendation should be included in the Executive Summary and then presented in the Findings text along with the analysis conducted and the theoretical basis for making the recommendation. The Findings section should also include a description of how the recommendation is expected to help the program, including the expected effect that implementing the change will have on the operations of the program.
4. Detailed Presentation of Findings	A detailed presentation of the findings from the study is essential. The presentation should convey the conditions of the program being evaluated and should provide enough detail so that any reader can understand the findings and the implications of the overall operations of the program and its cost-effectiveness

Table 2-11 provides guidance on structuring recommendations from a process evaluation.

[5] CA Evaluation Protocols, 2006

Table 2-11 Suggested Structuring of Recommendations from Process Evaluation[6]

Requirements for Recommendations from a Process Evaluation
▪ Realistic, appropriate to Entergy New Orleans' structure, constructive, and achievable using available resources ▪ Linked to specific conclusions ▪ Adequately supported. Each recommendation should be included in the Executive Summary of the report and then presented in the findings text along with analysis conducted and theoretical basis for making recommendation. Findings section should include a description of how recommendation is expected to help the program, including the expected effect implementing the change will have on the operations of the program. ▪ Focused on ways to increase overall program effectiveness and be linked to researchable issues addressed in process evaluation (e.g., ways to improve program design, approach, operations, marketing, or address issues related to program under-performance) ▪ Providing specific steps / tasks for implementation (to extent possible) ▪ Compared across program evaluations to identify areas for portfolio-level improvements

[6] CA Evaluation Protocols, 2006

2.5 Protocols for Evaluation of New Construction Projects

2.5.1 DESCRIPTION

This protocol is intended to describe the recommended method when evaluating the whole building performance of new construction projects in the commercial sector. The protocol focuses on energy conservation measures (ECMs) or packages of measures where evaluators can analyze impacts using building simulation. These ECMs typically require the use of calibrated building simulations under Option D of the International Performance Measurement and Verification Protocol (IPMVP).[7]

Examples of such measures include Leadership in Energy & Environmental Design (LEED) building certification, novel and/or efficient heating, ventilation, and air conditioning (HVAC) system designs, and extensive building controls systems. In general, it is best to evaluate any ECM expected to significantly interact with other systems within the building and with savings sensitive to seasonal variations in weather.[8] The protocol classifies commercial new construction projects as:

- Newly constructed buildings: The design and construction of an entirely new structure on a greenfield site or wholesale replacement of a structure torn down to the ground.
- Addition (expansion) to existing buildings: Significant extensions to an existing structure that requires building permits and triggers compliance with current codes.
- Major renovations or tenant improvements of existing buildings: Significant reconstruction or “gut rehab” of an existing structure that requires building permits and triggers compliance with current codes.

Evaluators may need to apply the evaluation methods described here for new construction projects for some projects in the retrofit programs. While some retrofit projects have much in common with new construction projects, their scope does not uniformly fall under the new construction categories previously described. Evaluators should assess these projects according to the guidelines described for retrofit equipment (described in separate protocols).

EM&V of new construction programs involves unique challenges, particularly when defining baseline energy performance. An agreed-upon building energy code or industry standard defines the baseline equipment evaluators use to measure energy impacts for new construction measures. As the baseline equipment for new construction measures does not physically exist and cannot be measured or monitored, evaluators typically employ a simulation approach. Due to the nuances involved in appropriately determining baseline equipment/performance evaluations, experienced professionals with a good understanding of building construction practices, simulation code limitations, and the relevant building codes should oversee these types of projects.

Further, evaluators typically assess new construction measures within the first few years of construction. During this period, there is often considerable change in building occupancy and operation before the measures design

[7] As discussed in the section “Considering Resource Constraints” of the Introduction chapter to this report, small utilities (as defined under U.S. Small Business Administration regulations) may face additional constraints in undertaking this protocol. Therefore, alternative methodologies should be considered for such utilities.

[8] Note the term whole-building modeling does not necessitate use of sophisticated stand-alone simulation software (e.g., eQuest, EnergyPlus). It is acceptable to employ engineering models using spreadsheet calculations, provided they meet the guidelines set forth in Section 4

intent becomes realized. This results in additional challenges for evaluators using monitored data and/or facility utility billing or energy consumption history to define as-built building performance.

2.5.2 APPLICATION CONDITIONS OF PROTOCOL

Use the algorithms and protocols described here to evaluate new construction whole-building performance ECM installed in commercial facilities. When new construction ECM do not directly impact HVAC energy use, it is often possible to use spot measurements and engineering calculations to evaluate savings with sufficient rigor (ASHRAE, 2002). This is usually the case, for example, with lighting and domestic hot water retrofits.[9] This protocol does not cover the guidelines for selecting the appropriate M&V rigor for such measures. Consult the IPMVP or measure-specific protocols within the Uniform Methods Project protocols to review evaluation guidelines for measures that do not require calibrated building simulation.

2.5.2.1 Incentive Types

Program administrators typically classify new construction program incentives as being either component-based or performance-based and design the program to offer one or both types of incentives.

2.5.2.1.1 Component-Based Incentives

Component-based (or “prescriptive”) incentives tend to involve individual technologies and equipment. Examples of prescriptive incentives may include lighting fixtures, occupancy sensors, motors, and small packaged (unitary) HVAC units. Evaluators often determine rebate amounts and claimed savings estimates based on stipulated per-unit estimates.[10] Evaluators will sometimes assess component-based rebates according to measure-specific protocols using partial or complete retrofit isolation evaluation strategies (IPMVP Option A or Option B).

2.5.2.1.2 Performance-Based Incentives

Performance-based incentives tend to target more complex projects involving improvements to the overall building energy performance. Whole-building performance incentives can:

- Encompass various specific (above-code) upgrades
- Fund design, analysis, equipment, and/or installation (labor) costs.[11]

An example of a performance-based project is LEED certification. Buildings that are LEED certified often encompass ECM that range from envelope improvements to high-efficiency equipment installations (often going beyond just HVAC) and complicated controls algorithms.

The complex interactions between these ECM can only be reliably determined through the use of calibrated building simulation models.

---

[9] While the general magnitude of the secondary impacts imparted by lighting measures on HVAC equipment are well-established for various building types, take care to estimate these impacts appropriately in new construction building stock. New buildings typically have more efficient HVAC equipment, which reduces the magnitude of heating and cooling interactive effects. Secondary impacts can be estimated using prototypical building models, representative of the physical facility. See the Uniform Method Project’s Chapter 2: Commercial and Industrial Lighting Evaluation Protocol or CPUC 2004 for guidelines regarding HVAC interactive factors.

[10] Units used do not necessarily represent quantity. Frequently applied units include installed horsepower, tons of refrigeration, and square footage.

[11] Some new construction programs have been successfully implemented without direct financial incentives (e.g., design assistance, financing, etc.).

Performance-based incentive amounts are typically determined by the expected annual energy and/or demand impacts (e.g., per kilowatt-hour, therm, kilowatt).12 Annual energy-savings estimates for performance-based projects (and programs) require evaluators to use custom calculations via whole-building simulation modeling tools. Therefore, highly skilled technical labor is required to successfully implement and evaluate these programs.[13]

2.5.3 SAVINGS CALCULATIONS

Use the following algorithm to calculate energy savings for new construction measures. Note that evaluators can calculate demand savings using the same algorithms by simply substituting "demand" for "energy use"[14].

$$Energy\ Savings = Projected\ Baseline\ Energy\ Use - Post\ Construction\ Energy\ Use$$

Where:

$Projected\ Baseline\ Energy\ Use =$ Projected energy use of baseline system at full designed occupancy and typical building operating conditions.

$Post\ Construction\ Energy\ Use =$ Energy use of measure systems at full design occupancy and typical building operating conditions.

As described in Section 4, Measurement and Verification Plan, calculate projected baseline energy use and post-construction energy use using a whole-building simulation model that is calibrated to monthly (or hourly) utility energy consumption histories. Evaluators can use four components to report savings for the new construction ECM:

- Expected (planned) measure savings
- Rebated measure savings
- Non-rebated measure savings
- Total achieved savings

Section 4 discusses each component.

2.5.4 MEASUREMENT AND VERIFICATION PLAN

2.5.4.1 IPMVP Option

The preferred approach to calculate savings for whole-building performance new construction projects is calibrated building simulation models according to IPMVP Option D (IPMVP, 2006). The recommended approach requires sufficient resources be allocated to the project to allow for detailed onsite data collection, preparation of the simulation models, and careful calibration. The method is less costly when a functioning ex-ante model is available to the evaluator, though obtaining the ex-ante model is not a prerequisite to its application.

Determine the appropriate modeling software by the specifics of the evaluated buildings (e.g., HVAC system and zoning complexity, building constructions, complexity of the ECM); there is no single software (currently

---

[12] Depending on program design, the "expected" energy impacts can be either *ex ante* or *ex post*.

[13] Johnson & Nadel, 2000

[14] When calculating the coincident peak demand savings, average the hourly demand savings over the "peak demand window" period, as defined by the utility.

available) that can simulate all variations of HVAC system type, building construction, and ECM. Thus, it may be necessary to use multiple tools to evaluate building performance accurately.

In general, the appropriate software for modeling building systems and energy performance must[15]:

- Create outputs that comply with American National Standards Institute (ANSI)/ASHRAE Standard 140-2011[16]
- Accurately simulate the building's systems and controls
- Use an hourly or sub-hourly time step to perform simulation[17]
- Simulate building performance using user-defined weather data at hourly intervals

The DOE Energy Efficiency and Renewable Energy website[18] contains a list of building energy simulation software. Although some tools listed are proprietary, the website also lists public-domain DOE-sponsored tools. Summary comparisons and descriptions of commonly used software can be found in Crawley, 2005.

The preferred full Option D approach will in some cases be intractable due to limited data availability or evaluation budgetary limitations. In such cases, alternate methodologies are acceptable, but the following guidelines should be followed:

- Onsite verification and review of as-built drawings and commissioning reports (as available) should be performed to verify which energy saving features were installed and are functioning
- *Ex ante* savings calculations should be based in a whole building simulation model of the building or of a building that is representative of the actual facility
- Results should be compared with billing data (when available), engineering rules of thumb, and/or secondary literature to review reasonability

2.5.4.1.1 Verification Process

Figure 2-1 depicts the overall process to verify savings under Option D, from the California Evaluation Framework (CPUC, 2004). The process starts by specifying which site data collection and equipment monitoring requirements are in an M&V plan. Additionally, the M&V plan should specify:

- The applicable version of the building codes and equipment standards that determine the baseline (or applicable 'practice' that may determine baseline); discussed in 2.5.4.3 *Baseline Considerations*
- The above-code technologies present in the building (claimed as ECMs)
- The software for modeling building performance
- Appropriate data for calibrating the simulations
- How to address modeling uncertainties
- Against what statistical indices calibration will be measured.

[15] For more information on specific requirements for simulation software, see pp. 133 in The California Evaluation Framework (CPUC, 2004) and pp. 26-27 in Appendix J – Quality Assurance for Statistical, Engineering, and Self-Report for Estimating DSM Program Impacts (CADMAC, 1998).

[16] ANSI/ASHRAE Standard 140-2011 establishes test procedures validating software used to evaluate thermal performance of buildings (and applicable HVAC equipment).

[17] It is preferable the software use unique time steps for each interval (e.g., 8,760 hours).

[18] This website can be found here: https://www.energy.gov/eere/office-energy-efficiency-renewable-energy

While reviewing the energy consumption data can be useful in developing data collection needs, it is not a prerequisite to creating and implementing the M&V plan. However, when developing the M&V plan, evaluators should consider how long a building has been occupied because that will determine amount and granularity of energy consumption data available. Fewer months of consumption data, or the availability of only monthly data, usually means there will be a greater emphasis on metering specific pieces of equipment. Conversely, the presence of a building automation system, energy monitoring system, lighting control panels, (collectively referred to here as building automation system) or other devices to control and/or store data about the operational characteristics of the building will allow for a lesser dependence upon utility usage data.

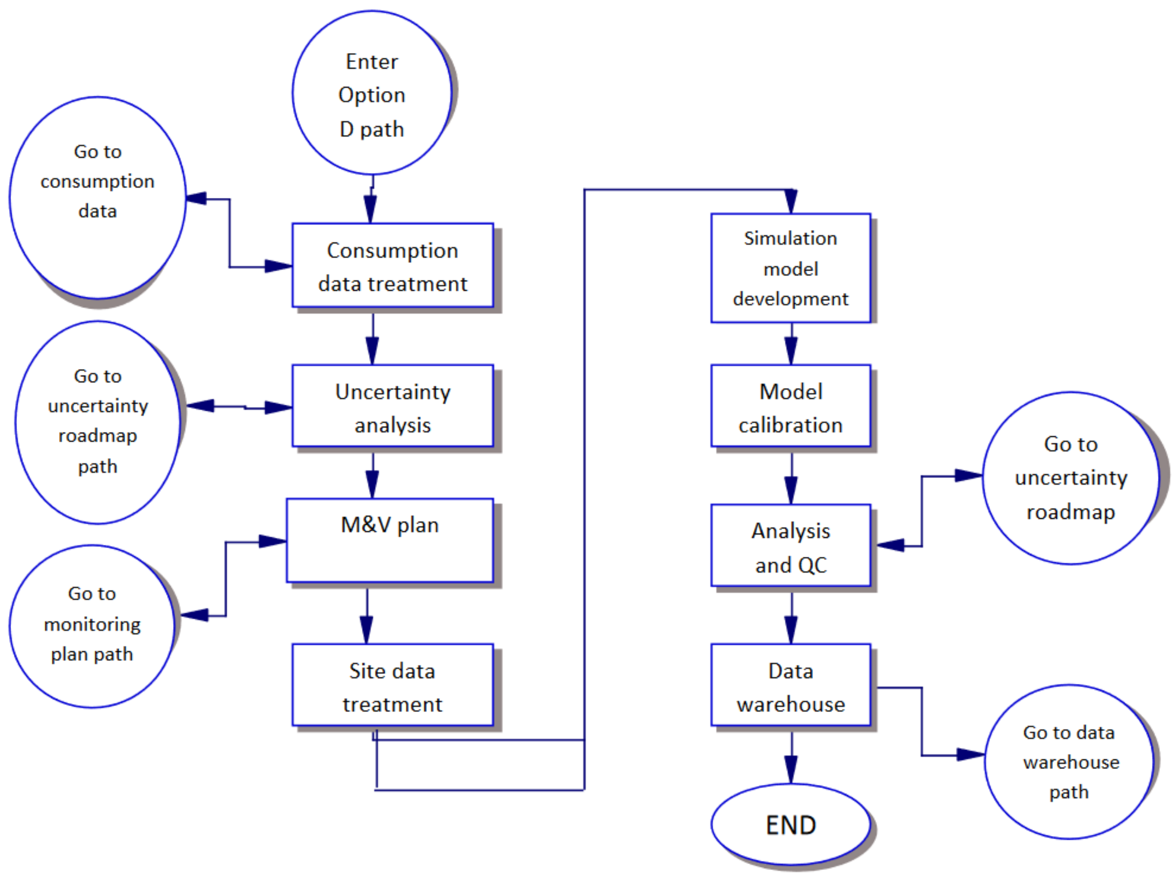


Figure 2-5 Roadmap for IPMVP Option D

2.5.4.1.2 Data Requirements and Collection Methods

Data collected during this step includes all of the information required to define and calibrate the building simulation model. Due to the unique nature of each new construction project, it is impractical to prescribe a comprehensive list of specific parameters evaluators should collect on site. Instead, use the following guidelines to identify key data points and minimize the uncertainty in the final calibrated simulations. After identifying specific parameters, refer to the Uniform Methods Project's (UMP) *Metering Cross-Cutting Protocols* for instructions regarding the methods to submeter the physical parameters. The data used to define building simulation models come from stipulated and physical sources. Furthermore, these data can be static or dynamic in nature, as described here:

- Static data points. These are essentially constant values that describe physical properties of the equipment and the building surfaces or the set point and operational range controlling the building equipment.[19] Examples of static data points are window glazing, motor efficiencies, and thermostat set points.
- Dynamic data. These are time-dependent variables that describe building and equipment operations. These data capture the behavioral and operational details (e.g., weather, motor loading, and building occupancy) needed to establish a building's energy-use characteristics. Dynamic data, which are often the most difficult to collect, represent the greatest source of uncertainty in a building simulation.

IPMVP Option D (IPMVP, 2006) allows use of stipulated data, although it is important to minimize the number of these inputs, as they represent degrees of freedom (and, therefore, additional uncertainty) in the model. Sources for such data include peer-reviewed research, engineering references, simulation program defaults, manufacturers' specifications, and/or survey information from on-site visits (e.g., mechanical, and architectural drawings and visual inspection of nameplate information).

The following are convenient categories of important physical data to collect on site (ASHRAE, 2002):

- Lighting systems
- Plug loads
- HVAC systems
- Building envelope and thermal mass
- Building occupants
- Other major energy-using loads[20]

Another important element of the data collection process entails the use of submetering to define behavioral and dynamic aspects of a building and its subsystems. In this protocol, the term submetering encompasses both direct placement of monitoring equipment by evaluation personnel and collecting data from the building automation systems (also known as trend data) when available. Even when the absolute accuracy of the collected data is unknown, sub-metered data is useful for informing operational schedules (e.g., lighting and ventilation) and calibrating the model.

The degree of submetering required is largely dependent upon the quality and resolution of the facility's energy consumption history. The following descriptions of submetering represent the minimum amount of data collected for calibrating simulation models. Additional submetering may be necessary to verify complex control schemes and/or set points. Perform additional submetering as budget and time permit. Use such data to inform model inputs rather than to function as a calibration target.

[19] 3 set points can refer to a control zone, thermostat, control valve, flow rate, voltage, photocell, or other parameter that is designed to maintain optimal environmental conditions within the building. Some set points are "dynamic" in that they may change according to the time of day.

[20] This category is particularly important in buildings such as grocery stores, refrigerated warehouses, and some retail.

(i) Submetering With Monthly Bills

When only a monthly utility billing history is available for a facility, it is important to submeter both HVAC fan schedules[21] and interior lighting fixtures. Also, if the facility has unique or considerable equipment loads (e.g., data centers), meter these as well.

When monitoring unitary HVAC equipment, isolate the power used by fans from that used by compressors. This ensures evaluators can use the resulting data when calibrating time-of-use and magnitude of fan power.

If, due to site or budget limitations, the electrical monitoring must comprise the unitary system as a whole, use motor nameplate information and fan curves in conjunction with local weather data to disaggregate the fan and compressor power.[22]

Alternatively, use one-time power measurements to establish a unit's demand for each operation mode. Combine these measurements with time-series data to identify time spent in each operation mode and, thereby, determine the fan schedules.

(ii) Submetering With Hourly Bills

Hourly (or sub-hourly) energy consumption histories contain much more information for model calibration than monthly usage alone. While this additional information reduces submetering requirements, it does not eliminate the need to submeter HVAC fan schedules as they are important for disaggregating base loads from ventilation. As described for monthly billing data, consider submetering other large energy-using features (e.g., pool-heating and space-cooling equipment, atria lighting, and internet technology loads) if possible given evaluation budgets.

2.5.4.2 Simulation Model Development

It is important to model several iterations of the simulated building to fully capture the various aspects of the savings for new construction ECM. Table 2-12 lists this iterative process, which entails three versions of the as-built building and two versions of the baseline building, including:

- As-built physical
- As-built design
- As-built expected design
- Whole-building reference
- Measure building reference

Table 2-12 does not include intermediate modeling of individual ECM. Intermediate modeling can be used to disaggregate individual measure impacts and interactive effects. If measure-level savings estimates (and therefore, intermediate modeling of measures) are required, work with the governing jurisdiction for the evaluation process to establish an appropriate hierarchy to govern the order in which measures are stacked and individual measure savings assessed.

[21] It is important to capture a building's ventilation schedule when HVAC systems are used to supply outside air to maintain required fresh requirements. If performing submetering on a sample of HVAC fans, place priority on accurately capturing when (and how much) outside air is introduced into the building.

[22] To employ this method, the modeler must have the requisite expertise to apply appropriate statistical and engineering modeling techniques to perform this analysis. For further information on energy consumption analysis, see the Whole-Building Retrofit with Consumption Data Analysis Evaluation Protocol.

Table 2-12 List of models used to simulate savings for NC ECM

Model	Model Name and Purpose	Model Description
1	As-Built Physical To calibrate simulations and assess uncertainty	Model and simulate, as found during site visit. Use the occupancy and building operation, as reflected in billed energy history and sub-metered data. Simulate using actual local weather observations matching the consumption history period.
2	As-Built Design To estimate typical usage at full occupancy	Base on as-built physical model. Use full design occupancy and expected typical building schedules. Use construction and equipment efficiencies, as found during site visits. Simulate using normalized weather data (e.g., typical meteorological year [TMY] datasets).[23]
3	As-Built Expected Design To estimate difference between original and as-built models	Base on as-built design model. Use full design occupancy and expected typical building schedules. Use assumed constructions and equipment efficiencies. Simulate using normalized weather data (e.g., TMY datasets).
4	Whole-Building Reference To estimate savings for the ECM	Base on as-built design model. Use full design occupancy and expected typical building schedules. Apply baseline requirements defined by reference codes or standards. Simulate using normalized weather data (e.g., TMY).
5	Measure Building Reference To isolate savings claimed by the participant	Base on whole-building reference model. Use full design occupancy and expected typical building schedules. Apply baseline requirements defined by reference codes or standards. Include ECM not incentivized by program. Simulate using normalized weather data (e.g., TMY).

Begin the development of the model by generating a model of the building as it was built and is operating during the site visit—and as reflected by utility energy consumption data. Use this initial model, the as-built physical model, to calibrate the modeled building to available physical data. This ensures evaluators can use successive iterations in a predictive capacity. A detailed discussion of the calibration process falls outside the scope of this protocol; however, for detailed calibration procedures and guidelines see Section 6.3.3.4 in ASHRAE Guideline 14- 2002 (ASHRAE, 2002).

Once calibrated, use the as-built physical model to generate the as-built design model, which should reflect the building at full-design occupancy and operation according to expected typical schedules. The only differences between these models are building occupancy, operational schedules, and any modeling guidelines incorporated from codes or standards used to define baseline performance. For buildings currently operating at full occupancy, there may be very little difference between these models. Refer to Table 11.3.1 and G3.1 in ASHRAE Standard 90.1-2007 (ASHRAE, 2007) for examples of modeling requirements specified by codes and standards.

[23] Note the TMY are referenced here as an example series of normalized weather data. When incorporating TMY weather data, use TMY3 weather data when available. While TMY weather represents a common standard, review the reporting needs of the project, as other normalized weather datasets may be more appropriate (e.g., Weather year for Energy Calculations [WYEC] or California Thermal Zones [CTZ]).

Then, use the as-built design model to generate the as-built expected design model. While this model simulates the building's operation according to its design intent, it also includes claimed assumptions regarding envelope constructions and equipment efficiencies. Review the model for discrepancies between claimed assumptions and the physical building; if no discrepancies exist, this model will be identical to the as-built design.

After developing as-built models, evaluators can model baseline building performance, which results in the whole-building reference model; to generate this model, apply the appropriate codes and standards used to define baseline building performance to the as-built design model. The M&V plan should identify such standards before modeling begins. The following section, *Baseline Considerations*, discusses additional considerations for baseline selection. Similar to the as-built design model, the whole-building reference model should reflect the building's operation according to its expected long-term patterns while using equipment and construction that minimally complies with the reference code or standard.

Finally, start with the whole-building reference model to generate the measure building reference model—this model will include ECM not incentivized by the program. It is likely all the implemented ECM are included in the whole-building performance incentives; therefore, both the baseline models may be identical. However, as incentives often are applied for during the building's design and construction process, additional above-code equipment or construction may be implemented that were not included in the final incentive.

2.5.4.3 Baseline Considerations

Defining baseline building physical characteristics and equipment performance is one of the most important (and difficult) tasks in evaluating savings for new construction ECM. This is for several reasons. As noted, new construction ECM do not have a physical baseline to observe, measure, or document. Rather, evaluators must define the baseline "hypothetically" through an appropriate interpretation of the applicable energy codes and standards. It is typically complicated to establish an appropriate interpretation due to the overlapping scope of federal, state, and local codes. Conversely, some states do not have a building energy-efficiency standard separate from the federal standards. Typically, evaluators determine baseline building characteristics and equipment performance requirements by locally adopted building energy codes. In some cases, however, applying a more rigorous, above-code baseline may better reflect standard local construction or industry-standard practices. Thus, in addition to a good understanding of the relationship between federal, state, and local standards, evaluators may need to consult with program guidelines (which often specify greater than code stringency or other technical specifications) or statewide evaluation frameworks. Enforcement of the state codes is the responsibility of the local building officials. The EM&V of programs is usually carried out by utility or other program administrators or by a public utilities commission. Whereas the public utilities commission usually has no enforcement responsibility for the codes and standards, they often point to the official state standards as the governing document regardless of the degree of enforcement of those codes at the local level.

In general, the baseline must satisfy the following criteria (IPMVP, 2006):

- It must appropriately reflect how a contemporary, nonparticipant building would be built in the program's absence.

- Evaluators must rigorously define it with sufficient detail to prescribe baseline conditions for each individual ECM and for the building components simulated.[24]
- Evaluators must develop it with sufficient clarity and documentation to be repeatable.

The BCAP-OCEAN website[25] can be a useful resource in identifying locally adopted energy codes and standards when starting the evaluation of a whole building or new construction project.

2.5.4.4 Calculating Savings

To calculate savings, apply simulation outputs (from models 2 through 5 in Table 2-13) to the formulas described in section 2.5.4.3 *Baseline Considerations*. In all cases except as-built physical, simulate the postconstruction energy use and the projected baseline energy use using normalized weather data (TMY).

As discussed in section 2.5.4.3 *Baseline Considerations*, there are four components that comprise calculated energy savings (defined in Table 2-13 and shown in Figure 2-6). Determine the final reported (verified) savings values in the context of M&V objectives.

Table 2-13 Comparison of Savings Components for NC ECM

Savings Component	Model Subtraction	Description
Expected Measure Savings	N/A	Energy savings expected by the building designers and/or the program application (also known as the project's planned savings)
Rebated Measure Savings	5 - 2	Evaluated (or realized) energy savings for incentivized ECM, often determined by the TPE. Calculate these savings by subtracting the difference in simulated energy use of the as-built design from the measure building reference (the result is also known as the project's *ex post* savings).
Non-Rebated Measure Savings	4 - 5	Energy savings resulting from ECM implemented in the final building design, but not rebated by the program. Calculate these savings by subtracting the difference in simulated energy use of the measure building reference from the whole-building reference (the result is also known as the spillover savings).
Total Achieved Savings	4 - 2	Evaluated (or realized) energy savings for all implemented ECM, whether rebated or not. These are often determined using the TPE and calculated by subtracting the difference in simulated energy use of the as-built design from the whole-building reference. Some programs report this (rather than rebated measure savings) as the project's *ex post* savings.

[24] Locally adopted building codes will define gross savings of new construction programs. Only consider standard construction practices of nonparticipant buildings when performing a net-to-gross analysis. One notable exception is when the evaluated program defines its own baseline, according to an above-code standard (for example, ASHRAE Standard 189.1-2011).

[25] This website can be found here: http://energycodesocean.org

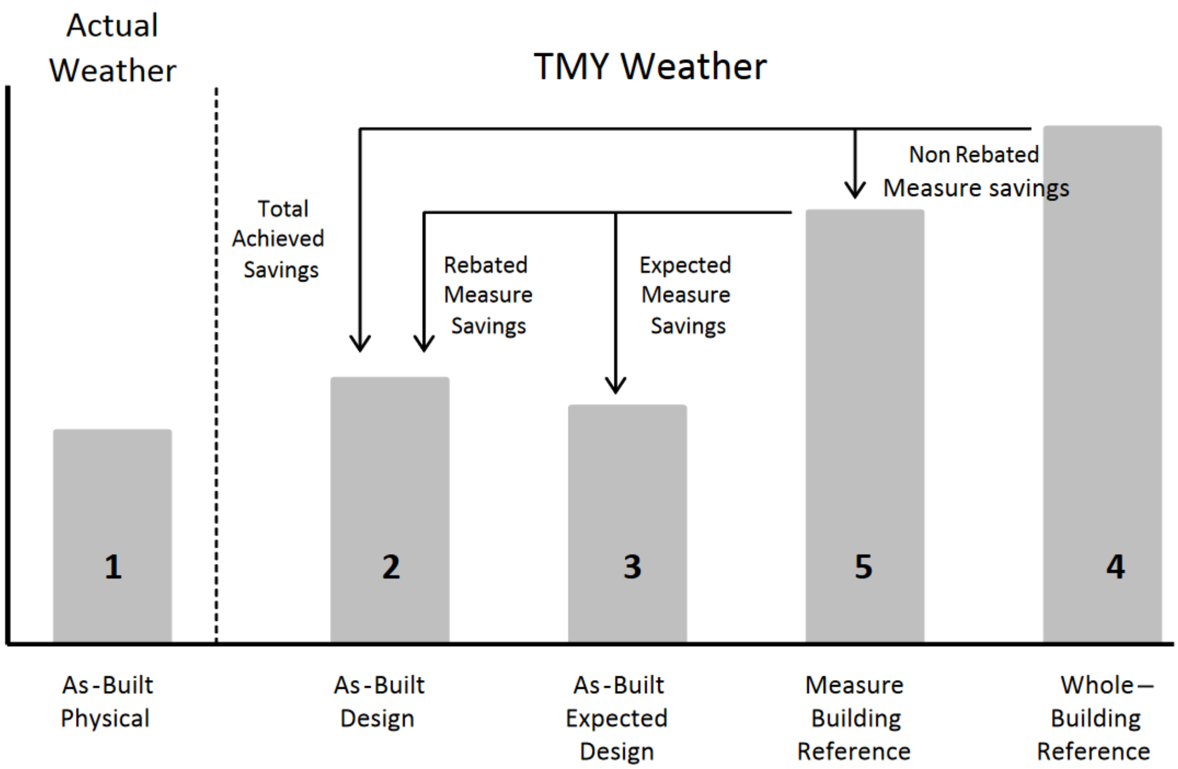


Figure 2-6 Illustration of savings components for NC ECM

2.5.4.4.1 Quantify and Locate Modeling Uncertainty

Due to the complex set of physical, thermodynamic, and behavioral processes simulated, it is difficult to fully characterize the uncertainty in modeled outputs without multiple statistical and analytical tools. Additionally, practical limitations on budgets and time allotted for M&V activities frequently result in qualifying uncertainty in final simulated savings by reporting uncertainty in the model's calibration to energy consumption history. Quantify calibration uncertainty using the Normalized Mean Bias Error (NMBE) and Coefficient of Variation of the Root Mean Square Error (CVRMSE)[26]. Pages 13-16 of ASHRAE Guideline 14-2002 (ASHAE, 2002), provides detailed descriptions of these calculations and their applications.

Determine calibration uncertainty by comparing outputs from the calibrated as-built physical model with the facility's consumption history. Table 2-14 shows calibration uncertainty targets for monthly and hourly consumption history resolutions (ASHRAE, 2002).

[26] These two statistical measurements provide an assessment of the variance between the simulated and measured (by the utility meter) energy use and electric demand. This protocol considers modeling uncertainty acceptable when this variance is below the thresholds suggested in Table 3

Table 2-14 Acceptable Tolerances for Uncertainty in Calibrated Building Simulations

Resolution of Energy Consumption History	NMBE Tolerance	CVRSME Tolerance
Monthly	±5%	±15%
Hourly	±10%	±30%

As newly constructed buildings have a short energy consumption history, it is important to consider how many monthly observations are required to attain a suitably calibrated model. The amount of consumption history required for calibration depends on building type and occupancy. Buildings with little seasonal variations in energy use[27] and short ramp-up periods may need as little as three or four months of consumption history, assuming building occupancy and usage are well-defined and stable. Typically, buildings in this category include grocery stores, restaurants, and data centers.

Conversely, buildings that experience significant seasonal variation, or that are not fully occupied for extended periods, may require a complete year (or more) of consumption history before modelers can determine a reliable calibration. For these buildings, occupancy and usage must be well-defined and stable during all observations used for calibration. Typical buildings of this type include offices, schools, and malls (both strip and enclosed).

Mandating definitive requirements for the minimum number of observations required to sufficiently calibrate a simulation would unduly constrain modelers and could place impractical limitations on EM&V efforts. However, this protocol recommends the following as guidelines:

- Observations should sufficiently characterize a building's energy use, so modelers can extrapolate reliable annual energy-use values.
- Observations should sufficiently describe expected seasonal variations in building operations.
- Building occupancy and operating conditions must be known for the set of observations.
- Building occupancy and operating conditions must remain stable for the duration of observations used for calibration.

While NMBE and CVRSME may prove useful in describing uncertainty in final savings, it is important to minimize the uncertainty in the simulation inputs. These metrics will not completely capture uncertainty in the inputs.

All software packages acceptable for use in Option D require modelers specify a significant number of physical parameters before simulating a building. Often, many of these parameters have default settings in the software package; however, evaluators can base the parameter inputs on experience or standard practices.

Any parameter not directly based on a physical building, or its equipment represents a degree of freedom for calibrating the model against a facility's consumption data.[28] By varying these parameters, the modeler can calibrate the same model to meet uncertainty targets in multiple ways, although for very different reasons.

[27] Although energy used by HVAC systems can vary seasonally, such usage generally correlates well with outside weather. Thus, the energy simulation model can sufficiently extrapolate such seasonality (when simulated using the appropriate weather data), reducing the number of billed observations required to calibrate buildings having HVAC use that is dominated by weather.

[28] Each parameter must be constrained by a physically realistic range of values.

Lack of a unique calibration point can cause misleading results for NMBE and CVRSME. Furthermore, the resultant calibrations respond differently to changes in other parameters, which can lead to significantly divergent savings estimates. Therefore, it is very important modelers minimize calibration uncertainty and they accomplish the calibration for the correct reasons. Modelers should not unreasonably alter inputs simply to reduce NMBE or CVRSME.

The following guidelines minimize uncertainty in the calibration process:

- Experienced simulators (or modelers directly supervised by an experienced simulator must perform the modeling.
- Modelers must document each simulation process step, so reviewers can audit the model, its outputs, and its assumptions.
- Simulators and auditors should determine the most influential default model parameters and confirm their appropriateness.[29]
- Simulated equipment (e.g., HVAC coils, chillers, pumps) should not "auto size" in final simulations.
- Simulators should identify the parameters to which the simulation outputs are most sensitive.[30]

In addition to quantifying NMBE and CVRSME errors, modelers should analyze the sensitivity of final savings to variations in key model inputs. Modelers should also report such parameters (including their effects on simulated energy savings and the uncertainty in their values) with calibration uncertainty.

2.5.4.5 Sample Design

Use sampling under the following conditions:

- When performing submetering on building equipment
- When performing a detailed survey of an entire building proves impractical.

Evaluators determine the specific targets for sampling certainty and relative precision in the context of the evaluation. For detailed information regarding sample design and for calculating certainty and precision, see the UMP *Sample Design Cross-Cutting Protocol*.

2.5.4.5.1 Sampling for Submetering

Perform submetering to collect information regarding a building's operational schedules. Monitored systems include lighting, ventilation, large equipment (e.g., data centers), and HVAC zone temperatures. Generally, it is acceptable to assume a coefficient of variation (CV) of 0.5 for most submetering; however, while many of these schedules are a function of the overall building type, significant variation in schedules can occur from space to space within a facility. Therefore, interview site personnel to identify any operational differences (and the magnitude of such differences) within the facility before creating a sample design. Account for variations in operating schedules and usage patterns by using a larger CV or by stratifying unique usage groups. See the

---

[29] When specific data are unavailable, auto-sizing can be helpful in determining appropriate coil capacities, fan speeds, etc. However, only use it for initial equipment sizing. Once equipment sizes have been determined, input them directly. Often, modelers must use auto-sizing to define baseline equipment, as the measures impact building loads. In such cases, calculate an oversize ratio for as-built equipment and apply it to the baseline simulation

[30] Further discussion regarding sensitivity analysis of simulation parameters falls outside this chapter's scope. For additional material on this topic, see Spitler, Fisher, & Zietlow 1989.

Uniform Method Project's Metering Cross-Cutting Protocols for additional considerations for commonly monitored equipment.

(i) Example: Monitoring the Lighting Schedule in a Two-Story Office Building

A two-story commercial office building receives a whole-building performance rebate for LEED certification. For the certification process, a DOE2.2 model is built, for which evaluators develop lighting loads and schedules. During the on-site visit, evaluators note the same tenant occupies both floors, and the building remains open from 6:30 a.m. to 10:00 p.m. The evaluators also identify two unique lighting usage patterns:

- Enclosed offices are located on the building's perimeter
- Open office space is located in the building's core.

As the evaluators identified two distinct usage patterns, they should design the sampling to capture the variability within the schedules for both space types.

- As the open office space is located in the building's core, lighting fixtures likely operate continuously during the building's open hours. Additionally, lighting is commonly shared by all workspaces in the building's core. Therefore, a CV of 0.5 is justified and may prove conservative in determining how many fixtures to monitor.
- Lighting fixtures located in enclosed office spaces typically experience significantly more usage variation due to exaggerated behavioral and external influences. Also, the enclosed office space fixtures receive additional light from perimeter windows, thereby reducing the need for interior lighting during daytime hours. These impacts can be exaggerated (or diminished), depending on fixture control types, building aspects, weather, and times of year. Such additional variability would necessitate a higher assumed CV and additional monitoring points.

2.5.4.5.2 Sampling for Building Surveys

The on-site data collection encompasses a detailed survey of building systems, such as:

- Lighting fixtures
- Plug loads
- HVAC equipment and controls
- Elevator and auxiliary equipment
- Fenestration
- Envelope constructions

For many buildings, surveyors can perform a complete walk-through and can install monitoring equipment within a single day. However, larger buildings (such as high-rise office buildings, hotel casinos, and hospitals) present logistical and budgetary complexities that make it impractical (and often impossible) to perform a complete facility walk-through. In these cases, it is permissible to perform a walkthrough of a representative sample of building areas and extrapolate the findings to the rest of the building. Evaluators can apply the findings to individual spaces or to entire floors (the exact sample design depends on the facility design, including any considerations, such as access to space).

(i) Example: On-Site Audit of a High-Rise Office Building

A 34-story high-rise commercial building located in a major city's downtown region receives a whole-building performance rebate. Various retail businesses rent the first floor, and various tenants use the remaining floors as office space, including a Department of Agriculture office. Evaluators collect data during the on-site visit to build a DOE2.2 model; however, the building owner will only provide evaluation personnel access to the building for a single day.

The building is too large to conduct a thorough walk-through in one day. Additionally, it is expected at least one tenant will have areas within its occupied space that evaluators will not be allowed to access. Therefore, evaluators will have to perform sampling for both floors and space types. Evaluators should audit enough floor space to sufficiently characterize internal loads and usage patterns for each tenant and for the building as a whole. The exact number of floors visited will depend on the number of tenants and on the homogeneity between spaces/floors.

The evaluators should:

- Identify unique operating conditions, such as occupancy schedules, lighting power density (and schedules), and equipment power density (and schedules)
- Identify currently vacant areas (or floors)
- Interview facility staff to:
- Identify differences in space temperatures or ventilation requirements for each tenant
- Determine variations in building occupancy (by month or as appropriate) since its opening
- Audit all central plant equipment
- Sample air distribution system equipment using sampling criteria described in the Uniform Method Project's Chapter 11 *Sample Design Cross-Cutting Protocol*

2.5.5 PROGRAM EVALUATION ELEMENTS

These elements differentiate evaluations of new construction programs from those of other programs:

- Evaluators need significantly more resources to define and justify a hypothetical baseline
- Evaluators have a limited selection of methods for determining site-level savings
- Buildings rarely operate at a "steady state" at the time of evaluation

While this is not a comprehensive list, it specifies critical factors that evaluators must consider in developing an evaluation plan—particularly regarding budget resources for defining and justifying the baselines used to determine energy savings.

Commonly applied codes (such as ASHRAE 90.1) provide multiple compliance pathways but leave room for local jurisdictions to maintain their own interpretations. Therefore, evaluators should work with local jurisdictions, program implementers, and evaluation managers and oversight agencies to identify the most appropriate baseline for a building. Further, local jurisdictions may adopt an updated building code during implementation of a program, so the evaluator may have to develop baselines from multiple building codes for a given program year.

Given the limited information available to assess new construction ECMs, using calibrated building simulations is often the only option for determining energy savings. Significant planning ensures:

- Evaluators develop detailed M&V plans each project site
- The evaluation allows sufficient time to perform the analyses

Evaluators often collect additional information using submetering and/or consumption data analysis. As this information is important for model calibration, the M&V plan should allot sufficient time for a thorough analysis of all sub-metered data and consumption data.

For programs offering incentives, evaluators usually assess energy efficiency measure performance during the first few years of their operation. During this period, building systems and controls typically require troubleshooting[31] and buildings have low, but growing, occupancy rates.

Evaluators should also keep in mind that owners (or tenants) may use building spaces differently than as originally designed. Thus, the specific codes or standards governing the originally permitted building drawings may not be appropriate for assessing actual energy use or energy savings. This protocol strongly recommends evaluators consider these and other such factors when calibrating models and simulating annual energy savings.

[31] Troubleshooting is formally done through a commissioning process; however, not all buildings are professionally commissioned. In many facilities, facility management must dial in building controls.

2.6 Protocols for Evaluation of Retrocommissioning Projects

2.6.1 MEASURE DESCRIPTION

Retrocommissioning (RCx) is a systematic process for optimizing energy performance in existing buildings. It specifically focuses on improving the control of energy-using equipment (e.g., HVAC equipment and lighting) and typically does not involve equipment replacement. Field results have shown proper RCx can achieve energy savings ranging from 5% to 20%, with a typical payback of two years or less (Thorne, 2003). [32]

The method presented in this protocol provides direction regarding: (1) how to account for each measure's specific characteristics and (2) how to choose the most appropriate savings verification approach.

A study conducted on behalf of LBNL analyzed data from 11 utilities operating RCx programs across the United States. The dataset included 122 RCx projects and more than 950 RCx measures (PECI, 2009). Table 2-15 lists a summary of the most common RCx measures, highlighting the nine measures that represent the majority of the analyzed project savings.

Table 2-15 Common RCx Measures

RCx Measure	Percentage of Total Savings
Revise control sequence	21%
Reduce equipment size	15%
Optimize airside economizer	12%
Add/optimize supply air temperature reset	8%
Add variable frequency drive to pump	6%
Reduce coil leakage	4%
Reduce/reset duct static pressure set point	4%
Ad/optimize optimum start/stop	3%
Add/optimize condenser water supply temperature reset	2%

As shown in Table 2-15 (PECI, 2010), RCx measures vary, depending on types of equipment and control mechanisms introduced or optimized. For example, some RCx measures control HVAC equipment according to a predefined schedule, while some measures introduce outdoor air temperature (OAT) dependent controls.

[32] As discussed in the section "Considering Resource Constraints" of the Introduction chapter to this report, small utilities (as defined under U.S. Small Business Administration regulations) may face additional constraints in undertaking this protocol. Therefore, alternative methodologies should be considered for such utilities.

Table 2-16 Categorization of RCx Measures

Control Mechanism	**Equipment Type**		
	HVAC Airside	**HVAC**	**Lighting**
Scheduled	Matching supply fan schedule to occupancy schedule	Adding/optimizing space setback temperatures	Matching lighting schedule to occupancy schedule
Variable	Optimizing airside economizer	Adding chilled water supply temperature set point reset strategy	Optimizing daylighting control

The classic RCx process helps identify, implement, and maintain improvements to building systems and operations via the following five phases (BPA, 2011a).

- Planning. This phase involves screening buildings to determine whether they provide a good fit for RCx by assessing indicators such as equipment age and condition, building energy performance and size, and type of control system. Ideally, facilities should have an existing building automation system (BAS) in good working order, as well as HVAC equipment that is in relatively good condition. A facility without a BAS can install the system; however, the project would then become an HVAC controls and commissioning project rather than an RCx project. When a facility's HVAC equipment nears the end of its useful life, undertaking RCx may not be appropriate because control measures could become obsolete with replaced equipment.
- Investigation. The investigation phase involves analyzing facility performance by reviewing building documentation; performing diagnostic monitoring and functional tests; interviewing staff; identifying a list of recommended improvements; and estimating savings and costs. Evaluators should clearly differentiate valid RCx measures that meet program eligibility guidelines from retrofit measures and/or operation and maintenance (O&M) activities at this phase.
- Implementation. The implementation phase involves prioritizing recommended measures and developing an implementation plan; implementing the measures; and testing to ensure proper operation. Implementation often entails an iterative approach, as the evaluator may need to determine the final control set points through several stages of modification and assessment. These stages ensure building equipment continues to operate properly and maintains the occupants' comfort. Typically, evaluators will review a facility's BAS to assess how effectively RCx measures operate.
- Turnover. The turnover phase involves updating building documentation (e.g., system operation manuals); developing and presenting a final report; and training building operators on proper O&M.
- Persistence. The persistence phase involves monitoring and tracking energy use over time; continually implementing persistence strategies (e.g., refining control measures or enhancing O&M procedures) to sustain savings; and documenting ongoing changes. Depending on the availability of resources and the timeline, program stakeholders may not always actively support this phase.

2.6.2 APPLICATION CONDITIONS OF PROTOCOL

The RCx program design includes activities intended to overcome several market barriers, as listed in Table 2-17.

Table 2-17 RCx Market Barriers

Market Segment	Barrier	Opportunities
Supply-Side Actors, End Users	No tangible examples of RCx performance in situ	Undertaking pilot opportunities
Supply-Side Actors	Lack of service provider capacity for undertaking the RCx investigation and implementation phases	Training for service providers
End Users	Lack of awareness and understanding of the RCx benefits	Education to increase building owner and operator awareness
End Users	Cost of undertaking RCx	Incentives

Ideally, programs overcome these barriers through various activities that address available opportunities. Retrocommissioning programs may include some or all the following activities:

- Pilot projects. Program administrators sometimes fund pilot projects to demonstrate the benefits of RCx to end users in their target markets. Evaluators can verify pilot savings using the methods presented later in this protocol and, in theory, these savings will attract participants to the program.
- Training. Program administrators sometimes fund or develop training for service providers. In some jurisdictions, service providers do not routinely provide RCx services to their customer base. Thus, to develop RCx capacity in the market, program administrators might offer training to service providers on how to provide common practice RCx investigation and implementation services. Service providers may also require training on how to sell these services to their clients.
- Education. Program administrators sometimes develop educational materials and hold events or workshops for end users. Prior to making a decision to undertake RCx activities in their facilities, building management and building operators need to understand the business case for RCx. Detailed case studies showcasing project savings are an example of education tools program staff can use to facilitate this decision-making process.
- Incentives. Program administrators often provide incentives to undertake the RCx investigation, implementation, and persistence phases. Even though the payback for RCx measures is typically low, end users often require incentives to encourage them to move forward with projects.[33] Incentives may also encourage end users to undertake projects sooner—or with a greater scope—than they would have without market intervention.

This protocol provides structured methods for determining energy savings resulting from the implementation of RCx measures. The approaches described here provide direction on how to verify savings consistently from pilot projects, as well as from projects implemented by program participants. It does not address savings achieved through training or through market transformation activities.

[33] Some programs may impose a penalty rather than an incentive. For example, if participants fail to implement the measures that fell below a certain payback threshold identified during the investigation phase, they may not be eligible for the full investigation phase incentive.

2.6.3 SAVINGS CALCULATIONS

Specific savings calculations[34] for RCx measures inherently vary, due to the breadth of possible RCx measures, which can differ by type of equipment or control mechanism. This section presents a high-level gross energy savings equation that is applicable to all RCx measures. Section 2.5.4 *Measurement and Verification Plan*, includes detailed directions for calculating savings for specific measure categories.

Use the following general equation (EVO, 2012) to determine energy savings:

$$
\begin{aligned}
Energy\ Savings \\
&= (Baseline\ Energy - Reporting\ Period\ Energy)\ \pm\ Routine\ Adjustments \\
&\pm\ Nonroutine\ Adjustments
\end{aligned}
$$

Where:

$Energy\ Savings =$ First-year energy consumption savings

$Baseline\ Savings =$ Pre-Implementation consumption

$Reporting\ Period\ Savings =$ Post-Implementation consumption

$Routine\ Adjustments =$ Adjustments made to account for routinely changing independent variables (variables that drive energy consumption). If applicable, normalize savings to typical meteorological year (TMY35) weather data, as well as other significant independent variables (e.g., occupancy, production data).

$Nonroutine\ Adjustments =$ Adjustments made to account for parameters typically not expected to change during the implementation period. Account for these parameters if they change and this change influences the reporting period energy use (e.g., changes to a facility's building envelope during implementation of and RCx HVAC measure). Evaluators only need to consider nonroutine adjustments if verifying savings using Option C of the International Performance Measurement and Verification Protocol (IPMVP).[36]

Determining RCx demand savings is not a straightforward extension of verified consumption savings (unlike lighting retrofits, where evaluators can easily apply established load savings profiles to consumption savings data). For RCx projects, load savings profiles vary depending on the type of measures implemented and the distribution of these measures. If applicable, evaluators should produce load savings profiles on a measure-by-measure basis, aggregate these profiles, and then apply site-specific coincidence factors to determine coincident peak demand savings at the project level.

---

[34] As presented in the Introduction, the protocols focus on *ex post* gross energy savings and do not include other parameter assessments, such as net-to-gross, peak coincidence factors, or cost-effectiveness.

[35] Evaluators should use the most recent typical meteorological year dataset. As of January 2014, the most comprehensive national typical meteorological year dataset is TMY3. Evaluators should confer with the local jurisdiction to see if they should use a different regional dataset.

[36] Option C is the "whole-facility approach" to verifying savings

2.6.4 MEASUREMENT AND VERIFICATION PLAN

This section outlines the recommended approaches to determining RCx energy savings and provides directions on how to use the approaches under the following headings:

- Measurement and verification (M&V) method
- Data collection
- Interactive effects
- Specific savings equations
- Regression model direction
- Deemed spreadsheet tool functionality requirements

2.6.4.1 Measurement and Verification Method

There is a structured method for determining the most appropriate approach to verifying RCx energy savings. This method balances the need for accurate energy-savings estimates with the need to keep M&V costs in check, relative to project costs and anticipated energy savings. Depending on which measures are implemented, different approaches to estimating the savings are appropriate. Following the IPMVP, the options are:

- Option A—Retrofit Isolation: Key Parameter Measurement
- Option B—Retrofit Isolation: All Parameter Measurement
- Option C—Whole Facility
- Option D—Calibrated Simulation

Measurement is inherent with most RCx projects because RCx measures typically involve modifications made through a facility's BAS. As mentioned, RCx implementation (an iterative process) often leverages metered data to evaluate and optimize changes throughout the process. Therefore, in many cases, a retrofit isolation approach adhering to Option A or Option B of the IPMVP proves most logical. That said, scenarios exist where Option C, Option D, or even a deemed approach may be more appropriate. Figure 2-7 presents a decision flow chart for determining the approaches to follow.

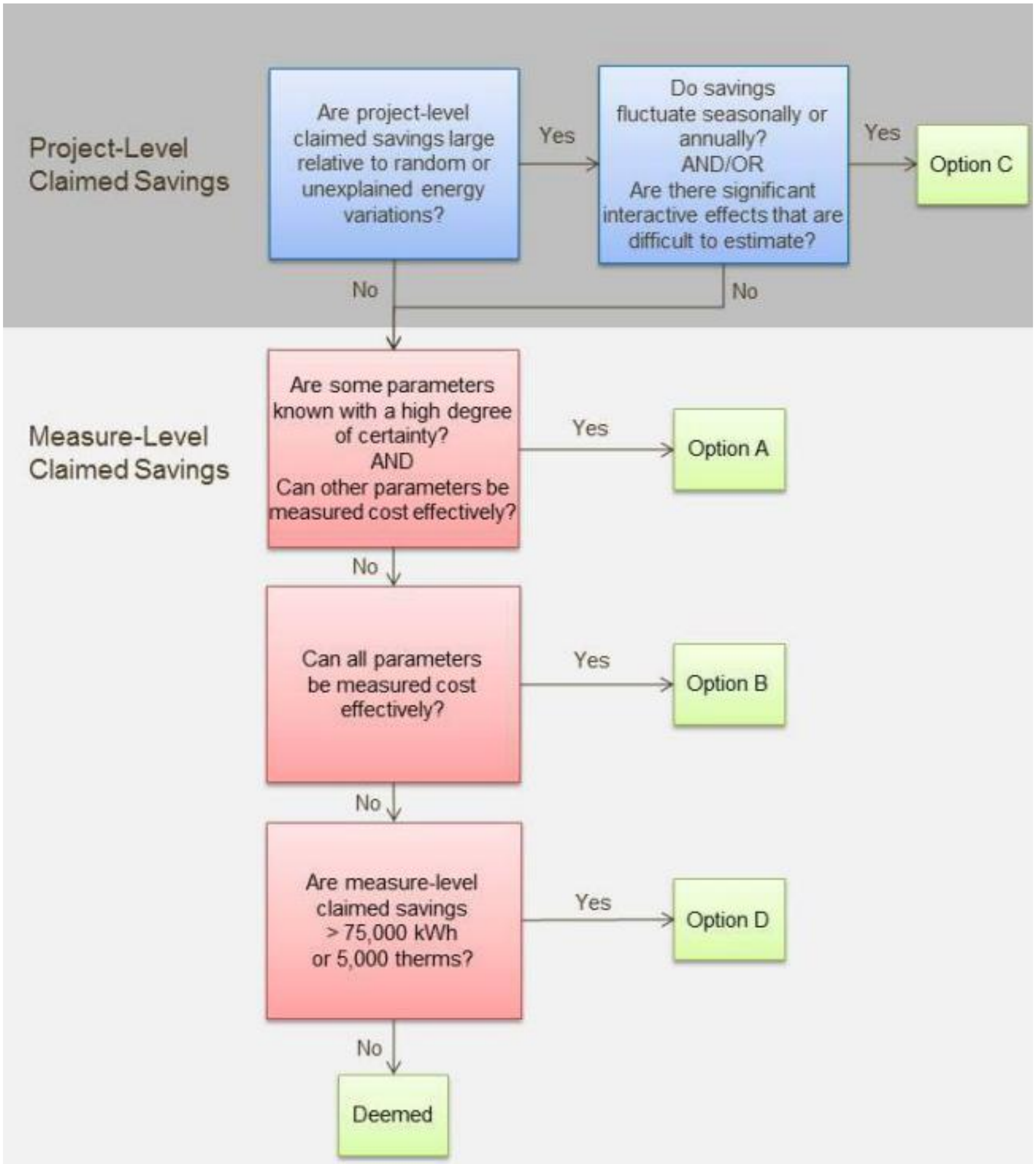


Figure 2-7 RCx Decision Flow Chart[37]

The decision flow chart accounts for factors such as the magnitude of estimated savings and the measurement's cost-effectiveness. Begin the process by considering project-level savings:

- Option C. Use a whole-facility approach—adhering with Option C of the IPMVP—if estimated project-level savings are large compared to the random or unexplained energy variations that occur at the whole-

[37] NREL RCx Evaluation Protocol https://www.nrel.gov/docs/fy17osti/68572.pdf

facility level[38] and if savings fluctuate over a seasonal or annual cycle (e.g., savings that fluctuate depending on OAT). This approach is likely the most cost-effective approach for verifying savings. The whole-facility approach is relatively inexpensive because evaluators can use utility billing data for the analysis. The downside of the approach is that evaluators cannot perform verification until after collecting a full season or year of reporting period data and monitoring and documenting any changes to the facility's static factors[39] over the course of the measurement period. Even if savings remain consistent month to month, Option C may provide the best approach if project measures cause complex, significant interactive effects. Such interactive effects are, by nature, difficult to estimate accurately. Also, if the effects are significant (large, relative to direct-measure savings), evaluators will be required to use a whole-facility approach to measure impacts accurately. The reduced heating and cooling energy resulting from schedule changes to an air-handling unit, when control modifications have also been undertaken for both the heating and cooling systems, is an example of a complex significant interactive effect warranting Option C.

If Option C is ruled out, consider performing verification on a measure-by-measure basis:

- Option A. If measures involve some parameters known with a high degree of certainty and other parameters can be measured cost-effectively, use a retrofit isolation approach adhering to Option A of the IPMVP. In many cases, evaluators can collect metered data directly from the facility's BAS. If required, the facility can add control points to the BAS, either as part of the implementation process or specifically for M&V purposes. Where the BAS cannot provide the information, use temporary meters to collect data (provided that costs are not prohibitive).
- Option B. If a given measure's parameters are uncertain but can be measured cost-effectively, use a retrofit isolation approach, adhering to Option B of the IPMVP. Again, collect metered data (similar to Option A) either through the BAS or by using temporary meters.
- Option D. For measures where it is prohibitive to meter all required parameters, use a calibrated simulation approach adhering to Option D of the IPMVP. Undertake calibrations in two ways: (1) calibrate the simulation to the actual baseline or reporting consumption data and (2) confirm the reporting period inputs via the BAS front-end system, when possible.[40] [41]
- Deemed. Finally, if a measure is relatively common[42] and its estimated savings are small, evaluators can deem savings rather than simulate them. Use this approach for common measures with savings less than 75,000 kilowatt-hour (kWh) or 5,000 therms[43] (PECI, 2010). Use a spreadsheet tool to calculate savings, adhering to functionality requirements presented later in the Protocol.

---

[38] Typically, savings should exceed 10% of the baseline energy for a particular meter (e.g., electricity meter) to confidently discriminate the savings from the baseline data when the reporting period is shorter than two years (EVO, 2012).

[39] Many factors can affect a facility's energy consumption, even though evaluators do not expect them to change. These factors are known as "static factors" and include the complete collection of facility parameters that are generally expected to remain constant between the baseline and reporting periods. Examples include building envelope insulation, space use within a facility, and facility square footage.

[40] In many cases, the simulation should represent the entire facility; however, in some cases, depending on the facility's wiring structure, a similar approach could be applied to building submeters, such as distribution panels that include the affected systems.

[41] See the Uniform Method Project's Commercial New Construction Protocol for more information on using Option D.

[42] If regulators are involved, going through the effort of deeming savings for a rare measure can be burdensome.

[43] Program administrators and evaluators may wish to customize these thresholds for particular programs and/or jurisdictions.

2.6.5 DATA COLLECTION

Depending on the approach followed, these M&V elements will require consideration:

- The measurement boundary
- The measurement period and frequency
- The functionality of measurement equipment being used
- The savings uncertainty

2.6.5.1 Measurement Boundary

For measures evaluators assess using Option A or Option B and that require metering external to the BAS, it will be important to define the measurement boundary. When determining boundaries—the location and number of measurement points required—consider the project's complexity and expected savings:

- While a narrow boundary simplifies data measurement (e.g., a single piece of equipment), variables driving energy use outside the boundary (i.e., interactive effects) still need to be considered.
- A wide boundary will minimize interactive effects and increase accuracy (e.g., systems of equipment like chilled water plants and air-handling units). However, as M&V costs may also increase, it is important to ensure the expected project savings justify the increased M&V costs.

2.6.5.2 Measurement Period and Frequency

For all measures assessed with Option A or Option B, consider two important timing metrics:

- The measurement period (the length of the baseline and reporting periods)
- The measurement frequency (how regularly to take measurements during the measurement period)

As a general rule, choose the measurement period to capture a full cycle of each operating mode. For example, if there is a control modification to heating equipment, collect data over the winter and shoulder seasons.

Choose the measurement frequency by assessing the type of load measured:

- Spot measurement: For constant loads, measure power briefly, preferably over two or more intervals.
- Short-term measurement: For loads predictably influenced by independent variables (e.g., HVAC equipment influenced by OAT), take short-term consumption measurements over the fullest range of possible independent variable conditions, given M&V project cost and time limitations.[44] For systems expected to have nonlinear dependence (such as air handling units with outside air economizers), measurements should incorporate sufficient range to characterize the full breadth of conditions.
- Continuous measurement: For variable loads, measure consumption data continuously, or at appropriate discrete intervals, over the entire measurement period.

See Section 4.4, Specific Saving Equations, for direction regarding measurement periods and frequency for specific measure types.

---

[44] For example, if a chiller plant undergoes control modifications, the measurement frequency should be long enough to capture the full OAT operating range. In a temperate climate zone, evaluators can accomplish this by taking measurements over a four-week period in the shoulder season and another four-week period during the summer season.

2.6.5.3 Measurement Equipment

When meters external to the BAS are required, follow these guidelines to select a meter[45]:

- Size the meter for the range of values expected most of the time.
- Select the meter repeatability and accuracy that fits the budget and intended use of the data.
- Install the meter as recommended by the manufacturer.
- Calibrate the meter before it goes into the field, and maintain calibration as recommended by the manufacturer. If possible, select a meter with a recommended calibration interval that is longer than the anticipated measurement period.

If BAS data is used, evaluators should exercise due diligence by determining when the BAS was last calibrated and by checking the accuracy of the BAS measurement points.

2.6.5.4 Savings Uncertainty

If possible, quantify the accuracy of measured data[46] and, if practical, conduct an error propagation analysis to determine overall impacts on the savings estimate.

2.6.6 INTERACTIVE EFFECTS

For projects following Option A, Option B, or deemed approaches, consider, and estimate interactive effects if they are significant. For example, if a facility reduces an air-handling unit supply fan schedule, not only will direct fan savings be achieved, but significant cooling and heating energy savings may be realized due to decreases in conditioned ventilation air supplied to the space. Estimate interactive effects using equations that apply the appropriate engineering principles. Ideally, use a spreadsheet tool adhering to the same functionality requirements discussed in 2.6.8 *Deemed Spreadsheet Tool Functionality Requirements* for the deemed spreadsheet tool to conduct these analyses. When interactive effects are large, it may be possible to measure them rather than apply engineering estimates. In the “supply fan” example discussed in the paragraph above, an evaluator can meter the chilled water plant to determine the cooling load reduction.

Interactive effects for projects being verified using Option C or Option D are typically included in facility-level savings estimates.

2.6.6.1 Specific Savings Equations

If following Option A or Option B, verify savings using equations matching a given measure’s characteristics—specifically, whether savings are dependent on independent variables (such as OAT) and the control mechanism for affected equipment.

Figure 2-8 shows the three categories of savings equations, with further explanations following the flow chart.

---

[45] For more information on selecting measurement equipment, see the Uniform Methods Project’s Metering Cross Cutting Protocols.

[46] Metering accuracy is only one element of savings uncertainty. Inaccuracies also result from modeling, sampling, interactive effects, estimated parameters, data loss, and measurements being taken outside of a meter’s intended range.

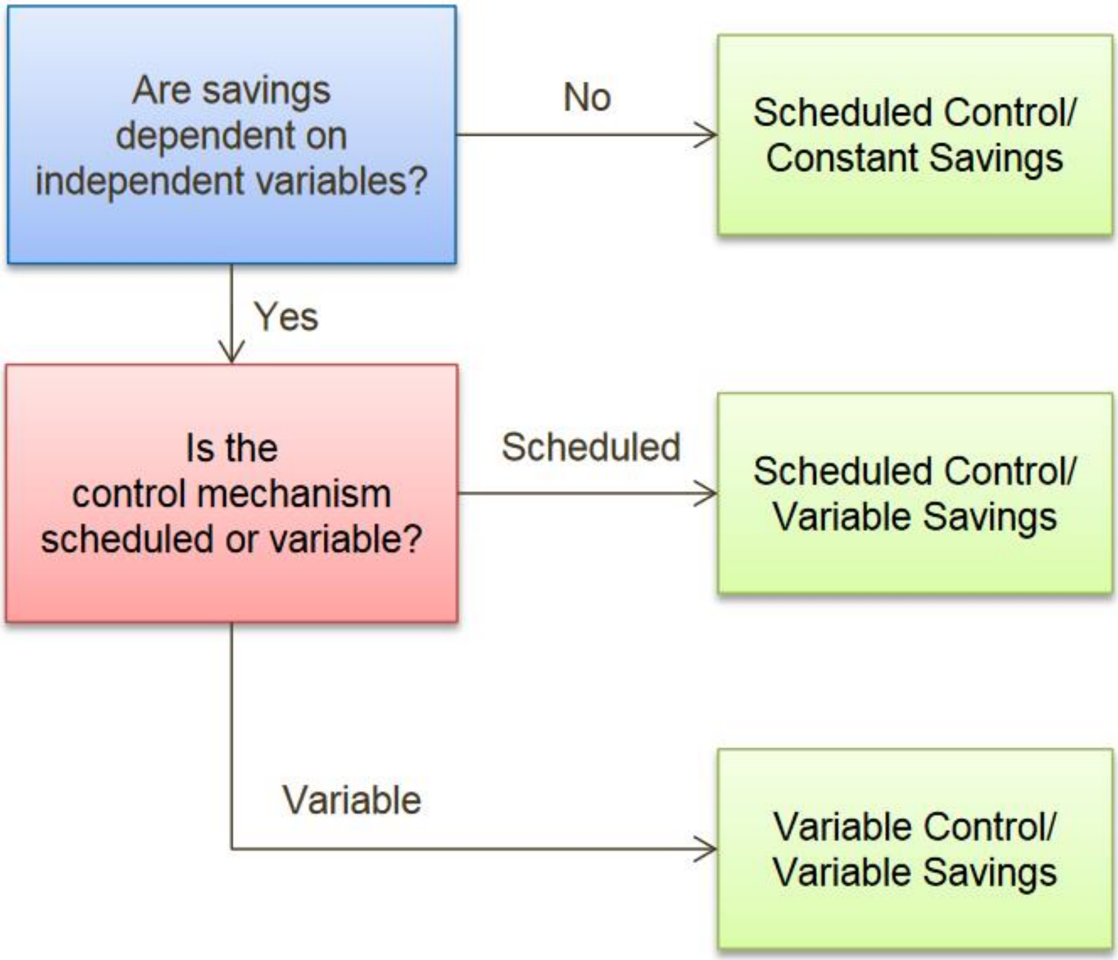


Figure 2-8 Savings Equation Categories[47]

2.6.6.2 Scheduled Control/Constant Savings

This savings equation category encompasses scheduled control measures on equipment not influenced by independent variables (such as OAT); therefore, this is the most straightforward equation category.

Lighting schedule optimization is an example of a measure verified using this savings equation category. In this example, lighting is turned off according to a schedule (scheduled control), and constant savings is achieved while it is off (constant savings).

$$Scheduled\,\frac{Control}{Savings} = Baseline\ Energy\ - Reporting\ Period\ Energy$$

[47] *Ibid.*

Where:

$Scheduled\ Control/Savings =$ First-year energy consumption savings resulting from a scheduled control measure with constant savings.

$Baseline\ Energy =$ $HRS_{baseline}$ x $kW_{controlled}$

$Reporting\ Period\ Energy =$ $HRS_{reporting}$ x $kW_{controlled}$

$HRS_{baseline}$ = Annual operating hours during the baseline: if this parameter is not known with a high degree of certainty, take short-term measurements for the duration of each existing schedule type.

$HRS_{reporting}$ = Annual operating hours during the reporting period: take short-term measurements for the duration of each new schedule type.

$kW_{controlled}$ = Electric demand controlled by scheduling measure: if this parameter is not known with a high degree of certainty, take spot measurements during the baseline or reporting period.

2.6.6.3 Scheduled Control/Variable Savings

This savings equation category encompasses scheduled control measures on equipment influenced by independent variables (such as OAT). Space setback temperature optimization provides an example of a measure verified using this savings equation category. In this example, the heating space temperature set point is lowered according to a schedule during unoccupied hours (scheduled control), and the savings achieved will vary, depending on OAT (variable savings).

Following the equation below, Table 2-18 lists the five-step process for determining adjusted baseline and reporting period energy consumption.

$$Scheduled\ Control/Variable\ Savings = Baseline\ Energy\ - Adjusted\ Reporting\ Period\ Energy$$

Where:

$Scheduled\ Control/Variable\ Savings =$ First-year energy consumption savings resulting from a scheduled control measure with variable savings.

$Adjusted\ Baseline\ Energy = \sum_{All\ Schedule\ Types} Adj\ Baseline\ Consumption_{Schedule\ Type}$ and determined through the five-step process listed in Table 2-18.

$Adjusted\ Reporting\ Period\ Energy =$ $\sum_{All\ Schedule\ Types} Adj\ Reporting\ Period\ Consumption_{Schedule\ Type}$ and determined through the five-step process listed in Table 2-18.

Table 2-18 Adjusted Consumption for Scheduled Control/Variable Savings Measures[48]

<table>
<tr><th>Steps</th><th colspan="3">Details</th></tr>
<tr><td>Develop baseline/reporting regression model(s) by measuring equipment operation and independent variables.</td><td colspan="3">Take short-term measurements at representative load levels for the affected equipment for each schedule type.
Take coincident measurements of the independent variable(s).
Do a regression analysis to determine the relationship between independent variables and equipment load. This relationship should be expressed in terms of an equation (baseline/reporting period model).
If there are schedules for occupied and unoccupied times during the reporting period, evaluators will need two regression models, one for each set of data.</td></tr>
<tr><td rowspan="3">Develop a bin operating profile[49] a by normalized independent variable data.</td><td colspan="3">Develop bin data tables presenting the following data:</td></tr>
<tr><td>Independent Variable</td><td>Load</td><td>Annual Hours</td></tr>
<tr><td>Create approximately 10 bins over the normalized independent variable data range (if the equipment's energy consumption varies depending on weather, use TMY data).</td><td>Calculate the normalized load by applying the baseline/ reporting period regression model to the midpoint of each bin.</td><td>Use short-term measured data to estimate hours of operation within each bin or base this on TMY data and the equipment operating schedule.</td></tr>
<tr><td>Calculate the baseline/ reporting period consumption at each load bin.</td><td colspan="3">Adjusted Consumption:
$$Load, Schedule\ Type = Load_{Schedule/Type} \times Annual\ Hrs_{Schedule\ Type}$$</td></tr>
<tr><td>Sum the consumption savings across bins for each schedule type.</td><td colspan="3">$$\sum_{All\ Load\ Bins_{Schedule\ Type}} Adj\ Consumption_{Load, Schedule\ Type}$$</td></tr>
<tr><td>Sum the consumption savings across schedule types.</td><td colspan="3">$$\sum_{All\ Schedule\ Types} Adj\ Consumption_{Schedule\ Type}$$</td></tr>
</table>

2.6.6.4 Variable Control/Variable Savings

This savings equation category encompasses variable control measures on equipment influenced by independent variables, such as OAT. Introducing a chilled water supply temperature set point reset strategy serves as an example of a measure verified through this savings equation category. In this example, the chilled water supply temperature set point is determined depending on OAT (variable control), and the savings achieved will vary depending on OAT (variable savings).

Following the equation below, Table 2-19 lists the four-step process for determining the adjusted baseline and reporting period energy consumption.

[48] Alternatively, of the independent variable is OAT, TPE can develop an hourly profile over the operating schedule of the affected equipment.

[49] Alternatively, if the independent variable is OAT, evaluators can develop an hourly profile over the full operating schedule of the affected equipment.

$$Variable\ Control/Variable\ Savings$$
$$= Adjusted\ Baseline\ Energy\ - Adjusted\ Reporting\ Period\ Energy$$

Where:

$Variable\ Control/Variable\ Savings =$ First-year energy consumption savings resulting from a variable control measure with variable savings.

$Adjusted\ Baseline\ Energy = \sum_{All\ Load\ Bons} Adj\ Baseline\ Consumption_{Load}$ and determined through the five-step process listed in Table 2-19.

$Adjusted\ Reporting\ Period\ Energy =$ and determined through the five-step process listed in Table 2-19.

Table 2-19 Adjusted Consumption for Variable Control/Variable Savings Measures

<table>
<tr><th>Steps</th><th colspan="3">Details</th></tr>
<tr><td>Develop baseline/reporting regression model(s) by measuring equipment operation and independent variables.</td><td colspan="3">Take short-term measurements at representative load levels for the affected equipment for each schedule type. Take coincident measurements of the independent variable(s). Do a regression analysis to determine the relationship between independent variables and equipment load. This relationship should be expressed in terms of an equation (baseline/reporting period model). If there are schedules for occupied and unoccupied times during the reporting period, evaluators will need two regression models, one for each set of data.</td></tr>
<tr><td rowspan="3">Develop a bin operating profile[50] a by normalized independent variable data.</td><td colspan="3">Develop bin data tables presenting the following data:</td></tr>
<tr><td>Independent Variable</td><td>Load</td><td>Annual Hours</td></tr>
<tr><td>Create approximately 10 bins over the normalized independent variable data range (if the equipment’s energy consumption varies depending on weather, use TMY data).</td><td>Calculate the normalized load by applying the baseline/ reporting period regression model to the midpoint of each bin.</td><td>Use short-term measured data to estimate hours of operation within each bin or base this on TMY data and the equipment operating schedule.</td></tr>
<tr><td>Calculate the baseline/ reporting period consumption at each load bin for each schedule type.</td><td colspan="3">Adjusted Consumption:

Load Schedule Type = $Load_{Schedule/Type}$ x Annual $Hrs_{Schedule\ Type}$</td></tr>
<tr><td>Sum the consumption savings across bins for each schedule type.</td><td colspan="3">$\sum_{All\ Load\ Bins_{Schedule\ Type}} Adj\ Consumption_{Load,Schedule\ Type}$</td></tr>
</table>

[50] *Ibid.*

Sum the consumption savings across schedule types.	$\sum_{All\ Schedule\ Types} Adj\ Consumption_{Schedule\ Type}$

2.6.7 REGRESSION MODELING DIRECTION

Calculating normalized savings for most projects—whether following the IPMVP's Option A, Option B, or Option C— will require the development of a baseline and reporting period regression model.[51] Use one of the following three types of analysis methods to create the model:

- Linear Regression: For one routinely varying significant parameter (e.g., OAT).[52]
- Multivariable Linear Regression: For more than one routinely varying significant parameter (e.g., OAT, occupancy).
- Advanced Regression: For a multivariable, nonlinear fit requiring a polynomial or exponential model.[53]

Develop all models in accordance with best practices and only use them when they are statistically valid (see Section 2.6.7.2 *Testing Model Validity*). If no significant independent variables arise (as with a lighting schedule measure), evaluators are not required to use a model because calculated savings will be inherently normalized.

2.6.7.1 Recommended Methods for Model Development

Use energy and independent variable data that is representative of a full cycle of operation. For example, if facility staff implement a heating space temperature setback measure, collect energy data across the full range of OAT for each of the operating schedules (occupied and unoccupied) for each season, as shown in Table 2-20.

Table 2-20 Example of Data Required for Model Development

	Shoulder Season	**Winter Season**
Occupied Hours	Short-term energy measurements during occupied hours. Measurements should be representative of the full range of shoulder season OAT (approximately 10 OAT bins).	Short-term energy measurements during occupied hours. Measurements should be representative of the full range of winter-season OAT (approximately 10 OAT bins).
Unoccupied Hours	Short-term energy measurements during unoccupied hours. Measurements should be representative of the full range of shoulder-season OAT (approximately 10 OAT bins).	Short-term energy measurements during unoccupied hours. Measurements should be representative of the full range of winter-season OAT (approximately 10 OAT bins).

Analyze the data collected to identify outliers. Only remove outliers when there is a tangible explanation to support the erratic data points. Discussion of how to identify outliers is outside the scope of this Protocol.

---

[51] This could either be a single regression model that uses a dummy variable to differentiate the baseline/reporting period data or two independent models for the baseline and reporting period, respectively.

[52] One of the most common linear regression models is the three-parameter change point model. For example, a model that represents cooling electricity consumption will have one regression coefficient that describes nonweather-dependent electricity use, a second regression coefficient that describes the rate of increase of electricity use with increasing temperature, and a third parameter that describes the change point temperature, also known as the balance point temperature, where weather-dependent electricity use begins.

[53] Evaluators may need to use advanced regression methods if RCx activities impact manufacturing or industrial process equipment.

2.6.7.2 Testing Model Validity

To assess the model's accuracy, begin by reviewing the parameters in the table below.

Table 2-21 Model Statistical Validity Guide[54]

Parameter Evaluated	Description	Suggested Acceptable Values
Coefficient of determination (R^2)	A measure of the extent that the regression model explains variations in the dependent variable from its mean value.	> 0.75
T-statistic (absolute value)	An indication of whether regression model coefficients are statistically significant.	> 2a[55]
Mean bias error	An indication of whether the regression model overstates or understates actual energy consumption.	Will depend on the measure, but generally: < ±5%

A model outside the suggested range indicates parameter coefficients that are relatively poorly determined, with the result that normalized consumption will have relatively high statistical prediction error. Ordinarily, evaluators should not use such a model for normalization, unless the analysis includes appropriate statistical treatment of this prediction error. Discussion of how to proceed in such circumstances is outside the scope of this protocol.

When possible, attempt to enhance the regression model by:

- Increasing or shifting the measurement period
- Incorporating more data points
- Including independent variables previously unidentified
- Eliminating statistically insignificant independent variables

Also, when assessing model validity, consider coefficient of variation of the root mean squared error, fractional savings uncertainty, and residual plots. Refer to ASHRAE Guideline 14-2002 and Bonneville Power Administration's Regression for M&V: Reference Guide for direction on how to assess these additional parameters.

2.6.8 DEEMED SPREADSHEET TOOL FUNCTIONALITY REQUIREMENTS

When collecting measured energy data is not cost-effective and claimed (*ex ante*) savings estimates for a given measure are sufficiently small (75,000 kWh or 5,000 therms), use a deemed approach to calculate savings. In this scenario, the protocol recommends using a spreadsheet tool to calculate savings, and this tool should meet these general requirements:

---

[54] EVO, 2012

[55] Determine the t-statistic threshold based on the evaluator's chosen confidence level; a 95% confidence level requires a t-statistic of 1.96. Evaluators should determine an acceptable confidence level depending on project risk (i.e., savings risk), budget, and other considerations.

- Ensure model transparency. A third party should be able to review the spreadsheet tool and clearly understand how the evaluator derived all savings outputs. To this end, clearly explain and reference all inputs and calculation algorithms within the spreadsheet. Do not lock or hide cells or sheets and check to ensure all links work properly.
- Use relevant secondary data. When using secondary data as inputs to savings algorithms, ensure they are relevant to the project's region or jurisdiction. Substantiate input relevancy within the spreadsheet. For example, if using assumed values for hours of operation for heating equipment, take these secondary data from a regional resource (e.g., a technical resource manual from the most applicable demand-side management authority).
- Verify input elements. Either on site or through the BAS front-end system. Even when using a deemed approach, verify and update some inputs with actual site observations (rather than solely relying on secondary data). For example, confirm a new lighting schedule through the BAS front-end system and note it in the spreadsheet tool.
- Establish default values for unverifiable parameters. Use default values for parameters that cannot be verified. For example, clearly state assumed values for motor efficiencies and load factors.

The Building Optimization Analysis Tool developed by PECI, now CLEAResult, provides an example of benchmark for RCx spreadsheet tools. Although the protocol does not require the following level of rigor, ideally, a best-practice spreadsheet tool should:

- Incorporate regional TMY data.
- Incorporate regional building archetype templates.
- Undergo a calibration process by using measured data from previous regional projects to test algorithms.

2.6.9 SAMPLE DESIGN

Consult the Uniform Methods Project's *Sample Design Cross-Cutting Protocols*[56] for general sampling procedures if the RCx program project population is sufficiently large or if the evaluation budget is constrained. Ideally, use stratified sampling to partition RCx projects by measure type, facility type, and/or project size. Stratification ensures evaluators can confidently extrapolate sample findings to the remaining project population. Regulatory or program administrator specifications typically govern the confidence and precision-level targets that influence sample size.

2.6.10 OTHER EVALUATION ISSUES

When claiming lifetime and net program RCx impacts, evaluators should consider persistence and net-to-gross in addition to first-year gross impact findings.

2.6.11 PERSISTENCE

Persistence of savings encompasses both the retention and the performance degradation of measures. Evaluators should consider persistence on a program-by-program basis because the persistence of RCx projects can vary widely depending on the distribution of measure types implemented and, perhaps more significantly,

[56] https://www.nrel.gov/docs/fy17osti/68567.pdf

on how well facility staff maintains the modifications. Consult the Uniform Methods Project's *Assessing Persistence and Other Evaluation Issues Cross-Cutting Protocols*[57] for more information.

2.6.11.1 Estimating EUL in RCx Projects

For cases where unable to determine measure persistence, the TPE has conducted an analysis of persistence for common measure types in RCx projects and extrapolated EULs suitable for cost-benefit analysis. The analysis was based on findings from a field study of persistence in RCx projects[58].

2.6.11.1.1 Methodology

The TPE calculated EUL for a group of measures using savings persistence estimates. The savings persistence estimates were calculated relative to a baseline program year when measures were implemented. As such, they represent both measure life and savings persistence. Savings persistence accounts for changes in equipment life (the amount of time before equipment fails), measure persistence (i.e., equipment failure or business turnover), and true savings persistence as defined by the UMP (i.e., changes in operating hours, process operations, or performance degradation of the equipment relative to the baseline option).

Savings persistence values were obtained for each measure at various dates following measure installation (e.g., every three years). Savings persistence in years not measured was interpolated between years in which saving persistence was known. This creates a step-like function with different slopes for each measured interval. For years that exceed the last measured persistence, the TPE extrapolated persistence using the slope from the prior measured interval. The EUL was capped at 7 years to account for a lack of savings persistence estimates after year 6.

The equation below shows how the EUL for each measure was calculated from the predicted savings persistence values.

$$Effective\ Useful\ Life = \sum_{t=0}^{n} Savings\ Persistence_t$$

Table 2-22 EUL by Measure

Measure Type	EUL Capped (Yr 7)
Air distribution	4.00
Plant optimization	5.00
Ventilation	5.00
Scheduling	5.50
Filters	5.50
General	5.50

[57] https://www.nrel.gov/docs/fy17osti/68569.pdf

[58] Seventhwave Field Study for ComEd, as referenced in the UMP chapter.

2.6.12 NET TO GROSS

Consult the UMP's *Estimating Net Energy Savings: Common Practices*[59] for a discussion about determining net program impacts at a general level, including direction on how to assess free-ridership. Supplementary to that chapter, however, evaluators may consider assessing participant spillover if evidence emerges of participants implementing no-cost measures. This would specifically apply to no-cost measures identified during the investigation phase, but not explicitly included under the scope of program-funded RCx implementation activities.

If no-cost measures exist and there are no savings claims, the attribution evaluation may involve interviews with building operators and their service providers to obtain estimates of the savings magnitude resulting from these measures. Participant spillover would positively influence the program's overall NTG.

[59] https://www.nrel.gov/docs/fy17osti/68578.pdf

2.7 Protocols for Evaluating Behavioral Programs

The table below outlines common initialisms made in this chapter.

Initialism	What it stands for
BB	Behavior-Based
DiD	Difference in Differences
IPMVP	International Performance Measurement and Verification Protocol
ITT	Intent To Treat
IV	Instrumental Variable
LATE	Local Average Treatment Effect
NREL	National Renewable Energy Laboratory
OLS	Ordinary Least Squares
PG&E	Pacific Gas & Electric
RCT	Randomized Control Trial
RED	Randomized Encouragement Design
SEE Action	State and Local Energy Efficiency Action
TOT	Treatment effect On the Treated
UMP	Uniform Methods Project

2.7.1 DESCRIPTION

Residential BB programs use strategies grounded in the behavioral and social sciences to influence household energy consumption. These may include providing households with feedback about their real-time or historical energy consumption; reframing of consumption information in different ways; supplying energy efficiency education and tips; rewarding households for reducing their energy use; comparing households to their peers; and establishing games, tournaments, and competitions.[60] BB programs often target multiple energy end uses and encourage energy savings, demand savings, or both. Savings from BB programs are usually a small percentage of energy use, typically less than 3%.[61] Utilities introduced the first large-scale residential BB programs in 2008. Since then, scores of utilities have offered these programs to their customers. Although program designs differ, many share these features:

- They are implemented as randomized experiments wherein eligible homes are randomly assigned to treatment or control groups.
- They are large scale by energy efficiency program standards, targeting thousands of utility customers.
- They provide customers with analyses of their historical consumption, energy savings tips, and energy efficiency comparisons to neighboring homes, either in personalized home reports or through a web portal or offer incentives for savings energy.
- They are typically implemented by outside vendors.

[60] See Ignelzi et al. (2013) for a classification and descriptions of different BB intervention strategies and Mazur Stommen and Farley (2013) for a survey and classification of current BB programs. Also, a Minnesota Department of Commerce, Division of Energy Resources white paper (2015) defines, classifies, and benchmarks behavioral intervention strategies.

[61] See Allcott (2011), Davis (2011), and Rosenberg et al. (2013) for savings estimates from residential BB programs.

Utilities will continue to implement residential BB programs as large-scale, randomized control trials (RCTs); however, some are now experimenting with alternative program designs that are smaller scale; involve new communication channels such as the web, social media, and text messaging; or that employ novel strategies for encouraging behavior change (for example, Facebook or other social network competitions to reduce consumption).6 These programs will create new evaluation challenges and may require different evaluation methods than those presented in this protocol. Quasi-experimental methods require stronger assumptions to yield valid savings estimates and may not measure savings with the same degree of validity and accuracy as randomized experiments.

2.7.2 APPLICATION CONDITIONS OF PROTOCOL

This protocol recommends the use of RCTs or randomized encouragement designs (REDs) for estimating savings from BB programs. A significant body of research indicates that randomized experiments result in unbiased and robust estimates of program energy and demand savings. Moreover, recently evaluators have conducted studies comparing the accuracy of savings estimates from randomized experiments and quasi-experiments or observational studies. These comparisons suggest that randomized experiments produce the most accurate savings estimates.[62] This protocol applies to BB programs that satisfy the following conditions[63]:

- Residential utility customers are the target.
- Energy or demand savings are the objective.
- An appropriately sized analysis sample can be constructed.
- Treated customers can be identified and accurate energy use measurements for sampled customers are available.
- It must be possible to isolate the treatment effect when measuring savings.

This Protocol applies only to residential BB programs.[64] This Protocol addresses best practices for estimating energy and demand savings. There are no significant conceptual differences between measuring energy savings and measuring demand savings when interval data are available; thus, evaluators can apply the algorithms in this protocol for calculating BB program savings to either. The Protocol does not directly address the evaluation of other BB program objectives, such as increasing utility customer satisfaction and engagement, educating customers about their energy use, or increasing awareness of energy efficiency.[65] But these program outcomes could be studied in a complementary fashion alongside the energy savings.

---

[62] Allcott (2011) compares RCT difference in differences (DiD) savings estimates with quasi-experimental simple differences and DiD savings estimates for several home energy reports programs. He found large differences between the RCT and quasi-experimental estimates. Also, Baylis et al. (2016) analyzed data from a California utility time-of-use and critical peak pricing pilot program and found that RCT produced more accurate savings estimates than quasi-experimental methods such as DiD and propensity score matching that relied on partly random but uncontrolled variation in participation.

[63] As discussed in the "Considering Resource Constraints" section of the UMP Chapter 1: Introduction, small utilities (as defined under U.S. Small Business Administration regulations) may face additional constraints in undertaking this protocol. Therefore, alternative methodologies should be considered for such utilities.

[64] Evaluators may be able to apply the methods recommended in this protocol to the evaluation of some nonresidential BB programs. For example, Pacific Gas and Electric (PG&E) offers a Business Energy Reports Program, which it implemented as an RCT (Seelig, 2013). Also, Xcel Energy implemented a business energy reports program as an RCT (Stewart, 2013b). Other nonresidential BB programs may not lend themselves to evaluation by randomized experiment. For example, many strategic energy management programs enroll large industrial customers with unique production and energy consumption characteristics for which a randomized experiment would not be feasible (NREL, 2017).

[65] Process evaluation objectives may be important, and omission of them from this protocol should not be interpreted as a statement that these objectives should not be considered by program administrators.

This Protocol also requires that the analysis sample be large enough to detect the expected savings with high probability. Because most BB programs result in small percentage savings, a large sample size (often in the thousands or tens of thousands of customers) is required to detect savings. This protocol does not address evaluations of BB programs with a small number of participants.

Finally, this Protocol requires that the energy use of participants or households affected by the program (for the treatment and control groups) can be clearly identified and measured. Typically, the analysis unit is the household; in this case, treatment group households must be identifiable and individual household energy consumption must be metered. However, depending on the BB program, the analysis units may not be households. For example, for a BB program that generates an energy competition between housing floors or residential buildings at a university, the analysis unit may be floors or buildings; in this case, the energy consumption of these units must be metered.

The characteristics of BB programs that do not determine the applicability of the evaluation protocol include:

- Whether the program is opt-in or opt-out[66]
- The specific behavior-modification theory or strategy
- The channel(s) through which program information is communicated.

Although this protocol strongly recommends RCTs or REDs, it also recognizes that implementing these methods may not always be feasible. Government regulations or program designs may prevent the utilization of randomized experiments for evaluating BB programs. In these cases, evaluators must employ quasi-experimental methods, which require stronger assumptions than do randomized experiments to yield valid savings estimates.[67] If these assumptions are violated, quasi-experimental methods may produce biased results. The extent of the biases in the estimates is not knowable *ex ante*, so results will be less reliable. As more evidence accumulates about the efficacy of quasi-experiments, NREL may update this protocol as appropriate.

2.7.2.1 Examples of Protocol Applicability

Examples of residential BB programs for which the evaluation protocol applies follow:

- Example 1. A utility sends energy reports encouraging conservation to thousands of randomly selected residential customers.
- Example 2. A utility sends email or text alerts to residential customers with tips about reducing energy consumption when their energy consumption is on track to exceed normal levels for the billing period.
- Example 3. A utility invites thousands of residential customers to use its web portal to track their energy consumption in real time, set goals for energy saving, find ideas about how to reduce their energy consumption, and receive points or rewards for saving energy.
- Example 4. A utility sends voice, text, and email messages to thousands of residential utility customers encouraging—and providing tips for— reducing energy consumption during an impending peak demand event.

Examples of programs for which the protocol does not apply follow:

[66] In opt-in programs, customers enroll or select to participate. In opt-out programs, the utility enrolls the customers, and the customers remain in the program until they opt out. An example opt-in program is having a utility web portal with home energy use information and energy efficiency tips that residential customers can use if they choose. An example opt-out program is sending energy reports to utility selected customers.

[67] For example, Harding and Hsiaw (2012) use variation in timing of adoption of an online goal-setting tool to estimate savings from the tool.

- Example 5. A utility uses a mass-media advertising campaign that relies on radio and other broadcast media to encourage residential customers to conserve energy.
- Example 6. A utility initiates a social media campaign (for example, using Facebook or Twitter) to encourage energy conservation.
- Example 7. A utility runs a pilot program to test the savings from in-home energy-use displays and enrolls too few customers to detect the expected savings.
- Example 8. A utility runs a BB program in a large, master-metered college dormitory to change student attitudes about energy use. The utility randomly assigns some rooms to the treatment group and other rooms to the control group.

The Protocol does not apply to Example 5 or Example 6 because the evaluator cannot identify who received the messages. This does not apply to Example 7 because too few customers are in the pilot to accurately detect energy savings. This does not apply to Example 8 because energy-use data are not available for the specific rooms assigned to the treatment and control groups.

2.7.3 SAVINGS CONCEPTS

The protocol recommends RCTs and REDs to develop unbiased and robust estimates of energy or demand savings from BB programs that satisfy the applicability conditions described in Section 2.7.2 Unless otherwise noted, all references in this protocol to savings are to net energy or demand savings.

Section 2.7.3.1 defines some key concepts and 2.7.3.2 describes specific evaluation methods.

2.7.3.1 Definitions

The following key concepts are used throughout this protocol.

- Control group. In an experiment, the control group comprises subjects (for example, utility customers) who do not receive the program intervention or treatment.
- Experimental design. Randomized experiments rely on observing the energy use of subjects who were randomly assigned to program treatments or interventions in a controlled process.
- External validity. Savings estimates are externally valid if evaluators can apply them to different populations or time periods from those studied.
- Internal validity. Savings estimates are internally valid if the savings estimator is expected to yield an estimate of the causal effect of the program on consumption.
- Opt-in program. A program in which customers must enroll themselves. Utilities use opt-in BB programs if the customers must agree to participate, and the utility cannot administer treatment without consent.
- Opt-out program. A program in which a utility can automatically enroll customers. Utilities use opt-out BB programs if the utility does not need prior agreement from the customer to participate. The utility can administer treatment without the customer’s consent, and customers remain enrolled until they ask the utility to stop the treatment.
- Quasi-experimental design. Quasi-experimental designs rely on a comparison group that is not obtained via random assignment. Such designs observe energy use and determine program treatments or interventions based on factors that may be partly random but not controlled.
- Randomized control trial. An RCT uses random variation in which subjects are exposed to the program treatment to obtain an estimate of the program treatment effect. By randomly assigning subjects to

treatment, an RCT controls for all factors that could confound measurement of the treatment effect. An RCT is expected to yield an unbiased estimate of program savings. Evaluators randomly assign subjects from a study population to a treatment group or a control group. Subjects in the treatment group receive one program treatment (there could be multiple treatments and treatment groups), whereas subjects in the control group receive no treatment. The RCT ensures that receiving the treatment is uncorrelated with the subjects' pretreatment 6 energy use, and that evaluators can attribute any difference in energy use between the groups to the treatment.

- Randomized encouragement design. In a RED, evaluators randomly assign subjects to a treatment group that receives encouragement to participate in a program or to a control group that does not receive encouragement. The RED yields unbiased estimates of the effect on energy consumption from the encouragement and the effect on energy consumption from participating in the program for subjects who participated because of the encouragement. This latter estimate is known as the local average treatment effect (LATE).
- Treatment. A treatment is an intervention administered through the BB program to subjects in the treatment group. Depending on the research design, the treatment may be a program intervention or encouragement to accept an intervention.
- Treatment effect. This is the effect of the BB program intervention(s) on energy consumption for a specific population and time period. The treatment effect may persist after the period in which the intervention is administered. This means that for long-running programs, some savings may be attributable to treatments administered in previous periods. Section B.6.6.1 of this protocol addresses BB program savings persistence and measure life.
- Treatment group. The experimental group of subjects who received the treatment.

2.7.3.2 Randomized Experimental Research Designs

This section outlines the application of randomized experiments for evaluating BB programs. The most important benefit of an RCT or RED is that, if carried out correctly, the experiment results in an unbiased estimate of the program's causal impact. Unbiased savings estimates have internal validity. A result is internally valid if the evaluator can expect the value of the estimator to equal the savings caused by the program intervention. The principal threat to internal validity in BB program evaluation derives from potential selection bias about who receives a program intervention. RCTs and REDs yield unbiased savings estimates because they ensure that receiving the program intervention is uncorrelated with the subjects' energy consumption.

Randomized experiments may yield savings estimates that are applicable to other populations or time periods, making them externally valid. Whether savings have external validity will depend on the specific research design, the study population, and other program features. Program administrators should exercise caution in applying BB program savings estimates for one population to another or to the same population at a later time, because differences in population characteristics, weather, or naturally occurring efficiency can cause savings to change.

A benefit of randomized field experiments is their versatility: evaluators can apply them to a wide range of BB programs regardless of whether they are opt-in or opt-out programs. Evaluators can apply randomized experiments to any program where the objective is to achieve energy or demand savings; evaluators can construct an appropriately sized analysis sample; and accurate measurements of the energy consumption of sampled units can be obtained.

Randomized experiments, particularly those with large sample sizes, yield highly robust savings estimates that are not model dependent; that is, they do not depend on the specification of the model used for estimation.

The choice of whether to use an RCT or RED to evaluate program savings should depend on several factors, including whether it is an opt-in or opt-out program, the expected number of program participants, and the utility's tolerance for subjecting customers to the requirements of an experiment. For example, using an RCT for an opt-in program might require delaying or denying participation for some customers. A utility may prefer to use a RED to accommodate all the customers who want to participate.

Implementing an RCT or RED design requires upfront planning. Program evaluation must be an integral part of the program planning process, as described in the randomized experiment research design descriptions in Section 2.7.3.3 *Basic Features.*

2.7.3.3 Basic Features

This section outlines several types of RCT research designs, which are simple but very powerful research tools. The core feature of RCT is the random assignment of study subjects (for example, utility customers, floors of a college dormitory) to a treatment group that receives or experiences an intervention or to a control group that does not receive the intervention.

Section 2.7.3.3.1 *Common Features of Randomized Control Trial Designs* outlines some common features of RCTs and discusses specific cases.

2.7.3.3.1 Common Features of Randomized Control Trial Designs

The key requirements of an RCT are incorporated into the following steps:

1. Identify the study population. The program administrator screens the utility population if the program intervention is only offered to certain customer segments, such as single family homes. Programs designers can base eligibility on dwelling type (for example, single family, multifamily), geographic location, completeness of recent billing history, heating fuel type, utility rate class, or other energy use characteristics.
2. Identify the treatment effect the experiment will measure and the measurement approach. Is the BB treatment designed to reduce peak demand, energy consumption, or both? For what periods will savings be measured? A year? Each month of the year or the sample? Hour of the day?
3. Determine sample sizes. The numbers of subjects to assign to the treatment and control groups should depend on the type of randomized experiment (for example, REDs and opt-out RCTs generally require more customers), the hypothesized savings, the variance of consumption, and tolerance for error. The number of subjects assigned to the treatment versus control groups should be large enough to detect the hypothesized program effect with the required probability (the statistical power of the experiment), though it is not necessary for the treatment and control groups to be equally sized. Furthermore, some jurisdictions or program administrators may require savings estimates to achieve certain levels of confidence and precision such as 90% confidence with +/-10% precision. An experiment may have sufficient statistical power, but not yield estimates that meet the required confidence and precision. Evaluators can use savings estimation simulations to calculate statistical power and confidence and precision for a sample of a given size. Repeated simulations for different sample sizes can be used to

obtain minimum sample sizes for the treatment and control groups that meet the desired level of statistical power and confidence and precision. Program administrators and regulators should specify requirements for statistical significance and/or confidence and precision before a program is designed so evaluators can size the experiment appropriately. It is not uncommon for BB programs with expected savings of less than 3% to require thousands of subjects in the treatment and control groups.

4. Randomly assign subjects to treatments and control. Study subjects should be randomly assigned to treatment and control groups. To maximize the credibility and acceptance of BB program evaluations by regulators and program administrators, this protocol recommends that a qualified independent third party perform the random assignment. Also, to preserve the integrity of the experiment, customers must not choose their assignments. The procedure for randomly assigning subjects to treatment and control groups should be transparent and well documented.
5. Verify equivalence. An important component of the random assignment process is to verify that the treatment and control groups are statistically equivalent or balanced in their observed covariates. At a minimum, evaluators should verify that before the intervention there are no statistically significant differences between treatment and control homes in average pretreatment energy consumption and in the distribution of pretreatment energy use. Evaluators should conduct analogous tests using customer demographic and housing characteristics data if such data are available.
6. Administer the treatment. The intervention must be administered to the treatment group and withheld from the control group. To avoid a Hawthorne effect, in which subjects change their energy use in response to observation, control group subjects should receive minimal information about the study. Depending on the research subject and intervention type, the utility may administer treatment once or repeatedly and for different durations. However, the treatment period should be long enough for evaluators to observe any effects of the intervention.
7. Collect data. Data must be collected from all randomized study subjects, not only from those who chose to participate or only from those who participated for the whole study or experiment. Preferably, evaluators should collect multiple pre and post-treatment energy consumption measurements. Such data enable the evaluator to control for time-invariant differences in average energy use between the treatment and control groups to obtain more precise savings estimates. Step 8 discusses this in further detail.
8. Estimate savings. Evaluators should calculate savings as the difference in energy consumption or difference in differences (DiD) of energy consumption between the subjects who were initially assigned to the treatment and those assigned to the control group. To obtain an unbiased savings estimate, evaluators must compare the energy consumption from the entire group of subjects who were originally randomly assigned to the treatment group to the entire group of subjects who were originally randomly assigned to the control group. For example, the savings estimate would be biased if evaluators used only data from utility customers in the treatment group who chose to participate in the study. The difference in energy consumption between the treatment and control groups, usually called an intent-to-treat (ITT) effect, is an unbiased estimate of savings because subjects were randomly assigned to the treatment and control groups. The effect is an ITT because, in contrast to many randomized clinical medical trials, ensuring that treatment group subjects in most BB programs comply with the treatment is impossible. For example, some households may opt out of an energy reports program, or they may fail to notice or open the energy reports. Thus, the effect is ITT, and the evaluator should base the results on the initial assignment of subjects to the treatment group, whether or not subjects actually complied with the

treatment. The savings estimation should be well documented, transparent, and performed by an independent third party.

2.7.3.4 Common Designs

This section describes some of the RCT designs commonly used in BB programs.

2.7.3.4.1 Randomized Control Trial with Opt-Out Program Design

One common type of RCT includes the option for treated subjects to opt out of receiving the program treatment. This design reflects the most realistic description of how most BB programs work. For example, in energy reports programs, some treated customers may ask the utility to stop sending them reports.

Figure 2-9 depicts the process flow of an RCT in which treated customers can opt out of the program. In this illustration, the utility initially screened its customers to refine the study population.

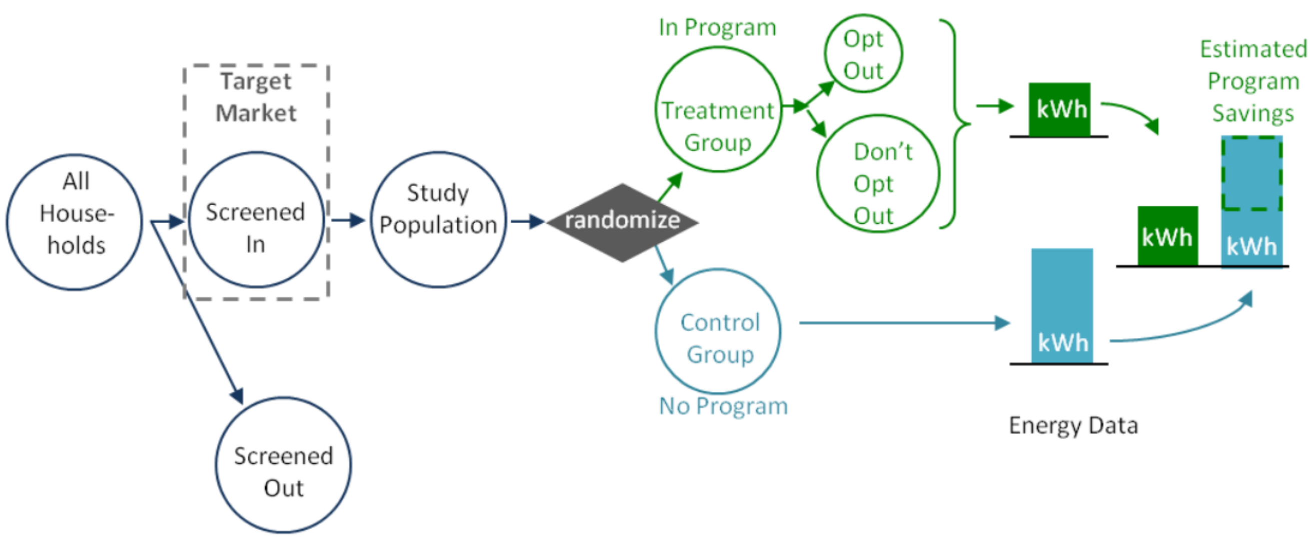


Figure 2-9 Illustration of RCT with Opt-Out Program Design[68]

Customers who pass the screening comprise the study population or sample frame. The ITT savings estimate will apply to this population. Alternatively, the utility may want to study only a sample of the screened population, in which case customers from the population should be sampled randomly. The analysis sample must be large enough to meet the minimum required sizes for the treatment and control groups.

The next steps in an opt-out RCT are to (1) randomly assign subjects in the study population to the program treatment and control groups, (2) administer the program treatments, and (3) collect energy use data.

The distinguishing feature of this randomized experimental design is that customers can opt out of the program. As Figure 2-9 shows, evaluators should include opt-out subjects in the energy savings analysis to obtain unbiased savings estimates. Evaluators can then calculate savings as the difference in average energy consumption between treatment group customers, including optout subjects and control group customers. Removing opt-out subjects from the analysis would bias the savings estimate because certain subjects in the control group would

[68] UMP Chapter 17, 2014

have opted out if they had been treated but it is impossible to know who that might be in the control group. The resulting savings estimate is therefore an average of the savings of treated customers who remain in the program and of customers who opted out.

Depending on the type of BB program, the percentage of customers who opt out may be small and opt outs may not affect the savings estimates significantly (for example, few customers opt out of energy reports programs).

2.7.3.4.2 Randomized Control Trial with Opt-In Program Design

Some BB programs require utility customers to enroll before they can be treated. Examples include web-based home audit or energy consumption tools; online courses about energy rates and home efficiency; or in-home displays. These interventions contrast with interventions such as home energy reports that can be administered to subjects without having their prior agreement.

An opt-in RCT (Figure 2-10) can accommodate the necessity for customers to opt into some BB programs. This design results in an unbiased estimate of the ITT effect for customers who opt into the program. The estimate of savings will have internal validity; however, it will not necessarily have external validity because it will not apply to subjects who do not opt in.

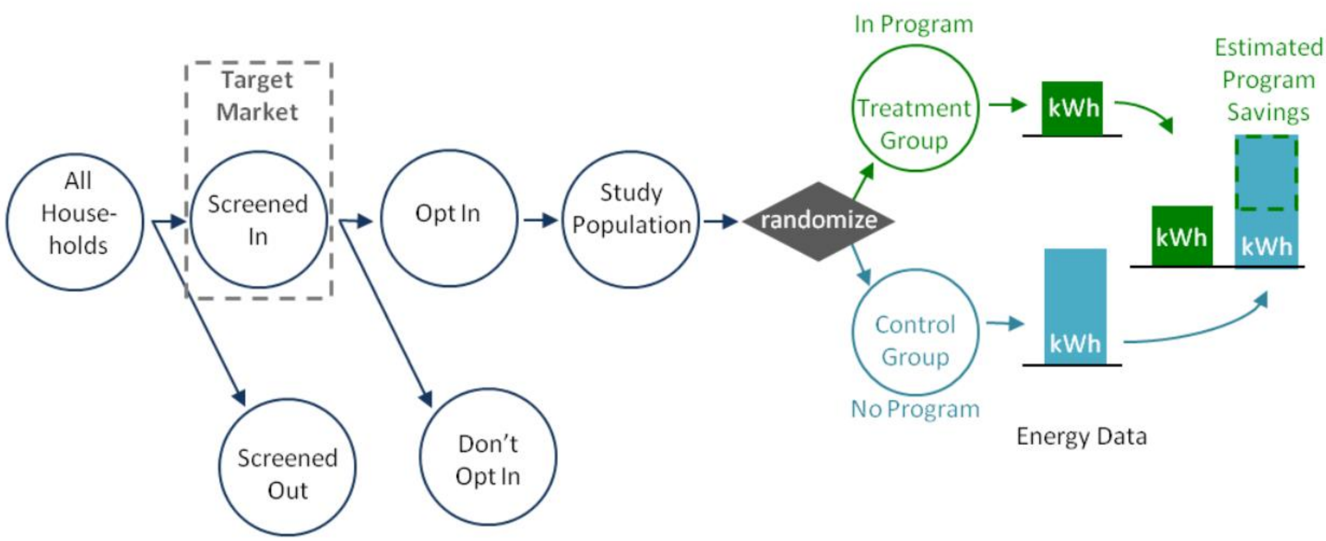


Figure 2-10 Illustration of RCT with Opt-In Program Design[69]

Implementing opt-in RCTs is very similar to implementing opt-out RCTs. The first step, screening utility customers for eligibility to determine the study population, is the same. The next step is to market the program to eligible customers. Some eligible customers may then agree to participate. Then, an independent third party randomly assigns these customers to either a treatment group that receives the intervention or a control group that does not. The utility delays or denies participation in the program to customers assigned to the control group. Thus, only customers who opted in and were assigned to the treatment group will receive the treatment.

[69] *Ibid.*

Randomizing only opt-in customers ensures that the treatment and control groups are equivalent in their energy use characteristics. In contrast, other quasi-experimental approaches, such as matching participants to nonparticipants, cannot guarantee either this equivalence or the internal validity of the savings estimates.

After the random assignment, the opt-in RCT proceeds the same as an RCT with opt-out subjects: the utility administers the intervention to the treatment group. The evaluator collects energy consumption data from the treatment and control groups, then estimates energy savings as the difference in energy consumption between the groups. The evaluator does not collect energy consumption data for customers who do not opt into the program.

An important difference between the opt-in RCT and opt-out RCT is how to interpret the savings estimates. In the opt-out RCT, the evaluator bases the savings estimate on a comparison of the energy consumption between the randomized treatment and control groups, which pertains to the entire study population. In contrast, in the opt-in RCT, the savings estimate pertains to the subset of customers in the study population who opted into the program, and the difference in energy consumption represents the treatment effect for customers who opted into the program. Opt-in RCT savings estimates have internal validity; however, they do not apply to customers who did not opt into the program.

2.7.3.4.3 Randomized Encouragement Design

Some BB interventions require participants to opt into treatment but delaying or denying participation to some customers may be undesirable. In this case, neither the opt-out nor the opt-in RCT design would be appropriate, and this protocol recommends an RED. Instead of randomly assigning subjects to receive or not receive the intervention, a third party randomly assigns them to a treatment group that is encouraged to accept the intervention (that is, to participate in a program or adopt a measure), or to a control group that does not receive encouragement. Examples of common kinds of encouragement include direct paper mail or email informing customers about the opportunity to participate in a BB program. Customers who receive the encouragement can refuse to participate, and, depending on the program design, control group customers who learn about the program may be able to participate.

The RED yields an unbiased estimate of the effect of encouragement on energy consumption and, depending on the program design, can also provide an unbiased estimate of either the effect of the intervention on customers who accept the intervention because of the encouragement or the effect of the intervention on all customers who accept it. Necessary conditions for a RED to produce an unbiased estimate of savings from the BB intervention is that the encouragement only influence the decision to accept the BB intervention and not energy consumption. For example, the RED must be such that customers who receive a direct mailing encouraging them to log into a website with personalized energy efficiency recommendations only save energy if they decide to log into the site; the mailing itself must not cause the customer to save energy if the customer never logs on. If the encouragement causes customers to save energy, it may be impossible to isolate the savings from the intervention. Programs designed as REDs should design and distribute encouragement materials that will not affect consumption. If evaluators expect that the encouragement will cause energy savings, they could send the similar messaging that excludes the program enrollment option to the control group or to a second randomized treatment group. Evaluators could use the second randomized treatment group to test whether the encouragement produces savings.

Figure 2-11 illustrates the process flow for a RED program evaluation. As with the RCT with optout and opt-in RCT, the first two steps are to identify the sample frame and select a study population. Next, like the RCT with opt out, a third party randomly assigns subjects to a treatment group, which receives encouragement, or to a control group, which does not. For example, a utility might employ a direct mail campaign that encourages treatment group customers to use an online audit tool. The utility would administer the intervention to treatment group customers who opt in. Although customers in the control group did not receive encouragement, some may learn about the program and decide to sign up. The program design shown in Figure 2-11 allows for control group customers to receive the behavioral intervention.

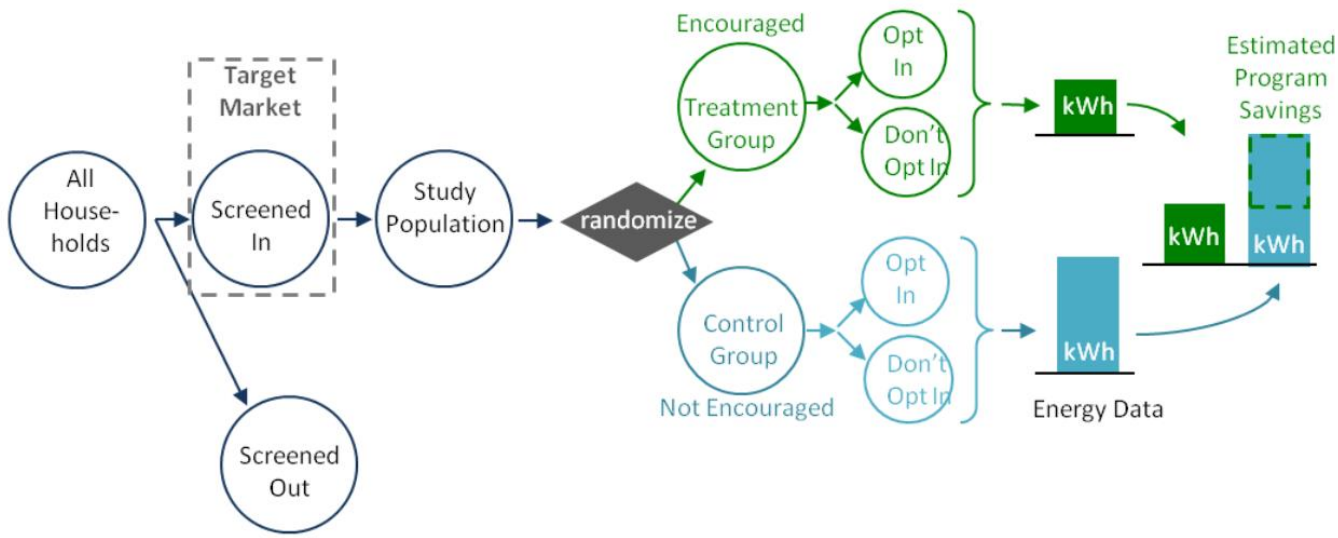


Figure 2-11 Illustration of RED Program Design[70]

In Figure 2-11, the difference in energy consumption between homes in the treatment and control groups is an estimate of savings from the encouragement, not from the intervention. However, evaluators can also use the difference in energy consumption to estimate savings for customers who accept the intervention because of the encouragement. To see this, consider that the study population comprises three types of subjects: (1) always takers, or those who would accept the intervention whether encouraged or not; (2) never takers, or those who would never accept the intervention even if encouraged; and (3) compliers, or those who would accept the intervention only if encouraged. Compliers participate only after receiving the encouragement.

Because eligible subjects are randomly assigned to groups depending on whether they receive encouragement, the treatment and control groups are expected to have equal frequencies of always takers, never takers, and compliers. After treatment, the only difference between the treatment and control groups is that compliers in the treatment group accept the treatment and compliers in the control group do not. In both groups, always takers accept the treatment and never takers always refuse the treatment. Therefore, the difference in energy consumption between the groups reflects the treatment effect of encouragement on compliers (known as LATE).

Furthermore, for the study to have enough statistical power to detect the expected effect, there must be very large encouraged and non-encouraged groups relative to a RCT or quasi-experimental design and/or a high proportion of compliers in the treatment group; a power calculation should be done to ensure that there are

[70] *Ibid.*

enough customers in the encouraged and non-encouraged groups to produce significant savings estimates for the expected take-up rate.[71]

To estimate the effect of the intervention on compliers, evaluators can either employ instrumental variables (IV), using the random assignment of customers to receive encouragement as an instrument for the customer's decision to accept the intervention (that is, to participate).

The IV approach is presented in Section 2.7.4.4.9 *Randomized Encouragement Design*. Another option is that evaluators can scale the treatment effect of the encouragement by the difference between treatment and control groups in the percentage of customers who receive the intervention (note that in this equation, if the non-encouraged customers are not allowed to take up the treatment, the second term in the denominator will be zero)[72].

$$\frac{1}{(\text{\% of encouraged customers who accepted} - \text{\% of nonencouraged customer who accepted})}$$

If customers in the control group are permitted to participate if they find out about the treatment even though they did not receive encouragement, the LATE does not capture the program effect on always takers. (Note, however, in most programs, the control group is not permitted to take up the treatment). If customers in the control group are permitted to participate, the LATE may differ from the average treatment effect unless the savings from the intervention is the same for compliers and always takers. However, the LATE will be equal to the average treatment effect if the control group customers (non-encouraged customers) are not permitted to take up the treatment.

For BB programs with REDs that do not permit control group customers to participate, evaluators can estimate the treatment effect on the treated (TOT). The TOT is the effect of the program intervention on all customers who accept the intervention. In this case, the difference in energy use between the treatment and control groups reflects the impact of the encouragement on the always takers and compliers in the treatment group. Scaling the difference by the inverse of the percentage of customers who accepted the intervention yields an estimate of the TOT impact.[73]

Successful application of a RED requires that compliers comprise a percentage of the encouraged population that is sufficiently large given the number of encouraged customers. If the RED generates too few compliers, the effects of the encouragement and receiving the intervention will not be precisely estimated. Therefore, before employing a RED, evaluators should ensure that the sample size is sufficiently large, and that the encouragement will result in the required number of compliers. If the risk of a RED generating too few compliers is significant, evaluators may want to consider alternative approaches, including quasi-experimental methods.

[71] For an example of a power calculation for REDs, see Fowlie (2010).

[72] This approach of estimating savings from the intervention because of encouragement assumes zero savings for customers who received encouragement but did not accept the intervention. If encouraged customers who did not accept the intervention reduced their energy use in response to the encouragement, the savings estimate for compliers will be biased upward.

[73] If the effect of program participation is the same for compliers as for others, those who would have participated without encouragement (always takers) and those who do not participate (never takers), then the RED will yield an unbiased estimate of the population average treatment effect.

2.7.3.5 Randomized Experiments Implementation Requirements and Evaluation Guidance

This protocol strongly recommends the use of randomized field experiments (RCTs or REDs) for evaluating residential BB programs. Table 2-23 summarizes the benefits and requirements of evaluating BB programs using RCTs and REDs, as described in Sections 2.7.3.1 *Definitions* through 2.7.3.4 *Common Designs*.

Table 2-23 Benefits and Implementation Requirements of Randomized Experiments[74]

Evaluation Benefits	Implementation Requirements
▪ Yield unbiased, valid estimates of causal program impacts, resulting in a high degree of confidence in the savings ▪ Yield savings estimates that are robust to changes in model specification ▪ Are versatile, and can be applied to opt-out and opt-in BB programs ▪ Are widely accepted as the “gold standard” of good program evaluations ▪ Result in transparent and straightforward analysis and evaluation ▪ Can be designed to test specific research questions such as persistence of savings after treatment ends	▪ An appropriately sized analysis sample ▪ Accurate energy use measurements for sampled units ▪ Advance planning and early evaluator involvement in program design ▪ Restricted participation or program marketing to randomly selected customers

The principal benefit of randomized experiments is that they yield unbiased and robust estimates of program savings or other treatment effects. They are also versatile, widely accepted, and straightforward to analyze. The principal requirements for implementing randomized experiments include the availability of accurate energy consumption measurements and a sufficiently large study population.

Also, this protocol specifically recommends REDs or RCTs for estimating BB program savings as both designs yield unbiased savings estimates. The choice of RED or RCT will depend primarily on program design and implementation considerations whether the program has an opt-in or opt-out design. RCTs work well with opt-out programs such as residential energy reports programs. Customers who do not want to receive reports can opt out without adversely affecting the evaluation. RCTs also work well with opt-in programs, for which customer participation can be delayed (for example, customers are put on a “waiting list”) or denied. For situations in which delaying or denying a certain subset of customers is impossible or costly, REDs may be more appropriate. REDs can accommodate all interested customers, but have the disadvantages of requiring larger analysis samples, two analysis steps to yield a direct estimate of the behavioral intervention’s effect on energy use, and a high proportion of compliers among encouraged customers.

Table 2-24 lists some issues to consider when choosing a RCT or RED.

[74] *Ibid.*

Table 2-24 Considerations in Selecting a Randomized Experimental Design

Experimental Design	Evaluation Benefits	Implementation and Evaluation Requirements
RCT	▪ Yields unbiased, robust, and valid estimates of causal program impacts, resulting in a high degree of confidence in the savings ▪ Simple to understand ▪ Works well with opt-out programs ▪ Works well with opt-in programs if customers can be delayed or denied	▪ May require delaying or denying participation of some customers if program requires customers to opt in
RED	▪ Yields unbiased, robust, and valid estimates of causal program impacts, resulting in a high degree of confidence in the savings ▪ Can accommodate all customers interested in participating ▪ Works well with opt-in and opt-out programs	▪ More complex design and harder to understand ▪ Requires a more complex analysis ▪ Requires larger analysis sample

2.7.3.6 Quasi-Experimental Methods

There are other evaluation design methods that use non-randomized control groups, called quasi-experimental methods. With these methods, the control group is not randomly assigned. Thus, quasi-experimental methods often suffer from selection bias and may produce biased estimates of energy savings. However, in specific cases in which RCTs are not feasible, quasi-experimental approaches can still meet the acceptability criteria recommended in this report, although the results they generate will be less reliable. These methods are discussed in Section 2.7.4.4.10 *Quasi-Experimental Methods*.

2.7.4 SAVINGS ESTIMATION

Energy savings for a household in a BB program is the difference between the energy the household consumed and the energy the household would have consumed if it had not participated. However, the energy consumption of a household cannot be observed under two different states. Instead, to estimate savings, evaluators should compare the energy consumption of households in the treatment group to that of a group of households that are statistically the same but did not receive the treatment. In a randomized experiment, assignment to the treatment is random; thus, evaluators can expect control group subjects to consume, on average, the same amount of energy that the treatment group would have consumed without the treatment. The difference in their energy consumption will therefore be an unbiased estimate of energy savings.

Savings can be estimated using energy consumption data from the treatment period only or from before and during the treatment. If energy consumption data from only the treatment period are used, evaluators estimate the savings as a simple difference. If data on energy consumption before treatment is administered are available, evaluators can estimate the savings as a DiD or a simple difference that controls for pretreatment energy consumption. The approach that estimates savings conditional on pretreatment consumption is sometimes referred to as a “post-only model with pre-period controls.”[75] The availability of energy consumption data for the period before the treatment will determine the approach but incorporating pretreatment consumption data in the analysis is strongly advised when such data are available.

Both approaches result in unbiased estimates of savings (that is, in expectation, the two methods are expected to yield an estimate equal to the true savings). However, estimators using pretreatment data generally result in more precise savings estimates (that is, the estimators using pretreatment data will have a smaller standard error) as they account for time-invariant energy use that contributes significantly to the variance of energy consumption between utility customers.[76]

Evaluators should collect at least one full year of historical energy use data (the 12 months immediately before the program start date) to ensure baseline data fully reflect seasonal energy use effects.

Regulators usually determine the frequency of program evaluation. Although requirements vary between jurisdictions, most BB programs are evaluated once per year. Annual evaluation will likely be necessary for the first several years of many BB programs such as HER programs because savings tend to increase for several years before leveling off. However, some program administrators may desire measurement or evaluation more frequently than annually to closely track program performance and optimize the program delivery.

2.7.4.1 IPMVP Option

This protocol’s recommended evaluation approach aligns best with IPMVP Option C, which recommends statistical analysis of data from utility meters for whole buildings or facilities to estimate savings. Option C is intended for projects with expected savings that are large relative to consumption. This protocol recommends regression analysis of residential customer consumption and statistical power analysis to determine the analysis sample size necessary to detect the expected savings.

2.7.4.2 Sample Design

Utilities should integrate the design of the analysis sample with program planning, because numerous considerations, including the size of the analysis sample, the method of recruiting customers to the program, and the type of randomized experiment, must be addressed before the program begins.

2.7.4.2.1 Sample Size

The analysis sample should be large enough to detect the minimum hypothesized program effect with desired probability.[77] If the sample is too small, evaluators risk being unable to detect the program’s effect and possibly wrongly accepting a hypothesis of no effect or there may be substantial uncertainty about the program’s effect at the end of the study, and it may be necessary to repeat the study with a larger sample. On the other hand, if

[75] The model with pretreatment consumption control variables is a more efficient estimator (that is, it is expected to have smaller variance) than the DiD estimator when the model errors are independent and identically distributed or when serial correlation of consumption is low (Burlig, Preonas, and Woerman 2017). This model is more efficient because it uses one degree of freedom rather than multiple degrees of freedom—one for each study subject—to account for between-subject differences in consumption. However, when serial correlation of customer consumption is high, there is little or no gain in efficiency over the fixed effects in the DiD approach.

[76] Postonly or DiD estimation with customer fixed effects also accounts for differences in mean energy use between treatment and control group subjects that are introduced when subjects are randomly assigned to the treatment or control group. Evaluators may not expect such differences with random assignment; however, these differences may nevertheless arise.

[77] A program can comprise a collection of randomized cohorts or waves in which the treatment effect of interest is at the program level and not at the level of individual cohorts. In this case, power calculations and tests of statistical significance can be applied to the collection of cohorts. Examples of this design include behavioral programs that consist of several waves launched over time or rolling enrollment waves.

the sample size is too large, researchers may risk wasting scarce program resources[78]. Oversizing the sample is primarily a concern for pilot programs, for which determining the savings is often a primary objective.

To determine the minimum number of subjects required and the number of subjects to be assigned to the treatment and control groups, researchers should employ a statistical power analysis. Statistical power is the likelihood of detecting a program impact of minimum size (the minimum detectable effect). Typically, researchers design studies to achieve statistical power of 80% or 90%. A study with 80% statistical power has an 80% probability of detecting the hypothesized treatment effect.

Statistical power analysis can be conducted in two ways. First, if data on consumption or another outcome of interest before treatment are available for the study population, researchers can use simulation to estimate the probability of detecting an effect of a certain size (for example, 1%) for possible treatment and control groups sizes, NT and NC.

Simulation follows these steps:

- Researchers should divide the pretreatment sample period into two parts, corresponding to a simulation pretreatment and post-treatment period. For example, an evaluator with monthly billing consumption data for 24 pretreatment months could divide the pretreatment period into months 1 to 12 and months 13 to 24 and designate the first 12 months as the simulation pretreatment period.
- From the eligible program population, researchers should randomly assign NT subjects to the treatment group and NC subjects to the control group.
- Researchers should decide upon the minimum detectable treatment effect (for example, 2 kWh/period/subject), and a distribution of treatment effects (for example, normal distribution with mean 2 and standard deviation 1). For each treatment customer, the researcher should simulate the program treatment effect, taken randomly from the distribution of treatment effects, during the simulation treatment period. (One could also assume the treatment effect is the same for all customers and merely apply the same effect to all households; however, the power calculation is likely to underestimate the number of households needed because it assumes zero variance for the treatment effect).
- Researchers should randomly sample with replacement NT customers from the treatment group and NC subjects from the control group.
- Researchers should estimate the program treatment effect for the sample only using data from the simulation pretreatment and simulation post-treatment periods and record the estimate and whether the estimate was statistically significant for a given Type 1 error.
- Researchers should repeat steps 4 and 5 many times (for example, >250), and calculate the percentage of iterations when the estimated treatment effect was statistically different than zero. This is the statistical power of the study, the probability of detecting savings of x with treatment group size NT and control group size NC.

It is important that the estimation method used in the statistical power simulation adheres as closely as possible to the method evaluators plan to use for the actual savings estimation. Otherwise, the statistical power analysis may be misleading about the likelihood of detecting the savings.

[78] The utility may also base the number of subjects in the treatment group on the total savings it desires to achieve.

The second approach to calculating statistical power uses analytic formulas. Researchers employing panel data methods and using statistical power formulas are advised to use the formulas in Burlig et al. (2017). Though more demanding to implement than those in Frison and Pocock (1992), the statistical power formulas in Burlig et al. (2017) are more accurate because they account for both intracluster correlations and arbitrary serial correlations of customer consumption over time. The required inputs for the power calculation are:

- The minimum detectable treatment effect
- The coefficient of variation of energy use, taken from a sample of customers
- The specific analysis approach to be used (for example, simple differences of means or a repeated measure analysis)
- The numbers of pretreatment and post-treatment observations per subject
- The tolerances for Type I and Type II statistical errors (as discussed in Section 2.7.4.3.3 *Other Data Requirements*)
- The intracluster correlation of an individual subject's energy use or error term covariances for pretreatment and post-treatment periods and between periods.

Many statistical software applications, including SAS, STATA, and R, include packages for performing statistical power analyses.

Researchers conducting statistical power analyses should keep in mind the following:

- For a given program population, statistical power will be maximized if 50% of subjects are assigned to the treatment group and 50% are assigned to the control group. However, especially for large programs, researchers may obtain acceptable levels of statistical power with unbalanced treatment and control groups. The principal benefit of a smaller control group is that more customers are available to participate in the program.
- If the BB program will operate for more than several months and repeated measurements are planned, researchers should adjust the required sample sizes to account for attrition (the loss of some subjects from the analysis sample because of account closures or withdrawal from the study).

Finally, many studies will not estimate statistically significant savings. This null result could mean that the program did not save energy or that the evaluation did not detect the savings. During the program and evaluation design phase, if clear guidelines are not already available, program administrators, regulators, and evaluators should reach agreement about how statistically insignificant savings estimates should be treated and reported and whether all or some savings based on such estimates can be claimed.

2.7.4.2.2 Random Assignment to Treatment and Control Groups by an Independent Third Party

After determining the appropriate sizes of the treatment and control group samples, researchers should randomly assign subjects to the treatment and control groups. For the study to have maximum credibility and acceptance, this protocol recommends that an independent and experienced third party, such as an independent evaluator, perform the randomization. If there is a significant risk that the random assignment will result in unbalanced treatment and control groups with statistically different consumption, this protocol recommends that evaluators first stratify the study population by pretreatment energy consumption levels and then randomly assign subjects in each stratum to treatment and control groups. Stratifying the sample will increase the likelihood that treatment and control group subjects have similar pretreatment means and variances.

This protocol also recommends that the unit of analysis (for example, a household) should be the basis for random assignment to treatment or control group. For example, in an analysis of individual customer consumption, it is better to randomly assign individual customers instead of all customers in the same neighborhood (for example, in a zip code or census block) to receive the treatment. However, for some BB programs, it may not be feasible to randomize the unit of analysis. For example, in some multifamily housing BB programs, the unit of analysis may be individual customers but all customers in the same multifamily building may receive the treatment. In this case, it will be necessary to randomly assign multifamily buildings to the treatment or control group. In this case, researchers will need to account for correlations in consumption between customers in the same housing units.

Although this protocol recommends that an independent and experienced third party perform the random assignment, circumstances sometimes make this impossible. In such cases, a third-party evaluator should verify that the assignment of treatment and control group subjects was done correctly and did not introduce bias into the selection process.

2.7.4.2.3 Equivalency Check

The third party performing the random assignment must verify that the characteristics of subjects in the treatment group, including pretreatment energy consumption, are balanced with those in the control group. If subjects in the groups are not equivalent, the energy savings estimates may be biased. Evaluators should perform two equivalency checks: (1) for all customers who were randomly assigned to the treatment and control groups; and (2) for all randomized customers who remain in the analysis sample after data cleaning and preparation are completed. Ideally, the consumption data used for the equivalency checks should cover 12 months preceding the start treatment and equivalency should be checked for each month of the year.

To verify the equivalence of energy consumption, this protocol recommends that the third-party test for differences between treatment and control group subjects in both the mean pretreatment period energy consumption and in the distribution of pretreatment energy consumption. Evaluators should attempt to verify equivalence of energy consumption using the same frequency of data to be used in the savings analysis. For example, evaluators should use hour interval consumption data to verify equivalence if the study objective is to estimate peak hour energy savings. Evaluators should also test for differences in other available covariates, such as energy efficiency program participation, home floor area, heating fuel type, and customer demographics. These tests can be used to further demonstrate that the treatment and control groups are well-balanced, as would be expected if assignment to treatment or control group was random. Evaluators can use t-tests or the following regression equation of energy consumption to verify the randomization.

Suppose the evaluator has monthly billing consumption data for all treatment and control group customers for the 12 months, m, m=1, 2, … 12, before treatment began.

$$y_{im} = \sum_{m=1}^{12} \beta_{1m} \times Tr_i + \mu_m + \varepsilon_{it}$$

Where:

y_{im} = The metered energy consumption of subject i in month m

β_{1m} = The average difference in daily energy consumption between the treatment and control groups in month m of the pretreatment period (2)

Tr_i = An indicator for whether subject i was randomly assigned to receive the treatment; the variable equals 1 for subjects in the treatment group and equals 0 for subjects in the control group

μ_m = A month-year fixed effect; the model controls for the month-year fixed effects with a separate intercept for each month, which represents the average daily consumption of the control group in month m

ε_{it} = The model error term, representing random influences on the energy use of customer i in month m.

In this simple model, the coefficient β1m provides an estimate of the difference in average daily consumption between the treatment and control group in month m of the pretreatment period. Because of the random assignment to treatment, it is expected that the differences will be close to zero and statistically insignificant. Ordinary least squares (OLS) estimation of this model will result in an unbiased estimate of β1m. The standard errors should be clustered on the customer or subject.[79]

Evaluators can check for differences in time-invariant (e.g., demographic or home) characteristics between treatment and control group customers by replacing the dependent variable with the time-invariant characteristics and replacing the month-year fixed effects with a constant β_0 and $\sum_{m=1}^{12}\beta_{1m} \times Tr_i$ with $\beta_{1m} \times Tr_i$. The coefficient β1 will measure the average difference between the treatment and control groups.

If significant differences are found, and it is possible to perform the random assignment again before treatment starts, the third party should consider doing so. Ideally, random assignment should not result in differences; however, differences occasionally appear, and it is better to redo the random assignment than to proceed with unbalanced treatment and control groups, which may lead to biased savings estimates.[80] As noted in Section 2.7.4.2.2 *Random Assignment to Treatment and Control Groups by an Independent Third Party*, stratifying the study population by pretreatment energy use will increase the probability that the groups are balanced.

If the evaluator is not the third party who performed the random assignment, they should perform an equivalency check before estimating the savings. The evaluator may be able to use statistical methods to control for differences in pretreatment energy consumption found after the program is underway.[81] This should be done whether the program is designed as an RCT or a quasi-experiment.

2.7.4.3 Data Requirements and Collection

2.7.4.3.1 Energy Use Data

Estimating BB program impacts using a field experiment requires collecting energy consumption data from subjects in the analysis sample. This protocol recommends that evaluators collect multiple energy consumption measurements for each sampled unit for the periods before and during the treatment.[82]

[79] Although the methods recommended in this protocol minimize the potential for violations of the assumptions of the classical linear regression model, evaluators should be aware of and take steps to minimize—potential violations. The clustering of standard errors accounts for the correlation of individual customer consumption across time periods. In general, it is incorrect to treat observations of a customer's consumption readings as being independent of one another.

[80] Evaluators should keep in mind that at a statistical significance level of 10%, it is expected that statistically significant differences from random assignment will be found 10% of the time as a result of random chance.

[81] If energy use data are available for the periods before and during the treatment, it is possible to control for timeinvariant differences between sampled treatment and control group subjects using subject fixed effects

[82] A single measurement of energy use for each sampled unit during the treatment period also results in an unbiased estimate of program savings. The statistical significance of the savings estimate depends on the variation of the true but unknown savings and the number of sampled units.

These data are known as a panel. Panels can comprise multiple hourly, daily, or monthly energy use observations for each sampled unit. In this protocol, a panel refers to a data set that includes energy measurements for each sampled unit either for the pretreatment and treatment periods or for the treatment period only. The time period for panel data collection will depend on the program timeline, the frequency of the energy consumption data, and the amount of such data collected.

Panel data have several advantages for use in measuring BB program savings:

- Relative ease of collection. Collecting multiple energy consumption measurements for each sampled unit from utility billing systems is usually easy and inexpensive.
- Can estimate savings during specific times. If the panel collects enough energy consumption observations per sampled unit, estimating savings at specific times during the treatment period may be possible. For example, hourly energy consumption data may enable the estimation of precise savings during utility system peak hours. Monthly energy consumption data may enable the development of precise savings estimates for each month of the year.
- Savings estimates are more precise. Evaluators can more precisely estimate energy savings with a panel because they may be able to control for the time-invariant differences in energy consumption between subjects that contribute to higher variance.
- Allows for smaller analysis samples. All else being equal, fewer units are required to detect a minimum level of savings in a panel study than in a cross-section analysis. Thus, collecting panel data may enable studies with smaller analysis samples and data collection costs.

Using panel data has some disadvantages relative to a single measurement per household in a cross-sectional analysis. First, evaluators must correctly cluster the standard errors within each household or unit (as described in the following section). Second, panel data generally require statistical software to analyze, whereas estimating savings using single measurements in a basic spreadsheet software program may be possible.

For the analyses of savings, we recommend using a panel data model that compares the change in energy use for the treatment group to the change in energy use for the control group, especially if the evaluation design is quasi-experimental.

This Protocol also recommends that evaluators collect energy consumption data for the duration of the treatment to ensure they can observe the treatment effect for the entire study period. Ideally, an energy efficiency BB program will last for a year or more because the energy end uses affected by BB programs may vary seasonally. For example, these programs may influence weather-sensitive energy end uses, such as space heating or cooling, so collecting less than one year of data may yield incomplete results. With these evaluation designs, failure to collect one year (twelve months) of historical data can result in severely biased estimates of energy savings that are imprecise and thus not advised. Quasi-experimental analysis specifications that use at least a year of baseline data are typically less biased because they control for pre-existing differences between the control and treatment groups. Below, Table 2-25 provides rule-of-thumb guidelines for length of baseline data collection for RCT and quasi-experimental design.

Table 2-25 Length of Baseline Period Recommendation[83]

If RCT	If Quasi-Experimental	Condition
Good	Good	12 months or more of historical data collected
Reasonable	Not Advisable	Less than 12 months of historical data collected
	Not Advisable	No historical data collected

2.7.4.3.2 Makeup of Analysis Sample

Evaluators must collect energy consumption measurements for every household or unit that is initially assigned to a control or treatment group, whether or not the household or unit later opts out. Not collecting energy consumption data for opt-out households will result in imbalanced treatment and control groups and could bias the savings estimates.

2.7.4.3.3 Other Data Requirements

Program information about each participant must also be collected. Evaluators will need to collect data on customer assignments to the treatment or control group and when the treatments began. Evaluators must have this information to accurately construct regression analysis model variables and to estimate savings. Also, depending on the research design and evaluation objectives, evaluators may also want to collect data on how many and when individual treatments were administered, if and when customers opted out, or details about the specific information included in the treatment. For example, evaluators will need information about the number of reports delivered to customers to estimate the impact of varying the number of delivered reports. Information about how many and which customers opted out may be helpful for evaluating opt-out behavior programs when the opt-out rate is high. The treatment effect for customers who received treatment (LATE) may be different than the ITT effect.

Temperature and other weather data may allow for more precise savings estimates but are often not necessary for estimating savings. Typically, researchers can use dummy variables for individual time periods to account for the effect of weather on household energy consumption. In a regression with time period fixed effects, weather data will improve the precision of the savings estimates only if there is significant variance between customers in weather. If weather data will be collected, evaluators should obtain them from the weather station nearest to each household.

2.7.4.3.4 Data Collection Method

Energy use measurements used in the savings estimation should be collected directly from the utility, not from the program implementer, at the end of the program evaluation period. Depending on the program type, utility billing system, and evaluation objectives, the data frequency can be at 15-minute, 1-hour, daily, or monthly intervals.

[83] If efficiency programs are designed to reduce usage only during a specific season (e.g., summer), then only historical and program year data from that season is necessary. However, comparing summer season measurements with winter season measurements of electricity load creates a situation where an incomplete year may produce significantly biased results or at least results that are difficult to interpret.

2.7.4.4 *Analysis Methods*

This protocol recommends using panel regression analysis to estimate savings from BB field experiments where subjects were randomly assigned to either treatment or control groups. Panel regression analysis is preferred to calculating savings differences of unconditional mean energy use, because regression results in more precise savings estimates. A significant benefit of randomized field experiments is that regression-based savings estimates are usually quite insensitive to the type of model specification.

Section 2.7.4.3.1 *Energy Use Data* addresses issues in panel regression estimation of BB program savings, including model specification and estimation, standard errors estimation, robustness checks, and savings estimation. It illustrates some specifications as well as the application of energy-savings estimation.

2.7.4.4.1 Panel Regression Analysis

In panel regressions, the dependent variable is usually the energy use of a subject (a utility customer home, apartment, or dormitory) per unit of time such a month, day, or hour. The right side of the equation includes an independent variable to indicate whether the subject was assigned to the treatment or control group. This variable can enter the model singularly or be interacted with another independent variable, depending on the analysis goals and the availability of energy use data from before treatment. The coefficient on the term with the treatment indicator is the energy savings per subject per unit of time. DiD models of energy savings must also include an indicator for whether the period occurred before or during the treatment period.

Many panel regressions also include fixed effects. Subject fixed effects capture unobservable energy consumption specific to a subject that does not vary over time. For example, home fixed effects may capture variation in energy consumption that is caused by differences such as home sizes or makeup of a home's appliance stock. Time-period fixed effects capture unobservable energy consumption specific to a time period that does not vary between subjects. Including time or subject fixed effects in a regression of energy consumption of subjects randomly assigned to the treatment or control group will increase the precision but not the expected unbiasedness of the savings estimates.[84]

Fixed effects can be incorporated into panel regression in several ways, as follows:

- Include a separate dummy variable or intercept for each subject in the model. The estimated coefficient on a subject's dummy variable represents the subject's time-invariant average energy use. This approach, known as least squares dummy variables, may, however, not be practical for evaluations with a large

[84] Standard econometric formulations assume that fixed effects account for unobservable factors that are correlated with one or more independent variables in the model. This correlation assumption distinguishes fixed-effects panel model estimation from other types of panel models. Fixed effects eliminate bias that would result from omitting unobserved time-invariant characteristics from the model. In general, fixed effects must be included to avoid omitted variable bias. In an RCT, however, fixed effects are unnecessary to the claim that the estimate of the treatment effect is unbiased because fixed effects are uncorrelated with the treatment by design. Although fixed effects regression is unnecessary, it will increase precision by reducing model variance.

Some evaluators may be tempted to use random-effects estimation, which assumes time- or subject-invariant factors are uncorrelated with other variables in the model. However, fixed-effects estimation has important advantages over random-effects estimation: (1) it is robust to the omission of any time-invariant regressors. If the evaluator has doubts about whether the assumptions of the random-effects model are satisfied, the fixed-effects estimator is better; and (2) it yields consistent savings estimates when the assumptions of the random-effects model hold. The converse is not true, making the fixed-effects approach more robust.

Because weaker assumptions are required for the fixed-effects model to yield unbiased estimates, this protocol generally recommends the fixed-effects estimation approach. The remainder of this protocol presents panel regression models that satisfy the fixed-effects assumptions.

number of subjects, because the model requires thousands of dummy variables that may overwhelm available computing resources.

- Transform the dependent variable and all independent variables (except for the fixed effects) by subtracting the subject-specific mean of each variable from the variable and then running OLS on the transformed data. This approach is equivalent to least squares dummy variables.[85]
- Estimate a first difference or annual difference of the model. Differencing removes the subject fixed effect and is equivalent to the dummy variable approach if the fixed-effects model is correctly specified.

2.7.4.4.2 Panel Regression Model Specifications

This section outlines common regression approaches for estimating treatment effects from residential BB programs. Unless otherwise stated, assume that the BB program was implemented as an RCT or RED field experiment.

2.7.4.4.3 Simple Differences Regression Model of Energy Use

Consider a BB program in which the evaluator has energy consumption data for the treatment period only and wishes to estimate the average energy savings per period from the treatment. Let t, t = 1, 2, …, T, denote the time periods during treatment for which data are available, and let i, i = 1, 2, …, N, denote the treatment and control group subjects in the analysis sample. For simplicity, assume that all treated subjects started the treatment at the same time.

A basic specification to estimate the average energy savings per treated customer per period is:

$$y_{it} = \beta_0 + \beta_1 \times Tr_i + \varepsilon_{it}$$

Where:

y_{it} = The metered energy consumption of subject i in period t

β_0 = The average energy consumption per unit of time for subjects in the control group

β_1= The average treatment effect of the program; the energy savings per subject per period equals -β1

Tr_i = An indicator for whether subject i received the treatment; the variable equals 1 for subjects in the treatment group and equals 0 for subjects in the control group

ε_{it} = The model error term, representing random influences on the energy consumption of customer i in period t.

In this simple model, the error term ε_{it} is uncorrelated with Tr_i because subjects were randomly assigned to the treatment or control group. The OLS estimation of this model will result in an unbiased estimate of β1. The standard errors should be clustered on the subject (customer). [86]

This specification does not include subject fixed effects. Because the available energy consumption data only apply to the treatment period, it is not possible to identify the program treatment effect and to incorporate

[85] Greene (2011) Chapter 11 provides more details.

[86] Although the methods recommended in this protocol minimize the potential for violations of the assumptions of the classical linear regression model, evaluators should be aware of and take steps to minimize—potential violations

subject fixed effects into the model. However, as previously noted, because of the random assignment of subjects to the treatment group, any time-invariant characteristics affecting energy use will be uncorrelated with the treatment, so omitting that type of fixed effects will not bias the savings estimates.

However, in the equation above in Section 2.7.4.2.3 *Equivalency Check*, more precise estimates of savings could be obtained by replacing the coefficient β0 with time-period fixed effects. The model would capture more of the variation in energy consumption over time, resulting in greater precision in the savings estimate. The interpretation of β1, the average treatment effect per home per time period, is unchanged.

2.7.4.4.4 Simple Differences Regression Estimate of Heterogeneous Savings Impacts

Suppose that the evaluator still has energy consumption data that apply to the treatment period only but wishes to obtain an estimate of savings from the treatment as a function of some exogenous variable, such as preprogram energy consumption, temperature, home floor space, or pretreatment efficiency program participation (to determine, for example, whether high energy users save more or less energy than low energy users). If data for treatment and control group subjects on the exogenous variable of interest are available, the evaluator may be able to estimate the treatment effect as a function of this variable.

Let m_{ij} be an indicator that subject i belongs to a group j, j = 1, 2, …, J, where membership in group j is exogenous to receiving the treatment. Then the average treatment effect per subject for subjects in group j can be estimated using the following regression equation:

$$y_{it} = \beta_0 + \sum_{j=1}^{J} \beta_{1j} \times Tr_i \times m_{ij} + \sum_{j=1}^{J-1} \gamma_{jmij}\, \mu_m + \varepsilon_{it}$$

Where:

m_{ij} = An indicator for membership of subject i in group j; it equals 1 if customer i belongs to group j and equals 0, otherwise

β_{1j} = The average treatment effect for subjects in group j; energy savings per subject per period j equals -β1j

γ_j = The average energy consumption per period for subjects in group j, j = 1, 2, …J-1.

All of the other variables are defined as in Section 2.7.4.2.3 *Equivalency Check.*

This specification includes a separate intercept for each group indicated by γ_j and the treatment indicator Tr_i interacted with each of the m_{ij} indicators. The coefficients on the interaction variables β_{1j} show average savings for group j relative to baseline average energy use for group j. It is important that the equation include the uninteracted indicator variables for the groups if average energy consumption varies between groups; otherwise, the treatment effect for group j will be incorrectly estimated relative to the average consumption of all control subjects rather than control subjects in group j.

2.7.4.4.5 Simple Differences Regression Estimate of Savings During Each Time Period

To estimate the average energy savings from the treatment during each period, the evaluator can interact the treatment indicator with indicator variables for the time periods as in the following equation.[87]

$$y_{it} = \sum_{j=1}^{J} \beta_{1j} \times Tr_i \times d_{ij} + \sum_{j=1}^{T} \theta_j d_{jt} + \varepsilon_{it}$$

Where:

> β_t = The average savings per subject for period j (for example, the average savings per subject during month 4 or during hour 6)
>
> d_{jt} = An indicator variable for period j, j = 1, 2, …,T. djt equals 1 if j = t (that is, the period is the tth) and equals 0 if j ≠ t (that is, the period is not the tth)
>
> θ_t = The average effect on consumption per subject specific to period j.

Equation 4 can be estimated by including a separate dummy variable and an interaction between the dummy variable and Tri for each time period t, where t = 1, 2, ..., T. When the time period is in months, the time-period variables are referred to as month-by-year fixed effects. The coefficient on the interaction variable for period t, βt, is the average savings per subject for period j. Again, because ε_{it} is uncorrelated with the treatment after accounting for the average energy consumption in period t, the OLS estimation of the equation in Section 2.7.4.4.4 *Simple Differences Regression Estimate of Heterogeneous Savings Impacts* (with standard errors clustered on subjects) results in an unbiased estimate of the average treatment effect for each period.

Evaluators with smart meter data can use this specification to estimate BB program demand savings during specific hours of the analysis period. The coefficient βj would indicate the demand savings from the treatment during hour j. Examples of research that estimates savings during hours of peak usage include Stewart (2013a), Todd (2014), and Brandon et al. (2019).

2.7.4.4.6 Difference-in-Differences Regression Model of Energy Use

This section outlines a DiD approach to estimating savings from BB field experiments. This protocol recommends DiD estimation to the simple differences approach but DiD requires information about the energy use of treatment and control group subjects during the pretreatment and treatment periods. These energy use data enable the evaluator to:

- Include subject fixed effects to account for differences between subjects in time-invariant energy use
- Obtain more precise savings estimates
- Test identifying assumptions of the model

Assume there are N subjects and T +1 periods, T > 0, in the pretreatment period denoted by t = - T, -T+1, …, -1, 0, and T periods in the treatment period, denoted by t = 1, 2, …, T. A basic DiD panel regression with subject fixed effects could be specified as:

[87] If the number of time periods is very large, the number of time period indicator variables in the regression may overwhelm the capabilities of the available statistical software. Another option for estimation is to transform the dependent variable and all of the independent variables by subtracting time-period-specific means and then running the OLS on the transformed data.

$$y_{it} = \alpha_i \times \beta_1 P_t + \beta_2 P_t \times Tr_i + \varepsilon_{it}$$

Where:

α_i = Unobservable, time-invariant energy use for subject i; these effects are controlled for with subject fixed effects

β_1 = The average energy savings per subject during the treatment period that was not caused by the treatment

P_t= An indicator variable for whether time period t occurs during the treatment; it equals 1 if treatment group subjects received the treatment during period t, and equals 0 otherwise

β_2= The average energy savings resulting from the treatment per subject per unit of time.

The model includes fixed effects to account for differences in average energy consumption between subjects. Including subject fixed effects would likely explain a significant amount of the variation in energy consumption between subjects and result in more precise savings estimates. The interaction of Pt and Tri equals one for subjects in the treatment group during periods when the treatment is in effect, and 0 for other periods and all control subjects.

The equation in Section 2.7.4.4.5 *Simple Differences Regression Estimate of Savings During Each Time Period* is a DiD specification. For control group subject i, the expected energy use is αi during the pretreatment period and αi + β1 during the treatment period. The difference in expected energy use between pretreatment and treatment periods, also known as naturally occurring savings, is β1. If that same subject i had been in the treatment group, the expected energy use would have been αi during the pretreatment period and αi + β1 + β2 during the treatment period. The expected savings would have been β1 + β2, which is the sum of naturally occurring savings and savings from the BB program. Taking the difference yields β2, a DiD estimate of program savings. The OLS estimation in Section 2.7.4.4.5 *Simple Differences Regression Estimate of Savings During Each Time Period* results in an unbiased estimate of β2.

A more general form of Section 2.7.4.4.5 *Simple Differences Regression Estimate of Savings During Each Time Period* would allow the treatment period to vary for each subject and substitute time-period fixed effects (such as a separate indicator variable for each day or month of the analysis period) for the stand-alone post period variable. The specification with time-period fixed effects in Eq. 6 can be handy when subjects begin the treatment at different times, such as with rolling program enrollments or if it is difficult to define when treatment would have begun for a control group subject.

$$y_{it} = \alpha_i \times \tau_t + \beta_2 P_{it} \times Tr_i + \varepsilon_{it}$$

Where:

τ_t = The time-period fixed effect (an unobservable that affects the consumption of all subjects during time period t); the time period effect can be estimated by including a separate dummy variable for each of T-1 time periods t, where t = -T, -T+1, …, -1, 0, 1, 2, ..., T; one time period dummy variable must be dropped to avoid collinearity

P_{it} = An indicator variable for whether time period t occurs during the treatment for subject i; it equals 1 if treatment group subject i received the treatment during period t, and equals 0 otherwise.

As in Section 2.7.4.4.4 *Simple Differences Regression Estimate of Heterogeneous Savings Impacts*, the coefficient β2 represents the average savings per treated customer per time period. The interpretations of the other variables and coefficients in the model remain unchanged.

2.7.4.4.7 Difference-in-Differences Estimate of Savings for Each Time Period

By re-specifying the equation in Section 2.7.4.4.5*Simple Differences Regression Estimate of Savings During Each Time Period* with time-period fixed effects, savings can be estimated during each period and the identifying assumption tested to determine that assignment to the treatment was random. Consider the following DiD regression specification:

$$y_{it} = \alpha_i + \sum_{j=-T}^{T} \theta_j d_{jt} + \sum_{j=-T}^{-1} \beta_j Tr_i \times d_{ij} + \sum_{j=1}^{J} \beta_j Tr_i \times d_{ij} + \varepsilon_{it}$$

Savings in each period are estimated by including a separate dummy variable and an interaction between the dummy variable and Tri for each time period t, where t = -T, -T+1, …, - 1, 0, 1, 2, …, T. The coefficient on the interaction variable for period t, βt T, is the DiD savings for period t.

Unlike the simple differences regression model, this model yields an estimate of BB program savings during all periods except one, which must be excluded to avoid collinearity, for a total of 2T-1 period savings estimates. Figure 2-12 shows an example of savings estimates obtained from such a model. The dotted lines show the 95% confidence interval for the savings estimates using standard errors clustered on utility customers.

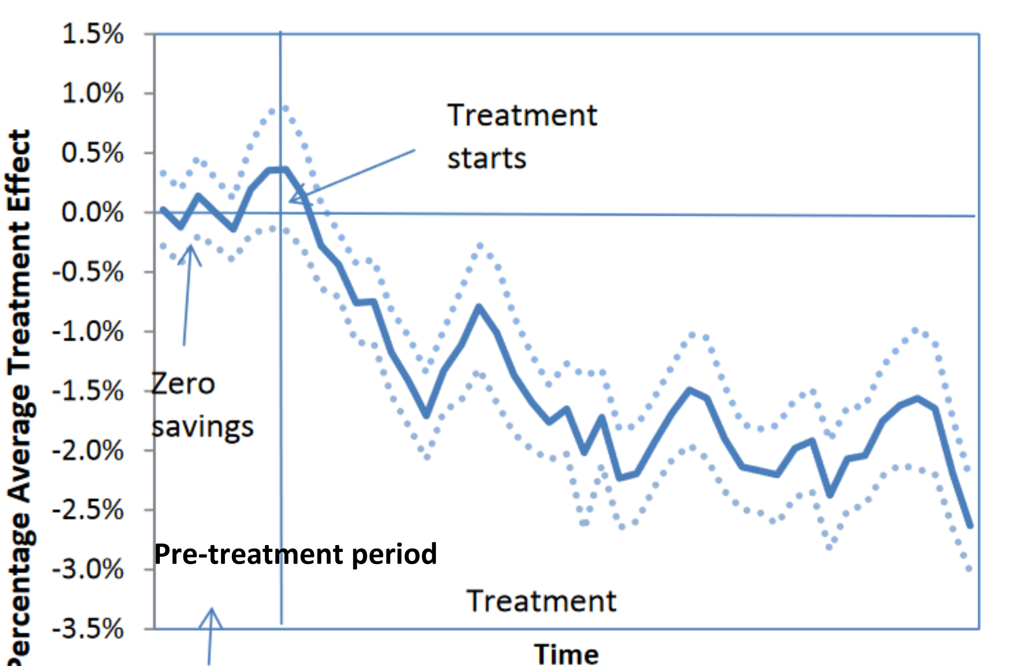


Figure 2-12 Example of DiD Regression Savings Estimates[88]

[88] *Ibid.*

Estimates of pretreatment savings can be used to test the assumption of random assignment to the treatment. Before utilities administer the treatment, it should not be possible to reject the hypothesis of statistically significant differences in energy consumption between treatment and control group subjects, that is, the confidence intervals should contain the x axis. BB program pretreatment saving estimates that were statistically different from zero might suggest a flaw in the experiment design or implementation or the evaluator's understanding of the experiment.

As with the equation in Section 2.7.4.4.3 *Simple Differences Regression Model of Energy Use* this specification can be used to estimate demand savings during specific hours. Energy consumption data for hours before the treatment are required, however.

2.7.4.4.8 Simple Differences Regression Model with Pretreatment Energy Consumption

In addition to estimating energy savings as a DiD, evaluators can estimate savings as a simple difference conditional on average pretreatment energy consumption. This estimator, often referred to as a post-only model with pre-period controls or lagged dependent variable, includes pretreatment energy consumption as an independent variable in the regression to account for differences between subjects in their post-treatment consumption, serving a purpose similar to that of customer fixed effects in the DiD model. However, many researchers favor the post-only estimator because it usually has smaller variance than the standard fixed effects DiD estimator when energy consumption is uncorrelated or weakly correlated over time.[89] However, evaluators can estimate both specifications and compare results. In large samples, the models should produce very similar estimates.

Consider the following post-only with pre-period controls regression specification:

$$y_{it} = \tau_t + \beta_1 \times Tr_{it} + \rho\overline{y_{\varphi}^{pre}} + \varepsilon_{it}$$

Where:

> τ_t= The time-period fixed effect (an unobservable that affects consumption of all subjects during time period t); the time period effect can be estimated by including a separate dummy variable for each time period t, where t = -T, - T+1, …, -1, 0, 1, 2, ..., T
>
> β_1 = Coefficient for the average treatment effect of the program; the energy savings per subject per period equals -β_1
>
> Tr_{it}= An indicator variable for whether subject i received the treatment in period t; the variable equals 1 for subjects who receive the treatment in period t and equals 0 otherwise
>
> ρ = Coefficient indicating the effect of average pretreatment consumption on consumption during the treatment period

[89] Some researchers refer to this model as a "post-only" model; however, this name is misleading because the model uses pretreatment consumption as an explanatory variable. In a personal correspondence with the authors, Hunt Allcott, who introduced this method in evaluation of Home Energy Reports, points out that if seasonal effects are being estimated, this model "has slightly smaller standard errors and can be better at addressing naturally occurring randomization imbalances that may result in the baseline pretreatment energy usage differing between the control and treatment group."

$\rho\overline{y_{\varphi}^{pre}}$ = Average consumption during the corresponding pretreatment period for subject i; for example, if the dependent variable was a customer's average daily consumption in July during the treatment period, $\rho\overline{y_{\varphi}^{pre}}$ would equal the customer's average daily consumption for July in the pretreatment period

ε_{it} = The model error term, representing random influences on the energy consumption of customer i in period t.

With random assignment of subjects to treatment and control groups, the OLS estimation of 2.7.4.4.8 *Simple Differences Regression Model with Pretreatment Energy Consumption* is expected to produce an unbiased estimate of the average savings per subject per period.

Evaluators can estimate slightly different versions of this model:

- Savings for each treatment period. Evaluators can include a treatment indicator variable for each period instead of a treatment indicator variable for the entire treatment period. This specification will produce an estimate of average savings per subject for each treatment period.
- Additional pretreatment consumption control variables. Instead of one pretreatment consumption variable, evaluators can include multiple pretreatment consumption variables, such as pretreatment consumption for different seasons or months of a year, days of the week, or hours of the day.
- Additional control variables. Evaluators can add other variables such as weather to the model. The addition of such variables might help to improve the precision of the savings estimates.

2.7.4.4.9 Randomized Encouragement Design

Some field experiments involve a RED in which subjects are only encouraged to accept a BB measure, in contrast to RCTs in which a program administers a BB intervention. This section outlines the types of regression models that are appropriate for estimating savings from REDs, how to interpret the coefficients, and how to estimate savings from RED programs.

Evaluators can apply the model specifications previously described for RCTs to REDs. The model coefficients and savings are interpreted differently; however, an additional step is required to estimate average savings for utility customers who accept the behavioral intervention. Treatment in a RED is defined as receiving encouragement to adopt the BB intervention, rather than actually receiving the intervention, as with RCTs.

Consider a field experiment with a RED that has energy consumption data for treatment and control group subjects available for the pretreatment and treatment periods. Equations 1 through 4 can be used to estimate the treatment effect, or the average energy consumption effect on those receiving encouragement. If control group customers can participate, the estimate only captures savings from compliers, because, as discussed previously, never takers never accept the intervention, and always takers accept the intervention with or without encouragement.

To recover an estimate of the LATE—the savings from subjects who accept the treatment because of the encouragement—evaluators can scale the estimate of β2 by the inverse of the difference between the percentage of subjects in the treatment group who accept the intervention and the percentage of subjects in the control group who accept the intervention (which is zero if control group subjects are prohibited from accepting the intervention). Estimate this as:

$$LATE = \frac{\beta_2}{(\pi_T - \pi_C)}$$

Where:

π_T= The percentage of treatment group subjects who accept the intervention

π_C= The percentage of control group subjects who accept the intervention.

A related approach for obtaining an estimate of savings for the BB intervention in a RED study is instrumental variables, two-stage least squares (IV-2SLS). This approach uses the random assignment of subjects to the treatment as an instrumental variable for the decision by encouraged customers to participate in the program. The instrumental variable provides the exogenous variation necessary to identify the effect of endogenous participation on energy consumption. Participation is endogenous because the encouraged customers' decisions to participate is not random and depends on unobserved characteristics that may be correlated with energy consumption. For encouragement to be a valid instrument, it must be that encouragement affects only energy consumption through its impact on BB program participation.

In the first stage, the evaluator regresses a binary program participation decision variable on an indicator for whether the customer was randomly assigned to receive encouragement and other exogenous independent variables from the second-stage energy consumption equation. The evaluator then uses the regression to predict the likelihood of participation for each subject and time period. In the second stage, the evaluator estimates the energy consumption equation, substituting the first-stage predicted likelihood of participation for the variable indicating actual program participation. The estimated coefficient on the predicted likelihood of participation is the LATE for the BB intervention.

For a detailed method of using an IV approach, see Cappers et al. (2013) and for a real-world example of the IV-2SLS approach applied to a home weatherization program implemented as a RED, see Fowlie et al. (2018).

2.7.4.4.10 Quasi-Experimental Methods

(i) Regression Discontinuity Method

Among the quasi-experimental methods, regression discontinuity typically yields the most unbiased estimate of energy savings. However, it is also the most complicated method: it requires knowledge of econometric models and often requires field conditions that allow the evaluator to utilize this analytic technique and is therefore not always practical. This method works if the eligibility requirement for households to participate in a program is a cutoff value of a characteristic that varies within the population. For example, households at or above a cutoff energy consumption value of 900 kWh per month might be eligible to participate in a behavior-based efficiency program, while those below 900 kWh are ineligible. In this case, the households that are just below 900 kWh per month are probably very similar to those that are just above 900 kWh per month. Thus, the idea is to use a group of households right below the usage cutoff level as the control group and compare changes in their energy use to households in right above the usage cutoff level as the treatment group. This method assumes that the program impact is constant over all ranges of the eligibility requirement variable that are used in the estimation (e.g., that the impact is the same for households at all levels of energy usage), although there are more complex methods that can be used if this assumption is not true.[90] In addition, regression discontinuity relies on the eligibility requirement being strictly enforced.[91]

(ii) Matched Control Group Method

If it is not possible to create a randomized control group, then savings estimates could be calculated by constructing a non-random control group made up of households that are as similar to the treatment group as possible. The challenge with a matched control group method is that households have both observable characteristics (e.g., level of energy use, zip code, presence of central air conditioning) that could potentially be matched, and unobservable characteristics (e.g., energy attitudes, or propensity to opt in to an energy efficiency program) that are harder or impossible to match.

(iii) Match on Observables

A matched control group or post-matched control group is a non-random control group where the observable characteristics of the households in the program are known or measured, and then a control group that best matches those characteristics is constructed. The idea is to create a control group that is as similar as possible to the treatment group. For example, with an opt-in program, it may be true that all households that opted in lived in a rural area and had high energy use. In this case, a matched control group might include households in the same rural area with high energy use that did not opt in to the program. This control group is matched on two observable characteristics (energy use and location). However, it is not matched on the unobserved variable of propensity to opt in: it ignores the fact that households that opt in to a program are fundamentally different than those that do not opt in. For example, these households may be more inclined to conserve energy than those that are not interested in participating in the program. In the case of an opt-out program, the households that could be used in the matched control group are either those that were screened out or those that opted out.

(iv) Propensity Score Matching

Propensity score matching attempts to match households on both observable and unobservable characteristics for the case of an opt-in program. This method uses observable characteristics to predict the probability that a household will decide to opt in to a program, and then chooses households that had a high probability of opting in to the program but did not actually opt in to be in the control group. While this method is better than a matching method without propensity scores, it still assumes that whatever observable characteristics of the households were used to calculate the propensity score are sufficient to explain any unobservable differences between the treatment and non-random control group. This method is more credible if accurate detailed household demographic information is obtainable, rather than generic categories (e.g., broad census demographics or categories such as "rural youth"). However, in cases for which RCTs and regression discontinuity methods are impractical, propensity score matching is an acceptable method.

(v) Variation in Adoption (With a Test of Assumptions)

This variation in adoption approach takes advantage of variation in the timing of program adoption. This allows for the comparison of the energy usage of households that opt in to the energy usage of households that have not yet opted in but will ultimately opt in at a later point. It relies on the assumption that in any given month, households that have already opted in and households that will opt in soon are the same types of households.

---

[90] See Imbens and Lemieux (2008).

[91] In addition, the eligibility requirements cannot be endogenously determined; that is, if there is prior knowledge that households above 900 kWh have a strong response to the program while those below 900 kWh do not, then regression discontinuity will yield biased estimates.

For this assumption to be valid, households must decide to opt in to the program at different times, and the decision of each household to opt in during any particular month should be essentially random, and only influenced by marketing exposure and awareness of the program (this is different than an RCT with a recruit-and-delay design, in which households do not decide when to opt in but rather are randomly assigned different times to opt in). The decision to opt in should not be related to observable or unobservable household characteristics (e.g., energy conservation attitudes). Because the validity of the estimated program impact depends upon this assumption, it should be tested to the extent possible with a test of assumptions.[92]

In addition, if the energy savings due to the program do not persist over time, then the estimated program impact will be biased and thus require corrections.[93] If the assumption that the timing of household program adoption is essentially random is valid, then this method is as good as a regression discontinuity method. However, although the assumption can be tested and found to not hold, it cannot be found to hold with certainty (e.g., household adoption may correspond to unobservable characteristics, such as willingness to opt in during a specific season).

(vi) Pre-Post Energy Use Method

Another quasi-experimental method is to compare the energy use of households in the treatment group after they were enrolled in the program to the same households' historical energy use prior to program enrollment. In effect, this means that each household in the treatment group is its own non-random control group. This is called a pre-post; within subjects; or interrupted time series design analysis. The challenge in using this method is that there are many other factors (independent variables) that may influence energy use before, during, and after the program that are not captured with this method. Some of these factors, such as differences in weather or number of occupants, may be reliably accounted for in the analysis. However, other factors are less easily observed and/or accounted for. For example, the economy could have worsened, leading households to decrease energy (even if there were no program), or a pop culture icon could suddenly decide to advocate for energy efficiency. With a pre-post analysis, there is no way to discern and separate the impact of other influences (e.g., economic recession) that may affect energy use over time compared to the impact of the behavior-based efficiency program leading to an estimate of energy savings that could be biased.[94]

2.7.4.4.11 Standard Errors

Panel data have multiple energy consumption observations for each subject; thus, the energy consumption data are very likely to exhibit within-subject correlations. Many factors affecting energy consumption persist over time, and the strength of within-subject correlations usually increases with the frequency of the data. When standard errors for panel regression model coefficients are calculated, the within-subject correlations must be accounted for. Failing to do so will lead to savings estimates with standard errors that are biased.

---

[92] One way to test it is by conducting a duration analysis, which tests whether household adoption in any particular month is driven by marketing activity, as opposed to observed household characteristics or unobserved heterogeneity. Another test is to determine if the energy usage of households before they opt in differs between households that opt in during one particular month as opposed to another month. In addition, propensity score matching can be used to further verify the assumption by accounting for potentially varying demographics of the households over time as they opt in to the program.

[93] For a detailed description of a robust variation in adoption methodology, see Harding and Hsiaw (2011)

[94] However, in programs outside the scope of this report such as critical peak pricing or critical peak rebates, a pre-post method may be less biased. This method should only be considered when the experimental factor can be presented repeatedly so that the difference between the behavior when it is present and when it is not present is observable. It is not really appropriate for circumstances where the effect of the experimental factor is expected to persist for a long period of time after exposure or is continuously presented throughout the experiment (e.g., time of use or information feedback).

This protocol strongly recommends that evaluators estimate robust standard errors clustered on subjects (the randomized unit in field trials) to account for within-subject correlation. Most statistical software programs, including STATA, SAS, and R, have regression packages that output clustered standard errors.

Clustered standard errors account for the fact that in a panel with N subjects and T observations per subject there is less information about energy consumption than in a data set with N*T independent observations. Because clustered standard errors account for these within-subject energy-use correlations, they are typically larger than OLS standard errors. When there is within subject correlation, OLS standard errors are biased downward and overstate the statistical significance of the estimated regression coefficients.[95]

2.7.4.4.12 Opt-Out Subjects and Account Closures

Many BB programs allow subjects to opt out and stop receiving the treatment. This section addresses how evaluators should treat opt-out customers in the analysis, as well as utility customers whose billing accounts close during the analysis period.

As a general rule, evaluators should include all subjects initially assigned to the treatment and control groups in the savings analysis.[96] Specifically, evaluators should keep opt-out subjects in the analysis sample. Opt-out subjects may have different energy consumption characteristics than subjects who remain in the program and dropping them from the analysis would result in nonequivalent treatment and control groups. To ensure the internal validity of the savings estimates, opt-out subjects should be kept in the analysis sample.

Sometimes treatment or control group subjects close their billing accounts after the program starts. Account closures are usually unrelated to the BB program or savings; most are a result of households changing residences. Subjects in the treatment group should experience account closures for the same reasons and at the same rates as subjects in the control group; evaluators can thus safely drop treatment and control group subjects whose accounts close from the analysis sample.

When dropping customers who close their accounts during the treatment from the regression estimation, evaluators should still count the savings from these subjects for periods during treatment when their accounts were active. To illustrate, when estimating savings for a 1-year BB program, evaluators can estimate the savings from subjects who closed their accounts and from those who did not as the weighted sum of the conditional average program treatment effects in each month:

$$Savings = \sum_{m=1^{12}} - \beta_m \times Days_m + N_m$$

Where:

> m = Indexes the months of the year
>
> $-\beta_m$ = The conditional average daily savings in month m (obtained from a regression equation that estimates the program treatment effect on energy consumption in each month)

---

[95] Bertrand et al. (2004) show when DiD studies ignore serially correlated errors, the probability of finding significant effects when there are none (Type I error) increases significantly.

[96] This protocol urges evaluators not to arbitrarily drop outlier energy consumption observations from the analysis unless energy consumption was measured incorrectly, the customer was not a residential customer, or the sample size is small enough that the outlier strongly influences the estimated savings. If an outlier is dropped from the analysis, the reasons for dropping the outlier and the effects of dropping it from the analysis on the savings estimates should be clearly documented. Evaluators should test the sensitivity of the results to dropping observations.

$Days_m$= The number of days in month m

N_m = The number of treatment group subjects with active accounts in month m.

2.7.4.5 Program Uplift and Double Counting of Savings

Many BB programs cause participants to increase their participation in other utility energy efficiency programs, a phenomenon often referred to as efficiency program uplift. For example, most home energy report programs encourage recipients to participate in other utility energy efficiency programs that provide cash rebates in exchange for adopting efficiency measures, such as efficient furnaces, air conditioners, wall insulation, windows, and light-emitting diodes (LEDs). The savings from this efficiency program participation caused by HERs are often referred to as joint savings or uplift savings. Quantifying the effects of BB programs on efficiency program participation is important for two reasons:

- Uplift can be an important effect of BB programs and a potential additional source of energy savings.
- Savings from efficiency program uplift may be double counted. When a utility customer participates in an efficiency program because of a BB program intervention, the utility may count the program savings twice: once in estimating BB program savings and again in estimating the rebate program savings. To avoid double counting, evaluators must estimate savings from program uplift and subtract these savings from the behavior program savings or the uplifted program savings or from both programs.[97]

2.7.4.5.1 Estimating Uplift Energy Savings

For BB programs implemented as randomized experiments, estimating savings from uplift is conceptually straightforward. To illustrate, suppose that a utility markets an energy efficiency measure to treatment and control group subjects identically through a separate rebate program. Customers in the behavioral treatment group also receive messaging encouraging them to adopt the measure. Because customers were randomly assigned to the treatment and control groups, the groups are expected to be equivalent except for the treated customers having received the BB program encouragement. Therefore, in comparing BB program treatment and control group customers, evaluators can attribute any difference in the uptake of the measure between the groups to the behavioral treatment. To improve the accuracy of the uplift estimate, evaluators can estimate the impact as a DiD, by comparing the change in uptake of the measure between the pre and post-treatment periods for treatment and control group customers. The DiD estimate will account for any preexisting differences between treatment and control groups in the tendency to adopt the measure. If data are not available on the installation of the measure in the pretreatment period (for example, if it was not rebated at that time), evaluators should estimate uplift savings based only on post-treatment differences.

Figure 2-13 illustrates the logic for calculating behavior program savings from the efficiency program as a DiD. The figure shows energy savings from utility rebate program participation for treatment and control group customers during the pretreatment and treatment periods. Although customers had been randomly assigned to

[97] This protocol does not take a position on which program gets credit for the uplift. When a BB intervention causes participation in an energy efficiency program, we know that the program participation would not have occurred without the intervention. However, the amount of uplift caused by the BB intervention may depend on the dollar incentives provided by the efficiency program. For example, the BB program may produce greater lift in participation for a program incentive of $200 than $100. To determine the relationship between uplift and the incentive amount, it would be necessary to randomize the incentive amount and to study participation as a function of incentives and who receives the BB intervention. It is possible to subtract the uplift savings from either the behavior program or the uplifted program. However, it is common practice for evaluators to attribute all joint or uplift savings to other energy efficiency programs by subtracting them from the BB program savings. This is a simple and convenient approach for avoiding double counting of savings.

receive treatment, treatment group customers had a slightly higher tendency to participate and greater savings (=5) during the pretreatment period than the control group (=4). In this case, estimating program uplift by taking the simple difference in post-treatment savings between the treatment and control groups (8-4) would ignore the higher savings for the treatment group that would have occurred in the absence of the BB treatment and yield a slightly biased uplift savings estimate of 4. The true uplift savings equal 3, and an accurate estimate can be obtained as a DiD: (8-5) – (4-4).

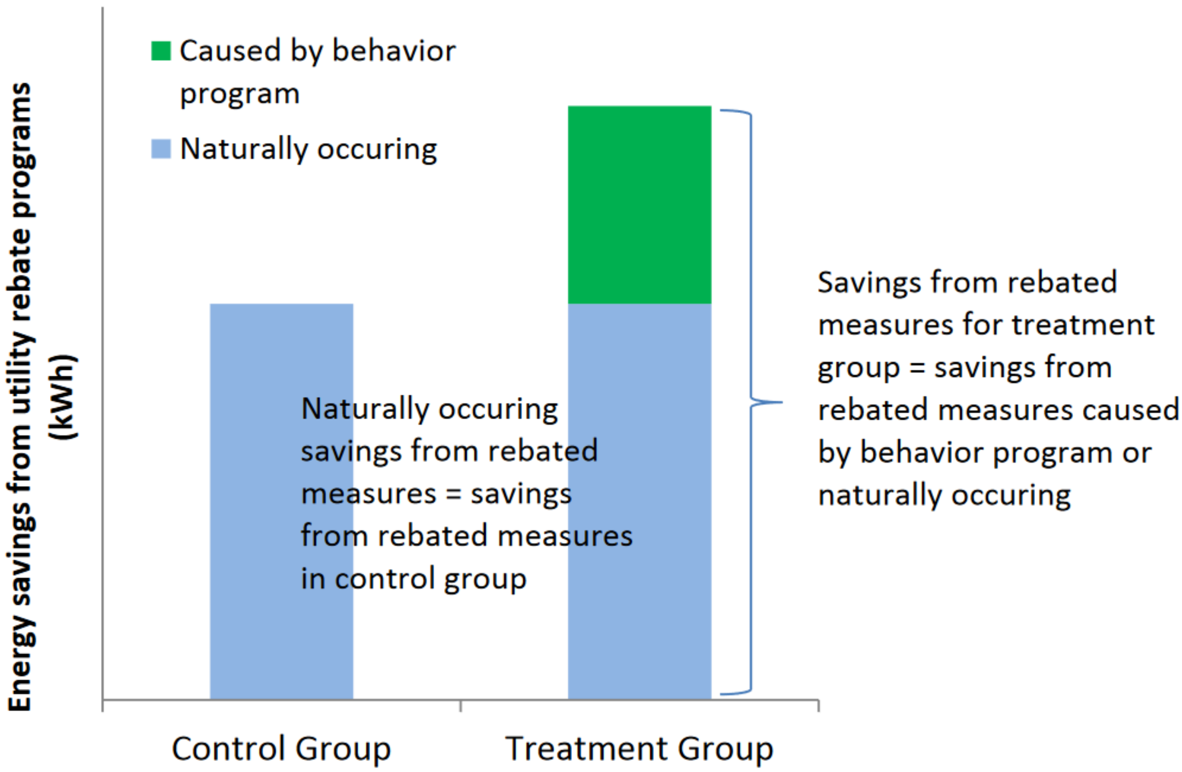


Figure 2-13 Calculation of Double-Counted Savings[98]

To estimate BB program savings from efficiency program uplift, evaluators should take the following steps:

- Collect energy efficiency program tracking data for treatment and control group customers for the year before treatment and all years of treatment.[99] Match the BB program treatment and control group subjects to the utility energy efficiency program tracking data.
- Calculate the average uplift savings per treatment group customer as the DiD between treatment and control groups in average efficiency program savings per customer, where the savings are obtained from the utility tracking database of installed measures.[100] The averages should be calculated over all treatment group customers and all control group customers, not just those who participated in efficiency programs.

---

[98] *Ibid.*

[99] These data should include a customer account number and premise number for linking the records to individual customers and homes, a measure description and category, the installation date, the quantity installed, and a unit annual savings value

[100] A simple difference can be used if evaluators verify that pretreatment energy efficiency program participation and savings are equal for treatment and control group customers or if pretreatment energy efficiency program data are not available. Pretreatment data will be unavailable for new programs.

Evaluators can calculate the average uplift savings per treatment group customer as a difference in unconditional means between treatment group and control group customers or in a regression. As described in the next few paragraphs, it may be necessary to adjust the deemed savings values in the utility tracking data for measures installed for less than 1 year.

- Multiply the uplift savings per treatment group customer by the number of customers who were in the treatment group to obtain the total uplift savings.

Evaluators can estimate BB program uplift savings for efficiency measures that the utility tracks at the customer level. Most measures for which utilities offer rebates—such as high-efficiency furnaces, windows, insulation, and air conditioners—fit this description. Also, evaluators can perform the uplift analysis for individual efficiency measures or programs or in aggregate across all programs and measures. Performing the analysis for individual measures or programs may provide useful insights about interactions between the BB program and other efficiency programs that an aggregate analysis cannot provide.

Evaluators should be mindful of specific reporting conventions for efficiency program measures in utility tracking databases. For example, many jurisdictions require utilities to report weather-normalized and annualized measure savings, which do not reflect when measures were installed during the year or the actual weather conditions that affect savings. In contrast, regression-based estimates of energy savings, such as from Eq. 4, will reflect installation dates of measures and actual weather. Evaluators should therefore adjust the annual deemed savings in the program reporting database to account for when measures were installed during the year and weather.

In addition, for BB programs treating customers for longer than 1 year, evaluators should account for the savings from uplift in previous years if uplift savings are subtracted from the behavior program. Measures with a multiyear life installed in previous program years will continue to save energy for the remaining life of the measure. Depending on the utility's conventions for reporting savings, it may be necessary to account for savings from program lift in previous program years from the BB program savings estimate.[101]

2.7.4.5.2 Estimating Uplift for Upstream Programs

Upstream measures are those that the utility does not track at the customer level. The most important of such measures are high-efficiency lights such as LEDs that are rebated through utility upstream programs. Most utilities provide incentives directly to retailers for purchasing these measures, and the retailers then pass on these price discounts to utility customers at the point of sale. Estimating behavior program savings for upstream measures is conceptually similar to that for downstream measures but requires a different data collection approach. Data on the purchases of rebated measures by treatment and control group subjects can be collected through customer surveys, store intercept surveys, or home site visits.[102]

Evaluators wanting to estimate the lift in LED adoption from upstream programs should be aware that it may be necessary to collect data for large numbers of customers to detect small BB program treatment effects. If evaluators perform surveys, they should size their survey samples with the objective of being able to detect small but economically significant effects. However, if the treatment effect is small, the uplift savings from LEDs will also be small, and it may not be worth conducting surveys to measure it. Also, evaluators should adjust the lighting purchases impact estimates for in-service rates and the percentage of high-efficiency lamps sold in the

---

[101] For an example of a HER program evaluation that makes these adjustments, see Cadmus (2018) and DNV-GL (2018).

[102] See PG&E (2013) for an example of a study employing home visits.

utility service area that received rebates.[103] Evaluators should also be aware that some energy savings from purchasing LEDs may be offset by reductions in the hours of use of those bulbs by treated customers. LEDs may save less because treated customers light their homes less than before.

2.7.4.6 Savings Persistence and Measure Life

Most behavior-based program administrators and utility regulators assume a 1-year measure life for HERs and other residential BB measures. Administrators and regulators have been conservative in their assumptions about measure life for several reasons. First, doubts exist about the persistence of behavioral savings after treatment ends for utility customers who had been changing thermostat settings, turning lights off in unoccupied rooms, or modifying other energy consumption behaviors. Second, until recently, there has been a lack of evidence demonstrating that BB savings persist. Finally, HERs and other BB measures are fundamentally different than home improvements, such as LEDs or air source heat pumps. This difference is because BB measures attempt to influence behaviors, which often requires repeated treatments to be effective. Further, their effects can decay. For all these considerations, the default assumption for most BB program administrators has been that behavioral savings do not persist and that measure life is 1 year.

However, in the last 7 years, researchers have conducted highly credible RCT studies demonstrating that HER customers continue to save energy after treatment ends and that savings may persist for several years. In addition, researchers have developed frameworks for estimating BB savings persistence and implementing a multiyear measure life (Khawaja and Stewart 2014; Jenkins et al. 2017). These frameworks account for repeated, multiyear program treatments and the gradual decay of behavior-based measure savings.

Because of this research, some BB program administrators and regulators have begun to reconsider the assumption of a 1-year measure life and allowed for savings persistence. For example, the Illinois (IL) TRM was recently updated to require adjustments to HERs savings for persistence. Other states previously or recently adopted a multiyear measure life for HERs or other BB measures or are proposing to adopt one.[104]

This part of the protocol provides evaluators with guidance about HER savings accounting and designing experiments to estimate BB savings persistence and measure life and about estimating BB savings when savings from previous treatments persist. The protocol does not recommend specific savings decay or measure life values.

2.7.4.6.1 BB Savings Persistence and Measure Life Concepts

BB savings persistence and measure life concepts presented in this section are meant to be illustrative of how program administrators can perform BB savings accounting with a multiyear measure life. BB savings accounting methods are still evolving, and there is not yet consensus about the details. Sections (i) *IL TRM* and (ii) *PA TRM* describe approaches that two states have implemented for performing HER savings accounting.

Figure 2-14 illustrates the measure life, savings persistence, and savings decay concepts for a multiyear BB program. The figure shows the average annual savings per customer for the first five program years. Suppose in

[103] Upstream lighting savings captured in the BB program savings calculation equals the product of the BB treatment effect on upstream lighting purchases (in bulbs, estimated from the comparison of treatment group and control group purchases), the in-service rate, and the unit savings. The portion of these upstream lighting savings claimed by the upstream lighting program equals the product of the upstream lighting savings, the ratio of upstream sales to total market sales, and the upstream program net-to-gross ratio.

[104] As of July 2019, Illinois, Connecticut, New Hampshire, and Minnesota have adopted a multiyear measure life for home energy reports. Pennsylvania is considering an HER multiyear measure life.

the first year that the BB treatment generates 100 kWh of savings. Assume that savings from this treatment and all subsequent treatments partially persist, decaying at a 20% annual rate. In the second year, the BB treatment generates 150 kWh, but not all these savings are attributable to the second year 2 treatment. Eighty kWh of savings are from the year 1 treatment, and the remaining 70 kWh of savings are new savings attributable to the year 2 treatment. In year 3 (and years 4 and 5), the same logic applies. Only a portion of the annual savings are attributable to that year's treatment. In year 3, 64 kWh of savings are from year 1 treatment, 56 kWh of savings are from the year 2 treatment, and 68 kWh are new savings, attributable to treatment in year 3.

Figure 2-14 Illustration of Savings Persistence[105]

Figure 2-14 shows: (1) for each year of BB treatment new savings are generated and that a fraction of the new savings persist in future years, and (2) for BB programs in which the same customers receive treatments in multiple years, some annual savings may be attributable to treatments provided in previous years. This implies that after year 1 only a portion of annual savings will be attributable to treatment in that year.

In this example, with a constant annual savings decay rate, the lifetime savings from the year t treatment is the sum of year t new savings (sn,t) and savings in future years from persistence of year t savings:

[105] *Ibid.*

$$Lifetime\ Savings = s_{n,t} + s_{n,t}(1-\delta) + s_{n,t}(1-\delta)^2 + \cdots = \frac{S_{n,t}}{\delta}$$

Where δ, 0≤ δ < 1, is the savings decay rate. For instance, if δ=0.2, lifetime savings would equal $5s_{n.t}$.

Also, with measurements of the annual savings in year t, new savings from previous years of treatment, and the savings decay rate, it is possible to deduce new savings in the program's t[th] year.

$$New\ savings\ in\ year\ t = s_t - \sum_{k=1}^{t}(1-\delta)^k s_{n,t-k}$$

Where s_t is an estimate of the annual savings.

For example, the new savings in program year 3 equals:

$$s_{n,3} = s_3 - (1-\delta)^2(1-\delta)^2 s_{n,1} - (1-\delta)(1-\delta)\ s_{n,2}$$

In the example, to estimate the year 3 new savings, the evaluator would estimate the year 3 annual savings (188 kWh) by regression analysis and then subtract the decay-adjusted year 1 and year 2 new savings, which equal 64 kWh and 56 kWh, respectively. The year 3 new savings equal 68 kWh.

The previously mentioned formulas for lifetime and new savings neglect that most behavioral energy-efficiency programs experience attrition in the number of program participants because of customers moving residences and closing their accounts. A more accurate estimate of these savings would account for this attrition. If the annual rate of customer attrition equals α, 0≤ α < 1:

$$Lifetime\ Savings = s_{n,t} + s_{n,t}(1-\delta)(1-\delta) + s_{n,t}(1-\delta)^2(1-\delta)^2 + \cdots = \frac{S_{n,t}}{\delta + \alpha - \delta\alpha}$$

$$s_{n,t} = \ s_{n,t} - \sum_{k=1}^{t}(1-\delta)^k(1-\delta)^k s_{n,t-k}$$

For example, with customer attrition, new savings in program year 3 would equal:

$$s_{n,3} = s_3 - (1-\delta)^2(1-\delta)^2 s_{n,1} - (1-\delta)(1-\delta)\ s_{n,2}$$

Evaluators may also need an estimate of BB measure life. The measure life of a behavior-based treatment (e.g., reports sent in the second year of a program) can be defined as the lifetime savings expressed in terms of first-year savings equivalents.[106]

$$Measure\ life_{n,t} = \frac{lifetime\ savings_{n,t}}{s_{n,t}} = \frac{1}{\delta + \alpha - \delta\alpha}$$

[106] TPA typically define measure life using the concept of effective useful life: "the median length of time (in years) that an energy efficiency measure is functional." (Hoffman et al. 2015) Because it is not possible to directly observe functionality of BB measures in contrast to a efficiency product, it is necessary to estimate BB measure life in terms of first-year savings.

For example, for δ = 0.2 and α = 0.1, measure life for a behavior-based treatment in year t would equal 3.57 years. The lifetime savings from the year t treatment equal approximately 3.5 times the new savings in year t.

This illustration of the savings persistence and measure life concepts has assumed that savings decay indefinitely at a constant annual rate and the customer attrition rate is constant, but these assumptions, while simplifying the savings accounting, may not hold and need not be used. For example, the savings persistence rate may change over time, savings may persist for a finite number of periods, or customer attrition rates may vary. Evaluators can relax the assumptions and adapt the previously mentioned framework to their own situations. However, even with alternative assumptions, the concepts of new savings, lifetime savings, and measure life described earlier are still valid, and with modifications, the formulas for these concepts can be applied.

The following section describes how Illinois and Pennsylvania have conducted HER savings accounting with a multiyear measure life.[107]

(i) IL TRM

The IL TRM incorporates the HER savings accounting framework with several modifications.[108] The TRM assumes that HER electricity and gas savings only persist for 5 years and that the electric savings decay at 20% in the first year after treatment and then at a higher rate for the second, third, fourth, and fifth years after treatment. After the fifth year, the savings completely decay. Gas savings decay at a faster rate.

Table 2-26 presents the TRM persistence factors[109] for new savings as a function of years since the savings were first realized. The savings persistence factors equal one minus the cumulative savings decay rate.

Table 2-26 Illinois TRM HER Savings Persistence Factors

Fuel	Persistence factor for year t new savings[110] in year t	Persistence factor for year t new savings in year t+1	Persistence factor for year t new savings in year t+2	Persistence factor for year t new savings in year t+3	Persistence factor for year t new savings in year t+4
Electricity	100%	80%	54%	31%	15%
Gas	100%	45%	45%	9%	4%

For example, with an annual customer attrition rate of α, new savings in program year 3 in Illinois would equal:

$$s_{n,3} = s_3 - 54\% * (1-\alpha)^2 s_{n,1} - 80\% * (1-\alpha) s_{n,2}$$

In this calculation, before accounting for attrition in the number of treated customers, 80% of year 2 new savings are assumed to persist to year 3 and 54% of year 1 new savings (all savings are new) are assumed to persist to year 3.

[107] Also, see NMR (2017) for application of this protocol's framework to a HER program in Connecticut and ADM (2018) for application to a Utah HER program.

[108] See Jenkins et al. (2017) for a description of the Illinois TRM framework development.

[109] See: https://www.ilsag.info/wp-content/uploads/IL-TRM_Effective_010121_v9.0_Vol_4_X-Cutting_Measures_and_Attach_09252020_Final.pdf

[110] New savings are the sum of avoided decay savings and incremental savings in year t.

The IL TRM determined the HER savings persistence factors based on empirically estimated HER savings persistence factors for electricity and gas utilities inside and outside of Illinois. The TRM persistence factors will be updated as findings from new studies about HER savings persistence become available.

(ii) PA TRM

The Pennsylvania (PA) TRM also assumes a multiyear HER measure life and incorporates, with modifications, the previously described savings accounting framework. The TRM assumes that HER savings decay continuously at a linear rate of 31.3% per year for program populations treated for 2 or more years. The savings decay factor was based on analysis of HER savings decay for Pennsylvania electric utility HER programs that paused delivery of energy reports. The savings persistence rate is assumed to be 0% for the first year of treatment.

Table 2-27 Pennsylvania TRM HER Electricity Savings Persistence Factors[111]

Fuel	Persistence factor for year t new savings[112] in year t	Persistence factor for year t new savings in year t+1	Persistence factor for year t new savings in year t+2	Persistence factor for year t new savings in year t+3	Persistence factor for year t new savings in year t+4
Electricity	100%	0%	0%	0%	0%
Gas	100%	84%	53%	22%	0%

The continuous linear decay rate means implies that following the second treatment year, 15.65% of second-year savings, all which are assumed to be "new," decay in the next year or, equivalently, that 84.4% (=1-0.313*(1-0.5)) persist.[113] Similarly, 53.1% (=1-0.313*(2-0.5)) of second-year savings persist after 2 years.

As an example, with an annual customer attrition rate of α, new savings in program year 4 would equal:

$$s_{n,4} = s_4 - 53.1\% * (1-\alpha)^2 s_{n,2} - 84.4\% * (1-\alpha) s_{n,3}$$

Because it is assumed none of the annual savings from the first program year persist, the first-year savings do not enter the calculation of savings for program year 4.

2.7.4.7 Estimating BB Savings Persistence

This section describes how evaluators can design studies to obtain estimates of savings persistence and savings decay for BB measures.

2.7.4.7.1 Study Design

This protocol recommends that evaluators employ RCTs to estimate the persistence of BB savings after participants stop receiving treatment. The implementation of an RCT to estimate savings persistence should proceed similarly to the implementation of RCTs previously discussed in this protocol.

---

111 The savings persistence factors were calculated using the default annual decay assumption of 31.3% and the persistence formulas in the PA TRM. New savings are the sum of avoided decay savings and incremental savings in year t.

112 New savings are the sum of avoided decay savings and incremental savings in year t.

113 If 31.3% of HER savings decay after 1 year, the average rate of savings decay over the year is 31.3%*0.5.

Figure 2-14 illustrates an RCT savings persistence experiment. The program administrator is assumed, as in Figure 2-9, to have implemented the BB program as an RCT with an opt-out design: customers from the study population were randomly assigned to receive the treatment or to a control group and treated customers can opt out of the program. To economize on space, Figure 2-14 does not show the utility's option at the beginning of the program to screen customers or that after treatment begins customers can opt out of the program.

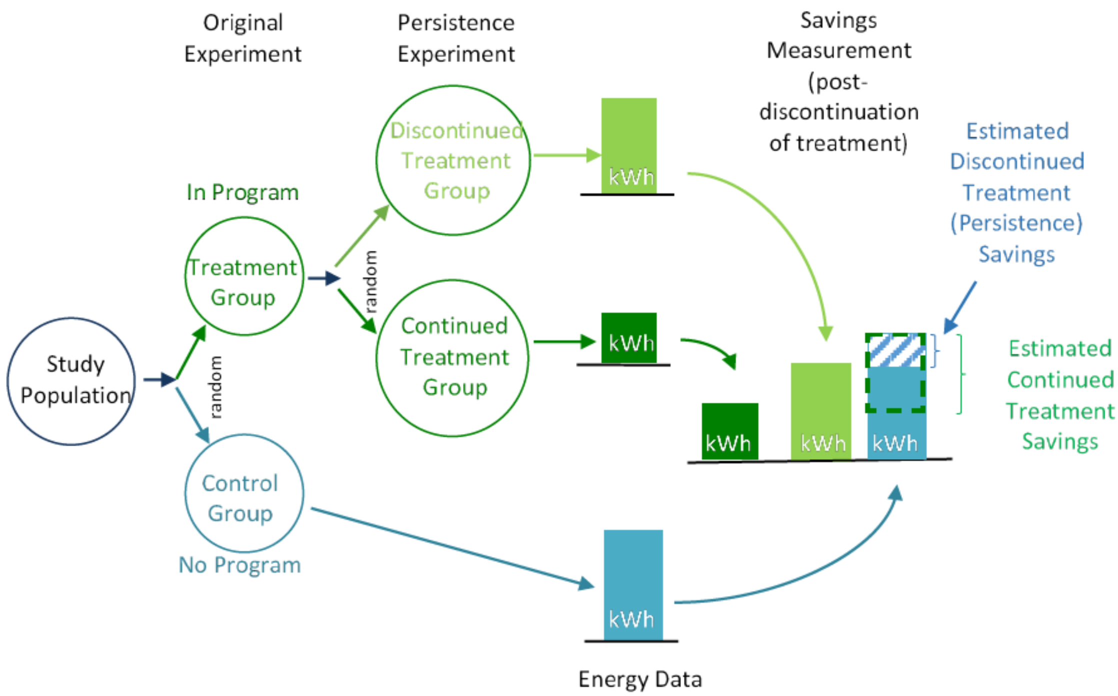


Figure 2-15 Illustration of Savings Persistence Study Design[114]

The persistence study starts after treatment group customers have received treatment for some duration (e.g., 1, 2, or 3 years). Though not illustrated, the utility may choose to screen the treatment group (and the control group) and study persistence for a specific subpopulation (e.g., by an energy use, socio-demographic, or housing characteristic). Also, the persistence study population must include treatment group customers who opted out, because evaluators will need to make energy use comparisons between the persistence study population and the original control group, which includes customers who would have opted out if they had been treated.

The next step is to randomly assign customers in the persistence study population to one of two groups. Customers in the "discontinued treatment" group will stop receiving the treatment; customers in the "continued treatment" group will continue receiving it. Evaluators should size, that is, assign enough customers to, the continued and discontinued customer treatment groups to detect the expected savings. The utility then administers the experiment and after enough time has passed collects energy consumption data for the report discontinuation period for control customers, discontinued treatment group customers, and continued treatment group customers to estimate savings persistence.

[114] *Ibid.*

To estimate savings for discontinued customers ("persistence savings"), the evaluator should compare the energy consumption of customers in the discontinued treatment group with the energy consumption of customers in the original control group during the discontinuation period. Under Savings Measurement in Figure 2-15, this difference is shown as the dashed, light-green box and represents the post-treatment savings for customers who no longer received the treatment.

The savings persistence rate can be estimated in two ways. This protocol recommends that evaluators compare the savings of the continued and discontinued treatment groups after treatment is discontinued. The continued treatment group savings represent the savings that the discontinued treatment group would have achieved if treatment had continued. Therefore, the ratio of the savings shows the percentage of the continued treatment group savings that persist after customers stop receiving treatment.

Evaluators can also estimate savings persistence by comparing the savings of the discontinued treatment group after treatment was discontinued with the group's savings before treatment was suspended. For evaluators wanting to measure savings persistence after a program administrator stops treating all customers in the behavior program, this approach is the only option. A limitation of this approach is, however, that savings may depend on weather, program implementation changes, or other time-varying factors, which, if not accounted for when comparing savings over time, can bias estimates of the savings persistence.

Both ways of calculating savings persistence only measure savings persistence rates for customers whose treatment was discontinued after a certain length of treatment (e.g., 2 years). Evaluators would need to conduct a series of discontinuation experiment to measure savings persistence for customers receiving treatment for fewer or greater number of years.

2.7.4.8 Estimating Savings Persistence

Suppose a utility started the treatment in period t = 1 and administered it for t*>0 periods. Beginning in period t = t*+1, the utility stopped administering the intervention for a random sample of treated customers. Evaluators can estimate the average savings per customer for a customer who continues to receive the treatment (continuing treatment group) and for those who stopped receiving the treatment after period t* (discontinued treatment group).

Assuming pretreatment energy consumption data are available, the following fixed effects DiD regression equation can be used to estimate savings during treatment and savings after treatment stops. This specification is estimated with consumption data for treatment and control group customers.[115]

$$kWh_{it} = \alpha_i + \tau_t + \beta_1 P_{1,t} \times T_{ci} + \beta_2 P_{1,t} \times T_{di} + \beta_3 P_{2,t} \times T_{ci} + \beta_4 P_{2,t} \times T_{di} + \varepsilon_{it}$$

Where:

kWh_{it} = electricity consumption by customer i in period t

α_i = A customer fixed effect (an unobservable that affects energy use for customer i); these effects can be estimated by including a separate intercept for each customer

[115] Evaluators can also implement a variant of the lagged dependent variable model (Eq. 7) to estimate savings persistence

τ_t = The time-period fixed effect (an unobservable that affects the consumption of all subjects during time period t); the time period effect can be estimated by including a separate dummy variable for each time period t, where t = -T, - T+1, …, -1, 0, 1, 2, ..., T

β_1= The average energy savings per continued customer caused by the treatment during periods t = 1 to t = t*

$P_{1,t}$ = An indicator variable for periods when customers in the continued and discontinued treatment groups received the treatment; it equals 1 if period t occurs between periods t = 1 and t = t* and equals 0 otherwise

T_{ci}= An indicator for whether customer i is in the continued treatment group; the variable equals 1 for customers in the continued treatment group and equals 0 for customers not in the continued treatment group β2 = The average energy savings per discontinued customer caused by the treatment during periods t = 1 to t = t*

T_{di} = An indicator for whether customer i is in the discontinued treatment group; the variable equals 1 for customers in the discontinued treatment group and equals 0 for customers not in the discontinued treatment group

β_3 = The average energy savings from the treatment for customers in the continued treatment group when t>t*

$P_{2,t}$= An indicator variable for periods when continued treatment group customers received the treatment and discontinued treatment group customers did not receive the treatment; it equals 1 if period t occurs after t = t* and equals 0 otherwise

β_4 = The average energy savings for customers in the discontinued treatment group when t>t*

If the persistence study is implemented as an RCT, OLS estimation of Eq. 9 is expected to yield unbiased estimates of savings for customers in the continued treatment group (β3) and discontinued treatment group (β4) after the discontinued group stops receiving treatment.[116] To estimate savings persistence after treatment stops, evaluators can take the difference between savings during treatment (β2) and post-treatment savings (β4) for subjects in the discontinued treatment group or the difference between post-treatment savings for the discontinued treatment group (β4) and the same period savings for the continued treatment group (β3).

2.7.4.9 Practical Evaluation Considerations

Evaluators conducting experiments to measure BB savings persistence should be mindful of several issues. First, stopping delivery of HERs or other BB treatments to estimate savings persistence may involve loss of some energy savings from discontinued customers, especially if the measure life is 1 year or program administrators are prevented from claiming persistence savings from discontinued customers. Also, the suspension of treatment may not result in a commensurate reduction in program administration and implementation costs, so

[116] 60 Evaluators can test the identifying assumption that assignment of treatment group customers to the discontinued treatment group was random by comparing the consumption of continuing and discontinuing treatment group subjects prior to the first treatment. If assignment was done at random, there should not be statistically significant differences in consumption between the two groups during this period.

that the program's cost-effectiveness may be adversely affected. It is also possible that suspending reports or treatment may dissatisfy some utility customers grown accustomed to receiving treatment.

Program administrators not wanting to conduct their own experiments can use findings about savings persistence from other studies but should borrow from studies that are valid for their own programs. As the rate of BB savings persistence may depend on climate; presence of other efficiency programs; BB program implementation strategies, including the frequency of prior treatment (e.g., quarterly vs. monthly); duration of prior treatment (number of years of treatment); and the form of the treatment (e.g., electronic or paper HERs); savings persistence estimates for one group of utility customers may not apply to other groups.

Finally, the equation in section Estimating Savings Persistence2.7.4.8 *Estimating Savings Persistence* above estimates savings for continued and discontinued treatment group customers for the actual weather during the analysis period, but evaluators may want to normalize the persistence savings estimates for year-to-year variation in weather. To obtain weather-normalized savings, evaluators can estimate savings as a function of cooling and heating degrees by adding stand-alone heating and cooling degree variables and three-way interaction variables of degrees with each of $P_{1,t}*T_{ci}$, $P_{1,t}*T_{di}$, $P_{2,t}*T_{ci,}$ and $P_{2,t}*T_{di}$ to the right side of the equation in section Estimating Savings Persistence2.7.4.8 *Estimating Savings Persistence*. All independent variables in the equation in section Estimating Savings Persistence2.7.4.8 *Estimating Savings Persistence* would also remain in this enhanced specification. For example, in a savings model estimated with monthly billing data, the coefficients on the interaction terms would indicate how savings before and after discontinuation of treatment depended on HDDs and CDDs. The coefficients on the two-way interaction variables $P_{1,t}*T_{ci}$, $P_{1,t}*T_{di}$, P2,t*T_{ci}, and $P_{2,t}*T_{di}$ would indicate the average savings unrelated to weather. Estimating this specification requires within-time period (e.g., a day or month) variation between customers in heating and cooling degrees. Without such variation, it is not possible to isolate the consumption's impact of weather from the impacts of other time-specific factors, which the time-period fixed effects account for.

2.7.5 REPORTING

BB program evaluators should carefully document the research design; data collection and processing steps; and analysis methods; and plan for calculating savings estimates. Specifically, evaluators should describe:

- The program implementation and the hypothesized effects of the behavioral intervention
- The experimental design, including the procedures for randomly assigning subjects to the treatment or control group. This should also include a careful description of the impacts measured by the experiment.
- The sample design and sampling process
- The processes for data collection and preparation for analysis, including all data cleaning steps
- Analysis methods, including the application of statistical or econometric models and key assumptions used to identify savings, including tests of those key identification assumptions
- Results of the savings estimation, including point estimates of savings and standard errors and full results of regressions used to estimate savings. Evaluators should clearly state the time periods to which the savings estimates pertain.
- Assumptions about measure life and savings persistence. If a behavior-based measure has a multiyear measure life, evaluators should describe the calculation of persistence savings and new savings.

A good rule of thumb is that evaluators should report enough detail such that a different evaluator could replicate the study with the same data. Every detail does not have to be provided in the body of the report; many of the data collection and savings estimation details can be provided in a technical appendix.

2.8 Protocols for Evaluating Demand Response Programs and Projects

2.8.1 INITIALISMS AND DEFINITIONS

ARC — Aggregator of Retail Customers

Businesses that combine one or more retail customers and represent those customers' combined capabilities for demand response in the wholesale markets

BLDR — Batch Load Demand Response

A special category of DRR-Type I resource that can reduce its load, or maintain its already reduced load beyond the normal BLDR duty cycle, to provide Demand reduction for economic, reserve, or Emergency services

BPM — Business Practices Manual

A set of manuals designed to provide Market Participants with detailed information regarding how to conduct business in the various markets administered by MISO

BTMG — Behind the Meter Generation

(1) General: Electrical generation that due to its location and metering is not "seen" by MISO through telemetry. (2) Specific: A defined term in the Tariff that refers to Behind the Meter Generation participating as a Load Modifying Resource in the MISO markets.

CPNode — Commercial Pricing Node

A nodal level created for commercial purposes that aggregates certain EPNodes; all Market Settlement activity is performed at a CPNode, and it is the level where LMPs and MCPs are publicly available

DR — Demand Response

Interruptible Load or Direct Control Load Management and other resources that can reduce Demand during an Emergency

Demand Response Event - A period of time defined by the System Operator, including notifications, deadlines, and transitions, during which Demand Resources provide Demand Response. All notifications, deadlines, and transitions may not be applicable to all Demand Response products or services.

DRR — Demand Response Resource

Retail customer facilities or operations that are capable of voluntarily reducing their demand on the system

DSRI — Demand Side Resource Interface On-line User Guide

The guide to manage Load Modifying Resources, including obtaining access state availability of assets, receive and respond appropriately to scheduling instructions, deploy resources, view event history, and participate in drills.

EDR	Emergency Demand Response (Initiative or Resource)
	A MISO-classification that provides for load reductions under Emergency conditions
EPNode	Elemental Pricing Node
	The lowest level of nodal relationship in the MISO market; EPNode are modeled as part of the Physical Network Model to represent points on the Transmission System where energy is injected or withdrawn
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LBA	Local Balancing Authority
	An operational entity that is responsible for compliance to NERC for certain Reliability Standards
LMP	Locational Marginal Price
	A nodal price for energy that combines the price of energy, transmission losses, and congestion
LMR	Load Modifying Resource
	A Tariff term that refers to resources that have qualified as planning resources, that is, resources that contribute towards the system's ability to meet the resource adequacy requirement. LMRs consist of two distinct resource types: Demand Resources and Behind the Meter Generation.
LSE	Load Serving Entity
	The business that provides power to retail customers
MCP	Market Clearing Price
	An equilibrium price paid for various ancillary reserves
MECT	Module E Capacity Tracking tool
	The Web-based computer program and interface that allows Market Participants to enter various data related to their loads and Module E requirements.
MISO	Midcontinent Independent System Operator, Inc.
	The operator / administrator of the transmission grid
MP	Market Participant
	A legal entity that is qualified, pursuant to procedures established by MISO to: Submit Bilateral Transaction Schedules; Submit Bids to purchase, and /or Offers to supply electricity in the Day-Ahead and/or Real-Time Energy Markets; Hold Financial Transmission Rights (FTRs) and submit bids to purchase, and /or offers to sell such rights; and Settle all payments and charges with MISO
NAESB	North American Energy Standards Board
	The NAESB Business Practice Standards developed terms for product/service categories demand response resources may provide, evaluation of performance, and other aspects of M&V to establish common terminology and criteria that could be used for wholesale and retail demand response programs.

NERC North American Electric Reliability Corporation

PRA Planning Resource Auction

An annual auction held to allow Load Serving Entities an opportunity to meet their obligations for obtaining required capacity for a given Planning Year

PRMR Planning Reserve Margin Requirement

The total capacity requirement, measured in MW, for an LSE, based on its customers' load coincident with MISO's peak during the planning year

RSG Revenue Sufficiency Guarantee

RSG is the financial mechanism through which MISO obtains and transfers funds to offset direct costs incurred by suppliers that are not compensated through normal market prices.

RTO Regional Transmission Organization

SCED Security Constrained Economic Dispatch

A model that selects units for dispatch from among those previously committed on the basis of their marginal economic costs

SCUC Security Constrained Unit Commitment

A model that selects units for commitment on a co-optimized basis, based upon their economic offers, operational parameters, and congestion

Tariff Open Access Transmission, Energy and Operating Reserve Markets Tariff

The FERC-approved set of rules under which MISO operates

TDRL Targeted Demand Reduction Level

2.8.2 BACKGROUND

2.8.2.1 Purpose of this Protocol

This document provides guidance on methods for M&V of demand response (DR) in wholesale and retail markets. The document is intended for use by designers and operators of DR programs and market mechanisms, by regulators, and by participants or potential participants in wholesale and retail DR program offerings.

Measurement and verification for DR means the determination of the demand reduction quantities. This document addresses M&V for DR in 2 broad contexts:

1. Settlement, meaning determination of the demand reductions achieved by individual program or market participants, and of the corresponding financial payments or penalties owed to or from each participant.
2. Impact estimation, meaning determination of program-level demand reduction that has been achieved or is projected to be achieved, used for ongoing program valuation and planning.

Some parties are accustomed to thinking of M&V primarily in the context of settlement, and some primarily in the context of impact estimation. In this document, we recognize the importance of measured reductions in both contexts for effective DR design and operation and draw linkages between the two.

This work is based on a product of the National Forum for the National Action Plan on Demand Response (NAPDR) which was developed with a goal of helping states to advance the development and deployment of demand response resources. This work contributes to that goal by helping to establish credible measurement of demand reductions provided by DR resources. This document describes M&V methods that work best in various market and program contexts, as well as identifying the types of inaccuracies to which different methods are subject. Also addressed are the relationships among different aspects of DR program design (e.g., payment/penalty levels and structure, characteristics of demand response resources (e.g., weather sensitivity and variability of load, and M&V method specification)).

The intent of this document is to provide common language and guidance on best DR M&V practices in various market and program contexts including wholesale capacity or Measurement and Verification for Demand Response energy markets, and DR programs in retail markets, all with varying operating rules. The document generally follows the terminology and framework of the NAESB Business Practices Standards document on Measurement and Verification for DR, and provides additional guidance, and the Midcontinent Independent System Operator, Inc. (MISO) Business Practices Manual (BPM) for Demand Response in the second half of this protocol provides guidance for demand response when a utility is connected to a system aggregator.

2.8.2.1.2 Areas Addressed

This work includes:

- A framing discussion of demand response as a resource, with an overview of the role of M&V, also referred to as performance evaluation
- A review of the NAESB Business Practice Standards for DR M&V. These Business Practice Standards are directed to the determination of achieved DR demand reduction quantities and provide some basic terminology for describing M&V methods
- Guidance on M&V methods for settlement, including design considerations and continuing challenges.
- Guidance on impact estimation methods
- Guidance on conducting DR programs while participating in Independent System Operator (ISO) and Regional Transmission Organizations (RTO)

2.8.2.2 Organization

A brief description of each section is listed below.

- Section 2.8.3 *The Role of M&V for a Demand Response as a Resource* discusses demand response as a resource, an overview of measuring demand response and applications for M&V.
- Section 2.8.4 *NAESB Business Practice Standards* provides a review of the NAESB Business Practice Standards for DR M&V. These Business Practice Standards are directed to the determination of achieved DR demand reduction quantities.
- Section 2.8.5 *M&V Methods for Settlement* provides detailed information on developing an M&V methodology, from fundamentals through design considerations and continuing challenges.
- Section 2.8.6 *Impact Estimation* discusses the purpose of impact estimation, impact estimation methods for DR, and suggested applications of impact estimation methods.
- Section 2.8.7 *DR When Connected to System Aggregator* Discusses rules, regulations, and procedures for demand response when Entergy New Orleans is connected to a system aggregator.

Supporting appendices, contained in Volume 3 of this TRM:

- Appendix B: Examples for Existing Baseline Methods for Settlement and Examples of Baseline Adjustments
- Appendix C: Prior work in DR M&V Methods

2.8.3 THE ROLE OF M&V FOR A DEMAND RESPONSE AS A RESOURCE

2.8.3.1 Demand Response as a Resource

With proper program and M&V design, demand response can be a reliable, measurable, and verifiable resource in retail and wholesale markets. The challenge program designers and administrators face are that treating load as a supply resource creates a fundamental evaluation problem: how to accurately measure that which cannot be directly observed (i.e., the "but-for" load). There is no unambiguous, incontrovertible way to measure what the load otherwise would have been. The goal of M&V design is to develop a performance evaluation methodology that can provide the best estimate of what the load would have otherwise been, appropriate for the product or service being provided.

Some wholesale or retail electric systems rely upon reduced demand (as an alternative to increased supply) and pay participants based on the amount reduced. A measurement of the quantity of demand reduced relative to a customer-specific baseline is used for the operation and settlement of these systems. Historical performance can be evaluated to estimate expected response of an individual resource, or to adjust the amount of capability that a resource is able to offer into a market in a future period. Historical performance can also be used to estimate the amount of demand response for planning and forecasting. Transparency and fairness of baselines, retrospective assessments, and the accuracy of short-term forecasts all contribute to resource reliability and market confidence. Providing guidance on developing a performance evaluation methodology is a major focus of this document and is addressed in detail in Section 2.8.5 *M&V Methods for Settlement*.

The quantity of demand reduced for a program or market mechanism as a whole and by component is determined via impact evaluation. This aggregate measurement is needed for a range of purposes, from retrospective regulatory oversight to long-term planning studies and day- or hour-ahead operator forecasts. Section 2.8.6 *Impact Estimation* describes uses of and methods for DR impact evaluation.

2.8.3.2 Measuring Demand Response[117]

Measurement of any demand response resource typically involves comparing observed load during the time of the curtailment to the estimated load that would otherwise have occurred without the curtailment. The difference is the load reduction. The load reduction is positive if the observed load is less than the estimated load absent a curtailment, negative if the observed load is greater.

For demand response, the market product defines how the load reduction is valued and measured. Many demand response programs use a baseline methodology to estimate the load level without a curtailment for each participating resource. Other performance evaluation methodologies may also be used, depending on the product or service provided (see Section 2.8.4 *NAESB Business Practice Standards*). Actual metered load data, or

[117] Although the term "measurement" is widely used in the industry, DR reduction quantities cannot be measured in the same sense that load and generation quantities can be measured through precise metering. Rather, DR "measurement" is in most cases an estimation process, as described further in this document.

an alternative value, is compared to the "no-curtailment" estimate to determine the reduction amount for performance and settlement.

Any estimate of what the load would have otherwise been subject to some error. This error should neither be ignored nor exaggerated. Rather, the estimation error can and should be understood and managed.[118]

This document provides general guidance to help understand how various features of program design, performance evaluation method design, and participants affect estimation error in different contexts. The document also offers methods for assessing the estimation errors in a specific context and suggests strategies for managing and mitigating these errors through design choices and revisions.

As background for the discussion of alternative M&V approaches, general concepts for understanding DR estimation error are discussed in Section 2.8.3.4 *Understanding and Managing Estimation Error For DR*. First, we review the different uses of M&V for DR.

2.8.3.3 Applications For M&V

M&V for DR is used for:

- Establishing the eligibility or capability of resources;
- Retail settlement;
- Wholesale settlement;
- Projecting the future performance of an individual resource based on its past performance relative to its capability;
- Impact estimation of a program or product as a whole; and
- Forecasting and planning.

Different methods may be used for each of these purposes. Across these applications, the M&V methodology and its accuracy affect incentives and payments to participants, costs borne by the market as a whole, program operations, forecasts, and re-design. The purposes are described further below.

2.8.3.3.1 Establishing Resource Capability

For most products and services that demand response can provide, the capability of the resource needs to be established before the resource can participate in the demand response program. The methodology for capability measurement may be applied for an individual end user participating as a resource, or for an aggregated resource as a whole. The capability assessment may be as simple as the deemed capability of the appliance that is being controlled through direct load control. The assessment may be something more complex like determining the maximum demand over a fixed period of time so that a resource can offer its capacity into a wholesale market. Alternatively, either a retail or wholesale program might require an actual demonstration of capability before the resource is permitted to offer the demand reduction into the program.

[118] Throughout this document, the term "error" is defined as difference between the estimated value and the actual value of interest. Although the actual value may not be observable, there are means of assessing the magnitude of the estimation error, as described in section **Error! Reference source not found.**.

2.8.3.3.2 Settlement

DR settlement is the determination of demand response quantities achieved, and the financial transaction between the program or product operator and the participant, based on those quantities.[119] The wholesale market operator settles the market and determines the financial flows to and from the wholesale market DR participants for their performance. Retail DR program operators determine performance-based settlement with their program participants.

For demand response programs that pay an incentive for load reductions provided, the estimated load without curtailment determines the calculated reduction quantity that is the basis for settlement with each demand response resource. In the wholesale market, the DR resource may be an individual end-use customer, but more commonly is an aggregate of end-use customers operated by a DR aggregator, or the total of a DR program operated by a retail Load Serving Entity (LSE). Wholesale settlement is between the market and the market-participating DR resource. Retail settlement is between the DR aggregator or retail program operator and the end-use customer participating in the aggregation or the retail program.

In retail demand response programs, payment to end-use customers may not depend on each customer's estimated load reduction but may be based only on participation. For example, a direct load control program may pay a single seasonal incentive for the right to control load or may pay a fixed amount for each control event. However, if the retail program is offered into the wholesale market as an aggregated DR resource, the program operator will typically be settled according to an estimate of the load reduction quantity for each wholesale DR event. In wholesale markets, settlement often includes not only payments for load reductions achieved, but also penalties if the reduction achieved is below a committed amount. More generally, different M&V may be used to settle between a retail program operator and its customers than is used to settle that program as an aggregated resource in the wholesale market.

An LSE operating a retail DR program does not necessarily offer that program as a wholesale market resource. Rather, the retail operator may use DR to manage its own supply costs and settle in the wholesale market only for the actual load of its customers (i.e., the final aggregated load of its customers after DR reductions). In this case, the measurement needed for load settlement in the wholesale market is the LSE's aggregated load by interval (by market zone or node). The aggregated interval load comes either directly from summing interval meters, or from a load profile estimate. However, even if measured reductions are not required for settlement either with retail participants or with the wholesale market, DR M&V via impact estimation is valuable for assessing program effectiveness and for ongoing planning.

Table 2-28 below indicates some common retail DR structures, and the corresponding M&V needed for retail and wholesale settlement. The M&V needs for these different contexts are discussed further below. Also indicated in the table is the M&V need for impact estimation. Impact estimation itself has multiple uses and methods, as discussed in Section 2.8.6 *Impact Estimation*.

As the table indicates, there are a variety of arrangements a retail operator may have with its DR customers; many of these program structures do not require measurement of demand reduction as the basis for settlement with the retail customer or DR aggregator. However, when the program- or segment-level reduction is offered

[119] More generally, for example, an ISO "administers and oversees the commodity market for buying and selling electricity within [a]. . . region. The ISO settlement process is used to determine the charges to be paid to or by a market participant to satisfy its financial obligations. The process measures the amount of energy purchased and sold through the energy market and arrives at each market participant's payment." http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/multi_settle/index.html

as a wholesale resource, the measured demand reduction amount for the program or segment is typically needed for wholesale settlement. For all program types, if impact estimation is conducted, its primary purpose is to determine the quantities of demand reduction achieved by the DR program. The focus of this document is on measuring the quantity of demand reduction for settlement and for broader impact estimation contexts. Particular emphasis is placed on wholesale and retail settlement using baseline methods (see highlighted cells in Table 2-28).[120]

Table 2-28 M&V Needs for Common DR Contexts

Retail Program or Service Structure	Common Applications	M&V Needed for Participant Settlement with Retail Program Operator	M&V Needed for Participant Settlement with Wholesale Market	M&V Needed for Program-Level Impact Estimation
Customer or retail DR aggregator is paid per demand reduction amount	Demand Bidding/Buyback, Peak-Time Rebate	Measured demand reduction for the individual customer or DR aggregator	Measured demand reduction for aggregate	Measured demand reduction for aggregate
Customer is paid based on participation metrics	Mass market Direct Load Control	Verification of event participation	Measured demand reduction for aggregate	Measured demand reduction for aggregate
Customer pays for usage by time interval	Dynamic of fixed time-varying rates	Metered usage by time interval	Measured demand reduction for aggregate	Measured demand reduction for aggregate
Customer pays a penalty/surcharge above a pre-set load level	Contract for differences, firm load demand response, curtailable rates	Metered usage by time interval	Measured demand reduction for aggregate	Measured demand reduction for aggregate
None-- end-use customer participates directly in the wholesale market	Large customer as direct wholesale market participant	N/A	Individual demand reduction	Individual demand reduction
End-use customer participates in the wholesale market via a DR Aggregator	End-use customer enrolled in wholesale DR aggregator and rewarded through agreed sharing of DR payments	Measured demand reduction for the individual customer	Measured demand reduction for aggregate	Measured demand reduction for aggregate

2.8.3.3.3 Impact estimation

Impact estimation is the determination of the response that occurred to a given event, curtailment instruction, dispatch or set of events. At its most granular level, impact estimation estimates the demand reduction of a single demand response resource for a given interval. However, the purpose of impact estimation is ordinarily to provide estimates for a program or product as a whole, or for market segments, across a program season or year.

[120] Goldberg, Miriam L, and G. Kennedy Agnew. Measurement and Verification for Demand Response (2013)

Impact estimation can support reporting of response on an event, daily or longer period, for a program or product overall. This information is used by stakeholders, system planners, reliability organizations, and regulators. Impact estimation is used not only as a “scorecard” on past performance, but also to develop or revise policies about the eligibility, treatment, and levels of demand response.

Ex post or retrospective estimation is the determination of savings achieved by a product or program over a particular span of time. This result is used to confirm or revise the *ex ante* or prospective assessment of program effectiveness or cost-effectiveness. *Ex post* estimation may also provide the basis for adjusting projections for future program operations.

Ex ante models can also be developed from impact evaluation results, to estimate demand reduction quantities as a function of event conditions including participation and weather. As described in section B.8.6, the resulting program-level *ex ante* estimates can be used to settle a retail program in a wholesale market.

In many instances, impact evaluation estimates of demand reduction are distinct from the estimates of demand reduction for settlement. Estimates of demand reduction for settlement need to occur within a short time of each curtailment event and must use calculation methods explicitly specified as part of the program rules. These requirements limit the range of feasible methods for securing the estimates. Impact evaluation demand reduction estimates can represent a more accurate estimate of load reduction given more data, a longer time frame, and sufficient time to apply more rigorous methods than are feasible for short term settlement.

Impact estimation is discussed further in Section 2.8.6 *Impact Estimation*.

2.8.3.3.4 Projecting Individual Resource Performance

For an individual DR resource, the estimated demand reduction quantities for individual events can be used not only for settlement, but also to assess the resource’s performance over a period of time. For each resource, a performance factor can be calculated reflecting the load reduction achieved compared to the resource’s committed reduction. For example, the NYISO calculates a performance factor for each individual resource as the maximum observed load reduction amount over a season, as a fraction of the commitment. Such “performance factors” can be used by aggregators and program administrators to assess the dependability of the individual resource to provide the level of reduction that it has committed to the demand response program.

To calculate performance factors, the “observed” load reduction may be the quantities used for settlement, as in the case of the NYISO, or could be determined by a more comprehensive impact evaluation. The design of this performance evaluation method needs to ensure consistency with the objective of the program, provide an accurate estimate of the “but-for” load, and align with treatment of other suppliers of the same products.

2.8.3.3.5 Forecasting and Planning

Load forecasting is estimation of load on an hourly and daily basis in advance of the operating day. Load forecasting is conducted on a long-term basis of one or more years ahead as part of resource planning, as well as on a day- and hour-ahead basis for operations.

In this context, DR M&V is used primarily to develop *ex ante* estimates of future load reduction capability for long-term forecasts, and to estimate reductions that will be achieved if an event is called in short-term operations.

DR M&V is also needed to construct the "reconstituted" total load that would have occurred in each control area, zone, or node if past DR the events had not been called. This reconstituted load is the basis for projecting the total future load to be served by the combination of supply- and demand-side resources.

Errors in estimates of past load reductions will also affect load forecasts developed from the reconstituted load determined from those estimates. The resulting load forecast errors may either overstate or understate the load, and in the short term may result in under-scheduling or over-scheduling of supply to meet the forecasted load.

System planners may also include demand response as a supply resource in resource adequacy planning. The M&V designed for measuring response of the individual or aggregated resource then affects long-term planning functions.

2.8.3.4 Understanding and Managing Estimation Error For DR

2.8.3.4.1 Measuring What Can't Be Observed

When creating mechanisms for load to participate in wholesale markets as a resource, a general principle is that load should be subject to the same requirements as generation, to the extent practical. It therefore may seem natural to require that load reductions be measured with the same accuracy as is required for metering of generation.

However, as noted above, there is a fundamental difference between load reduction and generation as resources: *It is not possible to meter or otherwise directly observe load reductions*. Rather, measurement of the performance of any demand-side resource necessarily means comparing observed load to an estimate of the theoretical load that would have occurred absent the resource's being dispatched—that is, compared to a calculated baseline.

This baseline is an estimate of load at a condition we can't observe and is necessarily subject to some estimation error. Even though the theoretical load can't be observed, it's nonetheless possible to measure and manage the estimation errors. In the discussion that follows, we review the relationships among the key quantities produced by DR M&V, and the relationships among their estimation errors. We then describe broad strategies for understanding and mitigating the effects of estimation errors. These strategies are revisited in more detail in later sections of this paper.

2.8.3.4.2 Key Quantities Produced by DR M&V

Key quantities produced by DR M&V include:

- The calculated baseline load. This is the estimate of the theoretical load that would otherwise have occurred, or the "but-for" or "no-event load."
- The calculated reduction, or difference between the calculated baseline load and the observed load. This is the estimated reduction from the theoretical no-event load
- The financial settlement amounts, that is the payments and penalties based on the calculated reduction.

All of these quantities are subject to estimation error, and these estimation errors are directly related to one another. The discrepancy between the calculated baseline and the theoretical no-event load produces a discrepancy in the calculated load reduction of the same MW magnitude: If the load estimate is high or low by 20 MW, the load reduction calculation will be off by the same 20 MW in the same direction. The discrepancy in the calculated reduction in turn results in a discrepancy between the financial settlement amounts compared to the settlements that would be made if the theoretical no-event load were observed.

In this document, when we refer to M&V accuracy, we mean how close the calculated baseline, load reduction, or financial settlement is to the value that would be obtained if the theoretical no-event load were observable. We discuss how to assess and manage DR M&V accuracy below.

How load reduction discrepancies translate into financial settlement discrepancies depends on the program rules and market conditions. Over- and under-payments mean that the price signals given to participants are distorted or blurred. The result is a weakening of the price response, a possible reduction in cost-effectiveness of the program, and/or a shifting in benefits and costs among stakeholders. How severe these effects are depending on the size of the financial discrepancy. M&V, and M&V accuracy, are important for getting the financial transactions as close to "right" as possible.

2.8.3.4.3 Bias and Random Error

Measurement or estimation error consists of systematic and "random" components.

- Systematic error or bias is a tendency for the estimate to be higher on average or to be lower on average than the actual value. A measure of bias is the average difference between the estimate and the actual value.
- Random or nonsystematic errors are deviations up and down that on average are zero. A measure of the magnitude of random error, the typical level of variability.
- Up and down, is the standard deviation of differences between estimates and actual values.

The level and direction of systematic error and the level of variability for a particular estimation method usually depends on the characteristics of the participating resource, and on the operating conditions including time of day, calendar, and weather. For example, some methods will tend to overstate baselines on very hot days and understate on mild days, and the degree of this bias will vary across resources of different types. Resources with more regular load patterns will tend to have baselines with smaller random errors than those with more variable operations.

If the baseline estimate is systematically overstated or biased upward, the load reduction estimate will be systematically overstated by the same MW amount. Incentive payments to the participant will be biased upward as well. Conversely, if the baseline estimate is systematically understated or biased downward, the load reduction estimate will be systematically understated, and the incentive payments will be biased downward. Likewise, variability in the baseline translates into variability in calculated load reduction and in the corresponding incentives.

For both systematic and random error, a given magnitude error in the baseline becomes a proportionately much larger error in the estimated load reduction. For example, for a load of 200 kW with a 40kW reduction, a 20 kW error in the baseline is a 10 percent error in estimating load but a 50% error in estimating the load reduction.

The up and down random errors in baseline and in corresponding load reduction estimates will tend to balance out over events and customers. However, the effects on incentives may not balance out. For payments tied to market prices, an error in one direction may be settled at a high market price while an equal error in the opposite direction may be settled at a low market price. In addition, program payment and penalty schemes may involve threshold requirements that result in higher consequences for errors in one direction or the other.

Managing DR M&V Estimation Errors

The means by which the effects of M&V error can be managed and mitigated include the following four practices:

1. Assessing the magnitude of the systematic and random estimation error.
   Impact evaluation reports provide confidence bands7 for *ex post* and *ex ante* estimates and compare evaluated savings with the nominal DR quantities based on program settlement rules. This information can be used to adjust settlement procedures or quantities, or to modify the baseline estimation method used for settlement on a going forward basis.
   Baseline method assessment studies can provide estimates of systematic and random errors for different types of resources, in terms of demand level, reduction quantity, or payments for demand reduction. Methods for conducting such assessments are described in section B.8.5.5, Means to Assess Settlement M&V Accuracy.
2. Operational adjustments based on assessment of estimation errors.
   Dealing with systematic estimation errors for demand reduction can take multiple forms. One is to de-rate individual resources for observed and projected under- or over-achievement. Another is to incorporate adjustment factors into operational forecasts. Still another is to modify the program or demand reduction calculation methods to reduce these systematic errors.
   Systematic errors can be addressed by applying adjustment factors once the degree of bias is determined. Residual uncertainty can be mitigated in part by aggregating over many different resources. However, even in aggregate, the amount of DR that has been provided will typically have more measurement/estimation error than a corresponding supply-side resource. Nonetheless, even with some uncertainty in the measurement of the actual reduction delivered, the magnitude of the DR resource may still be sizable, and the DR can provide a valuable and reliable resource as long as the associated measurement error magnitude is known.
3. Program adjustments to mitigate effects of M&V errors.
   Programs can reduce the effects of M&V errors by a number of means. One is to change the baseline specifications to reduce some of the sources of error identified. Another is to change program rules to eliminate some of the factors that contributed to baseline errors. Another, when allowed, is to try to direct potential participants into the type of DR program best suited to them. Program design features that can improve M&V accuracy are discussed in Section 2.8.5.5 *Means To Assess Settlement M&V Accuracy.*
4. Program design as an iterative process.
   Program design, including M&V methods for settlement, must be subject to ongoing re-assessment and refinement. Programs are designed and prospectively assessed based on an expected participant profile. As programs are modified to address the issues experienced by current program participants, the participant mix may change as a result of the modifications. The next round of program design in turn addresses the issues and behavior of the new set of participants, and the cycle continues.

2.8.4 NAESB BUSINESS PRACTICE STANDARDS

2.8.4.1 Overview

The electricity industry has been moving towards development and adoption of a common set of terminology, definitions, analysis methods and protocols for DR products and services in recent years. The North American

Energy Standards Board (NAESB) has developed Business Practice Standards for DR Measurement and Verification for wholesale and retail markets. The wholesale and retail standards were developed to be nearly the same, with some additional elements specific to retail business practices. A primary focus of the NAESB business practice standards is on M&V methods used for market operations and settlement, but the terminology applies also to other M&V applications.

The FERC, which regulates wholesale markets only, has adopted the Phase 1 version of the NAESB Business Practice Standards for DR M&V in wholesale markets, and has issued a Notice of Proposed Rulemaking (NOPR) to adopt the Phase 2 version. The Phase 2 standards, ratified by NAESB membership, expand, and clarify criteria described in the Phase 1 Business Practice Standards. This document uses the framework and terminology of the NAESB standards and offers additional discussion and guidance. Recommendations in this document are not proposed as standards.

2.8.4.1.1 Goals of the NAESB Business Practice Standards

Goals of the M&V standards are defined by NAESB as providing a common framework to ensure:

- Transparency: Facilitate market transparency by developing accessible and understandable M&V requirements for Demand Response products.
- Accountability: Promote accurate performance measurement of DR resources by system operator(s), in dispatch, operations management and market settlements.
- Consistency: Develop uniform and consistent methods and procedures applicable across all wholesale markets.

2.8.4.1.2 Scope of the NAESB DR M&V Standards

The NAESB DR M&V Business Practice Standards cover the following aspects of M&V:

- Provide standard terminology for defining program requirements, measurement methods, and data requirements;
- Identify elements that System Operators or Governing Documents must specify for each broad type of program and performance evaluation methods;
- Identify which elements and requirements are applicable to which broad types of methods (unless otherwise specified by the System Operator);
- Specify particular requirements for metering accuracy and granularity; and
- Identify five broad types of performance evaluation methodologies and related criteria.

The standards were not developed to provide specific requirements or guidance on how to specify particular elements of the performance evaluation methodologies. As a result, the NAESB Business Practice Standards do not:

- Provide guidance on best specifications for particular market/program rules and resource characteristics;
- Address the relationship between retail and wholesale DR M&V; or
- Address the relationship between M&V for settlement and program evaluation.

This document builds on the NAESB framework, adopting the terminology where applicable, to provide discussion and guidance on issues that were considered out of scope for the NAESB Business Practice Standards developed to date.

2.8.4.2 Key Terminology

The NAESB Business Practice Standards developed terms for product/service categories demand response resources may provide, evaluation of performance, and other aspects of M&V to establish common terminology and criteria that could be used for wholesale and retail demand response programs. Terminology from the NAESB Business Practice Standards has been incorporated into many demand response programs since the NAESB Business Practice Standards were ratified by NAESB members and incorporated into regulation by the FERC. The focus for this section will be on the terms relevant to performance evaluation methodologies.

- NAESB defines demand response as, "a temporary change in electricity usage by a Demand Resource in response to market or reliability conditions. For purposes of these standards, Demand Response does not include energy efficiency or permanent Load reduction."
- NAESB defines a demand response event as, "a period of time defined by the System Operator, including notifications, deadlines, and transitions, during which Demand Resources provide Demand Response. All notifications, deadlines, and transitions may not be applicable to all Demand Response products or services."
- An important distinction is required between demand response and demand reduction value which is defined as, "the measurement of reduced electricity usage by a Demand Resource during a Demand Response Event or Energy Efficiency performance hours expressed in MW."

Demand response is the more general term, while demand reduction specifically refers to load reduction during a demand response event. Throughout this document, we attempt to be consistent regarding this usage.

Figure 2-16 adapted from the NAESB *Business Practice Standards for Measurement and Verification of Wholesale Demand Response*[121], illustrates the general framing of a Demand Response Event, and associated terminology. This chart is intended to illustrate event-based demand response, not the dispatch of demand response that is scheduled and dispatched in real-time as a supply resource. Not every demand response event will include every component shown in the chart.

[121] https://www.naesb.org//pdf4/dsmee_group2_040909w5.pdf

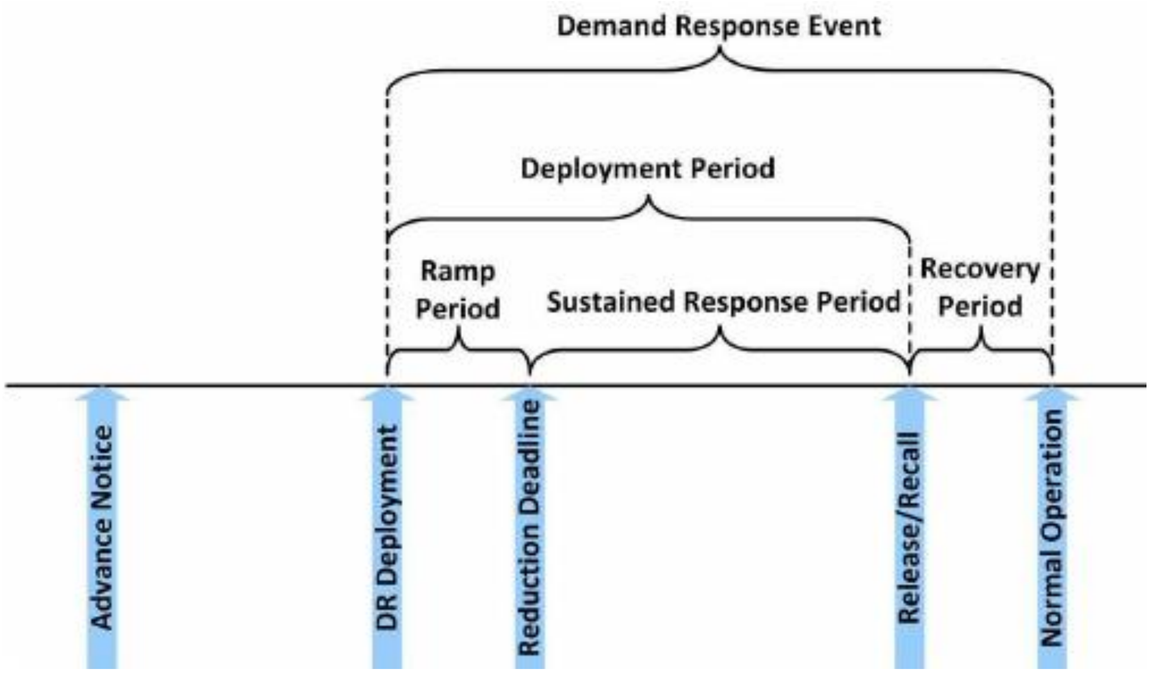


Figure 2-16 NAESB Demand Response Event Terms

2.8.4.2.1 Performance Evaluation Methodologies

Performance evaluation methodology refers to the approach taken to estimate the demand reduction value of the product/service provided by a demand response resource. Five performance evaluation methodologies have been defined in the NAESB Business Practice Standards:

- Maximum Base Load: A performance evaluation methodology based solely on a Demand Resource's ability to maintain its electricity usage at or below a specified level during a Demand Response Event.
- Meter Before / Meter After: A performance evaluation methodology where electricity Demand over a prescribed period of time prior to Deployment is compared to similar readings during the Sustained Response Period.
- Baseline Type-I: A Baseline performance evaluation methodology based on a Demand Resource's historical interval meter data which may also include other variables such as weather and calendar data.
- Baseline Type-II: A Baseline performance evaluation methodology that uses statistical sampling to estimate the electricity usage of an Aggregated Demand Resource where interval metering is not available on the entire population.
- Metering Generator Output: A performance evaluation methodology in which the Demand Reduction Value is based on the output of a generator located behind the Demand Resource's revenue meter.

These five performance evaluation methodologies are shown with the four service types defined for demand response in Table 2-29. The check marks indicate whether a performance evaluation methodology is applicable to specific product type.

Table 2-29 NAESB Service Types and Applicable Performance Evaluation Methodologies[122]

Performance Evaluation Methodology	Valid for Service Type			
	Energy	Capacity	Reserves	Regulation
Maximum Base Load	✓	✓	✓	
Meter Before/Meter After	✓	✓	✓	✓
Baseline Type-I Interval Metering	✓	✓	✓	
Baseline Type-II Non-Interval Metering	✓	✓	✓	
Metering Generator Output	✓	✓	✓	✓

2.8.4.2.2 Criteria for Performance Evaluation Methodologies

For each performance evaluation methodology, the *NAESB Business Practice Standards* provide applicable criteria to define; not all criteria are applicable to every performance evaluation methodology. The criteria are grouped together in three main categories: Baseline Information, Event Information, and Special Processing (see Table 2-30).

Table 2-30 NAESB Criteria for Performance Evaluation Methodologies[123]

Baseline Information	Baseline Window
	Calculation Type
	Sampling Precision and Accuracy
	Exclusion Rules
	Baseline Adjustments
	Adjustment Window
Event Information	Use of Real-Time Telemetry
	Use of After-the-Fact Metering
	Performance Window
	Measurement Type
Special Processing	Highly-Variable Load Logic
	On-Site Generation Requirements

Baseline Information. The criteria in this category cover the components used development of the estimated (“but-for”) load.

- Baseline Window: The range of data used for estimating the “but-for” load.
- Calculation Type: The arithmetic method used to compute the “but-for” load.
- Sampling Precision and Accuracy: Any sampling and accuracy requirements, if applicable, as for Baseline Type-II where interval meter data is not used.
- Exclusion Rules: Allowances for excluding any historic load data from the Baseline Window.

---

[122] Goldberg, Miriam L, and G. Kennedy Agnew. Measurement and Verification for Demand Response (2013)

[123] *Ibid.*

- Baseline Adjustments: Any calculations, based on a variety of conditions (such as temperature, humidity, event day operating conditions) for making adjustments to the baseline on the day of the event.
- Adjustment Window: The time period from which the adjustment data can be evaluated.

Event Information. This set of criteria covers the metering, data and measurement used for evaluating response.

- Use of Real-Time Telemetry: Specifies whether or not, real-time two-way communication with the program administrator is required for performance evaluation.
- Use of After-the-Fact Metering: Specifies whether or not after-the-fact metering can be used for performance evaluation.
- Performance Window: The period of time during the event that is used to evaluate the performance of the demand response resource.
- Measurement Type: The arithmetic method used to compute the demand reduction.

Special Processing. These additional considerations may need to be specified for demand response resources with highly variable load or behind-the-meter generation.

- Highly-Variable Load Logic: Any additional data requirements or calculations for treatment of highly variable loads providing demand reduction, either during an event or for determining the capability of the demand response resource.
- On-Site Generation Requirements: Any additional requirements for reporting the performance on on-site generation during an event.

2.8.4.3 Applications of NAESB performance Evaluation Methodologies

2.8.4.3.1 Energy Performance Evaluation Methodologies

The NAESB performance evaluation methodologies serve as a way to characterize the type of measurement used to estimate the reduction of a demand response resource. This report focuses on Baseline Type I and Type II to estimate energy response because they are the most common performance evaluation methodologies in use; these methods are typically used to estimate the amount of energy provided by a demand response resource during an event or schedule. Some demand response programs also use the Baseline Type I or Type II methodology to calculate the capacity provided during a demand response event, as described later in this section in *Capacity Performance Evaluation Methodologies*. Baseline Types I and II are frequently referred to as the Customer Baseline Load, or CBL.

The other three performance evaluation methodologies that are in use may be combined with a Baseline Type I or Type II. Metering Generator Output may be used in combination with a Baseline method for a generator that is used outside of DR events as well as to respond to these events. Products and services that require historical data beyond the data used in a Baseline Type I or Type II may incorporate a Maximum Base Load calculation Service types that require information closer to the real-time conditions of the demand response resource may use Meter Before/Meter After). As Table 2-29 indicates, most of the performance evaluation methodologies are applicable to all products and services. The design of the demand response program and the environment in which that program operates often provide the context for the performance evaluation methodology that will best align with the objectives of the program.

For Baseline Type I and Type II, the baseline calculation method can take many forms. The calculation method is specified by a combination of the baseline window, the exclusion rules, the calculation type, and the baseline adjustments and adjustment window. The combination of the baseline window and exclusion rule is intended to select days and hours that are similar to what the event day or period would have been absent the event. In many cases, the adjustments can make the baseline calculation less sensitive to the selection rules. Examples of criteria for Baseline Type I are provided below.

Baseline Window: A period of time preceding and optionally following a Demand Response Event over which electricity usage data is collected for the purpose of establishing a Baseline.

Examples of baseline windows include:

- the last 10 non-holiday weekdays;
- the 10 most recent program-eligible non-event days;
- the 10 most recent program-eligible days beginning 2 days before the event;
- the last 45 calendar days; or
- the previous year.

Exclusion Rules: Rules for excluding data from the Baseline Window. Common exclusion rules include:

- Excluding days with DR events.
- Excluding days with outages, or force majeure events.
- Excluding days with extreme weather.
- Excluding days with the highest or lowest loads.

Calculation Type: The method of developing the Baseline value using the data from the baseline window.

Examples of calculation types include:

- Average value: for each hour of the day, calculate the average of the load at that hour over the included days.
- Regression: calculate load by regressing the load from the included days on weather and other variables, usually with separate regression coefficients by hour of the day.
- Maximum value: take the maximum of the loads in the included period.
- Rolling average: the updated unadjusted baseline for an operating day is equal to 0.9 times the prior unadjusted baseline plus 0.1 times the most recent included day.

Baseline Adjustments: An additional calculation applied after the basic Calculation Type, to align the baseline with observed conditions of the event day. Factors used for adjustment rules may be based on but are not limited to; Temperature; Humidity; Calendar data; Sunrise/Sunset time and/or; Event day operating conditions.

Examples of baseline adjustments include:

- Additive: add a fixed amount to the provisional baseline load in each hour, such that the adjusted baseline will equal the observed load at a time shortly before the start of the event period.
- Scalar: multiply the provisional baseline load at each hour by a fixed amount or scalar, such that the adjusted baseline will equal the observed load on average during a window of time shortly before the start of the event period.

Adjustment Window: The period of time for which the adjusted baseline matches the observed load. The NAESB guidance is that the adjustment window shall begin no more than four hours prior to deployment. Examples of adjustment windows include:

- The hour before the event (hour -1)
- The 2 hours before the event (hours -1 to -2)
- The two hours that end two hours before the event (hours -3 to -4)

Sampling Precision and Accuracy: If the aggregate baseline is calculated from a sample of interval metering data (as for baseline Type II) the M&V method specification should include the statistical precision required. A common sampling precision requirement is that the load should be estimated so as to have a confidence interval that is +/- 10 percent of the estimate at a 90 percent confidence level. However, this precision standard, which derives from PURPA load research requirements, may or may not be appropriate for the operation of a particular program or market. Moreover, sampling accuracy is only one component of baseline accuracy. In general, better precision requires larger samples with higher associated metering costs.

The specific confidence and error levels of 90/10 precision are artifacts from PURPA and the world of load research. They may or may not serve the needs of DR M&V and, as a result, should be given due consideration.

Examples of baseline calculation methods, specifying data windows and exclusion rules, as well as the calculation method and adjustments are given in Volume 3, Appendix B: Examples for Existing Baseline Methods for Settlement and Examples of Baseline Adjustments. In addition, the ISO/RTO Council has a detailed table that lists the NAESB M&V parameters for the wholesale demand response programs across North America (link available in Appendix B: Examples for Existing Baseline Methods for Settlement and Examples of Baseline Adjustments.

2.8.4.3.2 Capacity Performance Evaluation Methodologies

This report does not address in detail the application of performance evaluation methodologies for estimating capacity response other than Baseline Type I or II approaches used to estimate the energy reduction provided by a demand response resource that has a capacity obligation. This is, in part, because the uses of performance evaluation methodologies for estimating capacity vary greatly.

Wholesale market demand response programs use a variety of methods to estimate the capacity of the resource from a comparable period, usually from the prior year. The program administrator may use the coincident peak load of the demand response resource, the average of multiple coincident peak loads, or something more complex that utilizes criteria of a Baseline Type I to estimate the maximum capacity of the resource.

For demand response resources that offer capacity, this maximum capacity often provides the upper bound that is used in conjunction with a Maximum Base Load performance evaluation methodology. The difference between the maximum capacity value and the Maximum Base Load that the resource can achieve during an event is the amount of capacity that the resource can enroll. For example, the Maximum Capacity Value may be the resource's historic peak load, while the Maximum Base Load is a demand level the resource commits not to exceed during an event. This relationship is illustrated in Figure 2-17.

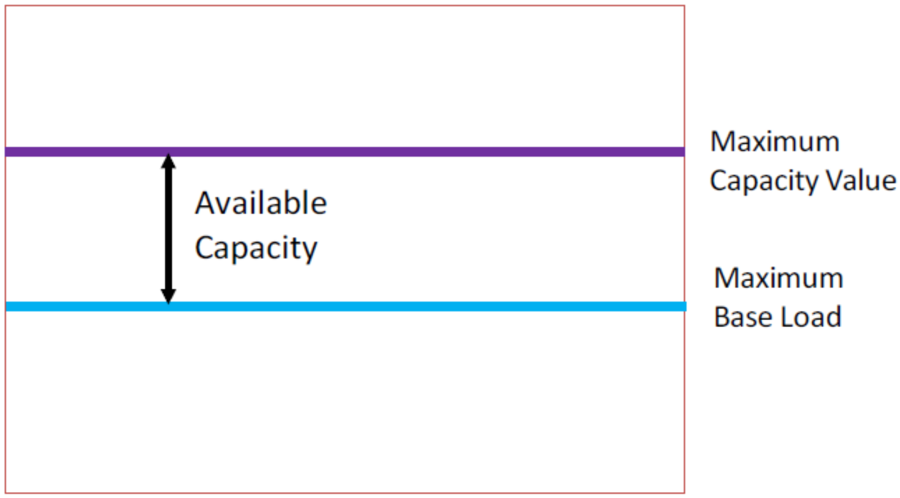


Figure 2-17 Illustration of a Maximum Base Load Performance Evaluation Methodology[124]

To estimate response after an event, the program administrator may use an energy baseline calculation, such as Baseline Type I or II. Alternatively, the program may calculate the demand reduction as the difference between the Maximum Capacity Value and the maximum interval metered load during the event; this measured reduction is then compared to the amount of capacity committed. For example, if a resource has a Maximum Capacity Value of 400 kW and a Maximum Base Load of 300 kW, the Available Capacity is the difference, 100 kW; if that resource has metered load of 320 kW during an event, the calculated demand reduction is 80 kW, or 80% of the committed amount. The Maximum Capacity Value, used to estimate the amount of available capacity in the illustration, may also be based on one of the types of performance evaluation methodologies, such as a Baseline Type 1 that uses a simple average of metered loads during certain peak hours,

Some capacity programs allow the resource to nominate the amount of capacity they can provide; these programs typically use the Baseline Type I energy performance evaluation methodology to estimate response.

2.8.4.4 Performance Evaluation Methodologies for Operating Reserves and *Regulation Service*

Demand response has demonstrated its potential in the ancillary services market by providing non-spinning reserves and regulation services in many markets.[125] For demand response resources that provide ancillary services, the performance evaluation methodologies may be similar to Baseline Type I, where the amount of energy reduction is measured from an estimated "but-for" load or may use any of the other applicable methods. The real-time nature of demand response providing these two services may lend itself to the use of the Meter Before/Meter After performance evaluation methodology, where change from a previous interval is measured, similar to a traditional supply resource. At the time of this report, the penetration of demand response providing ancillary services and details on common performance evaluation methods for these services are limited.

[124] Goldberg, Miriam L, and G. Kennedy Agnew. Measurement and Verification for Demand Response (2013)

[125] For example, PJM -- http://www.pjm.com/markets-and-operations/demand-response/dr-synchro-reserve-mkt.aspx, and ERCOT -- http://www.ercot.com/services/programs/load/laar/index Available CapacityMaximum Capacity ValueMaximum Base Load

2.8.4.5 Applying The NAESB M&V Terminology to Common Demand Response Program Concepts

Administrators of demand response programs may initially find it challenging to categorize their performance evaluation methodologies using the NAESB terminology. Table 2-31 lists some of the more common types of demand response programs and how those programs or program mechanisms align with the NAESB terminology and whether further discussion of the demand response program or program mechanism is included in this document. This summary indicates common examples and is not meant to be exhaustive of possible M&V applications to program mechanisms.

Table 2-31 Summary of Common DR Mechanisms and NAESB DR M&V Methods[126]

Program Mechanism	Market/Service Type	Resource/Customer Type	Applicable DR M&V Method	Further Guidance in this Document
Firm load: Reduce to pre-specified load on notification	Retail or Wholesale/Energy Capacity, Reserves	Any	Maximum Base Load Evaluation	Impact Estimation Approaches
Reduction from baseline	Retail or Wholesale/Energy Capacity, Reserves	Individual or aggregate loads, individually interval metered	Baseline Type 1 (interval meter)	Baseline methods by customer and program characteristics
		Individual or aggregate loads, NOT individually interval metered	Baseline Type 2 (not interval meter)	Baseline methods by customer and program characteristics
Reduction from baseline, short events	Retail or Wholesale/Energy Capacity, Reserves	Individual or aggregate loads, individually interval metered	Meter before/Meter after	None
		Aggregate loads, NOT individually metered	Baseline Type 2 (not interval meter)	Application of Meter before/Meter After for sample
Behind-the-Meter Generation	Retail or Wholesale/Energy Capacity, Reserves	Customer-sited generation	Metering Generator Output	Baseline methods applied to generation
Direct Load Control	Retail	Individual end users	N/A	Impact Estimation Approaches
Direct Load Control	Retail or Wholesale	Aggregate of retail participants	Baseline Type 1 or Type 2	Impact Estimation Approaches

In this table, a “Retail” market or service refers to a program or service operated by a load serving entity or DR aggregator to serve end use customers; A “Wholesale” market or service refers to a program or service operated by a wholesale market operator. In each case, the applicable DR M&V methods are the methods the operator would use to measure performance of the DR provider. A retail program may be offered as an aggregate DR

[126] Goldberg, Miriam L, and G. Kennedy Agnew. Measurement and Verification for Demand Response (2013).

resource in the wholesale market. Different M&V methods may be used for retail settlement than for wholesale settlement, or for determination of demand reduction quantities for individuals than for aggregates. Direct Load Control (DLC) is not ordinarily offered by wholesale markets. Wholesale Direct Load Control in the table refers to aggregated DLC participating as a DR resource in a wholesale market. While NAESB Baseline Type 1 could in principle be applied to individual DLC end users, this practice is neither common nor recommended for retail settlement.

As indicated in the table, guidance in this document focuses primarily on specification of baseline methods, and on program-level impact estimation, We turn first to methods for settlement, which are primarily baseline methods.

2.8.4.5.1 Firm Load

Demand response programs that require participants to reduce load to a pre-specified, individually negotiated “firm” level during the event window, upon notification from the program administrator are effectively using the Maximum Base Load performance evaluation methodology. For many of these programs, M&V for settlement with the participating load is a straightforward observation of how much the load exceeded the firm level. Typically, this determination is based on the maximum metered load during the event window.

2.8.4.5.2 Reduction From Baseline

Many DR programs require participants to reduce load relative to a baseline during a performance window after notification by the program administrator. These DR programs reward participants according to the amount of their demand reductions during that window. These programs include many wholesale demand response programs, and retail programs, including Peak Time Rebate programs.

- For a participant that is an individual end user with interval metered load data, the baseline is calculated from the participant’s individual interval load data and settlement is usually based on the magnitude of the reduction. This is an application of the NAESB Baseline Type I method.
- For a demand response program that permits the aggregation of individually metered end users, an aggregate baseline may be calculated from the aggregate of the individual end users’ interval load data and compared with the aggregate observed load to determine the demand reduction. Alternatively, the aggregate demand reduction may be calculated as the sum of individual end user reductions, each calculated from its own baseline and own actual load. These are also applications of the NAESB Baseline Type I method.
- For a participant that is an aggregate of individual end users who are not all on interval meters, interval metering may be required for a statistical sample of the end users. The baseline is calculated from the interval load data for the sample. This is an application of the NAESB Baseline Type II method.
- For short term demand reductions, such as ancillary services, NAESB Meter Before/Meter After method may be used, and may be used in conjunction with another performance evaluation methodology to ensure the best estimate of the response and to mitigate gaming opportunities. The method can be used directly when the end user(s) all have individual interval metered load. Although not in widespread use at this time, it is possible that for an aggregation of end users who do not have interval metered load, Meter Before/Meter After can be applied to the aggregate load estimates from a statistical sample of end users. The use of data from the sample makes this approach an application of the NAESB Baseline Type II method in combination with Meter Before/Meter After.

2.8.4.5.3 Behind-the-Meter Generation

If the use of behind-the-meter generation is permitted in the demand response program, specific performance evaluation methodologies may apply to the output of the behind-the-meter generation during a demand response event or schedule. The applicable NAESB DR M&V method is Metering Generator Output. However, depending on how the participant uses the generator absent an event, a baseline calculation may still be needed. The same performance evaluation methodologies that are used for load participating as a resource may be applied to behind-the-meter generation. The value contributed to the program is measured as the difference between the metered generator output and the baseline generation for the event window. For wholesale demand response, measuring only the metered generation does not capture the impact of the total demand response resource's load on the wholesale power grid. As a result, Metering Generator Output may be used in combination with another performance evaluation methodology when the demand response resource reduces load in addition to its behind-the-meter generation. Or metering at the retail delivery point may be used in lieu of separate metering of the behind-the-meter generator.

2.8.4.5.4 Direct Load Control (DLC)

Direct load control (DLC) programs allow the program operator to control customers' equipment directly via communicating technology that signals equipment to turn off and then releases the control at the end of the event window. Initially, control devices were radio-signaled switches that turned equipment off entirely or limited how much the equipment could run in each hour. Most commonly controlled equipment types were residential central air conditioners, water heaters, pool pumps, or heat pumps. More advanced control equipment includes re-setting thermostats rather than restricting equipment duty cycle, and two-way communication to allow customers to over-ride control and programs to record customer control status.

Most DLC programs do not pay individual participants for their individual amounts of load reduction. Rather, as noted above, payment is typically some type of fixed participation credit per season, event, or event hour. As a result, DLC programs may not require measurement of reduction amounts as a basis for settlement between the retail program and the end-use participant. However, to determine the amount of credit to provide or to determine the benefit of the program, an estimate of the aggregate load reduction is needed, and this can be determined using a baseline.

If the total DLC program reduction is offered into a wholesale market as a demand response resource, a method for determining the reduction quantity during each event is necessary for settlement of the program with the wholesale market. Currently, DLC performance in wholesale energy markets is measured using a variety of methods, discussed in Section 2.8.5 *M&V Methods for Settlement*. Some of these methods can broadly be interpreted as applications of Baseline 1 (for customers who all have interval metering data) or Baseline 2 (when a sample of customers is metered).

2.8.5 M&V METHODS FOR SETTLEMENT

2.8.5.1 Fundamental Method Design Concepts

Designing a performance evaluation methodology for demand response program settlement starts with basic criteria:

- Accuracy – the method should provide an accurate estimate of the load so that demand response resources are credited only for load reductions associated with the event and baseline manipulation is minimized.

- Flexibility – the method should provide an accurate estimate of the load for all types of demand response resources that are expected and take into consideration extraordinary circumstances such as excessively high load on event days and exclusions that may reduce the accuracy of the estimate.
- Simplicity/Comprehensibility – the method should be able to be conveyed in straightforward language so that the requirements and calculations are readily understood
- Reproducibility – the performance evaluation calculation should be reproducible by the demand response resource, aggregator and program impact evaluator

The criteria outlined in the *NAESB Business Practice Standards* were developed to provide the structure for designing performance evaluation methodologies that support these fundamental criteria. The performance evaluation methodology used for settlement of the demand response program is vital to the success of any demand response program; being able to estimate the available reduction capability and making payment for the amount of reduction at the time of the event are key aspects of demand response programs.

As illustrated in Figure 2-18, DR M&V methods and results affect and are affected by many aspects of program planning, design, and operations. The M&V method specification for settlement, program structure and rules, and cost-effectiveness analysis all need to be considered jointly as part of program design.

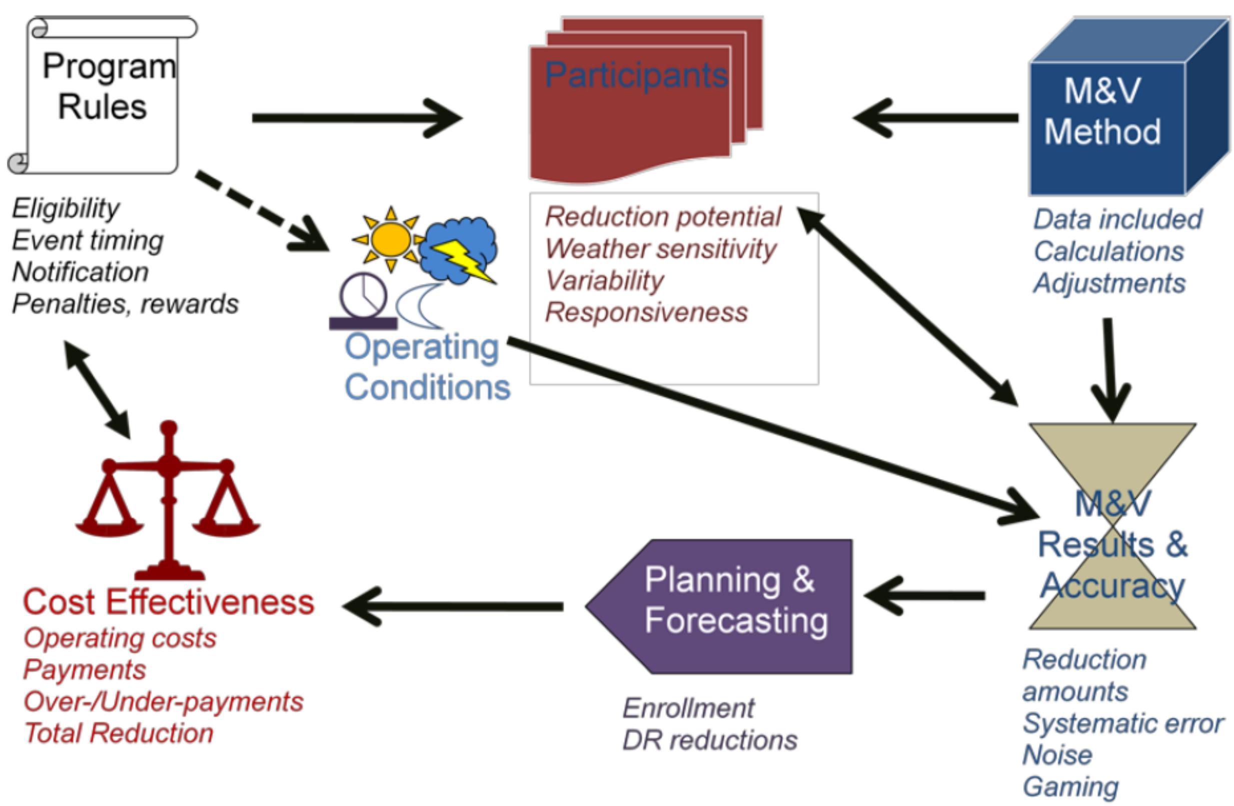


Figure 2-18 Methods and Results Affect and are Affected by Program Planning, Design, and Operations [127]

[127] *Ibid.*

Program rules, including measurement methods, payments, and penalties based on those measurements, affect the types of participants that will be interested in joining and staying in the program. Program rules also specify the conditions under which events are called, which can affect the results of M&V. M&V results and the accuracy of those results depend on the operating conditions as well as on the participant characteristics and M&V methods themselves. The M&V results may be incorporated into planning and forecasting, as well as the assessment of cost-effectiveness. Cost-effectiveness is the assessment of whether or not the benefits of the program outweigh its costs. Inaccurate M&V can result in over- or under-paying program participants and affect the level of program costs, program participation (i.e., over-paying will likely attract participation, and under-paying may reduce participation), and benefits computation. Over-estimated savings may result in over-stated benefits of avoided generation costs, which also reduces the benefit/cost ratio.

M&V method specification is an iterative process, as is all program design. After the initial design and implementation, modifications are suggested based on experience. Participant enrollment levels and behavior change in response to those program changes. The program rules and measurement methods must be re-evaluated and potentially revised based on customer response to changes in program design. The remainder of this section addresses baseline method specification for settlement. This specification is a primary challenge for designing DR programs that settle based on measured reductions. We first review the elements of baseline estimation error, and general means of managing those errors. We then discuss how the characteristics of participating resources and program rules can affect DR M&V accuracy. For each set of issues discussed, we provide recommendations.

2.8.5.2 Load Characteristics That Affect DR M&V Choices and Accuracy

As described in Section 2.8.4 *NAESB Business Practice Standards*, baseline calculation methods are specified by the combination of the data selection rules (baseline window and exclusion rules), the calculation type, and the adjustments (adjustment window and baseline adjustment method).

Simple baseline calculations support transparency. A variety of simple baselines are in use, using as the calculation method a simple or rolling average of load in each hour over days in the baseline window, subject to exclusion rules. Often an additive or scalar adjustment to recent pre-event hours is also included. Examples of such methods are included in Volume 3, Appendix B: *Examples for Existing Baseline Methods for Settlement and Examples of Baseline Adjustments.*

Empirical studies of baseline accuracy for commercial and industrial customers have shown that many simple baseline methods of this type for individual loads can have acceptable accuracy for program operations under a wide variety of loads and conditions. These studies have also found that, as long as a symmetric day-of adjustment is included, regression-based methods are no more accurate than these simpler averages. Additive adjustments are generally preferred to scalar adjustments because the resulting baseline can become volatile under a scalar adjustment.

For residential customers, however, simple baselines based on averages of recent eligible days have been found to have substantial biases for individual customers and, to a lesser extent, for program-level aggregates.[128] These biases are somewhat mitigated but are still substantial when day-of adjustments are used. While there

[128] See Oklahoma Corporation Commission Staff Report, Assessment of a Peak Time Rebate Pilot by Oklahoma Gas & Electric Company. Prepared by Dr. Stephen S. George, November 2, 2012.

are potentially ways to improve on these baselines, effective alternatives with much lower errors include the use of unit estimates based on prior evaluation work that incorporates more complete weather regression modeling, and the use of experimental design. Use of experimental design is discussed later in Section 2.8.4 *NAESB Business Practice Standards* and further in Section 2.8.5 *M&V Methods for Settlement*.

The types of loads participating in the DR program affect the types of baselines that can be effective, and the issues that need to be addressed in designing the program rules and baseline methods. Issues and methods associated with different load characteristics are discussed in what follows.

2.8.5.2.1 Business or Customer type

Business or customer type affects baseline accuracy primarily through its operational characteristics. Thus, if baseline methods are to be assigned based on customer type, this assignment is most effective if it is based on observable load characteristics, rather than a reported business category. For example, as noted, an industrial customer might have very consistent, non-weather-sensitive load patterns, weather-sensitive but otherwise consistent patterns, or highly variable patterns. Different methods will be most effective for these different customer types.

There are, however, broad differences between customer classes that relate to baseline method accuracy. Air conditioning tends to be a larger fraction of summer load for residential customers than for commercial customers, and many industrial customers have minimal weather sensitivity. Residential customers also use air conditioning more variably. Both these factors can make baseline accuracy more of a challenge in the residential sector compared to larger customers, for programs directed to summer peak use.

Recommendation: Business or Customer Type – If baseline methods are to be assigned based on customer type, this assignment is most effective if it is based on observable load characteristics and broad revenue class, rather than on a reported business category or customer segment. Key qualities that can be determined from customer load data include:

- Weather sensitivity
- Seasonality unrelated to weather
- Variability unrelated to season or weather.

2.8.5.2.2 Weather sensitivity

Residential and small commercial customers tend to have more weather sensitivity than large industrial loads. However, some large industrial facilities do include substantial weather sensitivity.

For weather-sensitive loads, it is particularly important to have days in the baseline calculation from the same season and with similar weather. In particular, as discussed above if events are called or bids clear on all hot (or cold) days, the accuracy of almost any baseline method is likely to be poor for weather-sensitive loads. Baselines for moderately weather sensitive loads work best when they include symmetric adjustments that reflect the weather of the event day. Without a day-of-event adjustment, reductions on very hot (or very cold) days can be substantially understated. This understatement occurs even if recent days are used and only higher-load days are included in the baseline computation.

Day-of-event adjustments will tend to over-state reductions for customers who pre-cool/heat in response to notification or in anticipation of a likely event. Customer-specific symmetric adjustments tend to understate reductions for customers who cancel work shifts before an event in response to notification. For this reason, it is recommended that adjustments rely on observed load in a time interval prior to the time of notification, or else use system or weather characteristics rather than the participants' pre-event load.

A common type of baseline is a simple average for each hour, taking the highest-load subset of X days in the baseline window of Y days. This "High X of Y" approach selects for days that are more like a peak day when events may be more likely. For weather-sensitive loads, however, this type of baseline still tends to understate baselines and corresponding load reductions on extreme hot days. On the other hand, "High X of Y" baselines will tend to be overstated on event days that are mild compared to recent days.

The inclusion of a day-of-event additive adjustment will substantially correct the understatement on peak days and the overstatement on mild days, though the load at the peak hours will still tend to be somewhat under- and over-stated in these respective cases.

Day-of-event adjustments do have some limitations (discussed later in this section, in Shift cancellation and other operational response to event notification or anticipation). Weather-based adjustments reflecting the load's historical relation to weather have been implemented successfully and provide an alternative for these scenarios (PJM weather sensitive adjustment method is discussed later in this section in Notification Rules and day-of-event adjustments, and in Volume 3 Appendix B: *Examples for Existing Baseline Methods for Settlement and Examples of Baseline Adjustments).* For residential customers with substantial weather sensitivity, baselines based on averages of recent days have been found to perform poorly, even with day-of-event adjustments. To calculate program-level reductions for programs with large numbers of homogenous customers, effective alternatives with higher accuracy are experimental design, or use of unit savings calculations determined from prior studies using regression analysis.

Recommendation: Weather-Sensitive Load – To reduce biases for moderately weather-sensitive C&I loads, include a symmetric day-of-event adjustment. Where anticipatory load changes are considered to be likely for many participants, a weather-based adjustment not affected by the customer's event-day load in pre-event hours should be considered. For program-level reductions for programs with large numbers of homogenous customers, use either unit savings calculations determined from prior studies using regression analysis, or experimental design.

2.8.5.2.3 Seasonality

Some loads have seasonal variations in operating patterns unrelated to weather. For such loads, baseline calculations that depend explicitly on weather variables, such as degree-day regressions or the PJM THI adjustment method, could create distortions. However, it is important to ensure that the data used in the baseline calculation are from the season of the event day.

Recommendation: Seasonal Non-Weather-Sensitive Load – To reduce biases for seasonal, non-weather-sensitive loads, include a symmetric day-of-event adjustment that is not explicitly related to weather terms.

2.8.5.2.4 Operational Variability—Highly Variable Loads

Some loads are very consistent for a given day, hour, and season, or can be well predicted using weather variables. Other loads are highly variable in ways that are not readily described by calendar and weather factors.

Loads that are highly variable apart from systematic weather response are a challenge for any performance evaluation methodology. For such assets, general customer baseline methods tend to produce demand reduction estimates with limited relationship to actual DR actions. The resulting disconnect between actions taken and payments to the participant can result in participant dissatisfaction, as well as detracting from market efficiency. If there are no penalties to the participant for under-performance, the highly variable asset is likely to stay in the program and receive erratic payments, without necessarily providing value to the market.

If a DR program is open to customers with highly variable loads, one strategy is to include a non-performance penalty to discourage customers who are unlikely to have a meaningful baseline from participating. Other strategies have been the subject of informal discussions by practitioners, but do not necessarily have any experience as of yet.

One potential strategy is to allow a procedure for customized baselines, to shift more of the prediction burden to the participant. For example, a customer may know what factors affect its load variations and may be able to provide operational data that allow a more meaningful baseline to be constructed. The customer would then be required to submit its planned levels of these operating conditions prior to bid submittal or the event notification. A simple example is that a plant with frequent, irregular shutdown periods might be required to provide advance notice of a pending shutdown and would be penalized for shutting down without prior notice if there is no DR event called.

Alternatively, the customer would be required to offer its own load prediction. If the participant is providing predictions of operations or load that will be the basis for calculating a baseline for settlement, the participant must also face a penalty if actual operations or load depart substantially from the prediction if a load reduction is not called. This approach is not currently in use, and details remain to be developed.

Another strategy is to establish formal criteria for measuring the predictability of a participant’s load. Assets whose load does not meet the predictability criteria either would not be allowed to participate or would have their calculated reductions de-rated. A variant of this approach would be to count load reductions only if they are beyond an uncertainty band for the baseline.

Highly variable loads are inherently problematic for baselines intended to represent the load absent the DR event. In terms of program operations and settlement with the participant, such loads may be better engaged in other DR strategies, such as critical peak pricing or a firm load requirement program. Even if baselines are not needed to operate those other types of DR, impact estimation of DR performance from highly variable loads remains a challenge for all program types.

Many program operators must accept any eligible customer, and do not actively target, encourage, or discourage particular participants. For those operators, the only means of restricting or directing customers is through meaningful and defensible program rules.

Recommendation: Highly Variable Loads – For resources with highly variable loads, to ensure that incentives payments are meaningfully aligned with demand reduction actions taken, the following strategies may be considered:

- Establish a “predictability” requirement for program eligibility.
- Allow a customized baseline that uses additional operational information supplied by the participant.
- Require the participant to provide its own baseline prior to notification and penalize large departures from the participant’s “scheduled” load on non-event days.
- If allowed, encourage the customer to participate in other types of DR programs that do not require calculation of demand reduction for program settlement.

2.8.5.2.5 Presence of Facilitating Technology

It is generally recognized that facilitating technology that allows customers to respond automatically to an event signal increases the responsiveness of participating customers. Automating technology also makes participation more attractive to customers. To a certain extent, facilitating technology can also improve the quality of M&V. A customer with effective control systems in place will tend to have more consistent operations during non-event periods, and more consistent response to events.

The control systems also may offer the opportunity to record additional operating parameters that can be useful in a more comprehensive impact estimation, or for other aspects of settlement not associated with baseline calculations. At a minimum, the program operator will typically have data on when control signals were sent. If the control signal technology is two-way, the operator may also have data on signal receipt and over-rides, if that is an option. Payments to customers can then be adjusted for failed signal receipt or over-rides. For example, some direct load control programs using two-way communicating thermostats allow customers to over-ride the thermostat re-set signal, and the customer pays a penalty or gives up an incentive payment for doing so. As described in Section 2.8.5, this system information on signal receipt and over-ride can be used for impact estimation, and for settlement based on *ex ante* unit savings and the number of units.

Recommendation: Facilitating Technology – For load control programs settled in the wholesale market based on the number of units controlled, information from the control system on control over-ride, success, or magnitude should be used as an input to the settlement calculation.

2.8.5.2.6 Shift Cancellation and Other Operational Response to Event Notification or Anticipation

As discussed above related to notification and adjustment timing, different types of customers have different inclinations to modify their load in preparation for or anticipation of a DR event. Participants who have to deal with shift scheduling will have different pre-event behavior from those who can turn major loads on and off on short notice. For customers with substantial heating or cooling of the premise or energy storage capability, pre-heating or pre-cooling is a consideration for baseline accuracy.

Some plants want to be able to respond to a DR notice by canceling a shift that is scheduled to start well before the event window. If the adjustment window would include part of the cancelled shift, the plant’s baseline will be reduced by the shift cancellation. For this reason, it is recommended that participant-specific adjustments are based on pre-notification periods. For demand response resources that participate through offers to the market, consider allowing participants to specify a notification/start up time as part of their offer.

A plant with stable operating patterns and no weather sensitivity is likely to be better represented by a baseline with no day-of-event adjustment. Using the unadjusted baseline would allow the plant to cancel shifts before the event window without a negative effect on its calculated reduction.

Long-term shutdowns may affect the baselines of DR resources in programs where historical data from a prior period, such as the same season in the prior year, is used in a baseline calculation. Establishing procedures for reporting such planned shutdowns in advance can reduce opportunities for a baseline to be overstated.

2.8.5.2.7 DR Resources Providing Load Reduction Every Day

In principle, any DR resource with a capacity obligation must be available to provide demand reduction during all times covered by its obligation. Otherwise, demand response used as a capacity resource may not be able to displace the need for generation capacity (i.e., additional generation may need to be acquired to cover the hours that demand response resources were unavailable). Likewise, entities offering demand resources typically want to minimize restrictions on their opportunity to sell this service.

Some demand response resources are indeed in a position to provide demand reductions consistently every day. For example, a customer with behind-the-meter generation potentially could use its own generation, within the constraint of environmental permitting rules, to reduce load taken from the market on as many days as required by DR calls, but otherwise use its own generation only in emergencies. Even without onsite generation, a facility might have the ability to shift loads such that it could go to a lower level of operation during any period called, on any number of successive days, but would stay at a higher operational level if not called.

Meaningful measurement of load reduction requires observation of “non-dispatched” operating conditions. A resource that is in reduction mode on a continual or daily basis no longer has a “no-dispatch” state of operation against which the reduction can be measured. However, setting explicit rules to limit how frequently a resource may offer reductions is at odds with the principle of resources being available across all times covered by the DR program.

To address this issue, ISO NE has established rules that limit the number of successive days on which an entity can participate as a demand resource before its baseline must be refreshed. Baseline refreshment means inclusion in the baseline calculation of meter data from a present operating day, even if the operating day included a dispatched load reduction—in this case, meaning that the resource was instructed to reduce load as a result of its demand reduction bid clearing in the energy market. The extent to which this rule is sufficient or excessive and its applicability to other systems and services are open empirical questions.

Further exploration is needed of mechanisms for ensuring that adequate “non-dispatch” days are available for baselines, and to assess how many days are “adequate.” Such studies can lead to guidance on the types of mechanisms to use and how to specify them in detail based on program experience.

2.8.5.3 Program Design Features Affecting M&V Choice and Accuracy

As described in Section 2.8.4 *NAESB Business Practice Standards*, performance evaluation methods using Baselines are specified by the combination of the data selection rules (baseline window and exclusion rules), the calculation type, and the adjustments (adjustment window and baseline adjustment method). All of these specifications are part of the program design. Other program rules affect how frequently and under what conditions events can occur, or the frequency that a demand reduction bid from a particular asset can clear in a market that incorporates DR in its energy market. The combination of these program rules and baseline specification, along with the characteristics of the participating loads discussed above, affect the baseline accuracy. Program design elements are discussed below in terms of their interaction with baseline rules and accuracy.

2.8.5.3.1 Rules to Ensure “Comparable” Days in Baseline Calculations

The baseline window is specified to select days that are in some sense similar to the event day, such as recent business days. Exclusions are sometimes applied to eliminate anomalously high or low load days. Typically, event days are also excluded from baseline calculations, since the baseline is intended to represent a participant’s consumption absent the event. Depending on the program rules and operating practices, these selection approaches can lead to a shortage of similar days in the baseline calculation, as described further below.

(i) Challenges if DR is Dispatched on Every Extreme Day

A common challenge is that DR events are often called on system peak days, which tend to be particularly hot summer days or cold winter days. The weather on recent non-event days will typically not be as extreme as on event days. If dispatchable events are called, or a particular bidding asset clears, on all of the most extreme weather days, it is difficult for any baseline methodology to provide accurate baselines for weather-sensitive loads for those days. This situation is a problem for impact estimation as well as for settlement baselines.

Baltimore Gas & Electric (BGE) addresses this issue by including weekends in the baseline calculation for a residential Peak Time Rebate (PTR) rate that has events only on weekdays, to ensure inclusion of hot days for each customer. An alternative approach, if program operators have discretion on when to call an event, is to operate the program in a way that ensures some event days and some non-event days for extreme weather conditions, as well as for mild conditions. For homogeneous customer groups, experimental design methods discussed in Section 2.8.6 *Impact Estimation* can provide this structure.

As described earlier in Section 2.8.5.2.2 *Weather sensitivity*, baseline methods based on averages of recent days, even with day-of-event adjustments, will tend to understate baselines on extreme weather days, and overstate on mild days, for highly weather sensitive loads. For weather-sensitive loads where this type of baseline is used, program rules that result in event days on a mix of extreme and mild weather days tend to produce a mix of over- and under-stated load reduction estimates. This mixing does not improve the accuracy of load or financial settlement for any single day but can improve the overall accuracy over a season. Of course, how over-, and under-stated reductions translate into net financial errors depends on the prices that apply to the different days.

If extreme weather days occur in sequential clusters, leaving one or more of the days in the cluster as a non-event day can partially improve the baseline accuracy for the event days that are called.

Recommendation: Program Operation to Reduce Baseline Error for Weather-Sensitive Loads – To improve the overall accuracy of settlement for weather-sensitive loads, if the baseline method is an average of recent days with possible exclusions and day-of-event adjustments, program dispatch rules that allow the following can be considered.

- Ensure that events are likely to be called on a mix of extreme and mild weather days.
- If extreme weather days are projected over several days in a row, leave one or more of these days as a non-event day.
- Even if there are no strings of sequential extreme days, ensure that some extreme days are not called as event days, for eventual impact evaluation.
- For residential programs, include weekend days in the baseline calculation even if they are not program-eligible days.
- For all but the last of these, a trade-off that must be recognized is that these practices to improve baseline accuracy would come at the cost of restricting the use of the DR resource.

(ii) Challenges from too few Recent Non-Event Days -- Static Baselines

For loads that vary seasonally, whether or not they are strongly weather sensitive, a related problem is frequent DR events. In demand response programs based on bids submitted by the demand response provider, some program rules may make it possible to bid in such a way so that events are called on every program-eligible day for several months. When event days are excluded from baseline calculations, as is commonly done, the result is a baseline frozen at the point before the string of DR event days began. In this case, there may be too few recent non-event days to provide the basis for an accurate baseline.

This problem will be partly ameliorated by use of a symmetric day-of-event adjustment, which roughly aligns the load level to conditions of the event day prior to the event. Day-of-event adjustments do not, however, address the changes in shape of the baseline over time. As a result, even with an adjustment, bias can increase as the source of baseline data become more distant from the event.

The frozen baseline phenomenon arises with the combination of:

- DR assets clearing every day in a bidding program
- Event days excluded from the baseline calculation
- Weather sensitive DR assets

In an example provided by ISO NE, several DR assets showed a pattern of bidding into the market every day at a price point that virtually assured they would be cleared, starting in the first cool period in the fall and continuing through the winter. Because these assets cleared every day, and prior event days were excluded from baseline calculations, baselines were fixed at their summer load levels. Thus, the assets received payments for the difference between summer and fall/winter load levels, even if they made no reduction in response to their bids clearing.

At the time, ISO-NE had an “asymmetric” day-of adjustment, meaning the adjustment was applied if it would increase the baseline, but not if it would decrease it. This adjustment method exacerbated the issue. Analysis of simulated load reductions and baseline calculations performed with program data explored the potential for frozen baselines. This analysis determined that applying a symmetric rather than asymmetric adjustment decreased the extent of the bias substantially but did not remove bias completely. The weather sensitive load shape underlying the static summer baselines remained quite different from the fall and winter load shapes and continued to show reduction according to the baseline calculation, where no true reduction had been made. The simulation data indicated that changing the baseline method to require a minimum number of program-eligible baseline days prior to the events would more effectively address this bias. Other alternative design criteria, such as changing the exclusion rules may provide a solution to reduce the likelihood of a static baseline when demand response is deployed frequently.

Thus, program rules can limit opportunities for static baselines by avoiding or limiting any of the bulleted conditions above. For example, ISO NE proposed incorporating cleared days (i.e., prior event days) to address baseline bias resulting from clearing every day. In this case, the main objective was to address the baseline bias.

Recommendations: Limiting Static Baseline Opportunities – To limit opportunities for “static baselines,” the following approaches can be considered.

- In programs where other program rules and requirements allow, and where event days will be excluded from baseline calculations, limit how frequently a given asset is allowed to clear or to have events.
- Incorporate event days or recent non-eligible days in the baseline calculation for assets that have too few recent non-event days in their baseline window. This should only be used in extreme situations, as doing so may increase the bias of the baseline calculation, reducing its accuracy and further understating the estimate of the load.

- For programs that have the flexibility to target particular types of customers, target loads with minimal weather sensitivity or other seasonality. This approach is not practical for all programs, but for large, non-seasonal industrial facilities, the static baseline phenomenon is unlikely to be a problem.

To determine if a static baseline may be an issue for program participants, model the proposed baseline calculation under extreme scheduling conditions to test its resilience to frequent scheduling. If a persistent bias develops under these conditions, one of the solutions listed above may be necessary to avoid paying for non-existent load reduction.

2.8.5.3.2 Notification Rules and day-of-event adjustments

Day-of-event adjustments are often included in baseline calculations to align the baseline calculated from recent non-event days with the conditions of the event day to improve the estimate of the “but-for” load level. The typical adjustment shifts or scales the baseline by a fixed amount so that it matches the actual load during a period before the event start (the adjustment window). This adjustment can help correct for load changes due to weather, as well as for variable operations.

In simulation studies of loads that are not participating in a DR program, symmetric day-of adjustments have been shown to improve the accuracy of a wide range of baseline calculations, including those that use explicit weather models, for a wide range of load types. However, for an asset that is in a DR program, there is the possibility that the load during the adjustment window will itself be affected by the event or the expectation of an event. The extent and nature of these effects is difficult to measure, but conceptually depends on the timing of the notification along with the specification of the adjustment window and method.

Event effects during the adjustment window can occur in a number of ways including the following:

- Preparatory increase in response to notification: A building is pre-cooled to a cooler than usual level from the time of event notification up to just before the event. This is a legitimate, reasonable response that makes program participation more viable for the building. However, if the adjustment window includes hours between notification and the event, the baseline will be inflated.
- Preparatory decrease in response to notification: A plant cancels a shift upon notification of an event. Facility load drops prior to the event start. If the adjustment window includes hours between notification and the event, the baseline will be substantially understated.
- Anticipatory increase prior to notification: A building is pre-cooled to a cooler than usual level beginning in the early morning whenever a very hot day is forecasted, which makes a DR event likely. As long as some hot days do not have DR events, the pre-cooling can be expected to occur in at least some of the non-event days used to calculate the baseline. The more routine the pre-cooling is, and the more the baseline window and exclusion rules select similarly hot days, the less bias there will be in the adjusted baseline.
- Anticipatory decrease prior to notification: A plant cancels a shift based on forecast conditions that suggest a likely event. Facility load drops prior to the event start. If the adjustment window includes hours between notification and the event and symmetric adjustment, the baseline will be substantially understated.
- Manipulative increase: A DR asset deliberately ramps up load during the adjustment window after event notification or based on its determination that an event is likely. The baseline is artificially inflated. This behavior may be difficult to distinguish from appropriate preparatory or anticipatory increases.

Setting the adjustment window to end prior to notification can limit opportunities for deliberate manipulation. On the other hand, the earlier the adjustment window, the less effective it may be in adjusting the baseline to estimate day-of load conditions.

Day-ahead notification is more attractive to participants who want more time to respond to events and is common in bidding programs. With day-ahead notification, any day-of-event adjustment is subject to preparatory effects, both legitimate and manipulative.

PJM's alternative weather sensitive adjustment16reflects the conditions of the event day without allowing pre-event responses to distort the baseline. This method uses a simple regression of load on whether to compare event-day weather conditions during the event window to the conditions during the baseline window at the same hours. The ratio of the regression-based load estimates for the two periods provides the adjustment. The approach has the advantage of adjusting to the event day weather conditions without requiring pre-event load to be informative. The disadvantage is that it adjusts only for weather and does not adjust for an asset's natural, non-distorting operations on the event day.

Some programs have used asymmetric adjustments, which apply the adjustment if it will increase the baseline but not if it would decrease the baseline. This practice avoids penalizing early shut-downs, but in general creates upward-biased baselines and can contribute to static baselines, discussed above.

Recommendations: Baseline adjustment methodologies by notification and load characteristics – To improve accuracy and reduce bias for almost any baseline method, use an additive, symmetric day-of-event adjustment. Table 2-32 summarizes recommended adjustment window and basis, based on the notification timing, and the likely accuracy problems remaining for different types of assets.

Table 2-32 Recommended Baseline Adjustment by Notification Timing and Load Characteristics[129]

If Notification Is-	For Load Characteristics		A Useful Adjustment Basis is-	Likely Accuracy Problems After Adjustment are-
	Non-Weather Variability	Weather-Sensitivity		
Same day	Low	Low	None or own load, 1-2hrs pre-notification	Minimal
	Low	High	Own load, 1-2 hrs. pre-notification or weather	Anticipatory pre-cooling can inflate baseline
	High	Low	Own load, 1-2 hrs. pre-notification	Underlying variable load
	High	High	Own load, 1-2 hrs. pre-notification or weather	Anticipatory load shifting can inflate baseline, underlying variable load

[129] *Ibid.*

Day Ahead	Low	Low	None	Minimal
	Low	High	System or weather, 1-2 hrs. pre-notification	Pre-cooling in response to notification/clearing inflates baseline; added variability compared to same-day notification, own-load adjustment
	High	Low	System or weather, 1-2 hrs. pre-notification	Underlaying variable load; added variability compared to same-day notification, own-load adjustment
	High	High	System or weather, 1-2 hrs. pre-notification	Pre-cooling in response to notification/clearing inflates baseline; added variability compared to same-day notification, own-load adjustment

(i) Concerns Related to Gaming Opportunities

A concern for any baseline method is that participants may manipulate their baselines to reap greater incentive payments. No baseline calculation method can eliminate the possibility of manipulation. However, such manipulation or "gaming" does not happen unless it is worth the trouble to the manipulator. The added energy costs and the operational inconvenience of changing load patterns simply to inflate a baseline have to be less than the expected excess payment. A DR aggregator attempting to adjust load for purposes of manipulating baselines needs the cooperation of its customers. While some end users, especially larger organizations, may find it worthwhile to follow a baseline manipulation strategy, this practice does not appear to be widespread in existing programs.

Bidding program participants typically want to know what baseline their reductions will be measured against prior to submitting a bid. This practice assures that even if the methods have biases, the participant has visibility to the results and can make an informed decision whether to offer a load reduction relative to that baseline. However, to reduce the incentive for selective bidding based on methodologically overstated baselines, the participant should not be able to submit a bid that is guaranteed to clear.

Recommendations: Limiting Gaming Opportunities – Elements that can reduce opportunities for baseline manipulation by participants include the following:

- Use a baseline calculation method that's fair on average on likely event days, absent any gaming.
- Ensure that baseline calculation data include recent "similar" days and are limited in how far back the "look-back" period can be so that data from another season cannot be used to overstate the baseline.
- Use rules that have the effect of limiting participants' ability to control or predict what days they will be called on to reduce.
- Investigate load and bidding patterns that seem perverse based on customer characteristics.
- Require advance notice of scheduled shut-downs.

2.8.5.4 Settlement Issues and Approaches For Particular Program Types

The settlement issues discussed above play out in different ways for particular program types. The following is a brief discussion of M&V issues for key types of DR programs. For each, we present a general discussion of the program type and outstanding issues to be addressed. We also identify some additional general issues requiring consideration.

2.8.5.4.1 Direct Load Control

As noted in Section 2.8.4.5 *Applying The NAESB M&V Terminology to Common Demand Response Program Concepts*, *Applying the NAESB M&V Terminology to Common Demand Response Program Concepts – DLC,* DLC programs typically pay incentives to participating customer based on participation only, and not based on a measurement of each customer's load reduction. However, DLC programs offered as DR resources in wholesale markets require a basis for measuring the reduction achieved by the program for a particular event. A variety of methods are currently in use for this purpose.

(i) *Ex ante* Unit Estimates and Current Participation

With this method of measuring DLC program load reduction, an *ex ante* estimate of savings per participant is multiplied by the number of successfully controlled participants. The unit savings estimate may come from engineering estimates at the start of a program, or from *ex post* program evaluation after some experience with the program. The average reduction per unit can be based on end-use metering, whole-premise metering, or other methods.

The *ex ante* estimates provide the average reduction per unit, typically by time of day or for the peak hour, and possibly also by temperature condition, by customer climate zone, or by equipment capacity. The number of successfully participating units begins with the enrollment level. This participant count should be adjusted by the rate of over-ride, if allowed by the program, and by signal success rates. These adjustment factors may be estimated from prior impact evaluation, or by event-specific information collected by the DLC program's control system, depending on the system capabilities.

Ex ante unit savings by geography, time of day, and weather condition based on analysis of multiple prior impact evaluations is the basis for PJM's "DLC method" for wholesale settlement. This method is used to settle DLC with PJM for participants who don't have interval metering in place as of the start of the season.

(ii) Firm Service Level

For retail customers who have interval meters, PJM uses another method, based on Firm Service level. The retail program operator determines the total Peak Load Contribution (PLC) of its DLC participants. This PLC serves as a Maximum Capacity Level. The operator commits to reduce the total load of the participants to a Firm Service Level during events, effectively the same as a Maximum Base Load. Performance relative to this committed reduction is calculated from the sum of the metered loads of the participants during the event.

(iii) General NAESB Baseline I or Baseline II

In principle, a Baseline method could be used that calculates a simple average of recent days, with adjustment to the event day, similar to many of the methods listed in Volume 3 Appendix B: *Examples for Existing Baseline Methods for Settlement and Examples of Baseline Adjustments*. This approach could be applied to individual customers with interval metering as a NAESB Baseline I method, or to a sample of customers who don't have interval metering, as a NAESB Baseline II method. However, application of these baseline methods to DLC programs for wholesale settlement does not appear to be in use currently and is not recommended. DLC programs that control air conditioning or heating involve loads and load impacts that are highly weather dependent. Simple baseline methods generally do not represent such loads as accurately as can the weather models used for the *ex ante* estimates.

(iv) Experimental Design

Experimental design, or the random assignment of eligible participants to treatment and control groups, has been used in recent years as an impact evaluation method. Operating a DR program using experimental design means that during each DR event, a randomly selected subset of participants is not dispatched, thereby serving as a control group. This approach can be useful for programs with large numbers of relatively homogeneous customers, primarily residential and small commercial.

For instance, some California direct load control programs have held back a random subset of participant households from each event activation. The event- period load for these non-activated but program participant households provide a statistically unbiased baseline for those households that were activated. This approach is not directly addressed in the *NAESB DR M&V Business Practice Standards*, though it could broadly be interpreted as an application of Baseline II method. Experimental design applications are discussed in (iv) *Experimental Design*.

2.8.5.4.2 Peak Time Rebate

Peak Time Rebate (PTR) is a retail rate or program that provides rebates to participants who reduce their use during an event window after notification that an event will be in effect has been issued. Retail settlement with participants requires a customer-specific baseline. The general baseline methods and issues described above apply in this context.

PTR often is available to smaller customers than have historically participated in DR programs (other than DLC). For these customers, reducing air conditioning use by raising summer thermostat settings can be a key part of their response strategy.

Common baseline methods used for PTR settlement are based on averages of metered consumption data from recent non-event days, with a baseline adjustment, or data exclusion rules to select hotter days. As discussed in Section 2.8.5 *M&V Methods for Settlement*, most of these methods tend to understate baselines on extreme hot days, resulting in penalties or lack of reward for customers who reduced energy consumption (and consequently made themselves uncomfortable) on very hot days. Understating the baseline and associated reduction in energy usage could be expected to lead to appreciable program dissatisfaction, though this response has not been seen in recent pilots.

Smaller load reductions that get lost in the noise can also result in underpayment. Further, customers with significant day-to-day variations in energy use could receive payments for naturally lower loads on days with event windows. In general, if the scale of reductions available to the customer is small compared to the customer's overall variation in energy usage, establishing meaningful baselines for PTR will be challenging. This problem of small responses relative to the customer's natural variability in energy usage is exacerbated if the PTR program is established as a default rate, with many non-engaged customers.

This issue was demonstrated in analysis of a proposed default residential PTR rate[130], with a baseline defined as the average of the highest 3 out of the most recent 10 eligible days, beginning 3 days before the event day, with no adjustment. The analysis of customer load on twelve key summer days showed that:

[130] https://www.pge.com/regulation/RateDesignWindow2010/Testimony/PGE/2012/RateDesignWindow2010_Test_PGE_20120403_234258.pdf

- 60% of customers would have received incentive payments based on the calculated baseline despite not reducing load at all during an event window. This would lead to incentive payments totaling $41 million each year to customers with no load reduction.
- Some customers who reduced their use (compared to a peak day with no event called) would receive no payment.

With this level of mismatch between actions and payments, this particular PTR program appears to provide little incentive to move this class of customers toward more efficient consumption behavior, in line with supply costs. Payments to customers who have not performed are costly to all ratepayers. Lack of payment to customers who have made reductions could dissuade customers from responding to future events.

The mismatch might be less severe with a different baseline method. However, even with a better baseline, there will still be payments to customers who took no action and non-payments to customers who did act for almost any PTR program.[131]

One reason PTR pilots have found high participant satisfaction despite baseline inaccuracies likely has to do with customer expectations.[132] Customers are not necessarily guaranteed a payment if they take certain actions but are paid if they beat their baselines. Moreover, baseline errors are not necessarily all in the same direction for a particular customer. In terms of the monthly bill, customers who tend to take actions during PTR events tend to see savings. Customers who respond minimally, if at all, to PTR events may or may not receive payments, and are not penalized.

Whether the baseline errors are too large for a particular program ultimately comes down to the question of whether the program is cost-effective with these baselines and the associated customer responses.

(i) Outstanding Issues for Peak Time Rebate

More study is needed to assess the accuracy of common baseline methods for the residential sector across a range of climate conditions. Future studies should include the implications for the monetary transfers and overall cost-effectiveness, under appropriate pricing assumptions.

More study is also needed on customer load and operating characteristics that make the customer a good PTR candidate. These characteristics include not only the ability and willingness to respond to events with observable demand reductions, but also predictable usage patterns outside of event days that will tend to result in stable and meaningful baselines. Understanding these characteristics can guide policies on whether and for what customer segments PTR should become a default rate.

Cost-effectiveness assessments are needed for PTR programs, based on impact estimations of load reductions actually achieved, as well as on observed customer acceptance rates from programs that have run for one or more seasons.

[131] For a more detailed assessment of alternative baseline methods, see Oklahoma Corporation Commission Staff Report, Assessment of a Peak Time Rebate Pilot by Oklahoma Gas & Electric Company. Prepared by Dr. Stephen S. George, November 2, 2012.

[132] "BGE's Smart Energy Pricing Pilot," Cheryl Hindes, PLMA Panel, November 8, 2012.

2.8.5.4.3 Ancillary Services

Ancillary Services is a relatively new product space for demand response, thus information on common performance evaluation methods for these new DR services is limited.

The Meter Before/Meter After performance evaluation methodology may prove to be a viable method for accurately estimating the response of DR resources under real-time dispatch conditions. Clearly Meter Before/Meter After requires demand resources with relatively flat load profiles during the time period of the dispatch. If a resource has periods of ramping up or down or general variability, the meter Before/Meter After approach can over- or under-estimate the actual level of load reduction even for the shorten period.

2.8.5.4.4 Programs Using New Control/Communication Technologies

New control and communication technologies that are being incorporated into demand response include:

- Remote control of equipment by customers;
- Automatic dispatch of demand reduction signals to customer equipment based on a price or command signal to the customer's meter, following a customer-specified response strategy;
- Communication that a control signal has been received or that specific equipment usage has been curtailed; and/or
- Real-time, two-way continuous communication with a system operator for dispatch of energy and/or ancillary service products.

The same general M&V methods can be applied for settlement (as well as for impact estimation) when these technologies are used as when they are not. However, these control and communication technologies also offer additional opportunities in the settlement context for verifying demand response and in the broader contexts of impact estimation for understanding demand response patterns.

The most useful information for M&V provided by this technology is the communication back to the program operator through new DR communication standards like OpenADR (Open Automated Demand Response). This information can be used for immediate verification of curtailment and identification of failed or over-ridden signals. As described in section B.8.6, this information can be used to determine DLC program accomplishment for wholesale settlement.

The operator may also receive more detailed information, such as the degrees of thermostat re-set, or particular pieces of equipment put into standby mode. This type of information is not currently being used for settlement but could be.

In the impact estimation and forecasting context, relating the equipment response information to empirical observations on load reductions over time allows more fine-grained forecasts of reductions for specific customers and for future customers. Comparing the equipment changed with the measured load reduction can also provide another level of verification of the load reduction measurement.

2.8.5.5 Means To Assess Settlement M&V Accuracy

As noted, there is no direct measurement of M&V accuracy. Only consumption can be metered directly, not reduction` in consumption. However, by using a form of load simulation it is possible to assess in general how well a particular baseline method represents what would have happened absent a DR event. The simulation calculates baselines according to the prescribed method for a set of customers and days when no DR event occurred. Comparisons to actual load during the DR event can then be made. Following are general steps for conducting such an assessment.

1. Obtain interval load data for a set of customers similar to those expected to be in the program. For an existing program, these customers might be actual participants on non-event days. For a prospective program, the customers who will be targeted, or a similar group of customers may be used. The more similar the customers used in this analysis are to the actual (likely or targeted) program participants, the more informative the analysis will be.
2. For days similar to days when DR events are likely to be called by the program, but when no DR event is affecting the study customers, use the designated baseline method to calculate the baseline for each customer and day. If events are likely to be called under a broad range of conditions, it is important to examine baseline performance for different conditions, including frequent successive deployments. If events are likely to be targeted to extreme weather days or system peak load days, it is important to examine baseline performance under these conditions.
3. For each customer in the study data set and each study day, calculate the following for one or more event hours:
    a. Calculated baseline using the baseline methodology;
    b. A simulated actual load reduction quantity assuming (for example) a 20% reduction from the actual load (actual load is known in the simulation exercise);
    c. The simulated actual event load with that simulated load reduction quantity;
    d. The simulated load reduction calculation using the baseline methodology: the difference between the calculated baseline and the simulated actual event load;
    e. The participant payment or penalty corresponding to the simulated actual load reduction quantity, applying the program payment/penalty rules to the actual reduction; and
    f. The participant payment or penalty corresponding to the simulated calculated actual load reduction quantity, applying the program payment/penalty rules to the calculated reduction using the baseline method.
4. Calculate the following accuracy metrics from the quantities in Step 3:
    a. Difference between (3a) the calculated baseline and actual load;
    b. Difference between (3d) the load reduction calculated from the baseline and the (3b) actual reduction. This metric translates (4a) the error in estimating load into (4b) the error in estimating the load reduction; and
    c. Difference between (3e) customer payments or penalties based on the reduction from the calculated baseline and (3f) what those payments or penalties would be if based on the actual reduction amount. This metric translates (4b) the error in estimating load reduction into (4c) the error in estimating the financial impacts.
5. Examine the distribution across customers and days for each of these accuracy metrics in terms of parameters such as the following:
    a. Systematic errors or bias: average difference between the calculated value using the baseline method and the actual value.
    b. Variability: what is the typical level of error for load, load reduction, and payment quantities?
    c. What fraction of customers or what types of customers showed no positive load reduction using the calculated baseline?

d. What fraction of customers would produce a baseline load estimate that would require no actual reduction to achieve a positive payment?

Examples of such studies are discussed in Volume 3 Appendix C: *Prior work in DR M&V Methods*. An important point that emerges from studies of this type is that a modest error in estimating the load itself can become a much larger error in the calculated reduction. For example, for a 20% actual load reduction, a 10% error in the estimated load level is a 50% error in the calculated reduction. These errors in measuring reductions translate into misalignments between payments and actual load reductions. Even with these imperfect calculations of reductions, the DR program may still provide benefits to the program administrator and to the market.

Several simulation studies of baseline accuracy are described in Volume 3 Appendix B: *Examples for Existing Baseline Methods for Settlement and Examples of Baseline Adjustments*. Each of these studies examines both systematic errors and the level of random error or variability. However, there are a variety of ways to summarize the “typical” errors across multiple customers, days, and event conditions. Different studies have used different metrics in line with the general guidance above. Development of a standardized analysis and reporting approach would improve comparisons across such studies.

2.8.6 IMPACT ESTIMATION

Impact estimation at the program level is another instance of measurement and verification and plays an important role in ongoing program assessment and improvement. As indicated in Figure 2-16 above, M&V methods for settlement should be considered in the context of program planning, design, and operations. In this context, program-level impact evaluation is a key element in the ongoing cycle of program development.

Impact estimation broadly speaking means determination of program effects. For DR programs, these effects can include load reductions (or load increases) related to a particular event or set of events, energy savings (positive or negative), monetary effects, and other impacts. The effects may be determined at the program level or at any level of granularity. For purposes of this document, we consider impact estimation primarily for calculation of load reductions (positive or negative) for a program as a whole or for specific customer segments (e.g., geographic regions, low income customers, etc.).

The discussion here focuses on event-based programs. To a large extent, similar issues and methods apply to impact evaluation of alternative rate designs that are not event-based. However, issues specific to the evaluation of alternative rate designs are not examined in this report.

Impact evaluation in general measures load reduction achievement, not load reduction capability. The discussion below does not address capacity markets, though results of an impact evaluation could be used to assess capacity performance.

2.8.6.1 Impact Estimation Purposes and Contexts

Impact estimation is used in a variety of contexts and for a variety of purposes. The estimation can be described in terms of the following dimensions:

- Purpose: how will the reduction determination be used, and by whom?
- Perspective: retrospective (*ex post*) or prospective (*ex ante*).
- Level of customer aggregation: individual retail customer, entire program, aggregations of customers by the DR provider, or customer segments.

- Level of event aggregation: individual event, summary of events in various forms (overall averages, averages as a function of temperature, customer segment, location (etc.) in a projection table or formula).
- Timing of impact determination (e.g., day after event, end of season, etc.).

These dimensions are discussed below.

2.8.6.1.1 *Ex Post* Impact Estimation and *Ex ante* Impact Estimation

Ex post impact estimation determines demand reductions retrospectively. *Ex post* estimation for a program season or year is commonly used as part of regulatory or stakeholder due diligence to determine if a program performed as planned and may be the basis for payments to program operators.

Ex post estimation not only provides the retrospective scorecard of what did happen, but also is typically the foundation for developing *ex ante* impact estimates and for understanding how to make a program perform better going forward. Explicit projections of impacts under future conditions are *ex ante* impact estimates.

Ex ante impact estimation provides projected demand reduction estimates for future program periods and/or for specific event conditions (e.g., normal weather, extreme weather, etc.). These projections may be functions of enrollment levels, participant characteristics, or event conditions.

Ex ante estimates also are important for assessing the cost-effectiveness of programs. DR resources have option value – that is, they are designed to be used under extreme conditions (e.g., system emergencies, high priced periods, etc.). In any given year, such conditions may not occur frequently or be as extreme as the conditions for which the program was designed. As such, for any particular year, the average impacts per unit may understate the true value of the program. Cost-effectiveness analysis using the *ex post* impacts specific to any particular year thus has limited use.

For programs with relatively homogenous participants such as residential programs, *ex ante* methods typically consist of projected savings per participant, together with projected enrollment numbers. The projected savings per participant and enrollment is likely to vary by geography and potentially other characteristics. Savings per participant also typically varies by time of day and weather conditions.

Ex ante impact estimation can be used as the basis for retrospective settlement. In this case, application of an *ex ante* projection table or formula to observed conditions and actual enrollment provides an *ex post* impact determination. For programs that allow dispatch to be over-ridden, enrollment is adjusted by the fraction responding or projected to be responding.

For example, PJM uses the “DLC method” to settle with utilities operating Direct Load Control programs. Prior *ex post* impact evaluations from the PJM region were mined to determine *ex ante* savings per participating unit for each utility as a function of a temperature-humidity index. Under the PJM DLC method, *ex post* savings for settlement are calculated by multiplying this unit savings by the number of participants and adjusting for over-ride rates where applicable.

2.8.6.1.2 Individual and Aggregate Impacts

Impact estimation is typically not concerned with accuracy for individual customers so much as accuracy of aggregate estimates at the program or participant subgroup level. Even when individual customer baselines for settlement have noise and recognized biases, impact estimation for the program as a whole can demonstrate DR as a reliable, measurable resource.

Often impacts are determined not only for the program as a whole but also by participant segments defined by program options, geography, and other customer characteristics. The segment-level analysis can provide insight into conditions where greater reductions are achieved. In addition, segmentation provides a basis for more meaningful *ex ante* estimates as the mix of participating customers' changes.

2.8.6.1.3 Timing of Impact Determination

Comprehensive aggregate *ex post* and *ex ante* impacts may be determined after the end of each program year or season or less frequently. Seasonal impacts may be summarized in terms of the maximum, average, or total reduction over all events in the season. Future impacts, as noted, may be expressed as functions of customer characteristics and event conditions.

Many programs determine *ex post* impacts within a few days of each event. Some programs need immediate impact calculations for settlement with participants. Methods commonly used for settlement with program participants are the focus of Section 2.8.5 *M&V Methods for Settlement*. For both program and participant operations, day-ahead *ex ante* estimates are important. Program operators need to know how much of each resource is likely to be delivered in response to an event call. Program participants, both DR aggregators and individual customers, need to know what their own resources are likely to deliver to make bid decisions and other operational choices.

2.8.6.1.4 Summary of Impact Estimation Applications

Table 2-33 summarizes the ways that impact estimation is used, and the associated perspectives, aggregation, and timing. The *ex ante* perspective refers to *ex ante* estimates developed from *ex post* impact estimations.

Table 2-33 DR Impact Estimation Methods By End-Use Participant Type and Perspective[133]

Purpose	Perspective	User	Level of Customer Aggregation	Event Aggregation	Timing
Annual or Seasonal due diligence program measurement	Ex Post	Program operator, Regulator	Program or specified aggregated load	Summary over events	End of season
Settlement with individual end users	Ex Post	Program operator	Individual account	Individual event	Day(s) after event or monthly
Settlement with DR aggregator	Ex Post	Program operator	Aggregated load	Individual event	Day(s) after event or monthly
Day-ahead or shorter operational planning	Ex Post	Program operator	All DR resources or targeted subset	Individual (possible) event	Day or hour(s) ahead
Daily Bidding and operators	Ex Post	Program participant (individual or aggregator)	Own resource	Individual (possible) event	Day or hour(s) ahead

[133] *Ibid.*

Annual planning	Ex Post	Program operator	All DR resources	Rangers of potential events under various scenarios	Season ahead
Annual planning	Ex Post	Program participant (individual or aggregator)	Own resource(s)	Rangers of potential events under various scenarios	Season ahead up to long term planning horizon

2.8.6.2 Impact Estimation Methods

For DR programs settled based on calculated reductions, the *ex post* impact can be calculated as the simple sum of the demand reductions determined for each participant using the program's settlement methods. This method is used, for example, by the NYISO for its Emergency Demand Response Program. With this approach, there is no difference between the total settled amount and the program-level impact.

Some programs, however, conduct a program-level impact estimation that does not rely on the settlement method or settled quantities. *Ex post* program-level impact estimation is not subject to many of the constraints of participant settlement. These constraints include the need for simplicity, rapid results, reduction amounts for each participant and event, and timely feedback to customers for an effective behavioral change program.

More accurate program-level results can typically be obtained by using impact estimation methods that are not practical for settlement applications. These methods include:

- Individual or pooled regression analysis involving more complex models and data from a broader span of time than typically used in settlement calculations that may provide *ex ante* and *ex post* results from the same model;
- Day matching to identify one or more non-event days that are similar to each event day, usually from a full season of data;
- Incorporation of supplemental information about customers, such as survey data, end-use metering data, or program tracking data; and
- Experimental Design, treatment/control group analysis.

These methods are discussed below. This guidance document does not attempt to specify analytic forms in detail or to identify the preferred analytic approach. Rather, the advantages and disadvantages of general methods in different contexts are described.

2.8.6.2.1 Individual Regression Analysis

Individual regression analysis fits a regression model to an individual customer's load data for a season or year. A basic model describes load at each hour of the day (or perhaps the average for an event window) as a function of weather terms such as cooling degree-days. More elaborate models can allow the cooling degree-day base to be determined by the regression best fit, and might include calendar and day of week effects, lag terms reflecting temperature over multiple hours, and humidity. An example of a basic individual hourly load regression model is shown in the equation below:

$$L_{jdh} = \alpha_{jh} + \beta_{jh} C_d + \varepsilon_{jdh}$$

Where:

> L_{jdh} = is the load of customer j at hour h of day d
>
> C_d = is the cooling degree-days for the day
>
> α_{jh} = is the base coefficient for each hour of the day, specific to customer j
>
> β_{jh} = is the cooling coefficient for each hour of the day, specific to customer j
>
> ε_{jdh} = is the residual error

Typically, the individual regression models are fit to loads on non-event days. The model is then applied with the conditions of each event day to provide an estimate of the customer's load that would have occurred on that day absent an event. The impact is calculated as the difference between the modeled and observed load for each hour of the event period. Post-event rebound (increased load to make up for foregone load during the event period) can also be calculated.

When load data are available for a sample of participating customers, the program-level results are estimated by sample expansion from the individual customer impacts. When load data are available for all participating customers, program-level results are the sum of the individual customer impacts.

The individual regression model can also include event-day terms and be fit across both event days and non-event days. In this case the event effect is the difference between the model applied to the event-day conditions with and without the event-day terms in effect. The second equation (below) provides a simple example. However, unless there are multiple event days spanning a wide range of the other terms in the model, including event-day terms in individual regressions will provide no more information than the average over event days of the modeled versus observed approach from the previous equation:

$$L_{jdh} = \alpha_{jh} + \beta_{jh}C_d + \delta_{jh}E_d + \varepsilon_{jdh}$$

Where:

> L_{jdh} = the load of customer j at hour h of day d
>
> C_d = the cooling degree-days for the day
>
> α_{jh} = the base coefficient for each hour of the day, specific to customer j
>
> β_{jh} = the cooling coefficient for each hour of the day, specific to customer j
>
> E_{dh} = a 0,1 dummy variable indicating that an event occurred on day d
>
> δ_{jh} = the event effect for hour h
>
> ε_{jdh} = is the residual error

Advantages of the individual regression method are:

- Results are determined for each customer, which provides a basis for richer analysis, including looking at distributions of results rather than averages only. Individual customer results can also be related to other customer information.
- Meaningful results can more easily be developed for groups of customers whose load patterns are dissimilar, since each is modeled separately.

- Results can be aggregated into any segments that are subsequently determined to be of interest after the initial analysis is completed.
- Customers for which the basic regression structure is not a good description can be identified by model diagnostics and treated separately.
- Weather response terms such as the best degree-day base can be determined separately for each customer, leading to better and more meaningful overall fits.
- *Ex ante* results can be derived by fitting individual regressions to design or extreme temperature data and then aggregating the resulting estimates.
- Results can be analyzed to understand relative customer engagement in programs that promote behavioral changes.

On the other hand, model fits for an individual customer are subject to a higher level of estimation error than are the fits from a pooled model. Examination of distributions across customers' needs to consider that the spread of observed results reflects both the spread of individual responses and the estimation "noise" or random errors.

Moreover, if event-day effects are estimated for an individual customer, these individually estimated effects can often be lost in the noise—that is, not be statistically significant—even if across all customers there is an effect. The opposite can also occur, where statistically significant effects are found for large numbers of control group customers who had no event to respond to. That pattern indicates a systematic modeling error, which would affect a pooled model just as much as it would affect the average of individual models.

In general, if the same model structure is applied with individual fits and with a pooled fit, the coefficients of the pooled fit will be approximately the average coefficients of the individual fits. This equality will be strictly true if the individual and pooled fits all use the same degree-day base and other variables, the individual fits all have the observations in the same hours, and all observations have equal weights. In particular, any bias in the individual fits will be present for the pooled fit as well.

A disadvantage of the individual regression approach is that it does not take advantage of the power of a pooled regression approach.

2.8.6.2.2 Pooled Regression Analysis

Pooled regression analysis uses a similar model structure to the individual regression analysis but fits a single model across a large group of participants and hours. In this case, a single set of coefficients is used to describe all customers' average load pattern. With a pooled analysis, it is more common to include event-day terms in the regression model. With the larger pooled sample, terms that might not be well determined for an individual customer can be estimated. A simple example is illustrated below:

$$L_{jdh} = \mu_j + \tau_{dh} + \alpha_h \beta_h C_d + \delta_h E_d + \varepsilon_{jdh}$$

Where:

L_{jdh} = the load of customer *j* at hour h of day d

τ_{dh} = an incremental fixed level for customer *j*

μ_j = fixed effect terms for affecting all customers for a particular day and hour (reducing the residual correlation for repeated observations at the same day and hour)

α_h = the base coefficient for each hour of the day, specific to customer *j*

β_h = the cooling coefficient for each hour of the day, specific to customer *j*

E_{dh} = a 0,1 dummy variable indicating that an event occurred on day d

δ_h = the event effect for hour h

ε_{jdh} = is the residual error

α_h, β_h and δ_h are not customer-specific.

Advantages of the pooled regression method are:

- The coefficients utilize information across all customers, so that effects that might be poorly estimated by each individual regression can be well determined.
- Segment level effects can be obtained by including segment indicators in the model, or by fitting the model separately by segment.
- Overall results are provided even if there are some customers for which the basic regression structure is not a good description.
- *Ex ante* estimates can be obtained directly from the event-day terms in the model.

Disadvantages of the pooled regression method include:

- Segments of interest need to be identified in the model development stage and cannot be easily estimated after the fact from the basic results.
- Weather response terms are estimated only in aggregate, which can reduce the model accuracy.
- The method works best when pooling is across a group of fairly similar customers, such as residential or small commercial.
- A pooled model approach has an added degree of complexity relative to the individual approach. Even with the inclusion of customer-specific intercepts (μj) and time-period terms (τdh) there will still tend to be serial correlations and patterns in the regression residuals (εjdh). If these correlations are not appropriately accounted for, the regression estimates can appear to be much more precise than they really are, especially if many thousands of customers are included in the regressions. That is, the calculated standard errors for the regression terms and associated savings estimates may be understated.

2.8.6.2.3 Match Days

Match day methods identify one or more non-event days that are similar to each event day, based on various criteria. Common bases for identifying match days for a given event day include:

- Similar temperature or temperature-humidity index;
- Similar system load; or
- Similar customer load at non-event hours for the individual customer.

For each participating customer, that customer’s load on the match day (or average of the match days if there are multiple) serves as the baseline or reference load. Demand reductions are calculated as the difference between the (average) match day and event day load at each hour.

A key advantage of match day methods is their simplicity and transparency. In addition, for variable loads that are not well described by hourly or weather models, match day methods may be more accurate than regression models if the matching criteria include characteristics of the individual customer's load.

Disadvantages of match day methods include:

- For loads that can be reasonably well described in terms of hourly loads and weather patterns, regression methods will tend to be more accurate. Match days are limited to actual observed days, and averages of those days. Regression models, if properly specified, effectively interpolate between particular observed conditions, and extrapolate from them. (It's easy to construct examples of weather models that consistently understate load in extreme weather conditions. A matched day could provide a better estimate at those conditions than such a model. However, a better model that does not systematically understate load at the conditions of interest, possibly by using only data from more extreme conditions, in most cases will be more reliable than a single best-fit day. Any basis for selecting match days should, in principle, be possible to capture more systematically and comprehensively in a regression framework.)
- Match day methods do not provide a direct basis for producing *ex ante* estimates. If a regression will be used to extrapolate from the match-day results, it may make more sense to use a regression for the *ex post* results to begin with.
- Assessing the accuracy of a match-day estimate is more problematic than assessing the precision of a regression model. Testing for lack of fit or systematic bias is not as straightforward with a matching procedure as with an explicit model, and is not commonly included in match-day analysis. Measuring the precision or level of random variability of a match-day estimate is also not as clear-cut. It's possible to calculate a standard deviation across match-day estimates from multiple event days, but it's not clear to what extent this variability reflects differences in event-day conditions versus random variations on the particular event days versus particular conditions or random variation on the non-event days used for matching. If the analysis is done for a sample of customers rather than for the full population, variability across different match days does not reflect the sampling errors (that is, the differences that would be expected with the same methods if different random samples were selected). As a result, determining the true uncertainty of both *ex post* estimates and projections based on those estimates is challenging.

2.8.6.2.4 Experimental Design

For DLC as well as other mass market programs, comprehensive interval metering offers the opportunity to use experimental design for M&V. This approach can be used to determine program-level reductions for individual events. It has begun to be used for *ex post* impact estimation and offers substantial promise. As noted in Section 2.8.4 *NAESB Business Practice Standards,* direct use of experimental design has not yet been seen as a basis for market settlement, though *ex ante* estimates based on experimental design may be.

Experimental design is random assignment of customers into two groups, one of which is "treated" and the other remains as a "control" group. In the case of DLC, customers enrolled in the program are randomly assigned to subgroups, and during any dispatch event one or more of the randomly assigned groups is not dispatched while the remainder are. That capability depends in part on the program's control technology, and in part on the operational capacity of the program. Thus, an essential feature of this impact estimation method is that it must be built into the program operation.

The average demand reduction per participant is calculated as the difference between the averages for the groups that are dispatched and those which were not. An alternative calculation with this design is a difference of differences method. A baseline calculation or load model constructed for each participant, in both the dispatched and non-dispatched groups (treated and control groups, respectively). The impact is then calculated as the difference between the dispatched group's modeled and observed load, minus the corresponding difference for the control group. With this approach, the departure of the control group from its modeled load essentially provides an estimate of how the treatment group's actual load would have been higher or lower than its model, absent a DR event.

With customers who all have interval metering via Advanced Metering Infrastructure (AMI), this type of design and analysis has been used to determine impacts of large-scale residential and/or commercial direct load control programs at PG&E, SDG&E and across multiple utilities in Ontario Canada for the Ontario Power Authority's (OPA) PeakSaver Program. The approach has been used also with a sample of interval metered customers prior to the implementation of AMI, for SDG&E.

In many contexts, randomly assigning customers to different rates or different dispatch regimes is not possible. In these cases, comparison groups of customers identified as similar to the participants after the fact are sometimes used for impact estimation. However, without true random assignment there are always unknown underlying differences between participants and nonparticipants, and these differences can bias any estimate based on comparing the groups. The remainder of this discussion focuses on the use of randomized treatment-control experimental design. In such a design, customers originally in a common pool are randomly assigned to either the treated or comparison (control) group, with minimal subsequent opportunity for customers to opt in or out of their assigned group.

The randomized control experimental design is conceptually the gold standard of evaluation approaches but has been limited in its practical applications until recently. The practical limitations result from the fact that most full-scale program applications and regulatory contexts don't allow for random assignment of customers to participate in a program or not. A recent exception in the energy efficiency context is behavior-based programs offering information to large numbers of randomly selected residential customers. The experimental design of the program offering establishes the basis for measuring the effect of the information program.

Where feasible, experimental design has the potential to produce the most accurate results possible for estimating load reduction. The method is valuable because it virtually eliminates any systematic difference between treatment and control, providing an unbiased estimate, and with sufficiently large samples can provide very high precision.

Experimental design is effective for impact estimation of relatively homogeneous groups of customers, such as residential or small commercial, where several hundred or several thousand customers participate in a program. The method is less effective for evaluating smaller numbers of customers or large commercial or industrial customers, because the treatment-control differences will have too much random error to be reliable.

When most participants have interval metered data available, experimental design offers many advantages including the following:

- First, because the M&V is conducted separately for each event day, participants do not have to be assigned to treatment or control permanently. In fact, it is more appropriate to have the control group be a different, randomly selected set of participants for each event. This approach best assures that the treatment and control group are the same in all ways other than being dispatched on a particular day, including that they have otherwise equivalent program experience.

- Second, for a large scale program, large control samples can be used to provide highly accurate results without substantially reducing the total dispatched resource. When load control programs had to be evaluated using metering samples installed specifically for that purpose, samples on the order of a few hundred (depending on the level of granularity desired) were sufficient to provide adequate accuracy for the estimated reductions. A program with 50,000 customers enrolled could easily have a control sample of 1,000 customers for each event day to produce accurate estimates of program load reductions.
- Third, for *ex post* estimation or for settlement directly based on the metering sample, determining savings based on a randomly assigned treatment-control difference provides a highly accurate estimate of the reduction without requiring explicit weather modeling. If weather modeling is used, the difference of differences method ensures that any systematic bias in the modeling can be corrected by subtracting the difference between the modeled and actual load of the control group from the difference between the modeled and actual load of the control group of the dispatched group.
- Fourth, for *ex ante* estimation, observing large numbers of both dispatched and non-dispatched customers during each event provides a much more accurate basis for modeling event effects as functions of weather or other conditions. This type of modeling can be very challenging in particular if all participants are dispatched on the few hot days.
- Fifth, as an extension of the last point, with a random control group as the basis for settlement and evaluation, calling events on every hot day does not create a problem for M&V.
- Finally, the experimental design approach can allow good load reduction estimates to be developed for a wide range of conditions, while exposing any individual customer to a limited number of control events. This feature can allow the method to be used to define *ex ante* estimates for a range of operating parameters and weather conditions. Implementing this aspect of the approach requires close coordination with the program operation.

The best ways to produce *ex ante* estimates based on experimental design are still to be explored. The per-unit results from different event days can be averaged, or a simple temperature regression can be fit to the results.

A more complete approach could be to fit a pooled model across all customers and days. Having treated and control customers on each event day as well as having both event and non-event days for each customer strengthens this analysis. The pooled model could provide *ex ante* estimates per unit as a function of weather conditions.

This type of analysis is relatively straightforward to conduct with a sample of a few hundred or even several thousand participating customers but may be computationally challenging for a large residential program with universal hourly load data available. Possible ways of addressing that challenge include:

- Conduct the analysis using data from a large sample of participants, not all of them.
- Aggregate the load for groups of customers who had the same DR dispatch schedule. Conduct a pooled analysis on the groups.

(i) Use of Experimental Design

Experimental design utilizes established statistical methods to produce unbiased, highly accurate *ex post* impact estimates. Key outstanding issues for increased use of this approach include:

- Explore with program operators the challenges of and potential for dispatching the program following an experimental design protocol.
- Work with wholesale markets to establish protocols that will allow use of experimental design as a basis for settlement.
- Establish recommended strategies for developing *ex ante* estimates when *ex post* or settlement is based on experimental design.

2.8.6.2.5 Applications of End-Use Metering for DR Impact Estimation

Until the last few years, interval load data has not been available for most small customers. Impact estimation for residential DR programs such as DLC has typically relied on metering samples installed for this purpose. In areas without AMI, that will still be the case in the future.

Since DLC programs control a particular end use, impact estimation can be conducted by metering only the affected end use(s). Many DLC evaluations have taken this approach. Advantages of end-use metering include the following:

- A single end-use can typically be modeled more accurately than whole-premise data, resulting in better precision for the overall estimates for a given sample size.
- Equipment operating characteristics such as duty cycle and connected load can be identified, providing additional insight into event response patterns.
- Load curtailment can be observed directly if end-use metering data are collected at 1-minute intervals.

On the other hand, whole-premise metering captures other effects in the home that are not reflected in the end-use metering. For example, control of the air conditioner compressor could result in increased use of fans or even room air conditioners.

When interval load data are broadly available via AMI, investment in end-use metering for impact estimation becomes more difficult to justify. Moreover, the large numbers of metered customers available with AMI makes up for the reduced resolution for individual customers in an impact evaluation. However, even on a small sample basis, supplemental end-use metering can provide finer grained understanding of load response patterns and mechanisms. In particular, modeling duty cycle and connected load as functions of temperature provides a strong basis for projecting the effects of alternative air conditioner control strategies, as described below.

End-use metering data can be analyzed using the same types of modeling approaches as whole-premise data, including use of a randomized treatment/control methodology. This approach has been used for example in the evaluation of the SDG&E Smart Thermostat program.

For air conditioner DLC, end-use metering analysis can take more complete advantage of the physical relationships that drive air conditioning. One such approach fits 2 types of models to 15-minute or finer air conditioning metering data for each unit in a metering sample:

1. A model that estimates the connected load of the air conditioner, the kW draw when the unit is running, as a function of current outside temperature. This connected load is not constant but increases by 1 to 2 percent per degree Fahrenheit.
2. A model of duty cycle, or the fraction of each hour the unit runs, as a function of daily weather conditions. The duty cycle model uses a structural form that recognizes that the duty cycle must be between 0 and 100%.

Advantages of this analysis approach include:

- The analysis reveals detailed patterns of customer equipment use at different conditions.
- These patterns can be related to other customer characteristics.
- Projected reductions can be estimated by time of day and weather condition, at any level and strategy of duty cycle control, not just those observed in the evaluation. That is, this approach more accurately models the technical limits of AC units thus more effectively accounting for units reaching full cooling capacity at extreme temperatures.

2.8.6.2.6 Custom Engineering and Field Studies

For individual large loads, special studies can be conducted to assess load impacts. These studies would typically include a site visit to identify what loads are controlled, together with end-use metering or extraction of existing operating log data to document load at event and non-event conditions. Analysis to estimate the load that would have occurred absent an event is specific to the operations of the facility. While this approach is not common, it may be the only practical method for large loads with irregular operating patterns.

2.8.6.2.7 Composite studies

An approach that has been used for *ex ante* impact estimation in the PJM market is to consolidate the results of multiple end-use metering studies conducted for *ex post* impact evaluations. The consolidated metering analysis was used to develop *ex ante* estimates for DLC programs, for several utilities operating in that market. This approach can provide a more robust result than any single study.

2.8.6.3 Guidance Summary

Table 2-33 summarizes which impact estimation methods are likely to be most useful for different types of end-use customers, for *ex post* impact estimation and *ex ante* impact estimation. In any particular evaluation context, the methods that will be most effective will depend on a variety of factors, including specific evaluation goals, participant load characteristics, data availability, numbers of participating customers, and evaluation budget and timeframe.

Table 2-34 Usefulness of DR Impact Estimation Methods by End-Use Participant Type and Perspective

Impact Estimation Method	**Homogeneous Customer Group (Residential, Small Commercial/Industrial**		**Heterogeneous Customer Group, Each Customer with Low or Moderate Load Variability**		**Customers with Highly Variable Loads**	
	Ex Post	***Ex ante***	**Ex Post**	***Ex ante***	**Ex Post**	***Ex ante***
Individual Regression	Very useful	Useful with additional work	Useful	Useful with additional work	Possibly useful	Useful with additional work

Pooled Regression	Useful	Very useful	Not useful	Not useful	Not useful	Not useful
Match Day	Possibly useful	Possibly useful with additional work	Possibly useful	Possibly useful with additional work	Useful if match on customer condition	Useful if match on customer condition, with work
Experimental design simple difference	Very useful	Useful with additional work	Not useful	Not useful	Not useful	Not useful
Experimental design with modeling	Very useful	Very useful	Not useful	Not useful	Not useful	Not useful
End use metering with Duty Cycle Analysis	Very useful	Very useful	Potentially useful	Potentially useful	Potentially useful	Potentially useful
Customer engineering and site analysis	Not generally useful	Not generally useful	Potentially useful	Potentially useful	Potentially useful	Potentially useful
Composite Analysis	Potentially useful	Potentially useful	Not generally useful	Not generally useful	Not useful	Not useful

2.8.7 DR WHEN CONNECTED TO SYSTEM AGGREGATOR

Independent System Operators (ISO) and Regional Transmission Organizations (RTO) have strict protocols for electricity providers who are connected to their markets. At the time of authorship, Entergy New Orleans is not connected to and ISO/RTO but is geographically located in the Midcontinent Independent System Operator, Inc. (MISO) territory.

At the time of protocol authorship, Entergy New Orleans is a MISO member but does not participate in the MISO Demand Response market. However, should Entergy New Orleans decide to participate in the future, the following Business Practice Manual (BPM), developed by MISO, will provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of MISO markets, provisions of transmission reliability services, and compliance with MISO settlements, billing, and accounting requirements.

All definitions in this document are as provided in the MISO Tariff, the NERC Glossary of Terms Used in Reliability Standards, or are as defined by this document.

Hyperlinks to all BPMs referenced appear in the 'Bibliography & References' section of this protocol, and a complete list of MISO Business Practice Manuals (BPMs) is available for reference through MISO's website .

2.8.7.1 Introduction to the MISO Business Practice Manual

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) Business Practices Manual (BPM) for Demand Response includes basic information about this BPM and the other MISO BPMs. The first section (2.8.7.1.1 *Purpose of MISO Business Practices Manuals* Introduction to the MISO Business Practice

Manual) of this Introduction provides information about the MISO BPMs. The second section (2.8.7.1.2 *Purpose of this Business Practices Manual*) is an introduction to this BPM.

2.8.7.1.1 Purpose of MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of MISO markets, provisions of transmission reliability services, and compliance with MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website. All definitions in this document are as provided in the MISO Tariff, the NERC Glossary of Terms Used in Reliability Standards, or are as defined by this document.

2.8.7.1.2 Purpose of this Business Practices Manual

This BPM: (1) provides Market Participants (MPs) with the information needed to understand the purpose and application of demand response within the MISO Region; (2) covers the rules, design, and operational elements governing the implementation of the various types of demand response within MISO's Day-Ahead and Real-Time Energy and Operating Reserve Markets; and, (3) describes how demand response can be accredited with Zonal Resource Credits and can be dispatched to interrupt their loads during system emergencies. Demand response used as a Non- Transmission Alternative is discussed separately in BPM-020: Transmission Planning.

MISO employs Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) algorithms to dispatch supply including Demand Response Resources, which simultaneously co-optimizes the Energy and Operating Reserve Markets. The Attachments to the Energy and Operating Reserves BPM explain these functions in greater detail.

This BPM benefits readers who want answers to the following questions:

- What are the roles of MISO and MISO's Market Participants in facilitating the participation of demand response in MISO Energy and Operating Reserve Markets?
- What are the basic concepts that one needs to know to understand the benefits to be derived from demand response?
- What activities must a Market Participant perform in order for its Demand Response Resources to participate in the Energy and Operating Reserve Markets?

2.8.7.2 Overview Of Demand Response

This section presents a high-level description of the role that demand response plays in MISO markets.

DR refers to the ability of a Market Participant to reduce its electric consumption in response to an instruction received from MISO. Market Participants can provide such demand response either with discretely interruptible or continuously controllable loads or with behind-the- meter generation. Market Participants are compensated by MISO for providing such load reductions, as described later in this BPM. MISO market structures provide the opportunity for MPs with demand response to participate either on the demand-side or the supply-side of its markets. For the demand-side, MPs have the ability to make consumption decisions based on the value of energy consumed compared to the market price, and this is discussed further in the BPM for Energy and Operating Reserve Markets. This BPM for Demand Response is devoted to the supply-side, where MPs can offer and monetize the flexibility of demand response to help MISO meet the power balance, meet its ancillary service needs and/or meet its capacity obligations.

2.8.7.2.1 Eligible Market Participants

Three types of entities who have been certified by MISO as Market Participants may provide demand response in MISO:

- Load Serving Entities (LSEs)
- Aggregators of Retail Customers (ARCs)
- End-use customers that have Market Participant status

If your entity is not a certified Market Participant, you must register and be certified as a MISO Market Participant prior to participation in any MISO Market. For more details on the registration processes, see Section 2.8.7.3 *Registration Options for Demand Response.*

2.8.7.2.2 Types of Demand Response Services

MISO employs demand response to:

- Reduce load in the Energy market (i.e., Economic Demand Response)
- Provide Regulating Service, Contingency Reserves (i.e., Operating Reserves Demand Response), or Ramp Capability Product (OR&RCP)
- Reduce demand during system Emergencies (i.e., Emergency Demand Response)
- Substitute for generating capacity (i.e., Planning Resources Demand Response)
- Substitute for transmission (i.e., Demand Response as a Non-Transmission Alternative)

Each of these services is further described below.

(i) Economic Demand Response

A Demand Response Resource (DRR) is a demand resource or behind-the-meter generation ("btmg") resource that can respond to instructions from MISO. DRRs are the only demand resources that can "inject" Energy on an economic basis. Currently, the minimum size for DRRs to participate in MISO's markets is one (1) MW.

There are two types of DRRs:

- A DRR – Type I is capable of supplying a fixed, pre-specified quantity of Energy, through physical load reduction, or behind-the-meter generation, to the Energy and Operating Reserve Market when instructed to do so by MISO
- A DRR – Type II is capable of supplying a range (continuum) of Energy through physical load reduction or behind-the-meter generation, to the Energy and Operating Reserve Market and is capable of complying with MISO's Setpoint Instructions.

Market Participants may submit DRR Energy offers into the Day-Ahead Market and/or the Real Time Market. DRR offers submitted to these two markets are independent, i.e., the price-quantity schedules offered into one market are not linked to the schedules offered into the other market.

Market Participants with DRR offers that clear the market and that subsequently follow MISO instructions, within acceptable tolerance, are paid the Locational Marginal Prices (LMPs) for the Energy they provided to the market through their load reductions. In addition, if necessary, they are made whole to their offers if committed by MISO as part of MISO's Security Constrained Unit Commitment (SCUC) process. These offers can include Energy Offers, Shut-Down Offers and Hourly Curtailment Offers, as described below.

(ii) Operating Reserves and Ramp Capability Product (OR&RCP) Demand Response

OR&RCP Services take on several forms:

- Regulating Reserve
- Spinning Reserve
- Supplemental Reserve
- Ramp Capability Product (RCP)

Together, Spinning Reserve and Supplemental Reserve are also known as Contingency Reserve.

In addition to providing Energy, DRR-Type I and DRR-Type II resources that are technically qualified to do so may provide one or more forms of Operating Reserve Service. DRR-Type I Resources can provide either Energy or Contingency Reserve Service but cannot provide both simultaneously. DRR-Type II Resources may provide Energy and/or one or more Operating Reserve products (as well as the Ramp Capability Product) simultaneously, in a fashion similar to other Generation Resources. MISO uses its SCUC and Security Constrained Economic Dispatch (SCED) algorithms to determine which product a resource will provide in any particular time interval. Currently, the minimum size of DRRs capable of offering these services is one (1) MW.

The technical capabilities required to qualify for each service (see BPM-002) are most stringent for Regulating Service and least stringent for Supplemental Reserve. A DRR that is qualified to provide a more stringent service is generally qualified to provide all of the services with less stringent requirements. Due to its “on/off” nature, DRR-Type I is not allowed to provide Regulation Service or the Ramp Capability Product. Due to the frequency responsive nature of Regulation Service, DRR-Type II resources without telemetry are not allowed to provide Regulation Service. In addition, DRRs cleared for Spinning Reserve Service cannot exceed 40% (on a MW basis) of the market-wide total for cleared Spinning Reserve.

In addition to providing the information required for an Energy Offer, a DRR that is available to provide one or more Operating Reserve products must submit additional pricing information in its offer (e.g., a reserve availability offer). Using these data, MISO will determine whether to clear the DRR offer to provide Energy and/or one or more Operating Reserve services plus RCP. A DRR Type II may submit a price curve (up to 3 MW-price pairs) for each Operating Reserve or other reserve product. A DRR may also choose to submit a daily limit per resource for the amount of Regulation or Contingency Reserve that may be deployed during one Operating Day of the Real Time-Market.

(iii) Emergency Demand Response

Market Participants can also offer to reduce their gross loads specifically when MISO declares an Emergency event (e.g., NERC EEA2 or EEA3 events). MISO’s Emergency Demand Response (EDR) Initiative allows, but does not require, EDR resources to indicate their willingness to provide demand response during such events (unless they are also claiming capacity credit as Planning Resources, in which case they must be available to reduce load during Emergency events, as discussed herein). A Market Participant’s decision to offer as an EDR is in addition to the choice of creating a DRR and/or an LMR. Currently, the minimum size of these EDRs is one hundred (100 kW).

Each day a Market Participant can decide how much of each of its EDR resources to make available to MISO for EDR service the following day, and at what cost. In addition to providing hourly curtailment costs in its daily EDR offer, the Market Participant can also specify a one-time shutdown cost and a number of operational constraints for each EDR resource. When an Emergency event occurs, MISO will use the information in the EDR offers to decide the order in which to curtail the associated EDR resources, using SCED protocols. EDR offers cannot vary across the hours of the Operating Day.

The EDR Initiative, set forth in Schedule 30 of the MISO Tariff, provides Market Participants with the flexibility to shape their EDR offers based on their near-term circumstances while also providing them with opportunities to increase their operating profits through load curtailments when energy prices are high. In addition, EDR resources may simultaneously qualify as Planning Resources as discussed below.

(iv) Demand Response as a Planning Resource

Planning Resources fall into two potential categories (see Table 2-35): Capacity Resources and LMRs. DRR Type I or II can qualify for either category of Planning Resource, as presented above. Load Modifying Resources (LMRs) qualify as such when the Market Participant registers, and MISO accepts, those assets as LMRs. LMRs are either Demand Resources or Behind-the-Meter Generation (BTMG)4[134]. Registering as an LMR and clearing the Planning Resource Auction (or being committed through a Fixed Resource Adequacy Plan (FRAP)) commits the Market Participant in advance to using the resource to reduce the gross load on the system when instructed to do so by MISO during an Emergency event. Module E-1 of the MISO Tariff prescribes how LMRs are accredited as Planning Resources. Planning Resources have monetary value because they can be substituted for Generation Resources by an LSE in meeting its assigned Planning Reserve Margin Requirement (PRMR). Currently, the minimum size of these LMRs is one hundred (100 kW).

Table 2-35 Planning Resource Categories[135]

	Planning Resource			
	Capacity Resource		Load Modifying Resource	
	Generation and External Resource	DR Resource	BTMG	DR
Capacity verification	x	x	x	
Must offer	x			
GADS Data Entry	x		x	
DADs Data Entry		x		x
Must Respond to EOP	x (x4)	x (x4)	x	x

As shown in Figure 2-19, there are many options available for demand response registration. Note that not all these configurations have been used by MISO Market Participants, but they are available. The finer distinctions between registering as a Capacity Resource, an LMR, a DRR, or an EDR should be evaluated by the Market Participant prior to registering under any of these categories.

[134] If the MP registers behind-the-meter generation as an LMR, then its acronym is BTMG. If not registered as an LMR, but registered as another demand response instrument, then its acronym is btmg

[135] MISO BPM-026-r6. Demand Response Business Practices Manual (2021)

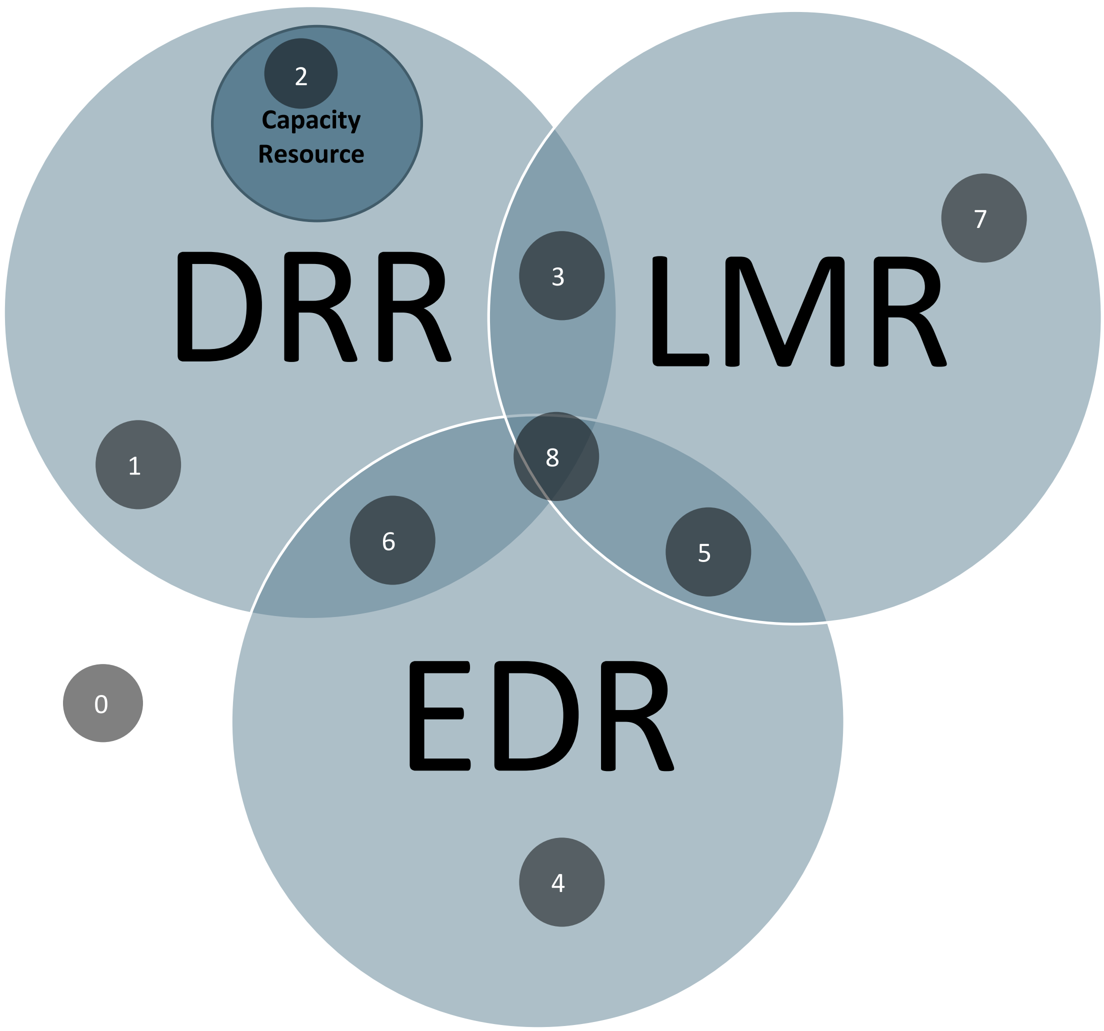


Figure 2-19 Demand Response Registration Options[136]

Notes:

- Note 0: Not MISO Registered; cannot participate
- Note 1: There is no DRR "must offer" requirement, since there are no capacity credits.
- Note 2: DRRs. "must offer" into the Energy & Ancillary Services markets.
- Note 3: Asset registers as an LMR and receives capacity credits, and also registers as a DRR with options to offer into the Energy & Ancillary Services markets.
- Note 4: EDR Only. No capacity credits or "must offer" requirement.
- Note 5: LMR that optionally provides an EDR offer for emergency energy.
- Note 6: Similar to "1", but optional participation in emergencies
- Note 7: LMR only. Not involved in Energy and Ancillary Services markets.
- Note 8: Similar to "5" but can optionally participate in Energy & Ancillary Services markets.

[136] MISO BPM-026-r6. Demand Response Business Practices Manual (2021)

Note that in Options 1 – 8, the entity must be a Certified MISO Market Participant in order to participate.

(v) Demand Response as a Non-Transmission Alternative

Consistent with Attachment FF of the Tariff, both transmission and Non-Transmission Alternatives (NTA) to resolve Transmission Issues will be considered on a comparable basis within the MISO transmission planning process. Non-transmission alternatives include contracted demand response, new or upgraded generators with executed interconnection agreements, and other non- transmission assets (e.g., energy storage not classified as a transmission asset, etc.). Additional details about this use for demand response are presented in Section 4.3.1.2 of BPM-020: Transmission Planning.

2.8.7.2.3 State and Other Retail Regulatory Requirements

In addition to MISO's own standards and requirements for demand response, the states or other retail regulatory entities within the MISO Region may also have various requirements and regulations that must be met regarding the use of demand response. MISO acknowledges the important role that state and other retail regulatory authorities play, in collaboration with FERC, and has developed its demand response initiatives to be supportive of these requirements.

For example, some state Relevant Electric Retail Regulatory Authorities (RERRA) currently do not allow ARCs to do business directly with retail customers subject to their jurisdiction. Such prohibitions may also be imposed by the RERRA having regulatory control over public power entities and cooperatives. Section B.8.7.3.2 below expands on this.

For further details, Market Participants are encouraged to review demand response registration provisions contained in the BPM for Market Registration (BPM-001), and the BPM for Resource Adequacy (BPM-011). Credit requirements for Market Participants with demand response are found in Attachment L of the Tariff; and modeling requirements are specified in the BPM for Network and Commercial Models (BPM-010).

2.8.7.3 Registration Options for Demand Response

Registration of demand resources requires knowledge of two key issues: what are the operational characteristics of the resource ("what is it capable of doing") and how much responsibility for market participation is the Market Participant willing to accept? There are various levels of market interaction available to demand resources; some of these may be beyond the capabilities of the resource (e.g. regulation service), while some may be more than the Market Participant is willing to assume (e.g. does not wish to voluntarily interrupt during certain time periods). Answers to these two key questions will usually provide the Market Participant with a clearer picture of how the resource should be registered with MISO.

Finally, while this section of this BPM is intended to aid Market Participants related to the registration of demand resources, please consult the BPMs for Market Registration (BPM-001) and for Resource Adequacy (BPM-011) for further details or contact your Client Services & Readiness representative.

2.8.7.3.1 Registration as a Market Participant

In order to ensure fair, efficient, and competitive markets, MISO requires all entities desiring to participate in the Open Access Transmission, Energy and Operating Reserve Markets to undergo Market Registration and Qualification processes, also described in section 38.2.2 of the MISO Tariff. Only valid legal entities not otherwise prohibited from market participation by FERC, or any appropriate regulatory authority, may register as a Market Participant.

Opportunities to join in the Open Access Transmission, Energy and Operating Reserve Markets for asset owning and non-asset owning MPs will be in accordance with Commercial Model or other applicable timelines[137], which allows new Applicants to be adequately informed and have their facilities properly modeled before they participate as MPs. To become a Market Participant, an Applicant must complete the Market Participant Qualification Process with MISO by completing the online application, submitting all sections, and required documents, completing the verification of assets by the quarterly Commercial Model deadline (as applicable), and completing the credit requirements as outlined in Section B.8.7.3.4 of the BPM.

To register as a Market Participant, all Applicants will use MISO's Online Registration tool. Applicants will be prompted to complete application sections based on intended market activities. The tool will direct Applicants to complete the applicable sections and accompanying legal documents. It is important to follow the directions carefully for each section as the Applicant's organizational structure and type of activities it wants to engage in will determine the Market Participant's rights and obligations under the MISO Tariff. All applicable forms and supporting documentation must be submitted in accordance with stated deadlines; failure to do so will delay processing of the application.

For full details on the process, please refer to the BPM for Market Registration (BPM-001).

(i) Demand Response Resources (DRRs)

Market Participants who wish to employ a demand resource in the Energy and Operating Reserve market must register their resource as a DRR. Such registration enables the resource to offer energy services, as well as providing any of the OR and RCP services for which the resource is qualified (capable).

The Market Participant may also decide to qualify the resource as a Capacity Resource; if so qualified, the MP accepts the "must offer" requirements associated with Capacity Resources and is also entitled to receive Zonal Resource Credits (ZRCs) commensurate with its ability to reduce load at MISO's peak. Note that a resource's maximum capability to reduce load may not be the same amount by which that resource is able to reduce load at MISO's peak. This distinction will be important to provide during registration. For example, an MP with a particular demand resource may be capable of reducing its load on the system by a maximum of 1.5 MW, but only capable of reducing its load by 1.0 MW at MISO's peak. The difference in these two values may be the result, for example, of the resource having its maximum operation at night or during the winter.

As an alternative to registering as a Capacity Resource, a DRR could be registered as an LMR (Planning Resource). An LMR receives ZRCs and is obligated to respond to a MISO Emergency any time they are available during the Planning Year, but no less than five times during the Planning Year, consistent with the availability indicated in the Demand Side Resource Interface (DSRI) and their Scheduling Instructions.

Failure to respond during these Emergencies when sent Scheduling Instructions may result in financial penalties and/or potential disqualification from participation in the Planning Resource Auction. The distinctions described in the previous paragraph related to load reduction would still apply here. While a DRR may also be registered

137 See BPM-001 Market Registration, Section 3.3: Commercial Model Timeline

either as a Capacity Resource or as an LMR (or neither, if it so chooses), it may not be registered as both. Market Participants are urged to review the benefits, potential costs, and requirements of various options in order to select the most appropriate to their circumstances and desired operation.

1. DRR Registration

If the DRR was not registered as a part of the initial Market Participant application, a Market Participant may register its DRR in accordance with stated Commercial Model deadlines posted on MISO's public website. The Market Participant must submit all required documentation to add such resource including, but not limited to:

- Attachment B – Change of Information Form
- Commercial Model Master Template
- Section XIX: Certificate Representation Relationship between Applicant/Market Participant and Owners of Demand Response Resource(s)

All documentation must be received by stated Commercial Model deadlines in order for the resource to be adequately modeled. The Market Participant submitting the registration request will also be required to confirm the requested change to the Commercial Model during the Asset Confirmation period. A member of the Client Services & Readiness team will notify Market Participants when the confirmation period has opened.

As part of the asset registration process for DRRs, Market Participants are required to submit two default offers, each consisting of 24-hourly parameters, for use in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market, respectively. These default offer parameters must include the data elements described in Section B.8.7.4 of the BPM.

To register a DRR that will also serve as a Capacity Resource or as an LMR, the Market Participant must also utilize the Module E Capacity Tracking (MECT) tool and comply with all registration deadlines as described in BPM-011 Resource Adequacy. For more information on the registration and qualification process for a DRR to serve as a Capacity Resource or as an LMR, please refer to BPM-011 Resource Adequacy.

(i) Load Modifying Resources (LMRs)

Registering demand response as a Load Modifying Resource commits the resource to respond to any MISO Emergency at least five times per Planning Year when called upon by MISO. In recognition of this responsibility, the resource is granted ZRCs in an amount commensurate with the amount of load reduction provided by the resource at the expected time of MISO's annual peak demand. Given MISO's current composition, the expected peak occurs during the period June through August during the hours from 2:00 pm through 6:00 pm. Market Participants must submit a variety of information at registration. While the following lists are intended to assist the Market Participant in understanding the required information, MPs are encouraged to review BPM-011 Resource Adequacy for details and contact Capacity Market Administration with any questions.

1. Demand Resource LMR

For a Demand Resource LMR, qualification and registration information include:

- The Demand Resource must be equal to or greater than 100 kW (grouping a number of smaller resources is allowed in meeting this standard).
- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.

- Submitting the documentation listed below if the LMR is only available less than 6 months or requires a notification time greater than or equal to 6 hours. If requested by MISO, the documentation below should be available within five (5) Business Days if an LMR is available less than 9 months or requires a notification time greater than 2 hours:
- Attestation by a senior employee describing the physical capability of the LMR
- LMR operational characteristics or seasonal load output
- Timeline from notice to output (Notification Only)
- Regulatory or contractual limitations
- The Demand Resource must be available to be scheduled for a Demand reduction at the targeted Demand reduction level or by moving to a specified firm service level with no more than 12 Hours advance notice from MISO. For the 2022/2023 Planning Year, a Demand Resource with a notification time requirement greater than 6 hours but less than or equal to 12 hours and a minimum of 10 interruptions allowed during the Planning Year will receive 50% credit as a Planning Resource. For the 2022/2023 Planning Year, Demand Resources with notification time requirements greater than 6 hours but less than or equal to 12 hours with less than 10 interruptions allowed will receive no credit.
- Once Scheduling Instructions are given by MISO that require a Demand reduction, the Demand Resource must be capable of ramping down to meet the targeted Demand reduction level or achieve the firm service level by the Hour designated by MISO's Scheduling Instructions.
- Once the targeted level of Demand reduction or firm service level is achieved, the Demand Resource must be able to maintain the targeted level of Demand reduction or firm service level continuously for at least four (4) consecutive hours.
- The Demand Resource must be capable of being interrupted at least the first five (5) times during the Planning Year when called upon by MISO. For the 2022/2023 Planning Year, Demand Resources with a notification time requirement less than or equal to 6 hours will receive credit as a Planning Resource based on a multiplier of:
- 80% if 5 to 9 interruptions per Planning Year are allowed on the Demand Resource; or,
- 100% if 10 or more interruptions per Planning Year are allowed on the Demand Resource.
- Market Participants with Demand Resources can demonstrate a real power test for accreditation. The real power test of the Demand Resource may be from a MISO called event or a self-scheduled implementation in accordance with section 4.2.9.8 of BPM-011. If a Demand Resource test is not performed for accreditation, additional options outlined in BPM-011 may be utilized.
- If the MP with the Demand Resource does not conduct a real power test under MISO's Tariff (Section 69.A.3.5.j) and is thus not accredited via a real power test, the MP can choose to opt out with potential 3x performance penalties and a credit requirement. If the MP has a regulatory preclusion it can document, it will not be subject to higher penalties. If the MP opts out or has a regulatory exclusion, the MP may provide operational data, or develop an alternative mechanism, subject to the approval of MISO, by which the demand reduction capability can be demonstrated, and the MP has to participate in at least one of the voluntary LMR drills MISO conducts.
- Unless the Demand Resource is unavailable as a result of maintenance requirements or for reasons of Force Majeure, when a Demand reduction is requested by MISO, the resultant reduction must be a reduction that would not have otherwise occurred within the next twenty-four (24) hour period. There

shall be no penalties assessed to a Market Participant representing the entity that has designated the ZRCs from the LMR if the Demand Resource is unavailable for interruption as a result of maintenance requirements or for reasons of Force Majeure, or in the event the specified Demand reduction had already been accomplished for other reasons (e.g., economic considerations, self-scheduling at or above the credited level of Demand Resource, or local reliability concerns in accordance with instructions from the LBA).

- A Demand Resource for which curtailment is voluntary or optional during Emergency events declared by MISO pursuant to MISO's emergency operating procedures will not qualify as an LMR.
- Demand Resources that are offered into the Energy and Operating Reserve Markets as price sensitive Bids are nevertheless obligated to be interrupted during an Emergency pursuant to MISO's emergency operating procedures, regardless of the projected or actual Energy Market LMP.
- MISO will use the MECT tool to ensure that there can be only one MP using ZRCs from a Demand Resource.
- A Market Participant must provide written documentation to MISO from the RERRA having jurisdiction over the Market Participant, or from customers represented by the LMR Market Participant, with the amount and type of Demand Resource and the procedures for achieving the Demand reduction. For a Market Participant without state or other retail regulatory accreditation procedures for a Demand Resource, the Market Participant must secure verification from a third party auditor that is unaffiliated with the Market Participant to provide documentation of the Demand Resource's ability to reduce to the targeted Demand reduction level or to a specified firm service level when called upon by MISO, or provide past performance data that demonstrates such reduction capabilities.

(i) Behind the Meter Generation LMR

A Market Participant that possesses ownership or equivalent contractual rights in a Behind-the-Meter Generator (BTMG) can request accreditation as a BTMG resource by:

- Registering such resource(s) with MISO as documented in BPM-011 Resource Adequacy
- Demonstrating Generation Verification Test Capacity (GVTC) capability for each Planning Year on an annual basis as established in BPM-011 Resource Adequacy, by conducting a real power test or using operational data, and by submitting the GVTC results to MISO no later than October 31 prior to such Planning Year for existing accredited BTMG. All new BTMGs, or an existing accredited BTMG that has an increased installed capacity, shall submit their GVTC to MISO prior to qualification as established in BPM-011 Resource Adequacy.
- Submitting generator availability data (including, but not limited to, NERC GADS information) into a database provided by MISO and as established in BPM-011 Resource Adequacy. A BTMG greater than or equal to 10 MW (based on GVTC) shall provide MISO with generator availability data. A Market Participant is not required to report generator availability data for a BTMG less than 10 MW if the Market Participant has never provided such data for that BTMG. A Market Participant that begins reporting generator availability data for such a BTMG must continue to report such data; and
- Confirming the BTMG can be available to provide energy with notice not to exceed 12 Hours.
- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.

- Submitting the documentation listed below if the LMR is only available less than 6 months or requires a notification time greater than or equal to 6-hours. If requested by MISO, the documentation below should be available within five (5) Business Days if an LMR is available less than 9 months or requires a notification time greater than 2-hours: For the 2022/2023 Planning Year, a BTMG with a notification time requirement greater than 6 hours but less than or equal to 12 hours and a minimum of 10 interruptions allowed during the Planning Year will receive 50% credit as a Planning Resource. For the 2022/2023 Planning Year, BTMG with notification time requirements greater than 6 hours but less than or equal to 12 hours with less than 10 interruptions allowed will receive no credit.
- Attestation by a senior employee describing the physical capability of the LMR
- LMR operational characteristics or seasonal load output
- Timeline from notice to output (Notification Only)
- Regulatory or contractual limitations

(ii) LMR Registration

Each LMR must be registered with MISO in advance of receiving accreditation. Only Certified Market Participants may register the LMR, and this process is completed by accessing the Module E Capacity Tracking (MECT) tool through the secure Market Portal.

To qualify as a Planning Resource the LMR must meet all of the Tariff provisions, summarized in Section 2.8.7.3 *Registration Options for Demand Response.*

For more information on the process and deadlines associated with registering LMRs, refer to BPM-011 Resource Adequacy.

(iii) Emergency Demand Response Resources

A Market Participant within MISO's footprint may register an Emergency Demand Response (EDR) resource if it has the ability to cause a reduction in demand in response to receiving an EDR Dispatch Instruction from MISO because the Market Participant: (i) is the operator of a facility capable of reducing demand; (ii) is a Load Serving Entity (LSE) or Aggregator of Retail Customers (ARC) with a contract that entitles the Market Participant to reduce Load at such facility, or; (iii) has the ability to cause an increase in output from a btmg resource to enable a net demand reduction, in response to receiving an EDR Dispatch Instruction from MISO. Only a Market Participant is allowed to register an EDR resource making itself eligible to submit EDR offers to MISO to reduce demand during an emergency event.

The Market Participant must be able to receive an EDR Dispatch Instruction from MISO via Extensible Markup Language (XML). Additionally, the Market Participant must utilize metering equipment that meets the requirements established in the Tariff, including, but not limited to, the ability to provide integrated hourly kWh values on a Commercial Price Node (CPNode) basis. A Market Participant with a registered EDR resource may provide hourly kWh values for non-interval metered demand reductions (e.g., direct Load control) using the alternative Measurements and Verification Criteria provided in Attachment TT of the Tariff. Measurement of demand reductions will be made on an aggregated applicable CPNode basis to enable the Market Participant's demand reduction to be identified with an LMP; EDR offers can set LMP.

A Market Participant that intends to use a btmg resource for the purpose of reducing demand shall confirm to MISO in writing that: (i) it holds all necessary permits (including, but not limited to, environmental permits) applicable to the operation of the generation resource; (ii) it possesses rights to operate the generation resource that are equivalent to ownership of such unit; and (iii) the generation resource is not a designated Network Resource. Unless notified otherwise, MISO shall deem such representation applies each time the generation resource is used to reduce demand during an emergency event and that the generation resource is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits. The Market Participant shall be solely liable for identification of, and compliance with, all such applicable permits.

If the generation resource designated by a Market Participant historically has operated during non-Emergency conditions, the Energy that can be offered under the EDR Initiative is the increase in output from a btmg resource to enable a net Demand reduction, in response to receiving an EDR Dispatch Instruction from MISO. Determination of such output shall be based on the EDR offer and the amount of load reduction provided, as described in the Measurement and Verification protocols.

A Market Participant with a registered EDR resource shall be required to identify if the Demand reduction can be variable (curtail to the firm service level) or alternatively provide a specific level of Demand reduction. Upon receipt of an EDR Dispatch Instruction, the Market Participant shall either: (i) curtail to the firm service level specified in their EDR offer or (ii) provide a specific level of Demand reduction as specified in their EDR offer. Market Participants electing the first option shall be required to identify an expected peak Load in their EDR offer, which can change daily.

The Market Participant is responsible for maintaining Demand reduction information, including the amount in MWh of reduced Demand during emergency events whenever the Market Participant responds to an EDR Dispatch Instruction from MISO. The Market Participant shall provide this information to MISO in accordance with the procedures specified in BPM-005 Market Settlements.

(iv) EDR Registration

Prior to participating in the EDR Initiative, a Market Participant must complete and submit all required EDR registration forms posted on MISO's public website (Markets and Operations > Market Participation > Supplemental Registration). An EDR Participant and its associated load asset or btmg asset must be defined in the EDR registration form. The required registration process includes:

- Submit a case through the Help Center at: https://help.misoenergy.org/
- Attach the following documents to the case:
- EDR Certification Form
- EDR Registration Form

Note the case must be submitted first and then the documents can be attached. Please refer to the MISO Help Center Online Guide located in the Learning Center at the following link: https://miso.csod.com/catalog

In addition to the above documentation, the following documentation is required for ARCs (due to the potential quantity of documents, please send these files to help@misoenergy.org):

- ARC EDR Physical Location Worksheet
- All registration forms
- Section XX Certificate Confirming Fulfillment of Requirements for Applicants Seeking to Participate as Aggregator of Retail Customers (ARC)

An EDR Participant shall verify in writing through the EDR Certification Form that it has received any required approvals from all applicable state regulatory agencies to enable the entity to participate in the EDR Initiative.

The aforementioned documentation must be received by MISO at least 30 days prior to the requested effective date of the EDR resource and the effective start date must be the first day of the month. MISO shall notify the Market Participant when it has met all required qualifications as set forth in Schedule 30, following which the Market Participant is eligible to submit EDR offers beginning on the first day of the month following its approval.

A Market Participant that wants an EDR resource to be accredited with Zonal Resource Credits under Module E-1 must separately register that resource as an LMR, as described in Section B.8.7.3.1 of the BPM.

For questions related to EDR registration, refer to BPM-001 Market Registration or contact a member of the Client Services & Readiness team.

2.8.7.3.2 Registration as an Aggregator of Retail Customers (ARCs)

By definition, an Aggregator of Retail Customers (ARC) is a Market Participant sponsoring one or more DRRs, LMRs, and/or EDRs provided by end-use customers that the ARC does not serve at retail. An ARC can, but need not, be an LSE sponsoring a DRR, LMR, or EDR that is the end-use customer of another LSE.

An entity may choose to participate as an ARC provided, they have met the registration requirements outlined in the BPM for Market Registration (BPM-001) and have received approvals from all required parties, including ensuring that their respective Relevant Electric Retail Regulatory Authority (RERRA) allows for ARC participation. LSEs can aggregate their own end- use customers subject to their retail regulatory authority approval; therefore, they need not register as ARCs to do so.

2.8.7.3.3 ARC Registration

An applicant will indicate its desire to register as an ARC during the Market Participant Application process. BPM-001 Market Registration contains complete information on the registration process. If the Market Participant did not register as an ARC during the initial Market Participant application, it may choose to submit required documentation in accordance with applicable timelines. If the Market Participant intends to register a DRR as an ARC, the Applicant needs to start the registration process at least 30 days prior to the Commercial Model deadline date to allow for registration and approvals (DRR Type I and DRR Type II). Additional information regarding the registration of LMRs as an ARC can be found in BPM-011 Resource Adequacy.

As a pre-requisite, the ARC must ensure it has followed registration procedures for its DRRs, LMRs, or EDRs, including the submission of all required documentation by stated deadlines. Applicants or Market Participants seeking to register as an ARC are required to complete the following document as proof that the entity meets applicable RERRA laws, regulations, or orders regarding participation in MISO’s Energy and Operating Reserve Markets (complying with Tariff 38.6): Certificate Confirming Fulfilment of Requirements for Applicants Seeking to Participate as Aggregator of Retail Customers (ARC), including a list of all RERRA areas that the ARC intends to operate in

An ARC can bundle multiple end-use loads to form an asset, but all loads must be located within a single LSE within an LBA. Each asset may be comprised of one or more Enrollments. Enrollments may be comprised of one or more physical or virtual locations. This applies for DRRs and EDRs. LMRs may only be aggregated up to a Load Zone CPNode level.

Additional data for each end-use load comprising the asset must be provided by applicable deadlines. Market Participants with DRR Type I and/or Type II resources will provide such data through the Demand Response Tool. Market Participants with EDRs will provide the information listed below by completing a physical location template. Market Participants with LMRs will provide the information listed below during registration in the MECT. The Applicant or Market Participant will provide information including, but not limited to, the following for each end-use load comprising the ARC's asset:

- The Local Balancing Authority Area where the end-use loads are located[138];
- The LSE serving each end-use load that the ARC will control;
- The Relevant Electric Retail Rate Authority (RERRA[139]) having jurisdiction over the LSE;
- Expected demand reductions of each registered DRR, LMR, or EDR resource;
- The Measurement & Verification methodology to be used for each identified demand resource;
- The names of relevant contact persons or entities, postal and e-mail addresses, and telephone numbers; and
- A list of end-use customer accounts that comprise the demand resources being registered, including names, addresses, and account numbers of such end-use customers.

In addition, the ARC must certify the following for each of its end-use customers:

- Where the utility serving the customer at retail distributed more than four (4) million MWh in the prior fiscal year.
- The ARC must certify that the laws, regulations, or order(s) of the RERRA do not preclude the end-use customer from participating directly in MISO's Energy and Operating Reserve Markets, providing Capacity or obtaining Zonal Resource Credits under Module E-1 of the Tariff, or being an EDR resource; or,
- Where the utility serving the customer at retail distributed four (4) million MWh or less in the prior fiscal year.
- The ARC must certify that the laws, regulations, or order(s) of the RERRA specifically permit the retail customer to participate directly in MISO's Energy and Operating Reserve Markets, providing Capacity under Module E-1 of the Tariff, or being an EDR resource.

The Market Participant registering as an ARC is required to provide the contact information of the RERRA via the submission of the section XX form. For DRR Type I and Type II registrations, a pull-down list of RERRAs is available in the Demand Response Tool; if the appropriate RERRA is not listed, the ARC will need to notify MISO (Market Settlements), and the RERRA will then be added so that the ARC can complete the registration. The ARC is responsible for initial and subsequent validation of the RERRA, notifying MISO of any changes.

Concurrent with MISO review of the application, the LBA and the LSE named by the ARC candidate will be notified, triggering concurrent review regarding the information presented by the ARC. The LBA and LSE have ten (10) business days from receipt of the submitted enrollment to "Confirm" or "Object to " the enrollment. Inaction on the part of the LBA or LSE will not result in delay of application approval. For DRR Type I and Type II, the Demand Response Tool will list the applicable reasons for "objection" as well as providing a field for

[138] An ARC can bundle multiple end-use loads to form an asset, but all such loads must be located within a single LSE. In addition, a single end-use load can be a DRR Asset. An ARC may register more than one asset.

[139] The RERRA will typically be a Commission, but it could also be the board of a public power entity or a rural electric cooperative.

Comments (e.g., helpful details regarding the reasons for “objection”). For EDRs, the “objection” reasons are provided in the physical location template. For LMRs, if the “objection” occurs after the LMR registration deadline (March 1st), the ARC will be given one chance to correct the error or clarify the enrollment and if “objection” after the second attempt, the registration will be reviewed by MISO . If the ARC candidate asset is ultimately denied by MISO as a result of the above processes, any further dispute resolution of the resource application occurs through the Tariff’s dispute resolution procedures[140].

2.8.7.3.4 ARC Participation and Review Process

ARC participation is different from other participation in the markets administered by MISO for several reasons. This section attempts to summarize certain issues related to ARC participation. General issues discussed here include the potential for double-counting, communication protocols related to information sharing between ARCs, LBAs, LSEs, and MISO, and re- constitution of load for settlement.

With regard to double-counting, ARC registration requirements include physical addresses and other information which may then be cross-checked by MISO, the LSE, and the LBA with other demand resources registered in MISO Markets. If apparent double counting occurs between MPs during the registration process, MISO will accept end-use customers in a demand resource into a MISO Market on a first-come first-serve basis. LBAs are requested to review and provide important location details (e.g., EPNodes) based on end-use customer addresses and other information and are thus made aware of ARC resources within their service areas. LSEs are requested to review if the end-use customer(s) is already included in the LMR, DRR or EDR for that LSE, if the end-use customer(s) is served by the LSE, account numbers, demand reduction capabilities for assets registering within their service territories and validating and/or providing the CPNode to represent the enrollment.

(i) LSE Responsibilities for EDRs registered by ARCs

Items for review include:

- Correct LSE is listed
- CPNode is owned by the LSE and is still active and not terminated
- Customer account number
- Customer meter number
- Physical location address (Note abbreviations and shortened versions of the street address are acceptable)
- No duplicate account numbers

The following are the confirm/object reasons: Please note other reasons could be included dependent upon changes in the EDR registration process.

- Confirm
- Object – the customer is already registered as part of a LMR, DRR, or EDR for the LSE
- Object – the customer is not served by the LSE
- Object – duplicate account number
- Object – the LSE CPNode provided for this location/customer is incorrect
- If MISO does not receive confirm/object within ten business days, the registrations are auto approved unless the approval is subject to RERRA review with respect to a utility with sales equal to or less than 4

[140] MISO Tariff Attachment HH: Dispute Resolution Procedures

million MWhs/fiscal year, in which case failure of the RERRA to confirm within ten business days will result in auto rejection.

With respect to information access for LBAs, the Tariff provides that the LBAs will participate with MISO in reviewing the composition of CPNodes. LBAs will have access to the electrical location and magnitude of resources in an ARC's portfolio of resources in order to perform operational planning studies. Further, LBAs will be notified of ARC demand reduction offers that have been cleared in the day-ahead and real-time markets in order to perform reliability assessments and planning roles in the day-ahead and real-time horizon.

(ii) LBA Responsibilities for EDRs registered by ARCs

Items for review include:

- Correct LBA is listed
- CPNode is still active and not terminated
- Customer account number
- Customer meter number
- Physical location address (Note abbreviations and shortened versions of the street address are acceptable)
- No duplicate account numbers

The following are the confirm/object reasons: Please note other reasons could be included dependent upon changes in the EDR registration process.

- Confirm
- Object – invalid location information
- Object – duplicate account number
- Object – invalid customer account information
- If MISO does not receive confirm/object within ten business days, the registrations are auto approved unless the approval is subject to RERRA review with respect to a utility with sales equal to or less than 4 million MWhs/fiscal year, in which case failure of the RERRA to confirm within ten business days will result in auto rejection.

To the extent that MISO is required to disclose information specific to ARC demand reduction, MISO will need to follow the Disclosure of Certain Confidential Market Participant Data to Balancing Authorities and Transmission Operators provisions set forth in section 38.9.1(A) of Module C of the Energy and Operating Reserve Markets Tariff.

LSEs will have access to all pertinent metering, settlements, and Measurement & Verification (M&V) information associated with the operation of an ARC in an LSE's zone upon submission of requested meter data. Upon submission of settlement data by the ARC, the LSE has ten (10) business days to complete its review and confirm or object to the settlement. If objected by the LSE, the ARC then has ten (10) business days in which to resubmit or dispute the objection. If resubmitted, the LSE then has five (5) business days to review. This process continues, including dispute resolution, until the settlement is approved or denied by MISO, or expires[141]. Also as part of the settlement process, LSEs will have access to data on Actual Energy Injections associated with DRRs

[141]If a settlement is not confirmed within 103 calendar days of the event, it will expire.

(and LMRs/EDRs), within seven (7) days of the Operating Day, so that LSEs can verify ARC-related charges. LSEs will also be notified of cleared ARC load reduction offers in real-time through settlement data.

With specific regard to DRR participation and RERRA approvals:

- MISO will not accept offers from new DRRs until after the ten-day deadline and the Commercial Model has been loaded to production
- MISO will automatically accept a DRR's registration following the ten-day deadline, unless the RERRA objects and unless the approval is subject to RERRA review with respect to a utility with sales equal to or less than 4 million MWhs/fiscal year, in which case failure of the RERRA to confirm within ten business days will result in auto rejection;
- RERRAs can reject a DRR's registration at any time, including after the ten-day notice period, and the demand asset will be promptly removed from participating in MISO's markets; and,
- If an otherwise prohibited end-use customer is registered in a DRR, or an end-use customer becomes non-compliant after having registered with MISO, then MISO will not allow the customer to participate in its markets.

MISO shall review the participation of an ARC in the Energy and Operating Reserve Market when the ARC's settlements submitted under section 38.6 of the Tariff are successfully disputed more than ten percent (10%) of the time by a relevant LSE. The ten (10) percent threshold is based on disputes made by a relevant LSE, irrespective of the RERRA, against an ARC and its representing end-use customers served by the relevant LSE for failure to actually perform as indicated during a given demand response event. This threshold will be addressed quarterly, based on the ARC's rolling average performance with regard to demand response events.

MISO shall have thirty (30) days to conduct a review pursuant to this section of the Tariff. MISO shall refer the matter to the RERRA and may refer the matter to the Independent Market Monitor, if the review indicates the relevant ARC and/or LSE is engaging in activity that is inconsistent with the Energy and Operating Reserve Market Tariff.

2.8.7.3.5 Resource Testing

Prior to participation, each demand resource and/or btmg unit that the Market Participant is proposing to use must document its ability to interrupt load within a prescribed time limit when instructed to do so. The prescribed time limit will depend on the particular service the resource is being qualified to provide. See Section 2.8.7.7 *Resource Testing* in this BPM for more details on Resource Testing. Additional requirements related to LMR testing may be found in the BPM for Resource Adequacy (BPM-011).

2.8.7.3.6 Credit Requirements

To participate in the MISO Markets, all Market Participants must have an approved credit application and must have established a Total Credit Limit with MISO Credit Department in accordance with MISO Credit Policy. Additional details on what is required in the credit application can be found in BPM-001 Market Registration or found in Attachment L of the MISO Tariff.

(i) Changes to Registration

Once a Market Participant is certified, changes may occur in the information originally provided, as specified in the Tariff. Depending on the desired change and the type of demand resource in question, the Market

Participant may need to submit documentation or use one of MISO's tools that supports the registration and maintenance of such information. Changes to registrations must follow the applicable timelines.

For questions regarding changes to the following demand response options, please contact the Client Services & Readiness team:

- DRR (Type I or Type II)
- EDR Resource
- ARC Participation

For questions regarding changes to LMRs, please contact the Capacity Market Administration team.

2.8.7.4 Economic Energy, Operating Reserves And Ramp Capability Product

The provision of economic energy is a service different from the provision of operating reserve and other Ancillary Services. Section 2.8.7.2.2 *Types of Demand Response Services* of the BPM refers to the former as, "Economic Demand Response" and to the latter as "Operating Reserve Demand Response." However, the two services are intimately linked through the algorithms MISO uses to schedule the future outputs of DRRs, for example, the Security Constrained Unit Commitment (SCUC) and the Security Constrained Economic Dispatch (SCED) algorithms. Working together, the SCUC and SCED "co-optimize" (i.e., maximize the market benefits derived from) the provision of these services by simultaneously determining which service (or services where qualified), and how much, each DRR should provide in each forthcoming hour of the day. See BPM-002 Attachment A for further insight into the SCUC and SCED optimization algorithms. In light of this interrelationship and because the provision of the two services shares much in common, this section concurrently addresses both Economic Demand Response and Operating Reserves Demand Response.

2.8.7.4.1 Demand Response Characteristics

As stated earlier, DRR-Type I and DRR-Type II resources are the only resources eligible to provide Economic Demand Response in MISO markets.

- A DRR-Type I is defined in Module A of the Tariff as a resource owned by a single Load Serving Entity or ARC within the MISO Balancing Authority Area and that (i) is registered to participate in the Energy and Operating Reserve Markets, (ii) that is capable of supplying a specific quantity of Energy, Contingency Reserve or Capacity, at the choice of the Market Participant, to the Energy and Operating Reserve Market through Behind the Meter Generation and/or controllable Load, (iii) is capable of complying with the Transmission Provider's instructions and (iv) has the appropriate metering equipment installed. Each Demand Response Resource – Type I will be modeled as a Commercial Pricing Node consisting of defined Elemental Pricing Nodes maintained and approved by the Transmission Provider that comprise injections of customer demand response within a single Local Balancing Authority Area for the purposes of scheduling, reporting Actual Energy Injections, and settling Energy and Contingency Reserve transactions. The Demand Response Resource – Type I can be modeled as aggregations of whole or portions of Elemental Pricing Nodes. Given the appropriate qualification, Demand Response Resource-Type I Resources can provide the following products: Energy, Contingency Reserve, and capacity under Module E.
- A DRR-Type II is defined in Module A of the Tariff a resource owned by a single Load Serving Entity or ARC within the MISO Balancing Authority Area and that (i) is registered to participate in the Energy and

Operating Reserve Markets, (ii) is capable of supplying a range of Energy and/or Operating Reserve, at the choice of the Market Participant, to the Energy and Operating Reserve Market through Behind The Meter generation and/or controllable Load, (iii) is capable of complying with Transmission Provider's Setpoint Instructions and (iv) has the appropriate metering equipment installed. Such Resources will be modeled and/or otherwise treated in a manner comparable as Generation Resources and must comply with the same Applicable Reliability Standards as Generation Resources. Given the appropriate qualification, Demand Response Resource-Type II Resources can provide the following products: Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, and/or capacity under Module E-1.

To comply with the MISO settlements process, the individual EPNodes comprising a DRR must be EPNodes associated with one Load Serving Entity (LSE).

The two types of DRRs differ primarily with respect to their flexibility in responding to dispatch instructions. A DRR-Type I resource has only two output states (either "on" or "off") whereas a DRR-Type II resource can deliver output over a continuous range of values.

(i) Modeling of DRR-Type I

No special modeling of a DRR-Type I is required in the MISO Network Model, where a DRR-Type I capable load is modeled as regular load. Commercial modeling of DRR-Type I is done using a "DRRNODE1" CPNode, which is similar to the Load Zone CPNode. More information can be found in Section 4.2.3 of the Network and Commercial Models BPM 010.

(ii) Modeling of DRR-Type II

Because a DRR-Type II may consist of both behind-the-meter generators and controllable load, special modeling is required to account for the DRR-Type II properly as a Resource. For Network Model purposes, the load and generator combination is represented by a single equivalent generator. The Commercial Model representation of a DRR-Type II is similar to that of modeling a traditional Generator, in which a single EPNode-CPNode relationship is used. More information can be found in Section 4.2.4 of the Network and Commercial Models BPM 010[142].

(iii) CPNode LMP Determination

The MISO settlement system pays MPs for their energy injections and charges MPs for their energy withdrawals using LMPs corresponding to their respective CPNodes. For each Operating Day, the Day-Ahead / Real-Time (DART) system calculates the LMPs at each EPNode for the Day Ahead Market and again for the Real Time Market. For resources that inject into a single EPNode or loads that withdraw from a single EPNode, their respective CPNode LMPs are simply their respective EPNode LMPs. However, DRR-Type I resources may consist of aggregations of suitable loads located at different EPNodes. In such cases, the hourly LMPs at each CPNode are calculated as a weighted average of the respective hourly LMPs at the EPNodes, where the weighting factors are the respective weighting factors based on the Target Demand Reductions that the Market Participant sponsoring the DRR submitted when the resource was registered. The calculation is described as follows:

[142] End-use customer assets can be aggregated as long as all assets originate electrically from a single EPNode.

$$CPNLMP_h = \sum_{i=0}^{k} (Weighting\ Factor_i \times EPNLMP_h)$$

Where:

h indexes each of the 24 hours in the Operating Day and

i indexes each of the EPNodes comprising the resource's CPNode.

2.8.7.4.2 Qualifications to Provide Energy

Both types of DRRs are qualified to provide Energy to the market. However, a DRR-Type I is only capable of delivering two levels of output: either zero or its Targeted Demand Reduction. In contrast, a DRR-Type II can deliver varying levels of output spanning a continuum and is also capable of following MISO 5-minute Setpoint Instructions. Because a DRR-Type II is treated as if it were a traditional generator, it must be capable of providing telemetered output data.

2.8.7.4.3 Qualifications to Provide Operating Reserves and RCP

To provide Operating Reserves and/or other Ancillary Services including the Ramp Capability Product, a DRR must be able to deliver energy to the grid within a prescribed time limit specific to the Operating Reserve product offered and must satisfy all other requirements set forth in the Energy and Operating Reserve Market Tariff. Table 2-36 displays these time limits based on reliability standards adhered to by MISO.

Notes for the table below.

- Note 1: Must provide both REG UP and REG DOWN service.
- Note 2: Must respond to AGC instructions within four seconds.
- Note 3: Must be capable of automatically responding to frequency deviations.
- Note 4: DRR-Type I resources only need to provide five-minute interval data within 5 days after a contingency event.
- Note 5: Must be physically located within MISO footprint.

Table 2-36 Operating Reserve Response Time Requirements[143]

<table>
<tr><th>Product</th><th>Maximum Allowed Response Time</th><th>Minimum Continuous Duration</th><th>Data Telemetry</th><th>Notes</th></tr>
<tr><td>Regulation</td><td rowspan="2">4 Seconds</td><td rowspan="2">60 Minutes</td><td rowspan="2">2 Seconds</td><td rowspan="2">1, 2, 3</td></tr>
<tr><td>DRR-Type II</td></tr>
<tr><td>Spinning Reserve</td><td rowspan="3">10 Minutes</td><td rowspan="3">60 Minutes</td><td></td><td rowspan="3">4, 5</td></tr>
<tr><td>DRR-Type I</td><td>None</td></tr>
<tr><td>DRR-Type II</td><td>10 Seconds</td></tr>
<tr><td>Supplemental Reserve</td><td rowspan="3">10 Minutes</td><td rowspan="3">60 Minutes</td><td></td><td rowspan="3">4, 5</td></tr>
<tr><td>DRR-Type I</td><td>None</td></tr>
<tr><td>DRR-Type II</td><td>10 Seconds</td></tr>
</table>

(i) Regulation

Only DRR-Type II resources can provide Regulation Service because this service requires near- continuous changes in output over a range of values. In addition, the resource must meet the qualifications for providing Regulation service, including the following:

- Fully deployable in both the regulation-up and regulation-down directions
- Capable of automatically responding to and mitigating frequency deviations via speed governor or similar device
- Capable of responding to Automatic Generation Control (AGC) signals within 4 seconds and telemetering its output data at 2-12 second periodicity
- Capable of providing the Regulation Service for a minimum continuous duration of sixty minutes or for the maximum duration specified by Applicable Reliability Standard.

2.8.7.4.4 Spinning Reserve

Both types of DRR resources are eligible to register to provide Spinning Reserve Service. In addition, these resources must be:

- Capable of deploying 100% of their cleared Spinning Reserve (including Spinning Reserve cleared to meet Supplemental Reserve Requirements) within the 10-minute Contingency Reserve Deployment Period
- Capable of sustaining 100% of their cleared Spinning Reserve as energy for a continuous duration of 60 minutes or the maximum duration specified by Applicable Reliability Standards
- Capable of automatically responding to and mitigating frequency deviations if required by Applicable Reliability Standards
- Capable of providing telemetered output data that can be scanned every 2-12 seconds periodicity (except for DRRs-Type I, which need only provide five-minute interval data no later than 5 days after they reduce load in response to a contingency event)

[143] *Ibid.*

- Physically located within the Market Footprint
- Any resource that is qualified to provide Regulating Reserve is also qualified to provide Spinning Reserve. A DRR Type-II registered as a Regulation Qualified Resource must also be registered in the Energy and Operating Reserve Markets as a Spin Qualified Resource and as a Supplemental Qualified Resource. Registration is necessary to allow cleared on-line Regulation Qualified Resources to supply Spinning and/or Supplemental Reserve through substitution of such Resources for Spin Qualified Resources. Currently, DRRs can only clear up to forty (40) percent of the spinning reserve requirement, measured in MWs. A special type of DRR Type I called a Batch-Load Demand Resource (BLDR), (as described in the Baseline Adjustment Examples section of Volume 3, Appendix B), can provide spinning reserve if a Spin Qualified Resource.

(i) Supplemental Reserve

Both types of DRR can provide Supplemental Reserve Service if the resource:

- Is capable of deploying 100% of its cleared Supplemental Reserve within the 10- minute Contingency Reserve Deployment Period
- Is capable of deploying 100% of their cleared Supplemental Reserve for a continuous duration of 60 minutes, or the maximum duration specified by Applicable Reliability Standards
- Has a Minimum Down Time of less than or equal to three hours if a Quick-Start Resource
- Is capable of providing telemetered output data that can be scanned every 2-12 seconds periodicity (except for DRRs-Type I, which need only provide five-minute interval data no later than 5 days after they reduce load in response to a contingency event)
- Is physically located within the market footprint

Any resource that is qualified to provide Spinning Reserve is also qualified to provide Supplemental Reserve. Any Resource registered as a Spin Qualified Resource must also be registered in the Energy and Operating Reserve Markets as a Supplemental Qualified Resource to allow cleared Spin Qualified Resources to supply Supplemental Reserve through substitution of such Resources for Supplemental Qualified Resources. A special type of DRR Type I called a Batch-Load Demand Resource (BLDR), described in Section 2.8.8 *Batch Load Demand Response* below, can provide supplemental reserve if a Supplemental Qualified Resource.

(ii) Ramp Capability Product

Only DRR Type-II resources are eligible to provide the Ramp Capability Product. The Ramp Capability Product is cleared in the Day-Ahead or Real-Time Energy and Operating Reserve Markets to reserve ramp capability to respond to net load variations and includes the following features:

- The Up Ramp Capability and Down Ramp Capability requirements are designed to model both the expected net energy demand change and additional uncertain variation across all market processes and across different system operational conditions at a system level (zonal values will be calculated).
- The contribution of a resource to the ramp capability constraint is limited by its operating limits and its ramp rate over the modeled deployment time. No Market Participant offer price is needed. Market Participants will be able to indicate their offered dispatch status as either “Economic” or “Not Participating”.

- Ramp capability is not explicitly "deployed." Rather Ramp Capability prepositions resources so that adequate ramp is available in subsequent dispatch intervals. Ramp Capability Requirement Demand Curve will enforce this constraint as a soft constraint.

See BPM-002 Sections 3.4 and 4.2.1.4 for additional Ramp Capability information.

2.8.7.4.5 DRR Offers

MISO maintains a Day-Ahead Schedule Offer and a Real-Time Schedule Offer for each DRR- Type I and DRR-Type II resource. These are standing Offers that are maintained for each market (DA and RT) independent of the other. Initially the standing Offers are established at the time the DRR is registered with MISO and may be updated by the sponsoring Market Participant. Updates may be designated as updating the Day-Ahead Schedule Offer only, the Real-Time Schedule Offer only, or both.

Starting in July 2016, the Real Time Offer Override Enhancement (RTOE) capability went live. RTOE allows the Market Participant to programmatically request overrides of resource capability offers in real time, through the Market Portal's DART MUI or XML. Overrides are grouped in nine independent sets. Complete sets must be submitted when requesting an override (see Table 2-37). Market Participant overrides will be valid for the current market hour and next market hour. Market Participant override termination date/time will be adjusted if the underlying offer is updated subsequent to the override request, termination date/time will be set to least of a) existing termination date; or b) start of updated schedule market hour.

Table 2-37 Real Time Offer Override Enhancement (RTOE) Sets[144]

Set	GEN/DRRII/EAR Parameters	SER Parameters	DRRI Parameters
Run Times	Notification Time		Notification time
Offer / Unit Limits	Eco Min, Eco Max, Reg Min, Reg Max, Emergency Min, Emergency Max	Reg Min, Reg Max	Target Demand Reduction MW
Offline Response	Offline Resource Limit		
Ramp Rates	RR Up, RR Down, Reg RR (bi-directional)	Reg RR	
Self-Schedule MW	Energy & Regulation MW, Spinning Reserve	Regulation MW	Spinning Reserve MW, Supplemental Reserve MW
	MW, Online & Offline Supp MW		
Dispatch Status	Energy Dispatch Status, Reg status, Spinning Reserve Status, Online	Regulation	Spinning Reserve, Supplemental Reserve
	Supp Status, Offline Supp Status, Ramp Capability		
Commit Status	Energy Commit Status	Energy Commit Status	Energy Commit Status
Offline Control	Off Control Flag, EEE Flag	Off Control Flag, EEE Flag	Off Control Flag, EEE Flag

[144] *Ibid.*

Fast Ramp Resource	Fast Ramp Resource Flag	Fast Ramp Resource Flag, Neutral Zone	
		Lower Limit, Neutral Zone Upper Limit	

MISO uses DRR offers as inputs to the SCUC and SCED (Real-Time Unit Dispatch System only uses SCED). Such offers may be submitted for the Day-Ahead and Real-Time Energy and Operating Reserve Markets. The contents of these offers are briefly described next. Detailed descriptions of the data elements comprising DRR offers can be found in the BPM for the Energy and Operating Reserve Markets (BPM-002).

(i) DRR-Type I

The tables below identify the data elements comprising a DRR-Type I offer.

Notes for Table 2-38 are as follows:

- Note 1: If qualified to provide the service.
- Note 2: The Targeted Demand Reduction is valid for the indicated hour. A DRR-Type I resource is capable of delivering this full reduction or no reduction, i.e., intermediate values are infeasible Note 3: Up to 3 MW/Price pairs may be submitted.
- Note *: Offer parameters can be overwritten in Real-Time Market using Real-Time Offer Override (RTOE). Override is effective next dispatch interval.

Table 2-38 DRR-Type I Economic Data Summary[145]

Data Element	**Units**	**DAM Offer**	**RTM Offer**	**Notes**
Energy Offer	$/MWh	Hourly	Hourly	2
Hourly Curtailment Offer	$/Hr	Hourly	Hourly	2
Shut-Down Offer	$	Daily	Daily	2
Spinning Reserve Offer	$/MW	Hourly	Hourly	1,2,3
Supplemental Reserve Offer	$/MW	Hourly	Hourly	1,2,3
Self-Scheduled Spinning Reserve	MW	Hourly	Hourly*	1
Self-Scheduled Supplemental Reserve	MW	Hourly	Hourly*	1

Notes for Table 2-39 are as follows:

- Note 1: If qualified.
- Note 2: The Targeted Demand Reduction is valid for the indicated hour. A DRR-Type I resource is capable of delivering this full reduction or no reduction, i.e., intermediate values are infeasible.
- Note 3: Default Offers are used if no values are submitted for the day.
- Note *: Offer parameters can be overwritten in Real-Time Market using Real-Time Offer Override (RTOE). Override is effective next dispatch interval.

[145] https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936258568

Table 2-39 DRR-Type I Operating Parameter Data Summary[146]

Data Element	Units	DAM Offer	RTM Offer	Notes
Targeted Demand Reduction Level	MW	Hourly	Hourly*	2,3
Minimum Interruption Duration	hh:mm	Daily	Daily	3
Maximum Interruption Duration	hh:mm	Daily	Daily	3
Minimum Non-Interruption Interval	hh:mm	Daily	Daily	3
Shutdown Time	hh:mm	Hourly	Hourly*	3
Shutdown Notification Time	hh:mm	Hourly	Hourly*	3
Energy Commitment Status	Select	Hourly	Hourly	
Spinning Reserve Dispatch Status	Select	Hourly	Hourly*	1
Supplemental Reserve Dispatch Status	Select	Hourly		1
Maximum Daily Contingency Reserve Deployment	MWh	N/A	Daily	1

(ii) DRR-Type II

Because DRR-Type II resources canprovide a greater range of output to the markets, their Offers are more complex than DRR-Type I Offers.

Table 2-40 through

[146] https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936258568

Table 2-42 identify the DRR-Type II offer data elements.

Notes for the following table:

- Note 1: If qualified.
- Note 2: If not Spin Qualified.
- Note 3: Quick-Start Resources only
- Note 4: Default Offers are used if no values are submitted for Energy and Operating Reserve Markets.
- Note 5: Can take the form of a Block Offer or a Slope Offer. See BPM-011 for further information.
- Note 6: For a DRR-Type II, “No Load Offer” is the hourly price for maintaining a readiness to reduce load.
- Note 7: For a DRR-Type II, its “Startup Offer” is the daily price for being available to reduce load.
- Note 8: Up to 3 MW/Price pairs may be submitted.
- Note *: Offer parameters can be overwritten in Real-Time Market using Real-Time Offer Override (RTOE). Override is effective next dispatch interval.

Table 2-40 DRR-Type II Economic Data Summary[147]

Data Element	**Units**	**DAM**	**RTM**	**Notes**
		Offer	**Offer**	
Energy Offer Curve	MW,$/MWh	Hourly	Hourly	5
No-Load Offer	$/Hr	Hourly	Hourly	4,6
Regulating Reserve Capacity Offer	$/MWh	Hourly	Hourly	1,5,8
Regulating Reserve Mileage Offer	$/MW	Hourly	Hourly	1
Spinning Reserve Offer	$/MWh	Hourly	Hourly	1,5,8
On-Line Supplemental Reserve Offer	$/MWh	Hourly	Hourly	1,2,5,8
Off-Line Supplemental Reserve Offer	$/MWh	Hourly	Hourly	3,5,8
Hot Start-Up Offer	$	Daily	Daily	4,7
Intermediate Start-Up Offer	$	Daily	Daily	4,7
Cold Start-Up Offer	$	Daily	Daily	4,7

[147] https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936258568

Self-Scheduled Regulation	MW	Hourly	Hourly*	1
Self-Scheduled Spinning Reserve	MW	Hourly		1
Self-Scheduled On-Line Supplemental Reserve	MW	Hourly		1,2
Self-Scheduled Off-Line Supplemental Reserve	MW	Hourly		3
Self-Scheduled Energy	MW	Hourly		
Fast Ramping Resource Flag	True/False	N/A	Hourly	

Notes for the following tables:

- Note 1: Default Offers are used if no values are submitted for Energy and Operating Reserve Markets
- Note 2: Hourly Ramp Rate is used in Day-Ahead and RAC
- Note 3: Ramp Rates may be submitted by MPs at any time and remain fixed until changed by MPs
- Note 4: Only applicable to Quick-Start Resources
- Note 5: Not applicable to Dispatchable Intermittent Resources in the Real-Time Market
- Note 6: Not applicable to Dispatchable Intermittent Resources
- Note 7: Only applicable to Dispatchable Intermittent Resources
- Note 8: Participant-limited to the level achieved during last deployment or test of Offline Supplemental Reserves issued by MISO
- Note 9: Only applicable to DRR-Type II Resources in Real-Time Market
- Note *: Offer parameters can be overwritten in Real-Time Market using Real-Time Offer Override (RTOE). Override is effective next dispatch interval.

Table 2-41 DRR-Type II Commitment Operating Parameter Data Summary[148]

Generation and DRR-Type II Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Hot Notification Time	hh:mm	Hourly	Hourly*	
Hot Start-Up Time	hh:mm	Hourly	Hourly	
Hot to Intermediate Time	hh:mm	Daily	Daily	
Intermediate Notification Time	hh:mm	Hourly	Hourly	
Intermediate Start-Up Time	hh:mm	Hourly	Hourly	
Hot to Cold Time	hh:mm	Daily	Daily	
Cold Notification Time	hh:mm	Hourly	Hourly	
Cold Start-Up Time	hh:mm	Hourly	Hourly	
Maximum Daily Starts	Integer	Daily	Daily	
Maximum Daily Energy	MWh	Daily	Daily	
Minimum Run Time	hh:mm	Daily	Daily	
Maximum Run Time	hh:mm	Daily	Daily	
Minimum Down Time	hh:mm	Daily	Daily	

148 https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936258568

Commitment Status	Select	Hourly	Hourly	1
Max Daily Regulation Up Deployment	MWh	NA	Daily	9
Max Daily Regulation Down Deployment	MWh	NA	Daily	9
Max Daily Contingency Reserve Deployment	MWh	NA	Daily	9

Table 2-42 DRR-Type II Dispatch Operating Parameter Data Summary[149]

Generation and DRR-Type II Offer Data	Units	Day-Ahead Schedule Offer	Real-Time Schedule Offer	Notes
Hourly Economic Minimum Limit	MW	Hourly	Hourly*	1
Hourly Economic Maximum Limit	MW	Hourly	Hourly*	1,5
Hourly Regulation Minimum Limit	MW	Hourly	Hourly*	1,6
Hourly Regulation Maximum Limit	MW	Hourly	Hourly*	1,6
Hourly Emergency Minimum Limit	MW	Hourly	Hourly*	1
Hourly Emergency Maximum Limit	MW	Hourly	Hourly*	1,5
Maximum Off-Line Response Limit	MW	Hourly	Hourly*	1,4,6,8
Energy Dispatch Status	Select	Hourly	Hourly*	1
Regulating Reserve Dispatch Status	Select	Hourly	Hourly*	1,6
Spinning Reserve Dispatch Status	Select	Hourly	Hourly*	1,6
On-line Supplemental Reserve Dispatch Status	Select	Hourly	Hourly*	1,6
Off-line Supplemental Reserve Dispatch Status	Select	Hourly	Hourly*	1,4,6
Hourly Single-Directional-Down Ramp Rate	MW/min	N/A	Hourly*	1,3
Hourly Single-Directional-Up Ramp Rate	MW/min	N/A	Hourly*	1,3

[149] *Ibid.*

Hourly Bi-Directional Ramp Rate	MW/min	N/A	Hourly*	1,3
Hourly Ramp Rate	MW/min	Hourly	Hourly	1,2,3
Single-Directional-Down Ramp Rate Curve	MW/min	N/A	Hourly	3
Single-Directional-Up Ramp Rate Curve	MW/min	N/A	Hourly	3
Bi-Directional Ramp Rate Curve	MW/min	N/A	Hourly	3
Combined Cycle Status	Select	Daily	Daily	
Forecast Maximum Limit	MW	N/A	Rolling 5-Min	7
Ramp Capability Dispatch Status	Select	Hourly	Hourly*	

2.8.7.4.6 Commitment and Dispatch

MISO uses two optimization algorithms, SCUC and SCED, to optimally schedule Resources in a least cost manner to meet the energy balance in its Day-Ahead and Real-Time Markets. Security Constrained Unit Commitment (SCUC) optimally commits Resources in a least cost manner considering Start Up (Shutdown) Offers and No Load (Hourly Curtailment) Offers. Security Constrained Economic Dispatch (SCED) optimally dispatches Resources to operating levels to meet Day-Ahead or Real-Time needs. Both algorithms are employed to simultaneously clear Supply Offers and Demand Bids for each time interval, efficiently allocate transmission capacity to Day-Ahead or Real-Time Schedules by resolving transmission congestion and commit and dispatch Resources at least-cost to meet the Energy and Congestion Management requirements throughout the Operating Day.

(i) DRR-Type I

The figure below shows the operation timeline for DRR Type I.

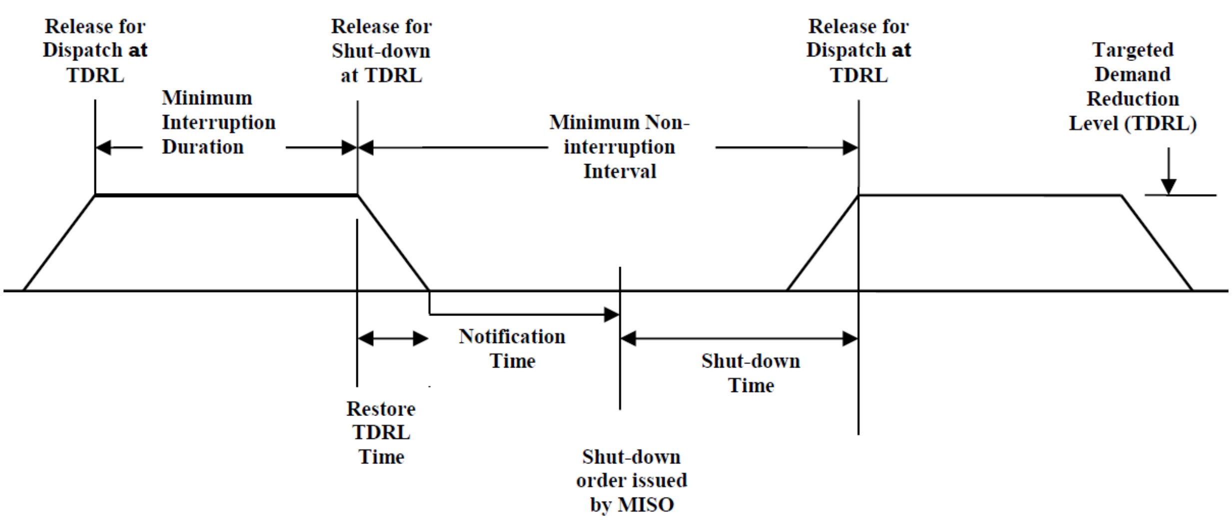


Figure 2-20 DRR-Type I Operation Timeline

(ii) DRR-Type I Commitment Status

The table summarizes how DRR-Type I operating parameters are used in MISO's Day-Ahead Energy and Operating Reserve Market and Reliability Assessment Commitment (RAC) process to commit and economically dispatch these resources.

Table 2-43 DRR-Type I Commitment and Dispatch

Parameter	Validation	Use
Shut-Down Notification Time	The Shut-Down Notification Time parameter is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. These times are accepted in hh:mm format. The default value is 00:00. This value cannot exceed 23:59.	The Shut-Down Notification Time is used in evaluating the commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This parameter, in conjunction with the associated Shut-Down Time, establishes the time required to shut down the Resource at the Targeted Demand Reduction Level.
Shut-Down Time	The Shut-Down Time parameter is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. This time is accepted in hh:mm format.	The Shut-Down Time is used in evaluating commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This parameter, in conjunction with the associated Shut-Down Notification Time, establishes the time required to shut down the Resource at the Targeted Demand Reduction Level.
Minimum Interruption Duration	The Minimum Interruption Duration is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. This time is accepted in hh:mm format.	MISO schedule commitments in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market are for at least as many consecutive hours as specified by Minimum Interruption Duration. Commitment times may be for greater than the Minimum Interruption Duration if a DRR -Type I is economic for additional hours.
Minimum Non-Interruption Interval	The Minimum Non-Interruption Interval is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. This time is accepted in hh:mm format. The default value is 00:00.	The Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market commitments respect the Minimum Non-Interruption Interval in determining when a DRR -Type I is available for shut down.
Maximum Interruption Duration	The Maximum Interruption Duration is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. This time is accepted in hh:mm format. The default value is 99:99.	The Maximum Interruption Duration restricts the number of consecutive hours a DRR -Type I can be committed during the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market.
Contingency Reserve Status	The Contingency Reserve Status is submitted as part of the Day-Ahead Schedule Offer and Real-Time Schedule Offer. Valid entries for Contingency Reserve Status are “online” and “offline”.	The Contingency Reserve Status determines whether the DRR – Type I will be considered to clear and deploy Spinning Reserves, or whether it will be considered to clear and deploy Supplemental Reserves. See Sections 0 and 8.2.9 for more information on the Contingency Reserve Status.

Maximum Daily Contingency Reserve Deployment	The Maximum Daily Contingency Reserve Deployment is submitted as part of the Real-Time Schedule Offer, in MWh.	The Maximum Daily Contingency Reserve is the maximum MWh a Resource is able to deploy as Contingency Reserve over a 24 hour Operating Day of the Real-Time Energy and Operating Reserve Market.

Both a Day-Ahead Schedule Offer and Real-Time Schedule Offer have an associated DRR-Type I commitment status. The commitment status impacts the decisions made in unit commitment. The three commitment status options are:

- Not Participating – Designates the DRR-Type I is not available for Energy commitment in the Energy and Operating Reserve Markets for that Hour but could be available for Contingency Reserve clearing depending on the Spinning Reserve or Supplemental Reserve Dispatch Status.
- Emergency – Designates the DRR-Type I is available for commitment for Energy in Emergency situations only.
- Economic – Designates the DRR-Type I is available for commitment for Energy by MISO.

For a DRR – Type I that is a designated Capacity Resource, the Not Participating Commitment Status is only applicable if that Resource is unavailable due to a forced or planned outage or other physical operating restrictions.

The single value commitment status can vary by hour in the Day-Ahead Schedule Offer or Real- Time Schedule Offer and will override the default status. The default status is set during asset registration. If the MISO SCUC algorithm commits the DRR Type I resource, then because of the on/off property of this asset, it is cleared for energy by definition.

(iii) DRR-Type I Offer Dispatch Status

Dispatch Status for a DRR-Type I can be selected on an hourly basis for Spinning Reserve and Supplemental Reserve (if it is a Spin Qualified Resource), or for Supplemental Reserve (if it is a Supplemental Qualified Resource but not a Spin Qualified Resource).

Spinning Reserve or Supplemental Reserve Dispatch Status selections made in combination with Commitment Status selections allow a DRR-Type I to choose whether or not they can be committed for Energy only or dispatched for Spinning Reserve or Supplemental Reserve only, as applicable, under both normal and Emergency conditions. Valid DRR-Type I Dispatch Status selections are: Economic, Self-Schedule, Emergency, Not Qualified or Not Participating. For a DRR-Type I that is a designated Capacity Resource and is qualified to provide Spinning Reserve and/or Supplemental Reserve, the Not Participating Spinning Reserve Dispatch Status or Supplemental Reserve Dispatch Status is only applicable if such Resource is unavailable due to a forced or planned outage or other physical operating restrictions.

The table below shows the valid Dispatch Status and Commit Status selection combinations to achieve the desired results.

Table 2-44 Valid DRR-Type I Commit and Dispatch Status Combinations

		Normal Operations	**Emergency Operations 1**

Commit Status	Spin or Supp Dispatch Status	Energy Only	Spin/ Supp Reserve Only	Either	None	Energy Only	Spin/ Supp Reserve Only	Either	None
Economic	Economic			X				X	
Economic	Not Participating	X				X			
Economic	Not Qualified	X				X			
Economic	Self-Schedule			X				X	
Economic	Emergency	X						X	
Not Participating	Economic		X				X		
Not Participating	Not Participating				X				X
Not Participating	Not Qualified				X				X
Not Participating	Self-Schedule		X				X		
Not Participating	Emergency						X		
Emergency	Economic			X				X	
Emergency	Not Participating				X	X			
Emergency	Not Qualified				X	X			
Emergency	Self-Schedule			X				X	
Emergency	Emergency				X			X	

DRR-Type I Dispatch status may be selected as part of the Day-Ahead and Real-Time Schedule Offer and will override the default status. The default status value is set during asset registration. For a DRR Type I that is a Spin Qualified Resource, if the MP elects 'not participating' for its Commit Status and either 'economic' or 'self-schedule' for its dispatch status, then the DRR Type I resource can be cleared for Spinning Reserve but the MP will not be guaranteed recovery of any Shut Down Offers because the resource has not been committed by MISO through its SCUC algorithm.

(iv) DRR-Type I Self-Schedule

DRR-Type I resources can only submit Self-Schedules for Energy, Spinning Reserve or Supplemental Reserve in amounts less than or equal to their Targeted Demand Reduction Levels (BPM-002 section 4.2.4.3.4). Submitting a Self-Schedule for Spinning Reserve or Supplemental Reserve will generally ensure that the DRR-Type I resource clears for Contingency Reserve provided that the DRR-Type I has not been committed for Energy. If the Self-Schedule MW value is less than the Targeted Demand Reduction Level, the Resource may clear Spinning Reserve or Supplemental Reserve above the Self-Schedule MW amount, based upon the DRR- Type I Spinning Reserve

Offer or Supplemental Reserve Offer, on an economic basis as part of the Energy and Operating Reserve Markets clearing process. A Self-Schedule is a price taker up to Self-Schedule MW level.

MISO will reduce Self-Schedules if such schedules cannot be physically implemented based upon the submitted Targeted Demand Reduction Level. Additionally, MISO may reduce accepted Self- Schedules as necessary to manage transmission constraints, maintain Operating Reserve requirements, satisfy Energy demand and/or maintain reliable operating conditions. In no case will MISO violate the DRR-Type I operating parameters; consequently, it will either accept the Self-Schedule or de-commit the DRR-Type I resource.

(v) DRR-Type II

Figure 2-21 below presents an Operational Timeline for DRR-Type II resource commitment and dispatch.

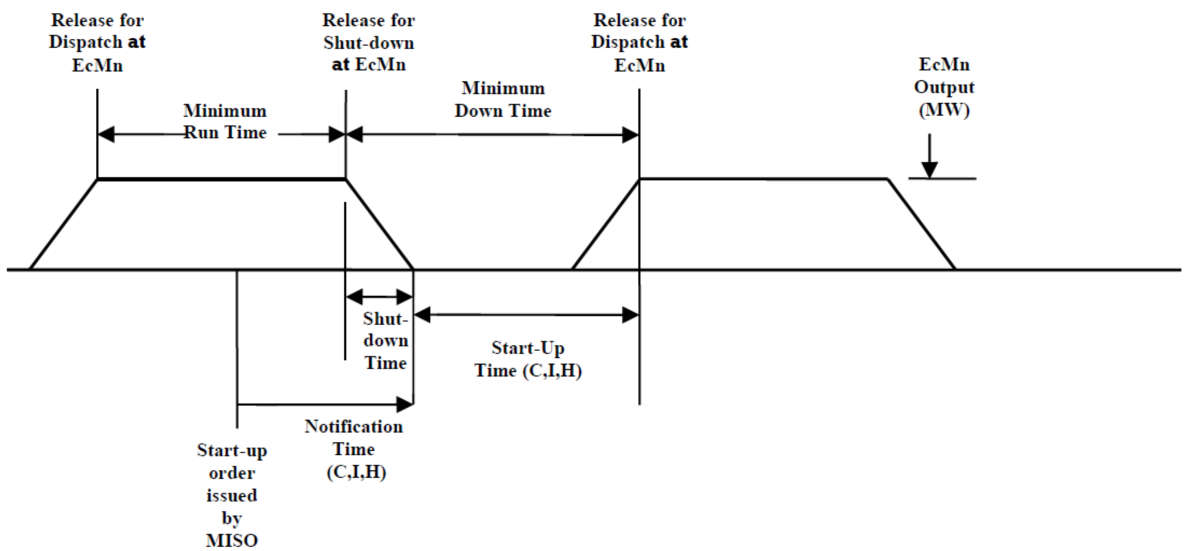


Figure 2-21 DRR-Type II Operation Timeline

The table below summarizes how DRR-Type II operating parameters are used in MISO's Day- Ahead and Real-Time Energy and Operating Reserve Market and Reliability Assessment Commitment ("RAC") processes to commit and economically dispatch DRR Type II resources. Section 4.2.3 of BPM – 002 further describes commitment and dispatch of DRR Type II, similar to generation resources.

Table 2-45 DRR-Type II Commitment and Dispatch

Parameter	Use	Format and Validation
Start-up Notification Time	The Start-up Notification Time is used in evaluating the commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This parameter, along with the associated Start-up Time, establishes the time required for the resource to begin following dispatch instructions to vary its load.	The Start-up Notification Time parameter is submitted as part of the Day-Ahead and Real-Time Schedule Offer. These times are accepted in hh:mm format. These values must be less than or equal to 23:59.
Start-up Time	See Above	The Start-Up Time parameter is submitted as part of the Day-Ahead and Real-Time Schedule Offer. These times are accepted in hh:mm format.

Hourly Economic Minimum Limit	The Hourly Economic Minimum Limit designates the minimum Energy output, in MW, from the Resource under non-Emergency conditions. This value may vary from hour to hour in the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The Overall Economic Minimum Limit affects both commitment and dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Energy and Operating Reserve Market dispatch is from Hourly Economic Minimum Limit to Hourly Economic Maximum Limit under normal conditions.	The Hourly Economic Minimum Limit may be submitted to override the default Offer, for both the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW. This value is expected to be negative, indicating the amount of baseline load when no Energy is cleared.
Hourly Economic Maximum Limit	The Hourly Economic Maximum Limit designates the maximum Energy available, in MW, from the Resource under non-Emergency conditions. This value may vary from hour to hour through submission in the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The Overall Economic Maximum Limit affects both commitment and dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Energy and Operating Reserve Market dispatch is from Hourly Economic Minimum Limit to Hourly Economic Maximum Limit under normal conditions	The Hourly Economic Maximum Limit may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.
Hourly Regulation Minimum Limit	The Hourly Regulation Minimum Limit designates the minimum operating level, in MW, at which the Resource can operate while scheduled to potentially provide Regulating Reserves. This value may vary from hour to hour through submission in the Day-Ahead Schedule Offer and Real-Time Schedule Offer. The Hourly Regulation Minimum Limit does not affect commitment but may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets.	The Hourly Regulation Minimum Limit may be submitted to override the default offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.
Hourly Regulation Maximum Limit	The Hourly Regulation Maximum Limit designates the maximum operating level, in MW, at which the Resource can operate while scheduled to potentially provide Regulating Reserves. This value may vary from hour to hour through submission in the Day-ahead Offer and Real-Time Schedule Offer. The Hourly Regulation Maximum Limit does not affect commitment but may affect Energy dispatch in both the Day-Ahead and Real-Time Energy and Operating Reserve Market.	The Hourly Regulation Maximum Limit may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.
Hourly Emergency Minimum Limit	The Hourly Emergency Minimum Limit designates the lowest level of energy, in MW; the Resource can produce and maintain a stable level of operation under Emergency conditions.	The Hourly Emergency Minimum Limit may be submitted to override the default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.
Hourly Emergency Maximum Limit	The Hourly Emergency Maximum Limit designates the highest level of Energy, in MW; the Resource can produce and maintain a stable level of operation under Emergency conditions.	The Hourly Emergency Maximum Limit may be submitted to override the Default Offer as part of the Day-Ahead Schedule Offer and/or Real-Time Schedule Offer. The data value accepted may be to the tenth of a MW.
Minimum Run Time	MISO scheduled commitments in the Day- Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market are for at least as many consecutive hours as specified by the Minimum Run Time. Commitment times may be for greater than the Minimum Run Time if a Resource is economic for additional hours.	The Minimum Run Time is submitted as part of the Day-Ahead and Real-Time Schedule Offer. This time is accepted in hh:mm format.
Minimum Down Time	The Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market commitments respect the Minimum Down Time in determining when a unit is available for Start-up.	The Minimum Down Time is submitted as part of the Day-Ahead and Real-Time Schedule Offer. This time is accepted in hh:mm format.

Maximum Run Time	The Maximum Run time restricts the number of hours a unit can be run during the Day- Ahead Energy and Operating Reserve Market or during a study period for the Real-Time Energy and Operating Reserve Market.	The Maximum Run Time is submitted as part of the Day-Ahead and Real-Time Schedule Offer. This time is accepted in hh:mm format.
Maximum Daily Starts	The Maximum Daily Starts are the maximum number of times a unit may receive a Start-Up per day during the Day-Ahead Energy and Operating Reserve Market or during a study period of the Real-Time Energy and Operating Reserve Market.	The Maximum Daily Starts are submitted as part of the Day-Ahead and Real-Time Schedule Offer. These times are accepted in integer number of times.
Maximum Daily Energy	The Maximum Daily Energy is the maximum MWh a Resource is able to supply over a 24 hour period during the Day-Ahead Energy and Operating Reserve Market or during a study period of the Real-Time Energy and Operating Reserve Market.	The Maximum Daily Energy is submitted as part of the Day-Ahead and Real-Time Schedule Offer, in MWh.
Maximum Daily Contingency Reserve Deployment	The Maximum Daily Contingency Reserve restricts the amount of contingency reserve that may be deployed on a DRR-Type II in the Real-Time Energy and Operating Reserve Market. It is not used in the Day-Ahead Market or RAC process.	The Maximum Daily Contingency Reserve Deployment limit is submitted as part of the Real-Time Schedule Offer. The format is MWh.
Maximum Daily Regulation Up Deployment	The Maximum Regulation Up Deployment restricts the amount of Regulating Reserve Up that may be deployed on a DRR-Type II in the Real-Time Energy and Operating Reserve Market. It is not used in the Day-Ahead Market or RAC process.	The Maximum Daily Regulation Up Deployment limit is submitted as part of the Real-Time Schedule Offer. The format is MWh.
Maximum Daily Regulation Down Deployment	The Maximum Daily Regulation Down Deployment restricts the amount of Regulating Reserve Down that may be deployed on a DRR-Type II in the Real-Time Energy and Operating Reserve Market. It is not used in the Day-Ahead Market or RAC process.	The Maximum Daily Regulation Down Deployment limit is submitted as part of the Real-Time Schedule Offer. The format is MWh.

2.8.7.4.7 Market Price Determination

This section briefly describes MISO market clearing processes that determine prices in the Day- Ahead Energy and Operating Reserve Markets and the Real-Time Energy and Operating Reserve Markets.

(i) Day-Ahead Markets

Offers for Energy and Operating Reserve submitted to the Day-Ahead Energy and Operating Reserve Markets are simultaneously cleared for each hour of the following Operating Day using SCUC and SCED computer-based algorithms to satisfy the Energy Demand Bids and Operating Reserve requirements of that Operating Day.

The Day-Ahead market clearing process produces hourly ex-ante Locational Marginal Energy Prices (LMPs) at each EPNode and hourly ex-ante Market Clearing Prices (MCPs) at each CPNode for Regulating Reserve, Spinning Reserve, Supplemental Reserve, and the Ramp Capability Product. The pricing algorithm has been enhanced with the Extended Locational Marginal Pricing (“ELMP”) mechanism that allows the cost of committing Fast Start Resources, and the Energy cost of Fast Start Resources dispatched at limits to set prices. It also produces hourly schedules for Energy Demand, Energy supply, Regulating Reserve, Spinning Reserve and Supplemental Reserve, Up and Down Ramp Capability for each Resource that was offered into the Day-Ahead Market. If the 40% constraint on the amount of DRRs that clear Spinning Reserve in the Day-Ahead Market binds, then the MCP for cleared DRRs will differ from the MCP for cleared Generation Resources.

(ii) Real Time Markets

Offers for Energy and Operating Reserve submitted to the Real-Time Energy and Operating Reserve Markets are simultaneously cleared every five minutes using the SCED computer-based algorithm to satisfy the forecasted 5-minute Energy Demand and Operating Reserve requirements of the Real-Time Markets based on actual operating conditions, as captured by MISO’s State Estimator. Similar to the Day-Ahead, the ELMP mechanism allows the cost of committing Fast Start Resources (“FSR”), the Energy cost of Fast Start Resources dispatched at limits and Emergency Demand Response Resources to set price. ELMP also provides the mechanism to introduce emergency pricing, in an ex-post manner, to prevent inefficient price depression during system or local area shortage conditions when MISO utilizes Emergency Resources, including the Emergency range of available resources, Emergency Demand Response Resources, Load Modifying Resources, External Resources that are qualified as Planning Resources or Emergency Energy purchases.

The Real-Time market clearing process produces five-minute ex-ante LMPs for Energy along with five-minute ex-ante MCP values for Regulating Reserve, Spinning Reserve, Supplemental Reserve, and Ramp Capability Product, and five-minute Dispatch Targets for each Resource operating in the Real-Time markets.

The SCED operating in real-time is supported by a Reliability Assessment Commitment (RAC) process that identifies in advance of Real-Time dispatch the need for additional resources to ensure that sufficient capacity will be online to meet Real-Time operating conditions. The RAC process utilizes the same SCUC algorithm employed in the Day-Ahead Markets to minimize the cost of committing the capacity needed to meet forecasted Energy Demand, confirmed Energy Interchange Schedule Exports, and forecasted Operating Reserve requirements.

The RAC process identifies the need for committing additional Resources after the clearing of the Day-Ahead Energy and Operating Reserve Market, after posting the Day-Ahead Markets results but before the start of the Operating day, or anytime during the Operating Day, as required.

Under LMP, DRR Type IIs within their limits can set price. Under ELMP, FSRs and EDRs can set price. Any DRRs can set MCPs for products they are qualified to provide. The BPM for Energy and Operating Reserve Markets (BPM-002), provides more detailed descriptions of how the Day-Ahead and Real-Time Energy and Operating Reserve Markets operate. If the 40% constraint on the amount of DRRs that clear Spinning Reserve in the Real-Time Market binds, then the MCP for cleared DRRs will differ from the MCP for cleared Generation Resources.

2.8.7.4.8 DRR Performance Assessment

Because it is impossible to directly measure the energy that a DRR resource would have consumed in the absence of the dispatch instruction to reduce load, its Demand reductions will be imputed through comparisons between the DRR's Consumption Baseline and its actual hourly metered consumption. Tariff Attachment TT provides detailed M&V criteria.

(i) Consumption Baseline

The selection, development and application of appropriate Consumption Baselines are part of the Measurement and Verification process.

The specific Baseline adopted depends, in part, on the specific product being delivered:

- Regulating Reserve service
- Energy
- Contingency Reserve service
- Capacity

2.8.7.4.9 Regulating Reserve Service

As stated earlier, only DRR-Type II resources are eligible to provide Regulating Reserve service. The Consumption Baseline used to estimate the amount of Regulating Reserve delivered by a DRR-Type II in any 5-minute Dispatch Interval uses the same measurement approach as used by generation resources providing this service.

2.8.7.4.10 Contingency Reserve Service

Contingency Reserve consists of Spinning Reserve and Supplemental Reserve. The Consumption Baselines are identical for both of these reserve products but are different for DRR- Type I and DRR-Type II resources.

A DRR-Type II providing Contingency Reserve service must provide telemetered demand data, scanned at 10-second intervals, to MISO. When a contingency event occurs, the DRR-Type II resource's Consumption Baseline is its telemetered average demand in the 10-second interval just prior to the start of the contingency event. The amount of contingency reserve deployed is then measured by the difference between its Consumption Baseline value and its telemetered demand in the 10-second interval occurring exactly 10 minutes after the start of the event.

The Consumption Baseline for a DRR-Type I resource is different because this resource is not required to provide telemetered data. The measurement and verification of Demand Response Type I Resource output is captured and calculated in the Demand Response Tool. The DRR- Type I Consumption Baseline is its metered demand for the 5-minute interval immediately preceding the start of the contingency event. The amount of contingency reserve deployed is then measured by the difference between its metered demand for the 5-minute interval ending 10 minutes after the start of the contingency event. BLDR Resources (section B.8.7.9 below) have a different measurement for assessing deployment. To the extent that an event starts or ends within a 5-minute interval reading, MISO requires that the Market Participant sponsoring the resource provide the actual load values for a DRR: (a) at the start of the event; (b) at 5 minutes into the event; and, (c) at 10 minutes into the event. The Market Participant should be prepared to provide supporting calculations based on the interval meter readings.

2.8.7.4.11 Energy

Four different generic Consumption Baselines exist for DRRs delivering the energy product:

- Metered Generation
- Calculated Baseline
- Direct Load Control
- Custom Baseline

2.8.7.4.12 Metered Generation

This type of Consumption Baseline only applies to behind-the-meter generation (btmg).For a btmg resource, the Consumption Baseline is the resource's actual metered generation over the hour beginning two hours prior to the hour in which the DRR is initially instructed to reduce load. The DRR's deemed demand reduction in response to a dispatch instruction in any hour is the difference between its metered output and its Consumption Baseline.

2.8.7.4.13 Calculated Baseline

This type of Consumption Baseline only applies to demand resources that actually reduce load. For a demand resource the Consumption Baseline is a profile of hourly demand (for the load behind the DRR asset) based on an averaged sample of historical data which may be adjusted for factors that reflect specific, on-the-day conditions, such as temperature. Unless the Market Participant sponsoring the DRR submits an alternative design for MISO approval, the default Consumption Baseline will be designed as follows:

- Separate hourly demand profiles will be determined for non-holiday weekdays and for weekends/holidays
- The “weekday” hourly profile will be based on the average of the ten (10), but not less than five (5), most recent weekdays that are not holidays or other non-standard “event” days
- The “weekend/holiday” hourly profile will be based on the average of the four (4), but not less than two (2), most recent weekend days or holidays that are not “event” days
- An “event” day is one during which there was, for the resource in question, a real- time energy or ancillary services dispatch, or a scheduled outage
- The maximum look-back window will be limited to 45 days
- If the 45-day window contains insufficient days to meet the minimum number of days described above, the profiles will be constructed based on the available days within the 45-day window that qualify, supplemented by the largest (MW) matching “event” day(s) values for that resource within that same window as necessary to obtain the minimum number of values.

The Market Participant sponsoring a DRR will have the option (at registration) to accept the unadjusted Consumption Baseline or to modify it by applying one of the following adjustment mechanisms:

2.8.7.4.14 Symmetric Multiplicative Adjustment (SMA)

- Adjusts each baseline hourly value (MW) during the event up or down by the ratio of the sum of hourly demands for the three hours beginning four hours prior to the event and (b) the sum of those same three hourly baseline demands.
- The adjustment is limited to a change in any individual baseline hour of plus or minus 20 percent.
- If multiple events occur during the same day, the SMA is calculated only for the first event, but applied to all events that day.

2.8.7.4.15 Weather Sensitive Adjustment (WSA)

- Adjusts each baseline hourly value (MW) up or down by a Weather Adjustment Factor
- The Weather Adjustment Factor is determined by a mathematical relationship derived through a regression analysis that considers the DRR load and historical hourly temperature data.

If the Market Participant sponsoring a DRR wishes to select either of the Adjustments described above or one of the non-default Consumption Baselines, the Market Participant must submit appropriate documentation to MISO for approval. Documentation must be credible and replicable analysis that supports the use of the applicable adjustment. The WSA baseline approach requires a complete, rigorous and defensible study or report that shows the complete statistical methods and analysis used to determine the Weather Adjustment Factor. The SMA baseline approach requires three (3) months of hourly data to be submitted with analysis used to justify the approach. Submitted documentation will be shared with the applicable LSE.

Example calculations of Calculated Baselines are provided in Appendix B: Examples for Existing Baseline Methods for Settlement and Examples of Baseline Adjustments. In addition, Calculated Baselines will not be adjusted for events beginning prior to 5:00 am Eastern Standard Time.

2.8.7.4.16 Direct Load Control

This type of baseline only applies to direct load control (DLC) programs consisting of many small, distributed resources that are not interval metered; consequently, only DRR-Type I resources are eligible.

A DLC Consumption Baseline will be statistically estimated from hourly metered demand data. MISO must approve the specific statistical methodology to be employed before the Market Participant can utilize a DLC Consumption Baseline. The input provided for the DLC Consumption Baseline becomes the performance (demand reduction) for that resource during an Event.

2.8.7.4.17 Custom Baseline

The Market Participant sponsoring a DRR may develop a custom Consumption Baseline if none of the three standard baselines described above would produce reasonable estimates of the resource's demand reductions. MISO must approve of the specific methodology to be employed before the Market Participant can utilize such a baseline. For custom Consumption Baselines, the input provided becomes the Consumption Baseline that will be subtracted from metered amounts to determine performance (demand reduction).

2.8.7.4.18 Capacity

The Consumption Baseline employed to determine a DRR's compliance with an instruction to reduce load during an emergency condition will be the same employed to estimate its delivered energy during normal conditions, i.e., those described in the preceding sections. The performance of Demand Resources in their role as Planning Resources is addressed in Section 2.8.7.6 *Demand Response as a Planning Resource.*

2.8.7.4.19 Metering

All MPs sponsoring DRRs are responsible for providing meter data appropriate to the services being provided. Revenue quality metering and telemetry equipment is required for DRR-Type II in order to support Regulation Reserve requirements. A DRR comprised of btmg must directly meter such generation. All DRRs must possess telemetry capabilities commensurate with the services to be provided. See MISO Tariff Module C section 38.2.5.e for additional detail on metering requirements. In addition, aggregated resources have specific metering requirements, detailed further in the section below on Meter Data Submission Types.

2.8.7.4.20 Meter Data File Formats

This section defines the details of the meter data that must be supplied by Market Participants for uploading settlement and compliance data into the Demand Response Tool system. Settlement and compliance data submitted by Market Participants will be available, through the system, to the LSE.

Two file formats are supported for submission of meter data: daily and interval. The daily file must always have 24 hour-ending (HE) values. The interval file must have sufficient data for the load reduction period and must match the hour, minute, and second of the required intervals. For an enrollment that contains more than one registered location, one set of entries should be provided for each registered location unless otherwise specified. Enrollments that contain virtual locations should provide one set of entries.

The file to be submitted must be of type ".xls". The format of each file is described in the tables below.

Table 2-46 Daily File Format

Column Header Name	Type	Definition	Example
Enrollment	Text preceded "R" or "r"	DRT-generated ID for an Enrollment	R9999

Unique ID	Text	LBA account number assigned to the location	12345
Date	Date format mm/dd/yyyy	Date for which load is submitted	6/15/2021
UOM	Text	Type of meter data submitted	Compliance
UOM	Text	Units of Measurement for meter data, which must always be value-kW (represents integrated energy consumption over the interval)	kW
Type	Text	Type of meter data submitted	See meter data submission types listed below
HE1 through HE24	Integer	Meter value for each hour	100, 83, 89, 93, 99

Table 2-47 Interval File Format

Column Header Name	Type	Definition	Example
Enrollment	Text preceded "R" or "r"	DRT-generated ID for an Enrollment	R9999
Unique ID	Text preceded "R" or "r"	LBA account number assigned to the location	12345
Date	Date format mm/dd/yyyy hh:mm:ss	Beginning Date and Time for consumption over the interval	Compliance
Type	Text	Type of meter data submitted	Compliance
UOM	Text	Units of Measurement for meter data, which must always be value-kW (represents integrated energy consumption over the interval)	kW
Value	Integer	Meter value of the interval	100

2.8.7.4.21 Meter Data Submission Types

This section describes the meter data types that can be submitted for each type of Enrollment program. Various types of meter data are supported:

- Hourly Load: Hourly load data used for economic energy settlements. This information will be used to calculate the baseline and to determine the actual load during an economic Event. In the case of an aggregate enrollment, the load must be provided for each registered location of the aggregate.
- Compliance: Five (5) minute interval data used for compliance. This information will be used to calculate the baseline and to determine the actual load during an Ancillary Service Event. In the case of an aggregate enrollment, the load must be provided for each registered location of the aggregate. Used only for Interval Reading.

- HourlyCBL: Baselines are calculated outside of the DRT system (designated as “Manual” baseline on the enrollment) by the participant. The data submission also requires HourlyLoad for each HourlyCBL provided. In the case of an aggregate enrollment, the aggregate baseline should be provided as a submission for one of the registered locations.
- HourlyGen: Generation meter data will be used to determine the quantity of load reduction. In the case of an aggregate enrollment, there must be generation values for each registered location.
- HourlyDLC: Hourly load reduction based on a statistical sample approved by MISO, the number of active sites controlled, and weather conditions during the event

2.8.7.4.22 Market Settlements

The payments made for DRR performance are treated differently for those sponsored by LSEs serving them at retail than for those sponsored by ARCs. Each treatment is described in the following sections. The reader is cautioned that these descriptions are intended to provide settlement information only in the most conceptual terms. Please consult the BPM for Market Settlements (BPM-005), and associated attachments MS-OP-029 Market Settlements Calculation Guide and MS-OP-031 Post Operating Processor Calculation Guide, for the controlling language, descriptions, and formulas.

Settlements are further complicated by the fact that, while demand resources are compensated at LMP at all times, the cost allocation to pay for such services differ according to a comparison of the LMP with the Net Benefits Price Threshold (NBPT). The NBPT is a single value applicable for an entire month and is posted no later than the 15th of the prior month. See a tab under https://www.misoenergy.org/markets-and-operations/settlements/market-settlements/ for more information. When the LMP equals or exceeds the NPBT, charges for the energy provided are recovered from all other real-time “buyers”[150] within the Reserve Zones that benefit; when the LMP falls short of the NPBT, then the LSE serving the load behind the DRR is charged. This can lead to a variety of possible settlement conditions, and the primary ones are described in the following sections.

(i) LSE-Sponsored DRRs

Currently, most DRRs are sponsored by their LSE. In many states, this arrangement is dictated by state regulatory policy, commission rules, etc. In return for some incentives provided by the LSE, the retail customer may agree to not consume some of the energy it is entitled to purchase through its retail tariff. Since the DRR is sponsored by its LSE, there are fewer net settlement issues.

Day-Ahead Energy and Operating Reserve Market Settlements – For DRR Energy that is cleared into the Day-Ahead Energy and Operating Reserve Market, LMP will be paid to the MP with the DRR by purchasers in the day-ahead market. From a settlement perspective, DRR Energy is indistinguishable from energy provided by other resources.

For a DRR providing Operating Reserve, the MP will be credited for the Day-Ahead cleared Regulation Amounts, Spinning Reserve Amounts, and Supplemental Reserve Amounts multiplied by the applicable Day-Ahead hourly

[150] A real-time “buyer” is a Market Participant who purchases power in real-time without an offsetting purchase in the day-ahead market. For example, if an LSE schedules 100 MWh in day-ahead and consumes 105 MWh in real-time, it would be a real-time “buyer” of 5 MWh. Note that resources may also be real-time “buyers” in order to cover day-ahead positions not fully provided in real-time.

MCPs. MCP will be paid to the MP with the DRR by purchasers in the day-ahead market of the same Reserve Zone.

Real-Time Energy and Operating Reserve Market Settlements – In the Real-Time Energy and Operating Reserve Market, each LSE will be credited (or charged) for Energy based upon the incremental difference between its real-time energy transactions and its Day-Ahead scheduled energy transactions multiplied by the applicable Real-Time LMPs.

The LSE with the DRR will be unaffected when the LMP is below the NBPT, as the credit for the DRR reduction is exactly offset by an identical charge for that same amount of energy. From the LSE's viewpoint, it simply buys less net energy. For example, the LSE might schedule the purchase of 100 MWh (including the amount the DRR would have used) in day-ahead. In real-time, other usage is as-predicted, except for the DRR that "provides" 5 MWh (its load reduction). In this case, the LSE would simply receive payment for the 5 MWh (the net position). However, the MP with the DRR may also receive a "make whole" credit equal to that needed to fully recover the DRR's Production Cost if the LMP revenues do not recoup such costs and the DRR was committed by MISO through the SCUC process. Production Cost is the sum of the DRR's Shutdown Offer(s) plus the sum of its hourly Curtailment Offers plus the sum of its hourly Energy Offers.[151]

When the LMP equals or exceeds the NBPT, then the LSE will be credited for the full amount of the DRR reduction, while only being charged its pro-rata share across all buyers of the Reserve Zones that benefit. Ignoring this relatively small charge, the LSE effectively benefits in two ways: first, it will only be charged for the amount of energy actually consumed (95 MWh in the example above); second, it will in addition receive a credit for the 5 MWh reduction.

For Operating Reserve, the MP will be settled based upon the incremental difference between the DRR's Real-Time cleared Operating Reserve and its Day-Ahead scheduled Operating Reserve multiplied by the applicable RT MCPs. For DRRs not committed by MISO as part of its SCUC process, clearing Spin Reserve Service and deployed during a Contingency Reserve Deployment (CRD) event, credits will be entirely based on the applicable LMP at its CPNode. No make whole payments will be made for the MWs deployed during the dispatch intervals for the CRD event, regardless of hourly curtailment offers exceeding LMPs. By eliminating these make- whole payments, the Market Participant is allowed to add the expected cost of deployment in excess of expected Market revenues (net cost of deployment) to its Spinning Reserve Offer through a probabilistic cost adder by multiplying the Market Participant's expected possibility of deployment by the net cost of deployment. Incorporating deployment risk into the Spinning Reserve Offer will more accurately reflect the cost of selecting and deploying these resources during a CRD Event, which provides for better alignment with Market-based procurement of Spinning Reserves.

Additional charges related to system reliability, asset performance, Operating Reserve and the distribution of system losses are also settled in the Real-Time Energy and Operating Reserve Market.

[151] The terms, "ShutDown Offer" and "Curtailment Offer," when applied to a DRR mean, respectively, its price to be available to initiate load reduction when instructed, and its hourly price to maintain its load reduction, when instructed. Note that a DRR may incur multiple shutdown costs if it is released from commitment, then recommitted at a later time.

(ii) ARC-Sponsored DRRs

The settlement procedure for ARCs works in the same way described above for LSEs, except that the MP receiving payments or charges related to the DRR is the ARC, not the LSE. For certain market charges (e.g., Revenue Neutrality Uplift), the LSE's Real-Time energy purchases will be adjusted to reflect the RT energy reductions of the DRR.

2.8.7.5 Emergency Demand Response

The Emergency Demand Response Initiative is established in Schedule 30 of the Tariff and is designed to encourage Market Participants that have demand response capabilities available to them to offer those resources to MISO for use during North American Electric Reliability (NERC) Energy Emergency Alert 2 ("EEA2") or Energy Emergency Alert 3 ("EEA3") events. EDR resources are only dispatched during such events in response to dispatch instructions from MISO. LMRs are eligible to provide EDR service but must include a one-to-one relationship between the registration of an LMR and an EDR.

In addition to encouraging demand response participation, the EDR Initiative provides information MISO needs to commit and dispatch available EDR resources in economic merit order, i.e. by first curtailing those loads that customers value the least (or dispatching btmg with the lowest production costs) and progressively curtailing loads of increasing value (or btmg with increasing production costs) until the target level of demand reduction has been achieved. Such an efficient dispatch will minimize Market Participants' total costs of responding to Emergency Events.

When an EEA2 or EEA3 Event is imminent, MISO will develop a schedule of EDR Dispatch Instructions based on the information provided in the EDR offers for that Operating Day. After the Event has been declared, MISO will send EDR Dispatch Instructions to the affected MPs who will then be solely responsible for compliance using the EDR resources they offered.

After the Emergency Event ends, the responses of each EDR resource to its EDR Dispatch Instructions will be measured by comparing the resource's metered hourly loads (or net output of btmg) with its Consumption Baseline (or its generation baseline for btmg). The methodology used to determine Consumption Baselines is discussed below.

Each Market Participant will be compensated for the net demand response reductions its EDR resource delivered in response to their EDR Dispatch Instructions, but not for excess reductions, and will be exempt from related RSG Charges. Any Market Participant whose EDR resources do not fully comply with their respective EDR Dispatch Instructions will be assessed a penalty as described later.

MISO will recover the total payments made to Market Participants with dispatched EDRs in any Hour, net of any noncompliance penalties collected for that Hour, from the LSEs located in the Local Balancing Authority Area(s) where the Emergency Event(s) occurred in that Hour. Thus, these payments will be recovered from the parties that benefit most from the demand reductions that gave rise to the payments.

2.8.7.5.1 EDR Characteristics

A Market Participant may participate in the EDR Initiative if it controls a resource that can either: reduce Loads (either by reducing demand by a fixed number of MW or by curtailing use to a fixed target amount) in response to a request from MISO; or increase the outputs of btmg resources beyond what they would normally produce, in response to receiving EDR Dispatch Instructions from MISO. In addition, the Market Participant must be able to receive EDR Dispatch Instructions from MISO via an Extensible Markup Language (XML) interface, as more fully described in section. Lastly, a Market Participant must be able to provide integrated hourly energy consumption data on a CPNode basis.

2.8.7.5.2 EDR Offers

When an EDR resource is first registered, the Market Participant sponsoring it will submit a default EDR Offer, which will remain valid until updated. MPs may submit updated offers at any time prior to DA Market Close for application to the following Operating Day. All Offers are applicable to every hour of the day and will remain valid until modified or revoked by the Market Participant. Updated Offers may take the form of a declaration that the EDR resource will be unavailable for interruption until a new Offer is submitted.

Table 2-48presents the information that a valid EDR Offer must contain. If any of these data elements are missing in the Offer submittal, MISO will substitute the corresponding data elements from the previous Offer.

Notes for the table below:

- Note 1. Reductions must be expressed in increments of 0.1 MWh per hour.
- Note 2. Enter either Maximum Demand Reduction or Reduction to Firm Load Level – not both.
- Note 3. Curtailment Price cannot exceed $3,500 per MWh.

Table 2-48 EDR Resource Offer Data

Data Element	Unit	Note
Maximum Demand Reduction	MW	1,2
Reduction to Firm Load Level	MW	1,2
Curtailment Price	$/MWh	3
Shutdown Cost	$	
Advance Notification	hh:mm	
Interval when Reduction is Available	hh:mm to hh:mm	
Minimum Down Time	hh:mm	
Maximum Down Time	hh:mm	
Daily Availability	Yes/No	
Any Temporary Limitations	Text Field	

EDR resources are not subject to the usual must-offer obligations because participation in the EDR Initiative is voluntary. However, any EDR resources that also qualify as LMRs under Module E-1 of the Tariff will have a must-offer obligation during MISO-declared Emergencies and thus cannot declare the portion of load that is an LMR as unavailable for curtailment.

2.8.7.5.3 Commitment and Dispatch

On a day when an Energy Emergency Alert (EEA 2) is anticipated, MISO will use the data in EDR Offers valid for that day to develop EDR Dispatch Instructions that minimize customers' total collective costs of achieving the load reductions needed to offset the supply resource shortfall. Typically, this will produce EDR Dispatch Instructions that call on EDR resources in order of their increasing EDR Production Costs, which consists of the EDR resource's Curtailment Cost (dispatch price multiplied by expected MWh curtailed) and its Shutdown Cost (or its one-time Startup Cost for btmg). However, because the EDR curtailment schedules are based on constrained optimizations that account for EDR resource inflexibilities and other operating constraints, including their location on the transmission grid, they may not reflect simple, monotonic rankings of EDR Production Costs.

Each Dispatch Instruction will include the following information:

- Hour the demand reduction is to commence
- Amount of demand reduction or the firm load level to be achieved
- Schedule of incremental changes to the reduction level, if any
- Duration of each demand reduction level

Dispatch Instructions and all other communications between MISO and Market Participants with EDRs will be via XML interface.

2.8.7.5.4 EDR Performance Assessment

As with other forms of demand response, an EDR resource's demand reductions must necessarily be imputed through comparisons between its metered hourly consumption and its Consumption Baseline.

2.8.7.5.5 Consumption Baseline

The Consumption Baseline is the actual usage of the facility containing the EDR resource in the Hour prior to the start of the instructed demand reduction.

For EDR resources that are under direct load control, the Market Participant must provide: a description of the direct Load control system, a description of Load Research data used in the measurement and verification analysis, a description of the methodology used to produce the estimate, and a description of all source information for the variables used in the analysis.

2.8.7.5.6 Metering

All MPs sponsoring EDR resources are responsible for providing meter data for the Hour prior to the start of the reduction and for every Hour in which the reduction occurred. This can be done through a third-party Meter Data and Management Agent (MDMA). MDMAs must provide meter data to MISO prior to noon EST of the 53rd day after the Operating Date. Along with a record of its meter readings, Market Participants utilizing on-site generation must also provide a written statement from the Market Participant certifying that the Demand reductions were made in response to MISO's EDR Dispatch Instructions and that they would not otherwise have occurred.

2.8.7.5.7 EDR Market Settlement

Market Participants with a registered EDR are compensated at the higher of the revenues resulting from hourly LMPs (i.e., applying the hourly Real-Time LMPs at each EDR resource's CPNode to the resource's instructed hourly demand reductions), or the EDR resource's Production Costs for the total period of reduction. EDR Production Costs are defined as the shutdown cost plus the lesser of the amount of hourly Demand reduction or the hourly Dispatch

Instruction, multiplied by the EDR Curtailment Price applicable to the period of actual Demand reduction.

To qualify for compensation an EDR resource must comply with MISO's EDR Dispatch Instructions. If an EDR resource reduces its Demand by an amount that exceeds the reduction level specified in the EDR Dispatch

Instruction, it will only be compensated for the amount specified in the MISO Dispatch Instruction. However, the MP will not be subjected to RSG charges for its excessive reductions.

Payments made in excess of market revenue will be funded on pro rata basis via Load Ratio Share to Market Participants in the Local Balancing Authority Area(s) where the Emergency event occurred.

Meter data is required within 53 days following the Operating Date of the Emergency event. Settlement will occur on the relevant applicable settlement statement after submission of meter data.

2.8.7.5.8 Penalty for Underperformance

An EDR resource that reduces Demand in any Hour by less than the amount specified in the EDR Dispatch Instruction will be fully compensated if the reduction is not less than the Demand Reduction Tolerance level (which is set equal to 95 percent of the EDR Dispatch Instruction amount) for that Hour. An EDR resource that reduces demand by less than the Demand Reduction Tolerance level will be charged an amount equal to the Demand Reduction Shortfall multiplied by the Real-Time LMP of the load zone in which the EDR resource is located. The Demand Reduction Shortfall is equal to the Demand Reduction Tolerance minus the actual Demand reduction, or zero, whichever amount is greater. Failure to reduce demand at a level higher than the Demand Reduction Tolerance level will also result in a loss of guaranteed cost recovery.

Revenue collected from the underperformance penalty will be distributed pro rata via Load Ratio Share to Market Participants in the Balancing Authority Area(s) where the Emergency event occurred.

2.8.7.6 Demand Response as a Planning Resource

Module E-1 of the Tariff defines a Load Modifying Resource (LMR) as a Demand Resource or BTMG that satisfies the requirements for being a Planning Resource. An LMR is not required to be a Network Resource[152]. An LMR need only be available for interruption during Emergency Events. The Emergency Operating Procedures (e.g., SO-P-EOP00-002 and SO-P-EOP-00-004) describe how and when LMRs will be called during an Emergency Event.

LMRs may also qualify as Emergency Demand Response (EDR) resources by meeting the requirements in Schedule 30 of the Tariff. LMRs may also participate in Planning Resource Auctions as briefly described later in this BPM. More detailed information regarding LMR participation under Module E-1 is contained in BPM-011 Resource Adequacy.

Each LMR must be registered, reviewed, and approved annually by MISO in advance of receiving capacity accreditation as a Planning Resource. Only Market Participants may register LMR and this process is completed by accessing the Module E Capacity Tracking (MECT) tool through the secure Market Portal.

2.8.7.6.1 Utilization of LMR Capacity

LMR capacity has value because it can be used to meet the Planning Reserve Margin Requirement (PRMR) of an LSE. The Market Participant registering the LMR (either the LSE or an ARC) may choose to treat an LMR as a Planning Resource for conversion into Zonal Resource Credits (ZRCs). When such treatment is requested (and

[152] Excess BTMG – the unforced capacity of an LMR BTMG in excess of an LSE's PRMR, can participate in the PRA as long as it demonstrates deliverability since it represents a net injection onto the transmission system Deliverability can be demonstrated by being granted commensurate Transmission Service or Interconnection Service. LMR DRs have no deliverability requirement. See the BPM for Resource Adequacy.

accepted) the LMR's accredited capacity will be entered into the MECT and the Market Participant can use these ZRCs to meet its PRMR, offer them into the PRA or trade these ZRCs with other MPs.

2.8.7.6.2 LMR Performance Assessment

Following an Emergency Event in which a LMR was instructed to curtail its load, the Market Participant that registered the LMR will collect data needed to perform the calculations comparing the LMR's actual load with a Consumption Baseline adopted at the time of registration and subsequently updated as needed. The Market Participant will certify the results of this analysis and submit them to MISO via the Demand Response Tool (DRT). MISO will use these results to determine if the LMR reduced by the targeted MW level (or to a specified firm service level if applicable), when called upon to do so by MISO. Additional details are available in Tariff Attachment TT. Each LMR will be evaluated on its individual performance and not in aggregate across a Market Participant's portfolio.

(i) Consumption Baseline

The Consumption Baseline for a DR will be the expected value of the DR's average hourly load, rounded to the nearest kWh, for each of the 24 hours in a day. A Consumption Baseline is required for each DR that is included in an LSE's Resource Plan. A default Consumption Baseline will be calculated for each hour in a day, as being the simple averages of hourly meter data from the ten business days prior to an Emergency Event. See attachment TT of the Tariff for additional details. The default baseline procedure will be used unless the Market Participant proposes an alternative Consumption Baseline procedure at the time it registers the DR, and it is accepted by MISO. For an LMR that agrees to reduce load to a specified level, its demand reduction will be the difference between its Consumption Baseline and the specified level.

Following an Emergency Event in which the LMR resource was deployed, the Market Participant that registered it shall collect and provide the hourly meter data to calculate the resource's Consumption Baseline in the Demand Response Tool and submit them to MISO within 53 days from the time the resource was deployed. MISO will review these metering data to verify that the Demand Resource reduced load by the targeted MW level, or to a specified firm service level, when called upon by MISO.

(ii) Metering

BTMG consisting of one or more generating units that have been identified by MISO must have metering equipment for operational security purposes. BTMG consisting of multiple generating units at a single site that have been identified by MISO must have metering equipment but may be metered as a single unit, in which case they will be treated as a single unit for purposes of LMR performance evaluation.

2.8.7.6.3 LMR Settlements

LMRs interact with MISO Settlements process in two ways:

- MPs trading ZRCs associated with an LMR that clears in a Planning Resource Auction are paid or charged based on the market clearing prices as established in the auction.
- If an LMR does not meet the Measurement and Verification protocol selected during registration (reduced by the targeted MW level or to a specified firm service level if applicable) during Emergency Events, the Market Participant that registered it may be penalized.

(i) Planning Resource Auction Settlements

MISO will settle each Planning Resource Auction (PRA) by charging the applicable Auction Clearing Price (ACP) for that Planning Year to MPs with PRMR and crediting the applicable ACP to MPs with cleared ZRC offers. The invoice credit will be available through the Market Portal daily during the Planning Year.

(ii) Penalty for Nonperformance

Unless the LMR is unavailable as the result of maintenance or for reasons of Force Majeure, the Market Participant representing the LMR will be penalized when the LMR fails to perform as instructed during an Emergency Event. See Tariff, section 69A.3.9 of Module E-1. However, no penalties will be assessed if an LMR is unavailable for interruption due to its Load being off the Transmission System for external reasons, or if the targeted Demand reduction had already been achieved for other reasons (e.g., economic considerations or local reliability concerns). MISO will credit the proceeds of LMR penalties to only those MPs representing the LSEs in the LBA area(s) that experienced the Emergency that triggered the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. An LMR, unavailable or unresponsive for reasons other than exempted by MISO, could be disqualified from participation for the rest of the Planning Year. Disqualification results in removal of ACP payments. In addition, the MP will be charged the ACP for the remainder of the Planning Year, and proceeds will be redistributed pro rata based on the LSE's PRMR in the LRZ. Additional details can be found in Section 69A.3.9 of Module E-1.

2.8.7.6.4 LMRs that dual-register as EDRs

Resources that register both as an LMR and an EDR have the following characteristics: a one-to- one relationship must occur between the registration of an LMR and an EDR; and the exact same end-use accounts must make up the defined LMR and EDR. At the current time, separate registration processes are required to dual-register the resource. All the requirements and characteristics specified in Section 2.8.7.3.1 *Registration as a Market Participant* above under LMRs must be met. For example, the joint LMR/EDR resource must meet the specified availability and notification times, and minimum run times as registered under LMRs in Section B.8.7.3.1. ARCs that dual-register resources must meet the requirements, as specified in Section *2.8.7.3.2 Registration as an Aggregator of Retail Customers (ARCs)* above, separately for both the EDR and LMR registrations. In addition, by registering as an EDR, the Market Participant can submit EDR Offers and must be able to receive EDR Dispatch Instructions via XML. Commitment and Dispatch will occur as specified as part of the SO-P-EOP00-002 and SO-P-EOP-00-004Emergency process. There can be only one selected Consumption Baseline for a dual-registered LMR/EDR resource. Payment for performance is based as specified under the EDR Initiative; any shortfall charges are based on the LMR paradigm. LMRs should not report their availability in the DSRI for days when they have active EDR Offers. It is the responsibility of the Market Participant to ensure there is no double counting of MWs offered across the dual registration types. Double counted MWs may be subject to underperformance penalties.

2.8.7.7 Resource Testing

To participate in MISO markets each resource must demonstrate its ability to interrupt load within a prescribed time limit after being instructed to do so. The prescribed time limit will depend on the particular service the resource is being qualified to provide.

2.8.7.7.1 DRR-Type I

DRR resources must provide information similar to what is provided by generating resources, including submission of data through the GADS or DADS, as appropriate. Annual testing and verification are required. Details may be found in the BPM for Energy and Operating Reserve Markets (BPM-002).

2.8.7.7.2 DRR-Type II

See DRR Type I above.

2.8.7.7.3 EDR Resources

There are no ex-ante resource testing requirements applicable to EDR resources unless the resource is dual registered as an LMR; such resources are measured and verified during the Emergency Events to which they respond.

2.8.7.7.4 Load Modifying Resources

(i) Demand Resources

Market Participants with Demand Resources should demonstrate a real power test for capacity accreditation. The real power test of a Demand Resource may be from a MISO called event or a self-scheduled implementation in accordance with section 4.2.9.8 of BPM-011 Resource Adequacy. If a Demand Resource test is not performed for accreditation, additional options outlined in BPM-011 Resource Adequacy section 4.2.9 may be utilized.

(ii) BTMG

BTMG capacity accreditation generally follows the same documentation requirements of generating resources. BTMG greater than 10 MW must submit performance and event data to GADS as well as an annual Generation Verification Test Capacity (GVTC). BTMG below this limit are only required to submit an annual GVTC and can accept the class average EFORd assigned to the unit type by MISO. Additional details regarding BTMG testing requirements may be found in BPM-011 Resource Adequacy Section 4.2.8.

2.8.7.8 Credit Requirements

MISO's Credit Policy requires all Market Participants to have an approved credit application and an established Total Credit Limit with MISO Credit Department. Attachment L of the Tariff describes in detail how MISO will determine a Market Participant's Total Credit Limit requirement as well as the procedures it will follow in evaluating the Market Participant's creditworthiness. It also contains all of the requisite forms and describes the procedures for a Market Participant to follow to establish its Total Credit Limit. Attachment L of the Tariff is available on MISO website: https://docs.misoenergy.org/legalcontent/Attachment_L_-_Credit_Policy.pdf

The remainder of this section briefly describes how MISO will determine the increase to a Market Participant's Total Credit Limit requirement contributed by the product offered by a given demand resource.

2.8.7.8.1 Economic Energy

As a supplier, the credit requirements for a new MP with a DRR are based on two factors: the amount of energy (MWh) that can be produced from the resource in an hour, and the historical average day-ahead LMP for the appropriate CP Node. The formula used to determine the credit requirement (in dollars) is the product of: (a) the maximum MWh value just described; (b) 600 hours, times; (c) the historical average LMP for the preceding three-month period, times; (d) 5%. For example, if a given DRR resource could produce 1 MWh in an hour and the historical average LMP was $30/MWh, the credit requirement would be equal to 1 × 600 × 30 × 5%, or $900.

This credit requirement is reduced for ARCs as specified in Attachment L of the Tariff. See Attachment L for credit conditions for existing certified MPs.E

2.8.7.8.2 Operating Reserve Services

Credit requirements for Operating Reserve Services are included in the credit requirements for Economic Energy. No additional credit requirements are applicable.

2.8.7.8.3 Emergency Demand Response

There are no additional credit requirements related to the provision of EDR service. Please see Attachment L of the Tariff for general credit requirements.

2.8.7.8.4 Planning Resources

There are no additional credit requirements related to the offer of Planning Resources (LMR) unless a Market Participant with a Demand Resource has waived its obligation to conduct a real power test per Tariff Section 69.A.3.5.j as described above in Section 2.8.7.3.1 *Registration as a Market Participant* of this document.

2.8.8 BATCH LOAD DEMAND RESPONSE

This section describes the business rules governing Contingency Reserves provided by Batch- Load Demand Response (BLDR) resources.

A BLDR resource is a load caused by a cyclical production process. During most of its duty cycle the load consumes energy at some nominal level but periodically reduces load for a short interval, typically less than 10 minutes. The following figure illustrates the actual consumption pattern of one such load in the MISO footprint.

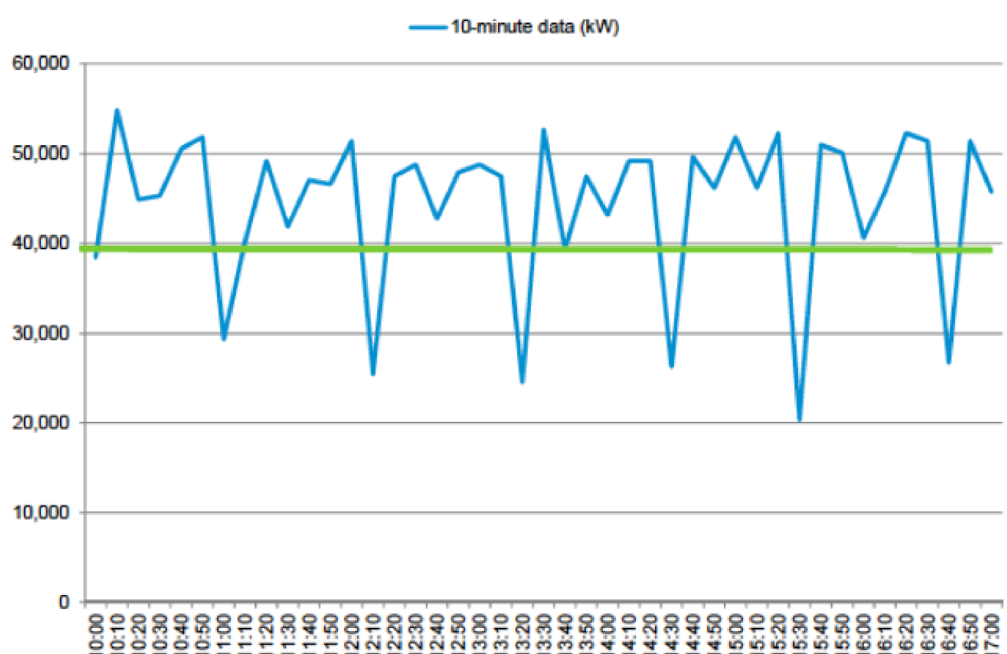


Figure 2-22 Batch Load Consumption Pattern of One MISO Market Participant

The MISO Tariff currently requires Contingency Reserve products to fully deploy their cleared Contingency Reserve within the 10-minute period (Contingency Reserve Deployment Period) following receipt of a MISO deployment instruction, as prescribed in ERO Standard BAL 002-0. In contrast with other Contingency Reserve assets, a BLDR resource may be capable of releasing little or no energy within the mandatory Contingency Reserve Deployment Period if it receives the MISO dispatch instruction while its load is not at the "top" of the cycle, as illustrated in the figure below. Nonetheless, by remaining at the bottom of its cycle, the BLDR resource helps MISO in meeting the BAL standard by not exacerbating the ACE deviation, which it would do if it resumed operations of its batch load process. This latter effect must be weighed when evaluating the resource that, most of the time, could release significant amounts of energy to assist MISO in responding to a contingency event.

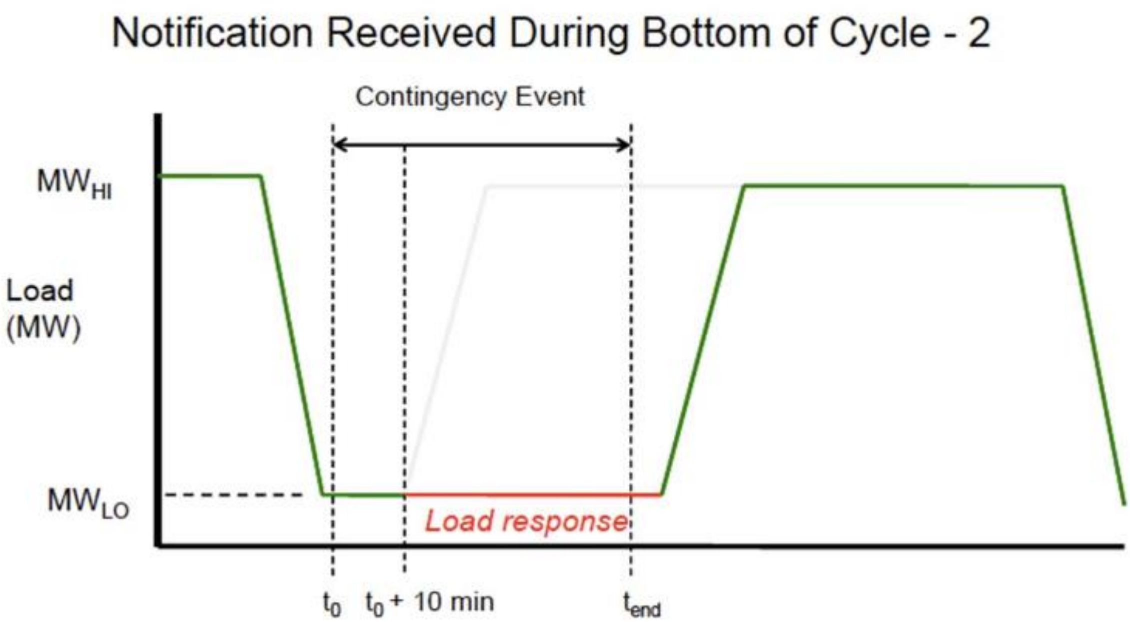


Figure 2-23 Operating Reserve Energy to Deliver

Because it is impossible to know *ex ante* where a BLDR resource will be when instructed to deploy its Contingency Reserve, the best that can be done is to credit the resource with the expected value of the amount of that reserve. Each BLDR resource will be responsible for estimating this expected value at the start of each day during which it offers Contingency Reserve into the market and will offer no more Contingency Reserve than that expected value amount.

When a BLDR resource is instructed to deploy its Contingency Reserve, it is also obligated to maintain its energy reduction until the contingency event ends.

The inability of any single BLDR resource to fully deliver the expected value of its Contingency Reserve will not impact MISO if the resource represents a small portion of total cleared Contingency Reserve. This will also be true if no single BLDR resource represents a large portion of a portfolio of BLDR resources whose duty cycles are relatively uncorrelated in time, because the diversification effect will drive the portfolio's performance toward deploying an amount of Contingency Reserve that approximates the expected value of its total cleared Contingency Reserve.

2.8.8.1.1 Registration and Scheduling Contingency Reserve from BLDR Resources

Market Participants desiring to register a DRR Type I as a BLDR resource will have to so indicate during the registration process. Qualifications for using this M&V approach include submittal of the most recent three months of 5' interval data and the asset being at its low duty cycle no longer than 10'. MISO will review the submitted data to decide whether to approve this M&V method. This baseline method is only available for contingency reserve assessment and not energy. After registration, the mP must retain a rolling three months of 5' interval data that MISO can audit at any time.

At the current time, there is a 40% cap on using Demand Response Resources for provision of Spinning Reserve service. BLDR procurement will be included in the 40% cap imposed in the Spinning Reserve market. If the total amount of Operating Reserve provided by all BLDR resources is small (e.g., less than 10 percent) the selection of BLDR is a non-issue. As Table 2-35 shows, a large BLDR load might offer about 30 MW of Spinning Reserve to the market, which is well below the 40 percent limit; however, if many BLDR loads begin offering Spinning Reserve, the total amount could easily get capped at the 40 percent limit.

On the positive side, aggregating BLDR loads will have the combined effect of diversifying away the likelihood that all, or most, loads are at the bottom of their cycles when called to deploy their energy. As the number of BLDR loads increases their combined response to a contingency event, the combined response ability will approach a normal distribution whose expected value of the total Contingency Reserve that will be deployed is equal to the sum of the expected values of the Contingency Reserve that will be deployed by each BLDR resource.

MISO's current Tariff allows the system operators to adjust the amounts of Contingency Reserve they procure based on contemporaneous system conditions. The current business rule is to place BLDR procurement under the 40% cap that currently exists in the spin market. The Supplemental Reserve market has no such caps.

2.8.8.1.2 Measurement and Verification of BLDR Contingency Reserve

BLDR resources are a special category of DRR Type – I resources. The current Tariff requires all DRR Type-I resources to provide 5-minute interval data to MISO no later than five (5) days after the end of the contingency event. This data must span the period starting five (5) minutes prior to when the contingency event began and ending at least 60 minutes later.

The DRR-Type I Consumption Baseline is its metered demand for the five (5)-minute interval immediately preceding the start of the contingency event. The amount of Contingency Reserve deployed is then measured by the difference between its Consumption Baseline value and its metered demand for the five (5)-minute interval ending ten (10) minutes after the start of the contingency event. If this M&V methodology is applied to a BLDR resource that is at the bottom of its duty cycle when it receives MISO's deployment instruction, the resource will be in noncompliance and will have little incentive to suspend its cyclical production process. Suspending production provides value to MISO because it assists in controlling the ACE. In addition, it could also bring about an earlier end to the contingency event. For these reasons, a separate M&V methodology is needed for BLDR resources.

If the resource ramps down to its minimum demand and remains at that level until the end of the contingency event, it will be in full compliance. To make this assessment, MISO requires a snapshot of the BLDR resource's normal consumption pattern. In such cases, the resource's eligible amount of deployed Contingency Reserve will be the smaller of the difference between the resource's demand for the five (5)-minute interval immediately preceding the end of the contingency event and: 1) its demand for the five (5)-minute interval beginning ten (10) minutes immediately following the end of the event; or, 2) the 50% trimmed mean of the five (5)-minute intervals for the three (3) hours immediately following the Contingency Reserve Deployment Period.

The Market Participant sponsoring a BLDR may develop a custom Consumption Baseline if the above approach would not produce reasonable estimates of the resource's demand reductions.

Example:

Demand 10-min. following end of dispatch =	43 MW
Demand during dispatch =	30 MW
Calculated response =	43 – 30 = 13 MW
50% trimmed mean for the next 3 hours =	45 MW
Demand during dispatch =	30 MW
Calculated response =	45 – 30 = 15 MW

13 MW < 15 MW; 13 MW response

How this would work: The "trimmed" mean removes X% of the largest and smallest values from the data. This has the effect of reducing the impact of "outliers". As part of an M&V protocol, this technique would remove the cyclic lows and any dispatch down. This method would also remove the highest values that are probably not reflective of typical demand. See illustration below.

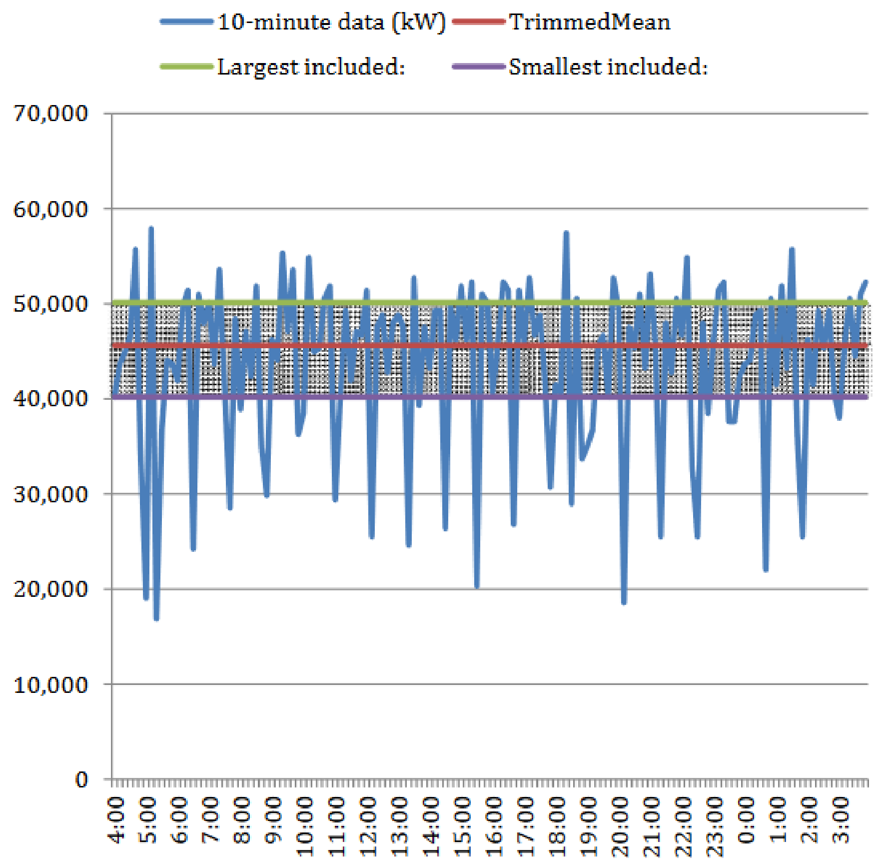


Figure 2-24 Consumption Trimming

2.8.8.1.3 Compensating BLDR Resources for Contingency Reserve

A BLDR resource will receive compensation comparable to that which a DRR Type – I resource would receive for its capacity and energy. The current Tariff compensates a DRR Type – I resource for being available to provide Contingency Reserve through capacity payments. In addition, when the resource reduces its load as instructed, it received energy payments for its foregone energy. This same compensation will apply to BLDR resources.

2.8.8.1.4 Underperformance Penalties

The underperformance penalties that currently apply to DRR Type – I resources will apply to BLDR resources when they are out of compliance. However, as stated earlier, a BLDR resource cannot control where it will be in the duty cycle when it receives a deployment instruction, so it should not be deemed out of compliance based solely on the amount of Contingency Reserve capacity it actually delivers. The resource will only be out of compliance if it fails to take action to shut down or resumes its batch load operation during the Contingency Reserve Deployment Period after receiving a deployment instruction. Table 2-35 and Figure 2-19 illustrate this situation. Although the resource deploys no Contingency Reserve energy, it is in compliance because none was available for deployment when the resource received the instruction to deploy. The resource would also be in compliance if some Contingency Reserve was available and all of that was deployed.

2.9 Protocols and Guidance for Establishing Quality Assurance / Quality Control for Programs

Continuous improvement in the operation of energy efficiency and demand response programs requires that procedures for quality assurance and quality control be put in place and applied continuously in real time.

- Quality Assurance (QA) are standards to promote consistency and minimize errors are developed and applied during the planning and design of a program.
- Quality Control (QC) activities are conducted continuously in real time to ensure that programs are being implemented and operated according to set quality standards.

2.9.1 QA/QC PROTOCOL 1: APPROACH TO QUALITY ASSURANCE

Quality Assurance activities occur throughout a program's lifecycle to ensure that program processes are aligned with objectives, that risk is avoided, and that efficiency is being promoted. QA activities are used to ensure that program rules and requirements are documented and current, that participating contractors and trade allies are properly licensed and trained and maintain high quality standards in interactions with customers, and that data are accurate and sufficient for analyzing energy savings analysis.

Examples of QA activities include the following:

- Developing program logic models and process maps that document the goals, processes, and expected outcomes associated with key activities in each program;
- Implementing training protocols that describe training procedures and requirements for key program stakeholders, such as CSPs and trade allies;
- Applying rigorous screening and qualifying protocols to CSPs, trade allies, and field staff that interact directly with customers;
- Documenting data collection protocols, including data and customer information needed to track activities and calculate savings for each program; and
- Summarizing CSPs' gross energy savings calculation methods that are reported at the measure or project level to support consistency and accuracy across programs.

Information on processes used with a program can be organized through preparation of a "program logic model" . In broadest terms, a logic model shows how resources are used in activities to produce outputs that yield outcomes. The logic model for a program should provide a clear description of the processes used with that program to provide energy efficiency services and / or products to customers participating in the program. Essentially, developing the logic model should show what the processes for a program are supposed to do, with whom and why. In particular, the program logic model should:

- Identify the group(s) involved with the program;
- Identify the resources being allocated to the program;
- Describe those activities or action steps that are being used to achieve outcomes;
- Define the outcomes or objectives for a program, where outcomes are those changes or benefits that result from activities; and
- Determine whether the objectives are being achieved.

While a program logic model shows the structure and practices desired and expected for a program, quality assurance procedures are used to identify and identify standards that eliminate variations or defects in program processes that may cause appropriate quality to not be achieved. A framework for assuring that quality requirements are being met is provided by the Plan-Do-Check-Act cycle paradigm that was popularized by Deming and that is the basis for ISO 9001: 2015, the international standard that specifies requirements for a quality management system. As summarized in Table 2-49, the PDCA cycle provides a four-step method for continuous quality improvement.

Table 2-49 Steps in PDCA Cycle for Quality Assurance

Step	Activity
Plan	Establish objectives for quality and determine processes or changes in processes that are required to deliver desired quality. Determine specific levels of quality or measurable results to be achieved
Do	Develop and test process and / or changes in processes.
Check	Monitor and evaluate processes or changes to determine whether quality is meeting predetermined objectives. To extent possible, use objective measurements or tests to determine whether quality goals are being met, rather than using subjective evaluation of quality.
Act	Implement actions that are necessary to achieve desired improvements in quality
If appropriate, repeat, beginning with new objectives being planned.	

Guidance on using the ISO 9001: 2015 standard and the PDCA cycle to develop and implement an effective quality assurance and management system can be found in a handbook published in 2016 by the International Standards Organization: ISO 9001: 2015 for Small Enterprises: What to do?

2.9.2 QA/QC PROTOCOL 2: PROCEDURES FOR QUALITY CONTROL

Quality control procedures should be applied continuously in real time to ensure that program activities adhere to the standards set through the QA work and conform to performance expectations at the program and portfolio levels. QC activities address operational procedures, data and records, and measure installation. Examples of QC procedures include the following:

- Ongoing tracking of program activities and costs.
- Reviewing all data and records to confirm that the proper data are collected consistently, resources are allocated appropriately, and program performance can be measured accurately.
- Conducting follow-up calls to participants to evaluate their satisfaction with the rendered services and to identify opportunities to improve the effectiveness of energy efficiency programs.

As shown in Table 2-50, quality control activities occur during both pre-implementation and post-implementation phases of a program.

Table 2-50 Quality Control Activities During Pre-Implementation and Post-Implementation Phases of a Program

Quality Control during Pre-Implementation
Documentation review: Program documentation should be examined to ensure that it is complete and that it provides all essential information for achieving and verifying savings.
Site pre-inspection and interviews: Site inspections may be conducted to verify preexisting conditions, quantities of measures, key operating parameters, equipment performance, and baseline assumptions in the measure documentation.
Measured data collection: Addresses uncertainties regarding performance of measures or to confirm validity of assumptions used in the baseline analysis. May include spot measurements, data trending (via data loggers or building control systems), or other data collection conducted before measures are implemented.
Quality Control during Post-Implementation
Documentation retention: Program-required documentation should be reviewed to ensure completeness and accuracy. All energy savings-related documentation should be retained for future savings validation or evaluation efforts.
Site post-inspection and interviews: Site inspections and interviews may be conducted to verify that measures were installed and commissioned and operate as intended.
Measured data collection: Data may be collected post-implementation to verify key operating parameters of measures or to meet requirements of an M&V plan.

Evaluation of programs by a TPE can also contribute to quality control of a program. In particular, quality control can be facilitated by having implementation and EM&V contractors coordinate and integrate their activities. Examples of how M&V activities can be coordinated and integrated with implementation activities include the following:

- Pre-installation review: This involves implementation and M&V contractor teams performing pre-installation review of measures and projects prior to a utility reserving incentive funding.
- Project-Specific M&V Plans: This involves implementation and M&V contractor teams coordinating to provide project-specific M&V plans for select projects to ensure the implementation contractor has a full understanding of the M&V approach for these projects prior to the projects being completed and incentivized.
- Coordinated joint site visits: This involves implementation and M&V contractor teams coordinating to conduct joint site visits for select projects. Joint visits reduce the impact on customers and allow data to be collected concurrently, reducing conflicting information collected during separate site visits.
- Project-Specific M&V Reports: This involves sharing project-specific M&V reports with implementation contractors prior to final program level analysis.

Sharing analysis files, energy models, engineering spreadsheets, etc. maintains transparency and allows all calculations used in determining evaluated verified energy savings to be reviewed by all parties.

The TPE should also conduct quality control for the evaluation work. Examples of areas where quality control should be exercised for evaluation work include the following.

Quality control assessment of evaluation plans:

- Analytical methods used to estimate savings
- Baseline determination
- Researchable questions
- Sampling approaches and segmentation or stratification (if appropriate)
- Data collection instruments and topics
- Mapping inputs and outputs for computation of effects
- Logical narrative

Quality control assessment of data procurement:

- Review of options for real time data collection
- Use of appropriate data collection procedures for sampling, collection, processing, attrition, bias, etc.
- How to best use data tracking systems to serve needs of both program implementation and evaluation

Quality control of evaluation reporting:

- Consistency of reporting with the corresponding plan and with best practices
- Cogency and clarity of reporting documentation
- Critical assessment of conclusions and recommendations
- Thoroughness of documentation of methods and results in reports

2.10 Protocol and Guidance for Updating the TRM

This protocol addresses the updating of the Technical Reference Manual (TRM). The protocol provides for periodically reviewing and, if appropriate, updating the content of the TRM. For many measures, updating may need to occur only when codes and standards affecting the specific measure change. Areas to focus on for major updating include:

- Making changes to existing measures, data, and calculations when significant changes are justified, typically because of changing baselines or availability of more current, applicable evaluation studies for updating values.
- Including new measures that are determined to be priorities in the TRM.

The focus of the updating should be on areas of high impact in the Energy Smart portfolio (e.g., duct sealing) and of potential future high impact measures (e.g., ductless mini-split HVAC systems).

A study of an existing or new measure is warranted when the following guidelines are met.

- Measures should be flagged for further review if they exceed 1% of portfolio savings. In such instances, it should be determined whether:
- Primary data have been collected in Energy Smart evaluations to support the deemed savings.
- The data is sufficiently recent to support its continued use.
- If data collection to support a deemed savings revision is cost-effective or cost-feasible, given the implementation and EM&V budgets for Energy Smart programs.
- Measures that are not over the high-impact threshold should be considered for impact or market assessment studies if:
- Stakeholders (the Council and their Advisors, ENO, implementers, interveners, the EM&V contractor, and/or other appropriate parties) conclude a measure is of strategic importance to future program implementation efforts; or
- A measure is high-impact within an important market sub-segment (such as low-income multifamily or municipal government).

Future implementation of Energy Smart programs may include measures that are not in the current version on the TRM. The treatment of these measures in the implementation and evaluation process will differ situationally.

- Many measures in the commercial and industrial segment are custom measures for which deemed savings are inappropriate. These measures will be validated individually based on IPMVP protocols.
- Direct load control (DLC) or load management (LM) programs curtail peak loads through installation of control devices on specific systems (DLC) or through voluntary self-curtailment (LM). These programs are not appropriate for inclusion in a TRM and should have their performance validated annually.

The TRM should be updated each year through a two-stage process.

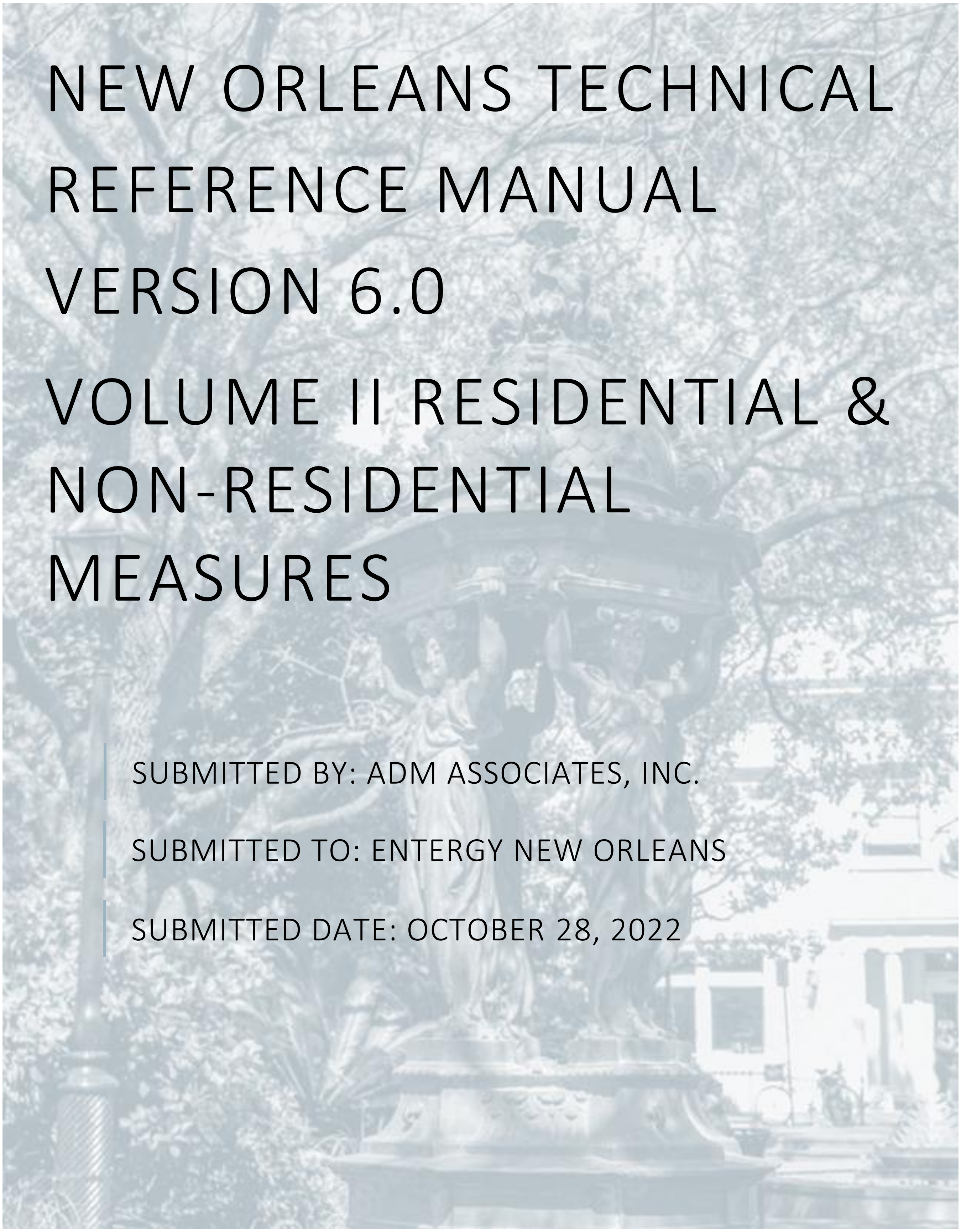
- In the first quarter of each calendar year, a technical forum will be held in which stakeholders may suggest measure additions or updates. This will inform the scope of TRM additions and/or updates to be completed that calendar year.

- Based on this scope, the EM&V contractor will develop the updates, and submit these for comment in July. The results of these comments will be discussed in a second technical conference in August, with the TRM updates finalized in October.

Measures that may be appropriate for the TRM but that are not included in the then-current version should be brought forward in the first-quarter technical conference when possible. If a measure is brought forward by program implementers or other stakeholders, the EM&V contractor may work with the appropriate stakeholders in finalizing an ad hoc measure whitepaper for use until the measure can be formalized in a TRM update. It is at the discretion of the EM&V contractor to determine if primary data collection is warranted before allowing deemed savings for measures through this whitepaper process.

Updating of the TRM should be accomplished using data and tools that are the “best available” (i.e., accurate, relevant, and current). In particular, TRM updates should be based on EM&V studies that are conducted regularly.

The ongoing annual updating process will provide assessments of the reliability of deemed savings values, deemed calculations, and deemed variables and factors. Such assessments may not necessarily result in changes to the TRM. However, the reviews should assess whether the use of the “best (currently) available” data regarding baseline assumptions remains accurate or needs updating (e.g., because of changing code requirements or changes in market practices).



NEW ORLEANS TECHNICAL REFERENCE MANUAL VERSION 6.0

VOLUME II RESIDENTIAL & NON-RESIDENTIAL MEASURES

SUBMITTED BY: ADM ASSOCIATES, INC.

SUBMITTED TO: ENTERGY NEW ORLEANS

SUBMITTED DATE: OCTOBER 28, 2022

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

ACRONYMS/ABBREVIATIONS

Table1 Acronyms/Abbreviations

Acronym	Term
AC	Air Conditioner
AOH	Annual operating hours
APS	Advanced Power Strip
AR&R	Appliance Recycling & Replacement
BP	Behavioral Program
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CEE	Consortium for Energy Efficiency
CF	Coincidence factor
CFL	Compact fluorescent lamp (bulb)
CFM	Cubic feet per minute
CRE	Commercial Real Estate
DI	Direct install
DLC	Direct Load Control
DLC	Design Lights Consortium
EER	Energy efficiency ratio
EFLH	Equivalent full-load hours
EISA	Energy Independence and Security Act
EL	Efficiency loss
EM&V	Evaluation, Measurement, and Verification
ES	ENERGY STAR
EUL	Estimated Useful Life
GPM	Gallons per minute
HDD	Heating degree days
HID	High intensity discharge
HOU	Hours of Use
HP	Heat pump
HPwES	Home Performance with ENERGY STAR
HSPF	Heating seasonal performance factor
HVAC	Heating, Ventilation, and Air Conditioning
IEER	Integrated Energy Efficiency Ratio
IEF	Interactive Effects Factor
IPLV	Integrated part load value
IQW	Income Qualified Weatherization
ISR	In-Service Rate
kW	Kilowatt
kWh	Kilowatt-hour

Acronym	Term
LCDR	Large Commercial Demand Response
LCIS	Large Commercial & Industrial Solutions
LCA	Lifecycle Cost Adjustment
LED	Light Emitting Diode
M&V	Measurement and Verification
MFS	Multifamily Solutions
MW	Megawatt
MWh	Megawatt-hour
NC	New Construction
NTG	Net-to-Gross
PCT	Participant Cost Test
PFI	Publicly Funded Institutions
PY	Program Year
QA	Quality Assurance
QC	Quality Control
RCA	Refrigerant charge adjustment
RIM	Ratepayer Impact Measure
RLA	Retail Lighting and Appliances
ROB	Replace on Burnout
RR	Realization Rate
RUL	Remaining Useful Life
SCDR	Small Commercial Demand Response
SCIS	Small Commercial & Industrial Solutions
SEER	Seasonal Energy Efficiency Ratio
SK&E	School Kits and Education
TA	Trade Ally
TPE	Third-Party Evaluator
TPI	Third-Party Implementer
TRC	Total Resource Cost Test
TRM	Technical Reference Manual
UCT	Utility Cost Test
VFD	Variable Frequency Drive

SAVINGS TYPES

Table 2 Savings Types

Savings Types	**Definition**
Energy Savings (kWh)	The change in energy (kWh) consumption that results directly from program-related actions taken by participants in a program.
Demand Reductions (kW)	The time rate of energy flow. Demand usually refers to electric power measured in kW (equals kWh/h) but can also refer to natural gas, usually as Btu/hr., kBtu/hr., therms/day, etc.
Expected / *Ex ante* Gross	The change in energy consumption and/or peak demand that results directly from program-related actions taken by participants in a program, regardless of why they participated.
Verified / *Ex post* Gross	Latin for "from something done afterward" gross savings. The energy and peak demand savings estimates reported by the evaluators after the gross impact evaluation and associated M&V efforts have been completed.
Net / *Ex post* Net	Verified / *ex post* gross savings multiplied by the net-to-gross (NTG) ratio. Changes in energy use that are attributable to a particular program. These changes may implicitly or explicitly include the effects of free-ridership, spillover, and induced market effects.
Annual Savings	Energy and demand savings expressed on an annual basis, or the amount of energy and/or peak demand a measure or program can be expected to save over the course of a typical year. The TRM provides algorithms and assumptions to calculate annual savings and are based on the sum of the annual savings estimates of installed measures or behavior change.
Lifetime Savings	Energy savings expressed in terms of the total expected savings over the useful life of the measure. Typically calculated by multiplying the annual savings of a measure by its EUL. The TRC Test uses savings from the full lifetime of a measure to calculate the cost-effectiveness of programs.

1. RESIDENTIAL MEASURES

1.1 Appliances

1.1.1 ENERGY STAR® CLOTHES WASHERS

1.1.1.1 Measure Description

This measure involves the installation of a residential ENERGY STAR® clothes washer > 2.5 ft^3 in a new construction or replacement-on-burnout application. This measure applies to all residential applications.

1.1.1.2 Baseline and Efficiency Standards

The baseline standard for deriving savings from this measure is the current federal minimum efficiency levels.

The efficiency standard is the ENERGY STAR requirements for clothes washers.

Efficiency performance for clothes washers is characterized by Integrated Modified Energy Factor (IMEF) and Integrated Water Factor (IWF). The units for IMEF are ft^3/kWh/cycle. Units with higher IMEF values are more efficient. The units for IWF are gallons/cycle/ft^3. Units with lower IWF values will use less water and are therefore more efficient.

Table 1-1 ENERGY STAR Clothes Washer – Baseline and Efficiency Levels

Clothes Washer Configuration	ENERGY STAR Efficiency Level Effective 2/5/2018
Top Loading	IMEF ≥ 2.06 IWF ≤ 4.3
Front Loading	IMEF ≥ 2.76 IWF ≤ 3.2

1.1.1.3 Estimated Useful Life

The EUL of this measure is 14 years according to the US DOE.

1.1.1.4 Deemed Savings Values

For retrofit situations, baseline and efficiency case energy consumption is based on the configuration of the replaced unit and new unit (top loading or front loading). For new construction applications, a top loading clothes washer is assumed as the baseline and the efficient equipment is either top loading or front loading.

Table 1-2 ENERGY STAR Clothes Washer – Deemed Savings

Baseline Configuration	Efficient Configuration	Water Heater Fuel Type	Dryer Fuel Type	kWh Savings	kW Savings
Top Loading	Top Loading	Gas	Gas	23	0.005
		Gas	Electric	62	0.015
		Electric	Gas	114	0.027
		Electric	Electric	153	0.036
Top Loading	Front Loading	Gas	Gas	38	0.009
		Gas	Electric	122	0.029
		Electric	Gas	191	0.045
		Electric	Electric	275	0.065
Front Loading	Front Loading	Gas	Gas	6	0.002
		Gas	Electric	148	0.035
		Electric	Gas	32	0.008
		Electric	Electric	173	0.041

Energy savings for this measure were derived using the ENERGY STAR Clothes Washer Savings Calculator[1]. Unless otherwise specified, all savings assumptions are extracted from the ENERGY STAR calculator. The baseline and ENERGY STAR efficiency levels are set to those matching Table 1-1. The calculator determines savings based on whether an electric or gas water heater is used. Calculations are also conducted based on whether the dryer is electric or gas. For applications using an electric water heater and an electric dryer, the savings are calculated as follows:

$$kWh_{savings} = \left(E_{conv,machine} + E_{conv,WH} + E_{conv,dryer}\right) - \left(E_{ES,machine} + E_{ES,WH} + E_{ES,dryer}\right)$$

Where:

$E_{conv,machine}$= Conventional machine energy (kWh)

$E_{conv,WH}$= Conventional water heating energy (kWh)

$E_{conv,dryer}$= Conventional dryer energy (kWh)

[1] The ENERGY STAR Clothes Washer Savings Calculator can be found on the ENERGY STAR website on the right hand side of the page at: https://www.energystar.gov/products/heating_cooling/guide/savings-calculator

$E_{ES,machine}$= ENERGY STAR machine energy (kWh)

$E_{ES,WH}$= ENERGY STAR water heating energy (kWh)

$E_{ES,dryer}$=ENERGY STAR dryer energy (kWh)

1.1.1.4.1 Energy Savings

Energy savings for the above factors can be determined using the following algorithms.

$$E_{conv,machine} = \frac{MCF \times RUEC_{conv} \times LPY}{RLPY} \; E_{conv,WH} = \frac{WHCF \times RUEC_{conv} \times LPY}{RLPY} \; E_{conv,dryer} = \left(\frac{CAP \times LPY}{IMEF_{FS}} - \frac{RUEC_{conv} \times LPY}{RLPY}\right) \times DUF \; E_{ES,machine} = \frac{MCF \times RUEC_{ES} \times LPY}{RLPY} \; E_{ES,WH} = \frac{WHCF \times RUEC_{ES} \times LPY}{RLPY} \; E_{ES,dryer} = \left(\frac{CAP \times LPY}{IMEF_{ES}} - \frac{RUEC_{ES} \times LPY}{RLPY}\right) \times DUF$$

Where:

MCF= Machine electricity consumption factor = 20%

$WHCF$= Water heating electricity consumption factor = 80%

$RUEC_{conv}$= Rated unit electricity consumption (kWh/year) = 381 (Top Loading); 169 (Front Loading)

$RUEC_{ES}$ = Rated unit electricity consumption (kWh/year) = 230 (Top Loading); 127 (Front Loading)

CAP= Clothes washer capacity = 3.5 (ft^3)

$IMEF_{FS}$= Federal Standard Integrated Modified Energy Factor (ft^3/kWh/cycle)

$IMEF_{ES}$= ENERGY STAR Integrated Modified Energy Factor (ft^3/kWh/cycle)

LPY = Loads per year = 295

$RLPY$= Reference loads per year = 392

DUF= Dryer use factor = 91%

1.1.1.4.2 Demand Reductions

Demand reductions are calculated using the following equation:

$$kW_{savings} = \frac{kWh_{savings}}{AOH} \times CF$$

Where:

AOH = Annual operating hours = LPY × d = 295 hours

CF = Coincidence factor = 0.07[2]

1.1.1.5 Incremental Cost

The incremental cost is $190 .

1.1.1.6 Future Studies

There are no planned studies for this measure at this time.

[2] Value from Clothes Washer Measure, Mid Atlantic TRM 2014. Metered data from Navigant Consulting "EmPOWER Maryland Draft Final Evaluation Report Evaluation Year 4 (June 1, 2012 – May 31, 2013) Appliance Rebate Program." March 21, 2014, p. 36.

1.1.2 ENERGY STAR DRYERS

1.1.2.1 Measure Description

This measure involves the installation of a residential ENERGY STAR dryers in a new construction or replacement-on-burnout application. This measure applies to all residential applications.

1.1.2.2 Baseline and Efficiency Standards[3]

The baseline standard for deriving savings from this measure is the current federal minimum efficiency levels. The efficiency standard is the ENERGY STAR requirements for dryers.

ENERGY STAR Clothes Dryers are more efficient than standard ones and save energy. They have a higher CEF (Combined Energy Factor) and may incorporate a moisture sensor to reduce excessive drying of clothes and prolonged drying cycles. ENERGY STAR Heat pump dryers or ventless dryers have higher CEF than conventional ENERGY STAR dryers.

Table 1-3 ENERGY STAR Dryer – Baseline and Efficiency Levels[4]

	Vented Gas Dryer	**Ventless or Vented Electric, Standard ≥ 4.4 ft^3**	**Ventless or Vented Electric, Compact (120V) < 4.4 ft^3**	**Vented Electric, Compact (240V) < 4.4 ft^3**	**Ventless Electric, Compact (240V) < 4.4 ft^3**	**Heat Pump Clothes Dryer**
ENERGYSTAR Required CEF	3.48	3.93	3.80	3.45	2.68	7.60
Federal standard CEF	2.84	3.11	3.01	2.73	2.13	3.11
Average load (in lbs.)	8.45	8.45	3.0	3.0	3.0	8.45
Default loads per year	283	283	283	283	283	283
Default capacity (in ft^3)	5.0	5.0	3.0	3.0	3.0	5.0

1.1.2.3 Estimated Useful Life

The EUL of this measure is 12 years according to the US DOE.

1.1.2.4 Deemed Savings Values

For retrofit situations, baseline and efficiency case energy consumption is based on the size of the replaced unit and new unit. For new construction applications.

---

[3] Current federal standards for clothes dryers can be found on the DOE website at: https://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/36.

Current ENERGY STAR criteria for clothes dryers can be found on the ENERGY STAR website at: https://www.energystar.gov/products/appliances/clothes_dryers.

ENERGY STAR Most Efficient criteria for clothes washers can be found at: http://www.energystar.gov/ia/partners/downloads/most_efficient/2015/Final_ENERGY_STAR_Most_Efficient_2015_Recognition_Criteria_Clothes_Washers.pdf.

[4] The ENERGY STAR Clothes Dryer Savings Calculator can be found on the ENERGY STAR website on the right hand side of the page at: www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=CW

Table 1-4 ENERGY STAR Clothes Dryer – Deemed Savings

Product Type	Energy Savings (kWh/yr)	Demand Reduction (kW)
Vented Electric, Standard (4.4 ft³ or greater capacity)	152.42	.0226
Vented Electric, Compact (120V) (less than 4.4 ft³ capacity)	55.71	.0083
Vented Electric, Compact (240V) < 4.4 ft³	61.66	.0092
Ventless Electric, Compact (240V) < 4.4 ft³	77.71	.0115
Heat Pump Clothes Dryer	431.56	.0641

Energy savings for this measure were derived using the *ENERGY STAR Dryer Savings Calculator*. Unless otherwise specified, all savings assumptions are extracted from the ENERGY STAR calculator.

The energy and demand savings are obtained through the following formulas:

$$\Delta kWh/yr = Cycles_{wash} \times \%_{dry/wash} \times Load_{avg} \times \left(\frac{1}{CEF_{base}} - \frac{1}{CEF_{ee}}\right) \Delta kW_{peak} = \frac{\left(\frac{1}{CEF_{base}} - \frac{1}{CEF_{ee}}\right) \times Load_{avg}}{time_{cycle}} \times CF$$

Where:

$Cycles_{wash}$ = Number of washing machine cycles per year = 283 cycles/year

$Load_{avg}$ = Weight of average dryer load, in pounds per load = Standard Dryer: 8.45 lbs/load and Compact Dryer: 3.0 lbs/load[5] [6]

$\%_{\mathrm{dry/wash}}$ = Percentage of homes with a dryer that use the dryer every time clothes are washed = 95%

CEF_{base} = Combined Energy Factor of baseline dryer (lbs/kWh) = See Table 1-3[7]

CEF_{ee} = Combined Energy Factor of ENERGY STAR dryer (lbs./kWh) = See Table 1-3[8]

$time_{cycle}$ = Duration of average drying cycle in hours = 1 hour

[5] Test Loads for Compact and Standard Dryer in Appendix D2 to Subpart B of Part 430—Uniform Test Method for Measuring the Energy Consumption of Clothes Dryers. http://www.ecfr.gov/cgi-bin/text-idx?SID=9d051184ada3b0d0b5b553f624e0ab05&node=10:3.0.1.4.18.2.9.6.14&rgn=div9

[6] 2011-04 Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial and Industrial Equipment. Residential Clothes Dryers and Room Air Conditioners, Chapter 7. Clothes Dryer Frequency from Table 7.3.3 for Electric Standard. http://www.regulations.gov/contentStreamer?objectId=0900006480c8ee11&disposition=attachment&contentType=pdf

[7] Federal Standard for Clothes Dryers, Effective January 1, 2015. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/36

[8] ENERGY STAR Specification for Clothes Dryers Version 1.0, Effective January 1, 2015. http://www.energystar.gov/products/specs/sites/products/files/ENERGY%20STAR%20Final%20Draft%20Version%201.0%20Clothes%20Dryers%20Specification_0.pdf

CF - Coincidence Factor = 0.042[9]

1.1.2.5 Incremental Cost

The incremental cost of high efficiency clothes dryers is detailed in Table 1-5.

Table 1-5 ENERGY STAR Clothes Dryer Incremental Costs

Product Type	**Incremental Cost**
Vented Electric, Standard: (4.4 ft^3 or greater capacity)	$40[10]
Vented Electric, Compact (120V): (less than 4.4 ft^3 capacity)	$40
Vented Electric, Compact: (240V) < 4.4 ft^3	$40
Ventless Electric, Compact: (240V) < 4.4 ft^3	$40

1.1.2.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. Thus, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents. Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

[9] 6) Central Maine Power Company. "Residential End-Use Metering Project". 1988. Using 8760 data for electric clothes dryers, calculating the CF according to the PJM peak definition.

[10] ENERGY STAR Appliance Calculator: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwihkoHI8f3OAhVW5mMKHe72Du4QFggeMAA&url=https%3A%2F%2Fwww.energystar.gov%2Fsites%2Fdefault%2Ffiles%2Fasset%2Fdocument%2Fappliance_calculator.xlsx&usg=AFQjCNFAy5-mu5GR3BjLp4MR1LqrOHegCA&sig2=8l5MGUh1_bJy3lSl9wAWIA

1.1.3 ENERGY STAR DISHWASHERS

1.1.3.1 Measure Description

This measure involves the installation of an ENERGY STAR dishwasher in a new construction or replacement-on-burnout situation. This measure applies to all residential applications.

1.1.3.2 Baseline and Efficiency Standards

The baseline for this measure is the current federal standard as displayed in the table below.

Table 1-6 ENERGY STAR Criteria for Dishwashers[11]

	ENERGY STAR Criteria		
	Capacity	**Annual Energy Consumption kWh/Year**	**Gallons/Cycle**
Standard Model Size (Effective On 1/26/2016)[12]	> 8 place settings + 6 serving pieces	AECbase + AECadderconnected AECbase: 270 AECadderconnected: 0.05 × AECbase	< 3.5
Compact Model Size (Effective On 1/26/2016)	< 8 place settings + 6 serving pieces	< 203	< 3.1

1.1.3.3 Estimated Useful Life

The EUL of this measure is 15 years according to the US DOE.

1.1.3.4 Deemed Savings Values

Deemed savings are per installed unit based on the water heating fuel type.

Table 1-7 ENERGY STAR Dishwashers – Deemed Savings Values

	Water Heater Fuel Type	kW Savings	kWh Savings
Standard Model Size	Gas	0.0005	5
Standard Model Size	Electric	0.0011	12

1.1.3.4.1 Energy Savings

Energy savings for this measure were derived using the ENERGY STAR Dishwasher Savings Calculator. The baseline and ENERGY STAR efficiency levels are set to those matching Table 1-6.

$$kWh_{Savings} = \left(E_{conv,machine} + E_{conv,WH}\right) - \left(E_{ES,machine} + E_{ES,WH}\right)$$

[11] ENERGY STAR criteria for dishwashers can be found on the ENERGY STAR website at: www.energystar.gov/index.cfm?c=dishwash.pr_crit_dishwashers

[12] ENERGY STAR efficiency requirements as of January 26, 2016 are defined on their website at www.energystar.gov/sites/default/files/ENERGY%20STAR%20Residential%20Dishwasher%20Version%206.0%20Final%20Program%20Requirements_0.pdf

Where:

$E_{conv,machine}$= Conventional machine energy (kWh)

$E_{conv,WH}$= Conventional water heating energy (kWh)

$E_{ES,machine}$= ENERGY STAR machine energy (kWh)

$E_{ES,WH}$= ENERGY STAR water heating energy (kWh)

Algorithms to calculate the above parameters are defined as:

$$E_{conv,machine} = MCF \times RUEC_{conv}$$

$$E_{conv,WH} = WHCF \times RUEC_{conv}$$

$$E_{ES,machine} = MCF \times RUEC_{ES}$$

$$E_{ES,WH} = WHCF \times RUEC_{ES}$$

1.1.3.4.2 Demand Reductions

Demand reductions can be derived using the following:

$$kW_{Savings} = \frac{kWh_{Savings}}{AOH} \times CF$$

Where:

MCF= Machine electricity consumption factor = 44%

$WHCF$= Water heating electricity consumption factor = 56%

$RUEC_{conv}$= Rated unit electricity consumption = 307 (kWh/year)

$RUEC_{ES}$ = Rated unit electricity consumption = 295 (kWh/year)

CPY = Cycles per year = 215

d = Average wash cycle duration = 2.1 hours[13]

AOH = Annual operating hours = CPY × d = 451.5 hours

CF = Coincidence factor = 0.036[14]

$\eta_{gas\ WH}$= Gas water heater efficiency = 75%

1.1.3.5 Incremental cost

The incremental cost of ENERGY STAR Dishwashers is $10 .

[13] Average of Consumer Reports Cycle Times for Dishwashers. http://www.consumerreports.org/cro/dishwashers.htm. Information available for subscribers only.

[14] Hendron, R. & Engebrecht, C. 2010, , National Renewable Energy Laboratory (NREL). “Building America Research Benchmark Definition: Updated December” US U.S. DOE. January 2010. p. 14 (peak hour of 4 PM was applied). http://www.nrel.gov/docs/fy10osti/47246.pdf

1.1.3.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. Thus, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents. Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

1.1.4 ENERGY STAR WATER COOLERS

1.1.4.1 Measure Description

This measure entails the replacement of an inefficient water cooler unit with an ENERGY STAR unit.

The categories of coolers considered are Cook & Cold / Cold Only units; and Hot and Cold units. Within these categories are three configurations Top-loading; Bottom-loading; or Point-of-Use (POU). Top-loading and Bottom-loading are units in which a 3 gallon or a 5 gallon bottle can easily be installed. POU water coolers are bottle-less units that are installed directly to a water line. This chapter provides deemed savings for top and bottom-loading units; POU models are not eligible at this time.

1.1.4.2 Baseline and Efficiency Standards

The previous energy consumption baseline and the current energy efficient energy consumption baseline for the two types of water coolers is shown in Table 1-8.

Table 1-8 Energy Consumption Baseline and ENERGY STAR Efficiency Criteria

Criteria	Water Cooler Category		kWh Per Day
Standard	Cook & Cold		≤ 0.29 kWh/day
	Cold Only		
	Hot and Cold		≤ 2.19 kWh/day
ENERGY STAR	Cold Only and Cook & Cold		≤ 0.16 kWh/day
	Hot and Cold Units - Conditioned Storage[15]	Low Capacity	≤ 0.68 kWh/day
		High Capacity	≤ 0.80 kWh/day
	Hot and Cold Units - On Demand		≤ 0.18 kWh/day

1.1.4.3 Estimated Useful Life

According to ENERGY STAR the EUL is 10 years.

1.1.4.4 Deemed Savings Values

Calculated deemed energy savings are shown in Table 1-9.

Table 1-9 Deemed kWh Savings and kW Reductions for Water Cooler Replacement

Water Cooler Category		Annual kWh Savings	Peak kW Savings
Cold Only and Cook & Cold		47.5	0.005
Hot and Cold Units - Conditioned Storage	Low Capacity	551.5	0.062
	High Capacity	507.7	0.057
Hot and Cold Units - On Demand		734.2	0.082

[15] Point-of-Use and bottled water coolers are included in this category

1.1.4.4.1 Energy Savings

Energy savings are based on the reduction of energy consumption resulting from replacing an inefficient water cooler unit with an energy-efficient unit and are calculated as follows:

$$kWh_{Savings} = \left(kWh_{base} - kWh_{efficient}\right) \times 365.25$$

Where:

kWh_{base} = Baseline daily kWh consumption of energy-inefficient unit (Table 1-8)

$kWh_{efficient}$ = Daily kWh consumption of energy-efficient ENERGY STAR model (Table 1-8)

365 = The number of days in a year water cooler is operating

For example, if an inefficient Cold Only water cooler were to be replaced with a Cold Only ENERGY STAR labeled efficient unit having an energy consumption rate of 0.16 kWh/day, then the annual energy savings would be

$$kWh_{Savings} = (0.29 - 0.16) \times 365 = 47.45\ kWh$$

$$kW_{savings} = kWh_{savings} \times Energy\ to\ Demand\ Factor\ (ETDF)$$

Where:

$ETDF = 0.0001119 \frac{kW}{kWh/_{year}}$ [16]

Continuing the example calculation shown in the previous subsection, the peak demand reduction is:

$$kW_{savings} = 47.45\ {}^{kWh}/_{year} \times 0.0001119\ \frac{kW}{kWh/_{year}} = 0.0053\ kW$$

1.1.4.5 Incremental Cost

The TPE conducted a market study of currently available ENERGY STAR and non-ENERGY STAR water coolers to determine incremental pricing. Prices were collected from New Orleans retail websites. The range of models in the “Cook & Cold” category was very limited (particularly for ENERGY STAR-qualifying models). Due to low measure incremental costs, the TPE recommends incentivizing the measure through mid-stream channels.

[16] Quantec in collaboration with Summit Blue Consulting, Nexant, Inc., A-TEC Energy Corporation, and Britt/Makela Group, prepared for the Iowa utility Association, February 2008. http://plainsjustice.org/files/EEP-08-1/Quantec/QuantecReportVol1.pdf

Table 1-10 Water Cooler Cost Summary

Type	Efficiency Level	Average Cost
Hot & Cold	Standard	$182.36 (n=22)
	ENERGY STAR	$188.81 (n=28)
Cook & Cold	Standard	$123.18 (n=6)
	ENERGY STAR	$127.52 (n=2)

- The incremental cost of an ENERGY STAR Cook & Cold or a Cold Only unit is $4.34.
- The incremental cost of an ENERGY STAR Hot and Cold unit is $6.45.

Due to low measure incremental costs, the TPE recommends incentivizing the measure through mid-stream channels.

1.1.4.6 Future Studies

At the time of authorship of this chapter, this measure was not implemented in the Energy Smart program. Future EM&V should be conducted to update this measure to align with any new federal standards, as well as to establish a net-to-gross ratio. If program administrators obtain additional cost data for Cook & Cold systems, this should be provided so that the incremental cost for this measure category can be updated with a more robust sample size.

1.1.5 ENEGRY STAR AIR PURIFIERS

1.1.5.1 Measure Description

This measure involves the installation of an ENERGY STAR certified room air purifier. An air purifier, also known as an air cleaner, is defined as a portable electric appliance that removes dust and fine particles from indoor air.

1.1.5.2 Baseline and Efficiency Standards

The baseline equipment is assumed to be a conventional unit. The efficient equipment is defined as an air purifier meeting the efficiency specifications of ENERGY STAR as provided below:

- Must produce a minimum 30 Clean Air Delivery Rate (CADR) for Smoke to be considered under this specification. Minimum Performance Requirement is expressed in Smoke CADR/Watt and it shall be greater than or equal to the Minimum Smoke CADR/Watt Requirement shown in the table below:

  Table 1-11 CADR/W Requirement

Clean Air Delivery Rate (CADR)	CADR/W
30 ≤ Smoke CADR < 100	1.9
100 ≤ Smoke CADR < 150	2.4
150 ≤ Smoke CADR < 200	2.9
200 ≤ Smoke CADR	2.9

- “Partial On Mode” Requirements are to be calculated as per Section 3.4.1 of the Energy Star Eligibility Criteria Standby Power Requirement: = Measured standby power shall not exceed 2 Watts.
- UL Safety Requirement: Models that emit ozone as a byproduct of air cleaning must meet UL Standard 867 (ozone production must not exceed 50ppb).

1.1.5.3 Estimated Useful Life

The EUL of this measure is 9 years according to ENERGY STAR.

1.1.5.4 Deemed Savings Values

The table below summarizes the deemed kWh and kW based on clean air delivery rate.

Table 1-12 ENERGY STAR Air Purifiers Deemed Savings

Clean Air Delivery Rate (CADR)	Energy Savings (kWh)	Demand Reduction (kW)
30 ≤ Smoke CADR < 100	133	0.015
100 ≤ Smoke CADR < 150	229	0.026
150 ≤ Smoke CADR < 200	302	0.034
200 ≤ Smoke CADR	570	0.065

1.1.5.5 Incremental Cost

ENERGY STAR Air Purifiers incremental cost is outlined in the table below.

Table 1-13 ENERGY STAR Air Purifier Incremental Cost[17]

Clean Air Delivery Rate (CADR)	CADR used in calculation (midpoint)	Average Incremental Cost ($)
30 ≤ Smoke CADR < 100	1.9	8.44
100 ≤ Smoke CADR < 150	2.4	22.33
150 ≤ Smoke CADR < 200	2.9	92.34
200 ≤ Smoke CADR	2.9	44.50

1.1.5.6 Future Studies

There are no future studies planned for this measures at this time.

[17] ENERGY STAR V2 Room Air Cleaners Data Package (October 11, 2019). See file “ENERGY STAR V2 Room Air Cleaners Data Package_GH 05122020_VEIC.xlsx”

1.1.6 ENERGY STAR CEILING FANS

1.1.6.1 Measure Description

ENERGY STAR ceiling fans require a more efficient CFM/Watt rating at the low, medium, and high settings than standard ceiling fans as well ENERGY STAR qualified lighting for those with light kits included. Due to EISA Phase II, savings calculations and deemed values do not consider lighting savings.

1.1.6.2 Baseline and Efficiency Standards

Current ENERGY STAR efficiency standards for ceiling fans are shown in Table 1-14 below.

Table 1-14 ENERGY STAR Ceiling Fan Standards

Type	Size (diameter) (in.)	Minimum Efficiency (cfm/W)	Minimum High Speed Airflow (cfm)
Ceiling Fan	D ≤ 36 inches	≥ 0.72*D + 41.93	≥ 1767
	36 inches < D < 78 inches	≥ 2.63*D - 26.83	$\geq 250*\pi*(D/24)^2$
	D ≥ 78 inches		≥ 8296
Hugger Ceiling Fan	D ≤ 36 inches	≥ 0.31*D + 36.84	≥ 1414
	36 inches < D < 78 inches	≥ 1.75*D - 15	$\geq 200*\pi*(D/24)^2$
	D ≥ 78 inches		≥ 6637

Savings are based on a comparison between ENERGY STAR fans and standard efficiency ceiling fan meeting the January 21, 2020, Federal efficiency requirements.[18]

1.1.6.3 Estimated Useful Life

The EUL for ceiling fans is 10 years.[19]

1.1.6.4 Deemed Savings

Deemed savings are calculated for fan-only ceiling fans.

Table 1-15 ENERGY STAR Ceiling Fan – Deemed Savings

Product Type (Fan Only)	Diameter, D (inches)	kWh Savings	kW Reduction
Standard and Low-Mount High Speed Small Diameter (HSSD) Ceiling Fans	D ≤ 36	0	0
	36 < D < 78	25	0.002
	D ≥ 78	34	0.002
Hugger Ceiling Fan	36 < D < 78	36	0.003

[18] Energy and water conservation standards and their compliance dates.10 C.F.R. § 430.32.

[19] Lifetime estimate is sourced from the ENERGY STAR Ceiling Fan Savings Calculator

The energy savings are obtained through the following formula:

$$\Delta kWh = \Delta W_{fan} \times \frac{1\ kW}{1000\ W} \times HOU_{fan} \times 365.25 \frac{days}{yr}$$

$$\Delta kW = \Delta W_{fan} \times \frac{1\ kW}{1000\ W} \times CF$$

Where:

ΔW_{fan} = Difference in wattage between standard and ENERGY STAR fan

Table 1-16 Differences in Fan Wattage

Ceiling Fan Type	**Diameter, D (inches)**	$\boldsymbol{\Delta W_{fan}}$
Standard and Low-Mount High Speed Small Diameter (HSSD) Ceiling Fans	D ≤ 36	0
	36 < D < 78	23
	D ≥ 78”	31
Hugger Ceiling Fan[20]	36 < D < 78	33

HOU_{fan} = fan daily hours of use (hours/day) = 3 hours/day

CF = Demand Factor= 0.091[21]

1.1.6.5 Incremental Cost

The incremental cost of a three-lamp ENERGY STAR Ceiling Fan is $46[22].

1.1.6.6 Future Studies

At the time of authorship of the TRM, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of the models actually incented through the program. The key parameters to be examined include:

- Content of the lighting included with the fan;
- Rated wattage of the fans at low, medium, and high speeds.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

[20] The ENERGY STAR 4.0 specifications allow for hugger ceiling fans with blade spans of ≤ 36” and ≥ 78”, however, as of August 2022, there are no ENERGY STAR qualified products meeting those criteria. They were therefore omitted from this characterization.

[21] EmPOWER Maryland 2012 Final Evaluation Report: Residential Lighting Program, Prepared by Navigant Consulting and the Cadmus Group, Inc., March 2013, Table 50.

[22] ENERGY STAR Lighting Fixture and Ceiling Fan Calculator. Updated September 2013

1.1.7 ADVANCED POWER STRIPS

1.1.7.1 Measure Description

This measure involves the installation of a multi-plug Advanced Power Strip (APS, also known as “Smart Strips”) that has the ability to automatically disconnect specific loads depending on the power draw of a specified load.

There are two categories of smart strips:

- Tier 1: Tier 1 advanced power strips have a master controls socket arrangement and will shut off items plugged into the controlled power-saver sockets when the sense that the appliance plugged into the master socket has been turned off. The power-saving functions of the control sockets is not used when the master appliance is turned on.
- Tier 2: Tier 2 advanced power strips manage both active and standby consumption. Tier 2 smart strips manage standby power consumption by turning off devices from a control event; this could be a TV or other item powering off, which then powers off the controlled outlets to save energy. Active power consumption is managed by monitoring a user’s engagement or presence in a room either by infrared remote signals or motion sensing. After a period of inactivity, the Tier 2 unit will shut off controlled outlets.

1.1.7.2 Expected Useful Life

- For Tier 1 advanced power strips, the EUL is 10 years .
- For Tier 2 advanced power strips, there has not been a study performed to validate EUL. Until better data is available, they should default to using the current EUL of Tier 1 devices, 10 years.

1.1.7.3 Baseline & Efficiency Standard

The baseline case is the absence of an APS, where peripherals are plugged in to a traditional surge protector or wall outlet. The efficiency standard case is the presence of an APS, with all peripherals plugged into the APS.

1.1.7.4 Estimated Useful Life

The EUL is 10 years according to the NYSERDA Advanced Power Strip Research Report from August 2011.

1.1.7.5 Deemed Savings Values

Deemed Savings for Residential APS are found in the table below.

Table 1-17 Deemed Savings for Residential APS

Tier	Size	Usage	kW Savings	kWh Savings
1	5-plug	Unspecified	.0056	48.9
		Entertainment	.0077	62.1
		Computer	.0037	35.8
	7-plug	Unspecified	.0067	57.7
		Entertainment	.0092	74.5
		Computer	.0045	42.9
2	5-plug	Unspecified	.0194	204.2
		Entertainment	.0316	307.4
		Computer	.0172	100.9

1.1.7.5.1 Calculation of Deemed Savings

Energy and demand savings for a 5-plug APS in use in a home office or for a home entertainment system are calculated using the following algorithm, where kWh saved are calculated and summed for all peripheral devices:

(i) Tier 1

$$\Delta kWh/yr. = \frac{(kW_{comp\ idle} \times HOU_{comp\ idle}) + (kW_{TVidle} \times HOU_{TV\ idle})}{2} \times 365 \frac{\mathbf{days}}{\mathbf{yr}} \times ISR = 48.9\ kWh\ (5\text{-plug});\ 57.7\ kWh$$

$$\Delta \text{kWh/yr. entertainment center} = \boldsymbol{kW_{TV\ idle}} \times \boldsymbol{HOU}_{\boldsymbol{TV\ idle}} \times 365 \frac{\mathbf{days}}{\mathbf{yr}} \times \text{ISR} = 62.1\ \text{kWh (5-plug); 74.5 kWh (7-plug)}$$

$$\Delta \text{kWh/yr. computer} = kW_{Comp\ idle} \times HOU_{\ Comp\ idle} \times 365 \frac{days}{yr} \times \text{ISR} = 35.8\ \text{kWh(5-plug); 42.9 (7-plug)}$$

$$\Delta \text{kW}_{\text{peak}}\ \text{unspecified use} = \frac{\text{CF} \times (\text{kW}_{\text{comp idle}} + \text{kW}_{\text{TV idle}})}{2} \times \text{ISR} = 0.0056\ \text{kW (5-plug); 0.0067 kW (7-plug)}$$

$$\Delta \text{kW}_{\text{peak}}\ \text{entertainment center} = \text{CF} \times \text{kW}_{\text{TV idle}} \times \text{ISR} = 0.0077\ \text{kW (5-plug); 0.0092 kW (7-plug)}$$

$$\Delta \text{kW}_{\text{peak}}\ \text{Computer} = \text{CF} \times \text{kW}_{\text{Comp idle}} \times \text{ISR} = 0.0037\ \text{kW (5-plug); 0.0045 kW (7-plug)}$$

(ii) Tier 2

$$\Delta \text{kWh unspecified use} = \frac{(\text{kWh}_{\text{comp}} + \text{kWh}_{\text{TV}})}{2} \times \text{ESF} \times \text{ISR} = 204.2\ \text{kWh}$$

$$\Delta \text{kWh entertainment center} = \text{kWh}_{\text{TV}} \times \text{ESF} \times \text{ISR} = 307.4\ \text{kWh}$$

ΔkWh Computer = $\mathrm{kWh_{Comp}} \times \mathrm{ESF} \times \mathrm{ISR}$ = 100.9 kWh

$\Delta \mathrm{kW_{peak}}$ unspecified use = $\frac{\mathrm{CF} \times (\Delta\mathrm{kWh}_{\mathrm{comp}} + \Delta\mathrm{kWh}_{\mathrm{entertainment}})}{2 \times 8760 \frac{\mathrm{hours}}{\mathrm{yr}}} \times \mathrm{ISR}$ =0.0194 kW

$\Delta \mathrm{kW_{peak}}$ entertainment center = $\frac{\mathrm{CF} \times \Delta\mathrm{kWh}_{\mathrm{entertainment}}}{8760 \frac{\mathrm{hours}}{\mathrm{yr}}} \times \mathrm{ISR}$ = 0.0316 kW

$\Delta \mathrm{kW_{peak}}$ Computer = $\frac{\mathrm{CF} \times \Delta\mathrm{kWh}_{\mathrm{computer}}}{8760 \frac{\mathrm{hours}}{\mathrm{yr}}} \times \mathrm{ISR}$ = 0.0172 kW

Table 1-18 APS Parameters

Parameter	**Unit**	**Value**	**Source**
kWcomp idle, Idle kW of computer system	kW	.0049 (5-plug) .00588 (7-plug)	Footnotes 23, 24, & 25
HOUcomp idle, Daily hours of computer idle time	Hours/day	20	23
kWTV idle, Idle kW of TV system	kW	. 0085 (5-plug) .00102 (7-plug)	23, 25
HOUTV idle, Daily hours of TV idle time	Hours/day	20	23
kWhTV, Annual kWh of TV system	kWh	602.8	25
kWhcomp, Annual kWh of computer system	kWh	197.9	25

[23] "Electricity Savings Opportunities for Home Electronics and Other Plug-In Devices in Minnesota Homes", Energy Center of Wisconsin, May 2010.

[24] "Smart Plug Strips", ECOS, July 2009.

[25] "Advanced Power Strip Research Report", NYSERDA, August 2011"

Parameter	Unit	Value	Source
ISR, In-Service-Rate	%	1.0	
CF, Coincidence Factor	%	Entertainment Center = .90 Computer System= .763 Unspecified = .832	Footnote 26
ESF, Energy Savings Factor. Percent of baseline energy consumption saved by installing the measure	%	Entertainment Center = .51	Footnote 27

1.1.7.6 Incremental Cost

The incremental cost for APS systems is as follows:

- Tier (1) – 5-plug: $16
- Tier (1) – 7-plug: $26
- Tier (2): $65

1.1.7.7 Net-to-Gross

The NTG is 80% for direct install applications.

1.1.7.8 Future Studies

At the time of authorship of the TRM, this measure has low participation numbers in Energy Smart programs. As a result, savings are calculated using values cited from evaluation reports completed on behalf of the New York State Energy Research & Development Authority (NYSERDA) and Wisconsin Focus on Energy. If participation reached 1% of residential Energy Smart program savings, the evaluation should include fieldwork to support in-service rates and to document an inventory of the equipment actually installed into the APS by New Orleans residents.

---

[26] C F Values of Standby Losses for Entertainment Center and Home Office in Efficiency Vermont TRM, 2013, pg. 16. Developed through negotiations between Efficiency Vermont and the Vermont Department of Public Service

[27] "Tier 2 Advanced Power Strip Evaluation for Energy Saving Incentive," California Plug Load Research Center, 2014.

1.1.8 ENERGY STAR DEHUMIDIFIERS

1.1.8.1 Measure Description

This measure is portable and whole-house humidifiers which meet the minimum qualifying efficiency standard set forth by the current ENERGY STAR Version 5.0 (effective 10/31/2019) and ENERGY STAR Most Efficient 2019 Criteria (effective 01/01/2019) that are purchased and installed in a residential setting in place of a unit that meets the minimum federal standard efficiency.

1.1.8.2 Baseline and Efficiency Standards

1.1.8.2.1 Definition of Efficient Equipment

To qualify for this measure, the new dehumidifier must meet the ENERGY STAR standards as defined in the table below.

Table 1-19 ENERGY STAR Dehumidifier Standard

Equipment Specification	Capacity (pints/day)	Federal Standard Criteria (L/kWh)
Portable Dehumidifier	Up to 25	≥ 1.57
	≤ 25.01 to ≤ 50	≥ 1.80
	≥ 50.01	≥ 3.30
Equipment Specification	**Product Case Volume (cubic feet)**	**Federal Standard Criteria (L/kWh)**
Whole-home Dehumidifier	Up to 8	≥ 2.09
	≥ 8.01	≥ 3.30

Qualifying units shall be equipped with an adjustable humidistat control or shall require a remote humidistat control to operate.

1.1.8.2.2 Definition of Baseline Equipment

The baseline condition for this measure is a new dehumidifier that meets the federal efficiency standards. The Federal Standard for Dehumidifiers as of June 13, 2019, are defined in the below.

Table 1-20 Federal Minimum Standards for Dehumidifiers[28]

Equipment Specification	Capacity (pints/day)	Federal Standard Criteria (L/kWh)
Portable Dehumidifier	Up to 25	≥ 1.30
	≤ 25.01 to ≤ 50	≥ 1.60
	≥ 50.01	≥ 2.80

[28] https://www.energystar.gov/sites/default/files/ENERGY%20STAR%20Dehumidifiers%20Version%205.0%20Program%20Requirements.pdf

Equipment Specification	Product Case Volume (cubic feet)	Federal Standard Criteria (L/kWh)
Whole-home Dehumidifier	Up to 8	≥ 1.77
	≥ 8.01	≥ 2.41

1.1.8.3 Estimated Useful Life

The EUL of a portable dehumidifier is 11 years and a whole house dehumidifier is 19 years.

1.1.8.4 Deemed Savings Values

Energy savings and demand reductions for residential dehumidifiers are based on the energy consumption. The following subsections outline deemed calculations for energy savings and demand reductions, respectively.

1.1.8.4.1 Energy Savings

$$\Delta kWh = \left[\frac{(Avg\ Cap * 0.473)}{24} \times Hours\right] \times \left[\left(\frac{1}{L/kWh_{Base}}\right) - \left(\frac{1}{L/kWh_{Eff}}\right)\right]$$

Where:

Avg Cap = Average capacity of the unit (pints/day)

= Actual, if unknown assume capacity in each capacity range as provided in table below, or if capacity range unknown assume average.

0.473 = Constant to convert Pints to Liters

24 = Constant to convert Liters/day to Liters/hour

Hours = Run hours per year

= 1632[29]

L/kWh = Liters of water per kWh consumed, as provided in tables above

Estimated annual kWh use for each capacity class are presented below in the table below.

[29] ENERGY STAR Dehumidifier Calculator; 24-hour operation over 68 days of the year.

Table 1-21 Annual Energy Savings by Capacity Range

Portable Dehumidifiers					Annual Use		
Capacity Range	**Capacity Used**	**Federal Standard**	**ENERGY STAR**	**ENERGY STAR Most Efficient**[30]	**Federal Standard**	**ENERGY STAR**	**ENERGY STAR Most Efficient**
(pints/day)	(pints/day)	(≥L/kWh)	(≥L/kWh)	(≥L/kWh)	(kWh)	(kWh)	(kWh)
Up to 25	25	1.3	1.57	2.2	619	512	366
≥ 25.01 to ≤ 50	41.1	1.6	1.8	2.2	827	735	691
≥ 50.01	76.6	2.8	3.3	N/A	880	747	N/A
Whole House					**Federal Standard**	**ENERGY STAR**	**ENERGY STAR Most Efficient**
(cubic feet)	(pints/day)[31]	(≥L/kWh)	(≥L/kWh)	(≥L/kWh)	(kWh)	(kWh)	(kWh)
Up to 8	Up to 59.2	1.77	2.09	2.3	1,076	911	828
> 8	> 59.2	2.41	3.3	N/A	790	577	N/A

Deemed annual kWh savings for each capacity class are presented below in the table below.

Table 1-22 Annual Energy Savings by Capacity Range

System Type	Capacity Range	Capacity Used	ENERGY STAR Savings (kWh)	ENERGY STAR Most Efficient Savings(kWh)
Portable (Pints/Day)	Up to 25	25	106	253
	>25 to ≤ 50	41.1	92	225
	> 50	76.6	133	N/A
Whole House (Cubic Feet)	Up to 8	59.2	165	248
	> 8	59.2	213	N/A

[30] ENERGY STAR 2019 Most Efficient Criteria exclude the following products from eligibility; dehumidifiers with capacity of 75 pints/day or higher, portable dehumidifiers with capacity of 50.01 pints/day or higher, and whole home dehumidifiers with case volume greater than 8.0 cubic feet.

[31] The capacity and relative weighting of the whole-home dehumidifiers was sourced from the average capacity of portable dehumidifiers as there were no whole-home dehumidifiers on the ENERGY STAR Qualified Products List, as accessed in May 2019. See "Dehumidifier Calcs_05062019.xls.

1.1.8.4.2 Demand Reductions

$$\Delta kW = (\Delta kWh/Hours) * CF$$

Where:

Hours = Annual operating hours

=1632 hours[32]

CF = Summer Peak Coincidence Factor for measure

= 0.37[33]

Demand results for each capacity range are presented below in the table below.

Table 1-23 Demand Reductions by Capacity Range

System Type	Capacity Range	Peak kW Savings	
		ENERGY STAR	ENERGY STAR Most Efficient
Portable (Pints/Day)	Up to 25	0.024	0.057
	>25 to ≤50	0.021	0.051
	> 50	0.03	N/A
Whole House (Cubic Feet)	Up to 8	0.037	0.056
	> 8	0.048	N/A

1.1.8.5 Incremental Measure Cost

The incremental cost for an ENERGY STAR unit is assumed to be $10.29 and for an ENERGY STAR Most Efficient unit is $75.

1.1.8.6 Future Studies

At the time of authorship of the TRM, this measure was not implemented in Energy Smart programs. Thus, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents. If there is notable participation from this measure, primary research may be conducted to develop a New Orleans-specific estimate of days per year of operation to override the ENERGY STAR estimate of 68 days per year.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

[32] Based on 68 days of 24 hour operation; ENERGY STAR Dehumidifier Calculator

[33] Assume usage is evenly distributed day vs. night, weekend vs. weekday and is used between April through the end of September (4392 possible hours). 1632 operating hours from ENERGY STAR Dehumidifier Calculator. Coincidence peak during summer peak is therefore 1632/4392 = 37.2%

1.1.8.7 ENERGY STAR Pool Pumps

1.1.8.8 Measure Description

This measure involves the replacement of a single-speed pool pump with an ENERGY STAR certified variable speed or multi-speed pool pump. This measure applies to all residential applications; however, pools that serve multiple tenants in a common area are not eligible for this measure.

Multi-speed pool pumps are an alternative to variable speed pumps. The multi-speed pump uses an induction motor that is basically two motors in one, with full-speed and half-speed options. Multi-speed pumps may enable significant energy savings. However, if the half-speed motor is unable to complete the required water circulation task, the larger motor will operate exclusively. Having only two speed-choices limits the ability of the pump motor to fine-tune the flow rates required for maximum energy savings. Therefore, multi-speed pumps must have a minimum size of 1 horsepower (HP) to be eligible for this measure.

1.1.8.9 Baseline and Efficiency Standards

The baseline condition is a 0.5-3 horsepower (HP) standard efficiency single-speed pool pump.

The high efficiency condition is a 0.5-3 HP ENERGY STAR certified variable speed or multi-speed pool pump.

1.1.8.10 Estimated Useful Life

According to DEER 2014 the EUL for this measure is 10 years.

1.1.8.11 Deemed Savings Values

Deemed savings are per installed unit based on the pump horsepower.

Table 1-24 Variable Speed Pool Pumps – Deemed Savings Values

Pump HP	kW Savings	kWh Savings
0.5	0.24	1,713
0.75	0.28	1,860
1	0.36	2,063
1.5	0.47	2,465
2	0.52	2,718
2.5	0.57	2,838
3	0.72	3,364

Table 1-25 Multi-Speed Pool Pumps – Deemed Savings Values

Pump HP	kW Savings	kWh Savings
1	0.30	1,629
1.5	0.40	1,945
2	0.41	1,994
2.5	0.46	2,086
3	0.54	2,292

1.1.8.11.1 Energy Savings

Energy savings for this measure were derived using the *ENERGY STAR Pool Pump Savings* Calculator .

$kWh_{Savings} = kWh_{conv} - kWh_{ES}$

Where:

kWh_{conv}= Conventional single-speed pool pump energy (kWh)

kWh_{ES}= ENERGY STAR variable speed pool pump energy (kWh)

Algorithms to calculate the above parameters are defined as:

$kWh_{conv} = \frac{PFR_{conv}\times 60\times hours_{conv}\times days}{EF_{conv}\times 1000}$ $hours_{conv} = \frac{V_{pool}\times PT}{PFR_{conv}\times 60}$ $kWh_{ES} = kWh_{HS} +$

kWh_{LS} $kWh_{HS} = \frac{PFR_{HS}\times 60\times hours_{HS}\times days}{EF_{HS}\times 1000}$ $kWh_{LS} = \frac{PFR_{LS}\times 60\times hours_{LS}\times days}{EF_{LS}\times 1000}$ $PFR_{LS} =$

$\frac{V_{pool}}{t_{turnover}\times 60}$ kWh_{HS} = ENERGY STAR variable speed pool pump energy at high speed (kWh)

kWh_{LS} = ENERGY STAR variable speed pool pump energy at low speed (kWh)

$hours_{conv}$ = Conventional single-speed pump daily operating hours (Table 1-26)

$hours_{HS,VS}$ = ENERGY STAR variable speed pump high speed daily operating hours = 2 hours

$hours_{LS,VS}$ = ENERGY STAR variable speed pump low speed daily operating hours = 10 hours

$hours_{HS,MS}$ = ENERGY STAR multi-speed pump high speed daily operating hours = 2 hours

$hours_{LS,VS}$ = ENERGY STAR multi-speed pump low speed daily operating hours (Table 1-27)

$days$ = Operating days per year = 7 months x 30.4 days/month = 212.8 days (default)

PFR_{conv} = Conventional single-speed pump flow rate (gal/min) (Table 1-26)

$PFR_{HS,VS}$ = ENERGY STAR variable speed pump high speed flow rate = 50 gal/min (default)

$PFR_{LS,VS}$ = ENERGY STAR variable speed pump low speed flow rate (gal/min) = 30.6 (default)

$PFR_{HS,MS}$ = ENERGY STAR multi-speed pump high speed flow rate (gal/min) (Table 1-27)

$PFR_{LS,MS}$ = ENERGY STAR multi-speed pump low speed flow rate (gal/min) (Table 1-27)

EF_{conv} = Conventional single-speed pump energy factor (gal/W·hr) (Table 1-26)

$EF_{HS,VS}$ = ENERGY STAR variable speed pump high speed energy factor = 3.75 gal/W·hr (default)

$EF_{LS,VS}$ = ENERGY STAR variable speed pump low speed energy factor = 7.26 gal/W·hr (default)

$EF_{HS,MS}$ = ENERGY STAR multi-speed pump high speed energy factor (gal/W·hr) (Table 1-27

$EF_{LS,MS}$ = ENERGY STAR multi-speed pump low speed energy factor (gal/W·hr) (Table 1-27)

V_{pool} = Pool volume = 22,000 gal (default)

PT = Pool turnovers per day = 1.5 (default)

$t_{turnover,VS}$ = Variable speed pump time to complete 1 turnover = 12 hours (default)

$t_{turnover,MS}$ = Multi-speed pump time to complete 1 turnover (Table 1-27)

60 = Constant to convert between minutes and hours

1000 = Constant to convert W to kW

Table 1-26 Conventional Pool Pumps Assumptions

Pump HP	$hours_{conv}$	PFR_{conv} (gal/min)	EF_{conv} (gal/W·h)
0.5	11.0	50.0	2.71
0.75	10.4	53.0	2.57
1	9.2	60.1	2.40
1.5	8.6	64.4	2.09
2	8.5	65.4	1.95
2.5	8.1	68.4	1.88
3	7.5	73.1	1.65

Table 1-27 ENERGY STAR Multi-Speed Pool Pumps Assumptions

Pump HP	$t_{,turnover,M}S$	$hours_{MS,LS}$	$PFR_{HS,MS}$ (gal/min)	$EF_{HS,MS}$ (gal/W·h)	$PFR_{LS,MS}$ (gal/min)	$EF_{LS,MS}$ (gal/W·h)
1	11.8	9.8	56.0	2.40	31.0	5.41
1.5	11.5	9.5	61.0	2.27	31.9	5.43
2	11.0	9.0	66.4	1.95	33.3	5.22
2.5	10.8	8.8	66.0	2.02	34.0	4.80
3	9.9	7.9	74.0	1.62	37.0	4.76

1.1.8.11.2 Demand Reductions

Demand savings can be derived using the following:

$$kW_{Savings} = \left[\frac{kWh_{conv}}{hours_{conv}} - \left(\frac{kWh_{HS}+kWh_{LS}}{hours_{HS}+hours_{LS}}\right)\right] \times \frac{CF}{days}$$

Where:

CF = Coincidence factor[34] = 0.31

[34] Southern California Edison (SCE) Design & Engineering Services, 2008., *"Pool Pump Demand Response Potential, DR 07.01 Report."* June 2008. Derived from Table 16 assuming a peak period of 2-6 PM.

1.1.8.12 Incremental Cost

The incremental cost for ENERGY STAR Pool Pumps is :

- $549 for Variable Speed
- $235 for Multi-Speed

1.1.8.13 Future Studies

This measure has low-to-moderate participation in Energy Smart programs. If measure savings reach a minimum of 500,000 kWh in a program year, the TPE recommends a metering study to validate usage assumptions.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

1.1.9 ENERGY STAR REFRIGERATORS

1.1.9.1 Measure Description

This measure involves replace-on-burnout or early retirement of an existing refrigerator and installation of a new, full-size (7.75 ft^3 or greater) ENERGY STAR refrigerator. This measure applies to all residential or small commercial applications.

To qualify for early retirement, the ENERGY STAR unit must replace an existing, full-size, working unit that is at least six years old. For early retirement, the maximum lifetime age of an eligible piece of equipment is capped at the point at which it is expected that 75 percent of the equipment has failed. Where the age of the unit exceeds the 75 percent failure age, ROB savings should be applied. This cap prevents early retirement savings from being applied to projects where the age of the equipment greatly exceeds the estimated useful life of the measure.

1.1.9.2 Baseline and Efficiency Standards[35]

For ROB, the baseline for refrigerators is the DOE minimum efficiency standards for refrigerators, effective September 15, 2014.

For an individual refrigerator early retirement program, the baseline for refrigerators is assumed to be the annual unit energy consumption of the refrigerator being replaced, as reported by the Association of Home Appliance Manufacturers (AHAM) refrigerator database , adjusted for age according to the formula in the Measure Savings Calculations section. AHAM energy use data includes the average manufacturer-reported annual kilowatt hour usage, by year of production. This data dates back to the 1970s.

Alternatively, the baseline annual kilowatt hour usage of the refrigerator being replaced may be estimated by metering for a period of at least three hours using the measurement protocol specified in the US DOE report, “Incorporating Refrigerator Replacement into the Weatherization Assistance Program.”

To determine annual kWh of the refrigerator being replaced, use the formula:

$$kWh/yr = \frac{WH \times 8{,}760}{h \times 1{,}000}$$

Where:

WH = the watt-hours metered during a time period

h = measurement time period (hours)

8,760 = hours in a year

1,000 watt-hours = 1 kWh

[35] Current federal standards for refrigerators can be found on the DOE website at: http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/43. Current ENERGY STAR criteria for refrigerators can be found on the ENERGY STAR website at: www.energystar.gov/index.cfm?c=refrig.pr_crit_refrigerators

For the early retirement application, all new refrigerators must replace refrigerators currently in use, and all replaced refrigerators must be dismantled in an environmentally-safe manner in accordance with applicable federal, state, and local regulations. The installer will provide documentation of proper disposal of refrigerators.

Newly-installed refrigerators must meet current ENERGY STAR efficiency levels. All newly-installed refrigerators must be connected to an adequately-sized electrical receptacle and be grounded in accordance with the National Electric Code (NEC).

Minimum efficiency requirements for ENERGY STAR refrigerators are set at 10% more efficient than required by the minimum federal government standard. The standard varies depending on the size and configuration of the refrigerator. See Table 1-28.

Configuration Codes (Table 1-28):

- BF: Bottom Freezer
- SD: Refrigerator Only – Single Door
- SR: Refrigerator/Freezer – Single Door
- SS: Side-by-Side
- TF: Top Freezer
- TTD: Through the Door (Ice Maker)
- A: Automatic Defrost
- M: Manual Defrost
- P: Partial Automatic Defrost
- AV = Adjusted Volume[36]

Table 1-28 Formulas to Calculate the ENERGY STAR Refrigerator Criteria[37]

Product Category	Federal Standard (kWh/YR)	Maximum Energy Usage (kWh/YR)[38]	Ice (Y/N)	Defrost	Adjusted Volume	kWh	kW
Refrigerator-only—manual defrost	6.79 × AV + 193.6	6.111 × AV + 174.24	Y, N	M	20.8	33.48	0.0077
Refrigerator-freezers—manual or partial automatic defrost	7.99 × AV + 225.0	7.191 × AV + 202.5	Y, N	M, P	24.51	42.08	0.0097

[36] Adjusted Volume (AV) can be found for ENERGY STAR certified refrigerators on their website under the "advanced view" option. https://data.energystar.gov/Active-Specifications/ENERGY-STAR-Certified-Residential-Refrigerators/p5st-her9. Scroll to the right until you reach the column named "Adjusted Volume".

[37] Available for download at http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/43.

[38] Ten percent more efficient than baseline, as specified in the ENERGY STAR appliance calculator.

Product Category	Federal Standard (kWh/YR)	Maximum Energy Usage (kWh/YR)[38]	Ice (Y/N)	Defrost	Adjusted Volume	kWh	kW
Refrigerator-only-automatic defrost	7.07 × AV + 201.6	6.363 × AV + 181.44	Y, N	A	15.75	31.30	0.0072
Built-in refrigerator-only-automatic defrost	8.02 × AV + 228.5	7.218 × AV + 205.65	Y, N	A	16.97	36.46	0.0084
Refrigerator-freezers-automatic defrost with bottom-mounted freezer without an automatic icemaker	8.85 × AV + 317.0	7.965 × AV + 285.3	N	A	18.36	47.95	0.0111
Built-in refrigerator-freezers-automatic defrost with bottom-mounted freezer without an automatic icemaker	9.40 × AV + 336.9	8.46 × AV + 303.21	N	A	17.57	50.21	0.0073
Refrigerator-freezers-automatic defrost with bottom-mounted freezer with an automatic icemaker without TTD ice service	8.85 × AV + 401.0	7.965 × AV + 360.9	Y	A	24.6	61.87	0.0143
Built-in refrigerator-freezers-automatic defrost with bottom-mounted freezer with an automatic icemaker without TTD ice service	9.40 × AV + 420.9	8.46 × AV + 378.81	Y	A	21.67	62.46	0.0091
Refrigerator-freezers-automatic defrost with bottom-mounted freezer with an automatic	9.25 × AV + 475.4	8.325× AV + 427.86	Y	A	32.34	77.45	0.0179

Product Category	Federal Standard (kWh/YR)	Maximum Energy Usage (kWh/YR)[38]	Ice (Y/N)	Defrost	Adjusted Volume	kWh	kW
icemaker with TTD ice service							
Built-in refrigerator-freezers-automatic defrost with bottom-mounted freezer with an automatic icemaker with TTD ice service	9.83 × AV + 499.9	8.847 × AV + 449.91	Y	A	21.67	71.29	0.0164
Refrigerator-freezers-automatic defrost with side-mounted freezer without an automatic icemaker	8.51 × AV + 297.8	7.659 × AV + 268.02	N	A	30.44	55.68	0.0128
Built-in refrigerator-freezers-automatic defrost with side-mounted freezer without an automatic icemaker	10.22 × AV + 357.4	9.198 × AV + 321.66	N	A	33.71	70.19	0.0102
Refrigerator-freezers-automatic defrost with side-mounted freezer with an automatic icemaker without TTD ice service	8.51 × AV + 381.8	7.659 × AV + 343.62	Y	A	30.44	64.08	0.0093
Built-in refrigerator-freezers-automatic defrost with side-mounted freezer with an automatic icemaker without TTD ice service	10.22 × AV + 441.4	9.198 × AV + 397.26	Y	A	34.06	78.95	0.0182

Product Category	Federal Standard (kWh/YR)	Maximum Energy Usage (kWh/YR)[38]	Ice (Y/N)	Defrost	Adjusted Volume	kWh	kW
Refrigerator-freezers-automatic defrost with side-mounted freezer with an automatic icemaker with TTD ice service	8.54 × AV + 432.8	7.686 × AV + 389.52	Y	A	33.06	71.51	0.0165
Built-in refrigerator-freezers-automatic defrost with side-mounted freezer with an automatic icemaker with TTD ice service	10.25 × AV + 502.6	9.225 × AV + 452.34	Y	A	33.6	84.70	0.0195
Refrigerator freezers-automatic defrost with top-mounted freezer without an automatic icemaker	8.07 × AV + 233.7	7.263 × AV + 210.33	N	A	17.8	37.73	0.0087
Built-in refrigerator-freezers-automatic defrost with top-mounted freezer without an automatic icemaker	9.15 × AV + 264.9	8.235 × AV + 238.41	N	A	17.8	42.78	0.0062
Refrigerator-freezers-automatic defrost with top-mounted freezer with an automatic ice maker without TTD ice service	8.07 × AV + 317.7	7.263 × AV + 285.93	Y	A	21.22	48.89	0.0071
Built-in refrigerator-freezers-automatic defrost with top-mounted freezer without an automatic ice maker with TTD ice service	9.15 × AV + 348.9	8.235 × AV + 314.01	Y	A	21.22	54.31	0.0079

Product Category	Federal Standard (kWh/YR)	Maximum Energy Usage (kWh/YR)[38]	Ice (Y/N)	Defrost	Adjusted Volume	kWh	kW
Refrigerator-freezers-automatic defrost with top-mounted freezer with TTD ice service	8.40 × AV + 385.4	7.56 × AV + 346.86	Y	A	21.22	56.36	0.0082

1.1.9.3 Estimated Useful Life

According to the Department of Energy Technical Support Document, the EUL of High Efficiency Refrigerators is 17 years .

1.1.9.4 Deemed Savings Values

Deemed peak demand and annual energy savings should be calculated as shown below. Note that these savings calculations are different depending on whether the measure is replace-on-burnout or early retirement.

1.1.9.4.1 Energy Savings

(i) Replace-on-Burnout

$$kWh_{savings} = kWh_{baseline} - kWh_{ES}$$

Where:

$kWh_{baseline}$ = Federal standard baseline average energy usage (Table 1-28)

kWh_{ES}= ENERGY STAR average energy usage (Table 1-28)

(ii) Early Retirement

Annual kWh and kW savings must be calculated separately for two time periods:

- The estimated remaining life of the equipment that is being removed, designated the remaining useful life (RUL); and
- The remaining time in the EUL period (17 – RUL).

For the RUL:

$$kWh_{savings} = kWh_{pre} - kWh_{ES}$$

kWh_{pre} refers to manufacturer data or a measured consumption that is adjusted using the applicable degradation and in-situ adjustment factors.

$$kWh_{pre} = kWh_{manf} \times (1 + \mathrm{PDF})^{n}$$

For the remaining EUL period:

Calculate annual savings as you would for a replace-on-burnout project using the equation below. Lifetime kWh savings for Early Retirement Projects is calculated as follows:

$$Lifetime\ kWh_{savings} = \left(kwh_{savings,ER} \times RUL\right) + \left[kWh_{savings,ROB} \times (EUL - RUL)\right]$$

Where:

kWh_{NAECA}= NAECA baseline average energy usage (Table 1-28)

kWhpre = Adjusted manufacturer energy usage

kWh_{ES} = ENERGY STAR average energy usage (Table 1-28)

kWh_{manf} = annual unit energy consumption from the Association of Home Appliance Manufacturers (AHAM) refrigerator database[39]

PDF = Performance Degradation Factor 0.0125/year. Refrigerator energy use is expected to increase at a rate of 1.25% per year as performance degrades over time[40]

n = age of replaced refrigerator (years)

RUL = Remaining Useful Life (Table 1-29)

EUL = Estimated Useful Life = 17 years

1.1.9.4.2 Demand Savings

Since refrigerators operate 24/7, average kW reduction is equal to annual kWh divided by 8,760 hours per year. As shown below, this average kW reduction is multiplied by temperature and load shape adjustment factors to derive peak period kW reduction.

$$kW_{savings} = \frac{kWh_{savings}}{8{,}760\ hrs} \times \mathrm{TAF} \times \mathrm{LSAF}$$

Where:

TAF = Temperature Adjustment Factor[41] = 1.188

LSAF = Load Shape Adjustment Factor[42] = 1.074

---

[39] AHAM Refrigerator Database. http://rfdirectory.aham.org/AdvancedSearch.aspx.

[40] 2009 Second Refrigerator Recycling Program NV Energy – Northern Nevada Program Year 2009; M&V, ADM, Feb 2010, referencing Cadmus data on a California program, February 2010.

[41] Proctor Engineering Group, Michael Blasnik & Associates, and Conservation Services Group, 2004, *"Measurement & Verification of Residential Refrigerator Energy Use: Final Report – 2003-2004 Metering Study"*. July 29. Factor to adjust for varying temperature based on site conditions, p. 47.

[42] Proctor Engineering Group, Michael Blasnik & Associates, and Conservation Services Group, 2004, "Measurement & Verification of Residential Refrigerator Energy Use: Final Report – 2003-2004 Metering Study". July 29. Used load shape adjustment for "hot days" during the 4PM hour, pp. 45-48.

(i) Derivation of RULs

ENERGY STAR Refrigerators have an estimated useful life of 17 years. This estimate is consistent with the age at which 50 percent of the refrigerators installed in a given year will no longer be in service, as described by the survival function in Figure 1-1.

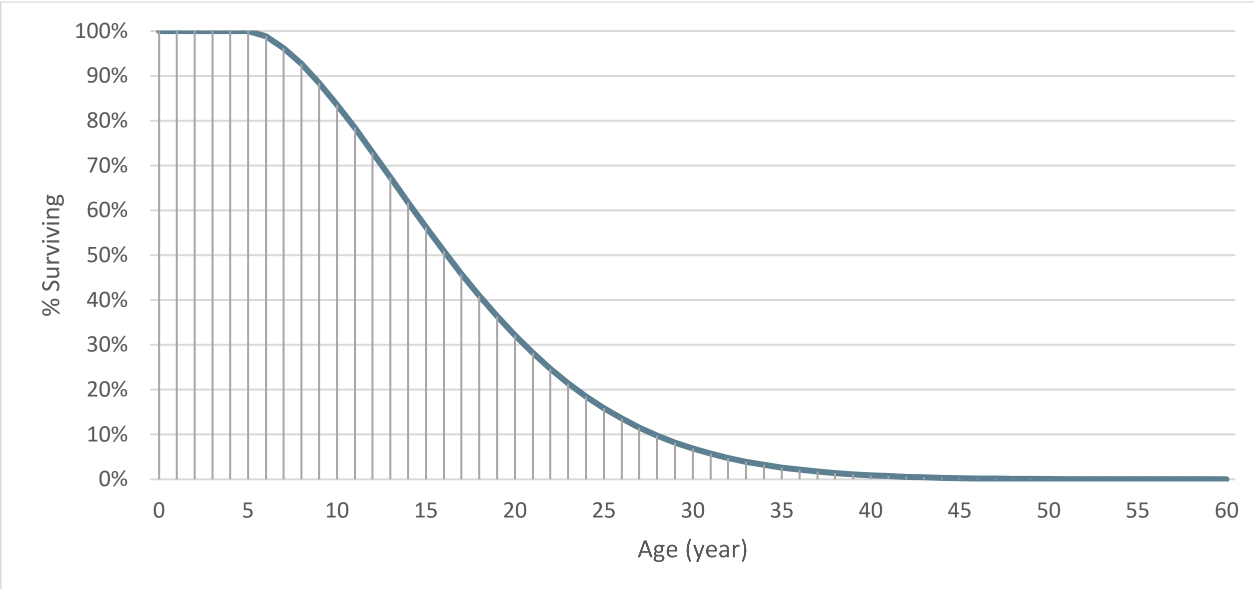


Figure 1-1 Survival Function for ENERGY STAR Refrigerator[43]

The method for estimating the RUL of a replaced system uses the age of the existing system to re-estimate the projected unit lifetime based on the survival function shown in Figure 1-1. The age of the refrigerator being replaced is found on the horizontal axis, and the corresponding percentage of surviving refrigerators is determined from the chart. The surviving percentage value is then divided in half, creating a new estimated useful lifetime applicable to the current unit age. The age (year) that corresponds to this new percentage is read from the chart. RUL is estimated as the difference between that age and the current age of the system being replaced.

Table 1-29 Remaining Useful Life (RUL) of Replaced Refrigerator[44]

Age of Replaced Refrigerator (years)	RUL (years)	Age of Replaced Refrigerator (years)	RUL (years)
6	10.3	15	6.0
7	9.6	16	5.8
8	8.9	17	5.5
9	8.3	18	5.3
10	7.8	19	5.1
11	7.4	20	4.9

[43] U.S. DOE, Technical Support Document, 2011, "Residential Refrigerators, Refrigerator-Freezers, and Freezers, 8.2.3 Product Lifetimes." September 15. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/43.

Download TSD at: http://www.regulations.gov/#!documentDetail;D=EERE-2008-BT-STD-0012-0128.

[44] Use of the early retirement baseline is capped at 22 years, representing the age at which 75 percent of existing equipment is expected to have failed. Equipment older than 22 years should use the ROB baseline.

12	7.0	21	4.8
13	6.6	22	4.6
14	6.3	23 +	0.0

1.1.9.5 Incremental Cost

The incremental cost for efficient refrigerators is $40 for ENERGY STAR units and $140 for CEE Tier II units. For early retirement, incremental cost is calculated using:

- Full installed cost of the refrigerator: program-actual purchase price should be used. If not available, use $451 for ENERGY STAR and $551 for CEE Tier 2 units .
- Present value of replacement cost of a baseline refrigerator after the RUL of the initial replaced unit is exhausted. This unit costs $411 at the time of purchase, and should be discounted by the number of years of RUL. If RUL is unknown, use 4 years. Default discount rate is 10% . This results in a deferred replacement cost of $281.
- Overall incremental cost of early retirement is then calculated as:
    - ENERGY STAR: $451 - $281 = $70
    - CEE Tier II: $170

1.1.9.6 Net-to-Gross

The NTG for this measure is 44% .

1.1.9.7 Future Studies

There are no future studies planned for this measures at this time.

1.1.10ENERGY STAR FREEZERS

1.1.10.1 Measure Description

This measure is for the purchase a freezer meeting the efficiency specifications of ENERGY STAR is installed in place of a model meeting the federal standard (NAECA). An ENERGY STAR freezer must be at least 10 percent more efficient than the minimum federal government standard.

1.1.10.2 Baseline and Efficiency Standards

The baseline equipment is assumed to be a model that meets the federal minimum standard for energy efficiency. The efficient equipment is defined as a freezer meeting the efficiency specifications of ENERGY STAR, as defined below.

Table 1-30 ENERGY STAR Freezer Specifications

Equipment	Volume	Criteria
Full Size Freezer	7.75 cubic feet or greater	At least 10% more energy efficient than the minimum federal government standard (NAECA).
Compact Freezer	Less than 7.75 cubic feet and 36 inches or less in height	At least 20% more energy efficient than the minimum federal government standard (NAECA).

The standard varies depending on the size and configuration of the freezer (chest freezer or upright freezer, automatic or manual defrost) and is defined in the table below.

Energy usage specifications are defined in the table below (note, AV is the freezer Adjusted Volume and is calculated as 1.73*Total Volume).

Table 1-31 Energy Usage Specifications

Product Category	**Volume (cubic feet)**	**Assumptions after September 2014**	
		Federal Baseline Maximum Energy Usage in kWh/year[45]	**Maximum Energy Usage in kWh/year[46]**
Upright Freezers with Manual Defrost	7.75 or greater	5.57*AV + 193.7	5.01*AV + 174.3
Upright Freezers with Automatic Defrost	7.75 or greater	8.62*AV + 228.3	7.76*AV + 205.5

[45] See Department of Energy Federal Standards.

[46] See Version 5.0 ENERGY STAR specification.

Chest Freezers and all other Freezers except Compact Freezers	7.75 or greater	7.29*AV + 107.8	6.56*AV + 97.0
Compact Upright Freezers with Manual Defrost	< 7.75 and 36 inches or less in height	8.65*AV + 225.7	7.79*AV + 203.1
Compact Upright Freezers with Automatic Defrost	< 7.75 and 36 inches or less in height	10.17*AV + 351.9	9.15*AV + 316.7
Compact Chest Freezers	<7.75 and 36 inches or less in height	9.25*AV + 136.8	8.33*AV + 123.1

1.1.10.3 Estimated Useful Life

The EUL of this measure is 22 years .

1.1.10.4 Deemed Savings Values

1.1.10.4.1 Energy Savings

$$kWh_{savings} = kWh_{base} - kWh_{efficient}$$

Where:

kWh_{base} = Baseline kWh consumption per year as calculated in algorithm provided in table above.

$kWh_{efficient}$ = ENERGY STAR kWh consumption per year as calculated in algorithm provided in table above.

1.1.10.4.2 Demand Savings

Demand savings should be calculated using the following formula:

$$kW_{savings} = kWh_{savings} \times Energy\ Demand\ Factor$$

Where:

$Energy\ Demand\ Factor$ = 0.0001614

The table below outlines the deemed savings for this measure.

Table 1-32 Deemed Energy Savings and Demand Reductions

Freezer Category	Average Unit Adj. Volume (Ft^3)	Conventional Usage (kWh/YR)	ENERGY STAR Usage (kWh/YR)	kWh Savings	kW Reduction
Upright Freezers with Manual Defrost	27.9	349.1	314.1	35.0	0.0057
Upright Freezers with Automatic Defrost	27.9	468.8	422.0	46.8	0.0076
Chest Freezers and all other Freezers except Compact Freezers	27.9	310.4	280.0	30.3	0.0049
Compact Upright Freezers with Manual Defrost	10.4	315.7	284.1	31.5	0.0051
Compact Upright Freezers with Automatic Defrost	10.4	457.7	411.3	46.4	0.0075
Compact Chest Freezers	10.4	233.0	209.7	23.3	0.0038

1.1.10.5 Incremental Cost

The incremental cost for this measure is $42 .

1.1.10.6 Future Studies

There are no future studies planned for this measure at this time.

1.1.11 REFRIGERATOR AND FREEZER RECYCLING

1.1.11.1 Measure Description

This measure involves early retirement and recycling of an inefficient but operational existing, full-size (7.75 ft^3 or greater) refrigerator/freezer in a residential application. Savings represent the entire estimated energy consumption of the existing unit and are applicable over the estimated remaining life of the existing unit. A part use factor is applied to account for those secondary units that are not in use throughout the entire year.

1.1.11.2 Baseline and Efficiency Standards

Without program intervention, the recycled refrigerator or freezer would have remained operable on the electrical grid. As a result, the baseline condition for early retirement programs is the status quo (continued operation) and the basis for estimating energy savings is the annual energy consumption of the refrigerator or freezer being retired.

1.1.11.3 Estimated Useful Life

It is difficult to determine the number of years that a recycled refrigerator would have continued to operate absent the program and, therefore, the longevity of the savings generated by recycling old-but-operable refrigerators through the program. According to the DOE Technical Support Document , the EUL of High Efficiency Refrigerators is 17 years. The EUL for a freezer is 12 years . Section C.1.12.3.1 details a survival analysis and the derivation of refrigerator and freezer RULs. Below, Table 1-33 has been taken from said section and presents RULs by refrigerator or and freezer age.

Table 1-33 Remaining Useful Life of Replaced Refrigerator[47]

Age of Replaced Refrigerator (years)	Refrigerator RUL (years)	Freezer RUL (years)
6	10.3	7.3
7	9.6	6.8
8	8.9	6.3
9	8.3	5.9
10	7.8	5.5
11	7.4	5.2
12	7	4.9
13	6.6	4.7
14	6.3	4.4
15	6	4.2
16	5.8	4.1
17	5.5	3.9
18	5.3	0
19	5.1	0
20	4.9	0
21	4.8	0

[47] Use of the early retirement baseline is capped at 22 years, representing the age at which 75 percent of existing equipment is expected to have failed. Equipment older than 22 years should use the ROB baseline.

22	4.6	0
23 +	0	0

If refrigerator or freezer age is unknown, use a measure life of 6 years for refrigerators, 4 years for freezers.

1.1.11.3.1 Derivation of RULs

The DOE Technical Support Document[48] estimates that high efficiency refrigerator useful life is 17 years. This estimate is consistent with the age at which 50 percent of the refrigerators installed in a given year will no longer be in service, as described by the survival function in Figure 1-2.

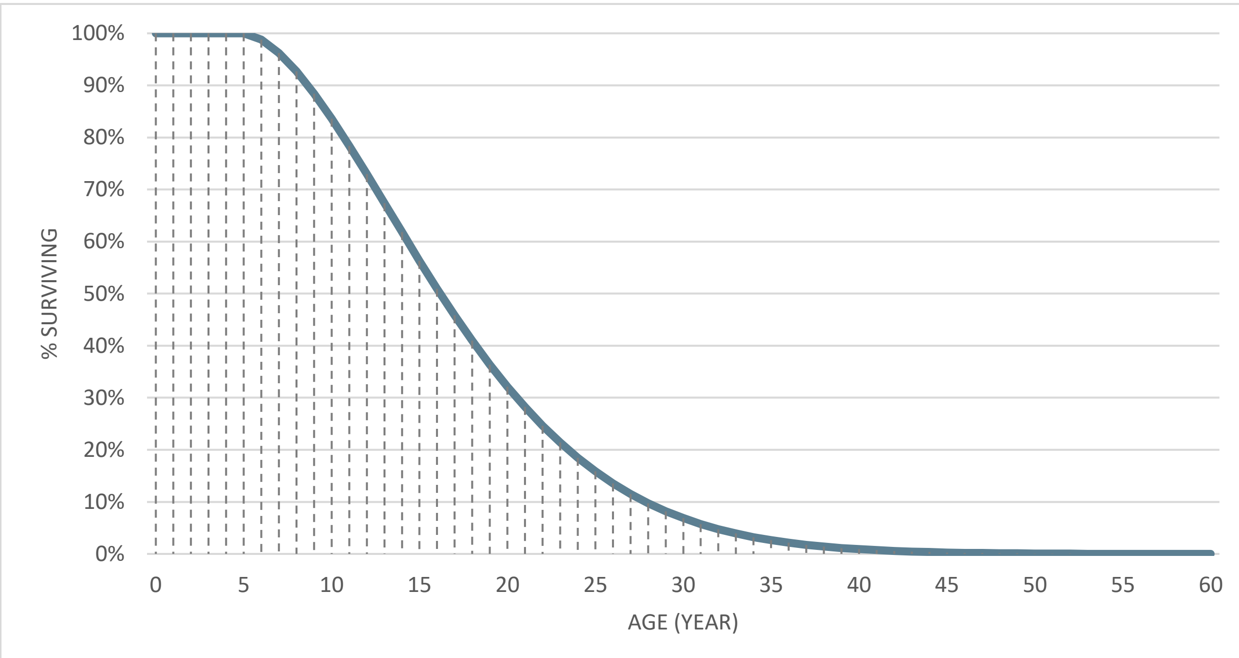


Figure 1-2 Survival Function for ENERGY STAR Refrigerators[49]

The method for estimating the RUL of a replaced system uses the age of the existing system to re-estimate the projected unit lifetime based on the survival function shown in Figure 1-2. The age of the refrigerator being replaced is found on the horizontal axis, and the corresponding percentage of surviving refrigerators is determined from the chart. The surviving percentage value is then divided in half, creating a new estimated useful lifetime applicable to the current unit age. The age (year) that corresponds to this new percentage is read from the chart. RUL is estimated as the difference between that age and the current age of the system being replaced. To scale freezer RULs the TPE multiplied refrigerator RULs by the ratio of freezer/refrigerator EULs (12/17 = 0.706).

[48] *Ibid.*

[49] U.S. DOE, Technical Support Document, 2011, "Residential Refrigerators, Refrigerator-Freezers, and Freezers, 8.2.3 Product Lifetimes." September 15. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/43.

Download TSD at: http://www.regulations.gov/#!documentDetail;D=EERE-2008-BT-STD-0012-0128.

1.1.11.4 Deemed Savings Values

Energy savings and demand reductions for retired refrigerators and freezers are based upon a linear regression model using equations and coefficients listed below.

1.1.11.4.1 Refrigerators

Table 1-34 displays the model coefficients and default inputs in the absence of program data. The coefficients presented are a combination of estimates from NREL, Illinois TRM V7.0, Texas TRM V6.0, and MidAtlantic TRM V8.0. Certain characteristics are 0-1 dummy indicators (such as whether a unit has side-by-side configuration). For these inputs, the Default Input is reflective of the average prevalence of that configuration the NREL UMP. For example, a default input of .323 for side-by-side indicates that 32.3% of units recycled could be expected to be side-by-side, based on prior research cited by the TPE.

Table 1-34 Savings Coefficients for Refrigerator Savings

Independent Variable	Estimated Coefficient[3]	Default Input[50]	kWh Impact
Intercept	0.750	1	273.75
Age (years)	0.032	17.10	199.73
Pre-1990	1.140	.081	33.70
Size (square feet)	0.067	19.00	464.65
Single Door	-1.085	.039	-15.44
Side-by-Side	0.957	.323	112.83
Primary Usage	0.477	.696	121.18
Unconditioned x CDD	0.007	.259*3,470	6.29
Unconditioned x HDD	-0.016	.259*1,058	-4.38
Total Unit Energy Consumption		1,192	
Part-Use Adjustment		93.2%	
Default kWh Savings		1,111	

$$\text{Savings}_{kWh} = [0.75 + (Age \times 0.032) + (Pre - 1990 \ \times 1.140) + (Size \ \times 0.067) +$$

$$(Single\ Door \times \ -1.085) + (Side - by - Side \times 0.957) + (Primary\ Usage \times 0.477) +$$

$$(Unconditioned\ CDD \ \times \ 0.007) + (Unconditioned\ HDD \times -0.016)] \times 365.25 \times 0.932$$

Where:

Age = Age of retired unit

Pre-1990 = Pre-1990 dummy (=1 if manufactured pre-1990, else 0)

Size = Capacity (cubic feet) of retired unit

Single Door = Single door dummy (=1 if one door, else 0)

[50] Unit inputs based on averages from Public Service Company of New Mexico 2016 EM&V Report, ADM Associates Inc. Weather inputs based on TMY3 estimates for CDD and HDD for New Orleans). https://www.pnm.com/documents/396023/3157050/2016+Independent+Measurement+and+Verification+Report%2C%20Part+1%2C%20ADM+Associates%2C%20Inc.pdf/011b6c03-4358-4396-acf8-73cd8a24009e

Side-by-Side = Side-by-side dummy (= 1 if side-by-side, else 0)

Primary Usage = Primary usage type (in absence of the program) dummy (= 1 if Primary, else 0)

Unconditioned x CDD = Weather interaction for units located in unconditioned spaces (=1*CDD). New Orleans CDD base 65 = 3,470

Unconditioned x HDD = Weather interaction for units located in unconditioned spaces (=1*HDD) New Orleans HDD base 65 = 1,058[3]

Part Use = To account for those units that are not running throughout the entire year.

For example: A resident decides to recycle a 20 square foot single door, non-side-by-side refrigerator. They originally purchased the unit in 1995 and has since been replaced, so this unit is now located in an unconditioned garage as extra food and beverage storage.

$$\text{Savings}_{kWh} = [0.75 + (24 \times 0.032) + (0 \times 1.140) + (20 \times 0.067) + (1 \times -1.085) + (0 \times 0.957) + (0 \times 0.477) + (1 \times 0.007) + (1 \times -0.016)] \times 365.25 \times 0.932 = 600.49 \text{ kWh}$$

1.1.11.4.2 Freezers

Table 1-35 Savings Coefficients for Freezer Savings

Independent Variable	Estimated Coefficient	Default Input	kWh Impact
Intercept	-0.296	1	-108.04
Appliance Age (years)	0.039	17.1	243.42
Pre-1990	0.486	0.081	14.37
Size (square feet)	0.104	15.9	603.56
Freezer Chest	0.122	0.119	5.30
Unconditioned x CDD	-0.002	.741*3470	-5.14
Unconditioned x HDD	0.024	.741*1,058	18.82
Total Unit Energy Consumption		772	
Part-Use Adjustment		85.5%	
Default kWh Savings		660	

$$\text{Savings}_{kWh} = [-0.296 + (Age \times 0.039) + (Pre - 1990 \times 0.486) + (Size \times 0.104) + (Freezer\ Chest \times 0.122) + (Unconditioned\ CDD \times -0.002) + (Unconditioned\ HDD \times 0.024)] \times 365.25 \times 0.855$$

Where:

$Freezer\ Chest$ = Chest freezer dummy (= 1 if chest freezer, else 0)

$$\text{Savings}_{kW} = \left(\frac{\Delta kWh}{8{,}760}\right) \times CF$$

Where:

CF = Coincident factor defined as summer kW/average kW

= 1.082 for Refrigerators

= 1.065 for Freezers

The coincident factor aggregates two adjustments:

- The duty cycle of the equipment during the peak period; and
- The declining efficiency of the compressor when subject to higher outside air temperatures.

The resulting aggregate effect is a coincidence factor > 1.0 for refrigerators and freezers.

Based on the default inputs specified in Table 1-34 and Table 1-35, the recommended default kW values are:

- Refrigerators: 1,111 / 8,760 * 1.082 = 0.137
- Freezers: 660 / 8,760 * 1.065 = 0.080

1.1.11.5 Incremental Cost

The incremental cost for this measure is the actual cost associated with the removal and recycling of the secondary refrigerator. If unknown, use $170 per unit.

1.1.11.6 Future Studies

This chapter is based on regression coefficients averaged from NREL, the Illinois TRM 7.0, the Texas TRM 6.0 and the Mid-Atlantic TRM 8.0 and citation of unit data from a refrigerator recycling evaluation completed on behalf of Public Service Company of New Mexico. It is recommended that program administrators collect the data needed to support energy savings estimates based on actual units recycled. Administrators should collect:

- Unit age;
- Size (cubic feet);
- Configuration (Refrigerators: side-by-side, single-door, top-freezer, bottom-freezer. Freezers: upright, chest);
- Location of use (conditioned versus unconditioned space); and
- Unit make and model number.

A net-to-gross study will be conducted in PY13, which will address the extent to which the units would have been disposed of by program participants in the absence of the program; free-ridership for refrigerator recycling addresses the question of “would the unit be plugged in in the absence of a program intervention”, and as a result the savings are program attributable if a participation would have otherwise kept it in use, gave it to a friend or relative, donated it to charity, or sold the unit.

If refrigerator/freezer cycling constitutes 5% or more of portfolio-level residential savings, the TPE would recommend an in-situ metering study to develop a New Orleans-specific unit energy consumption regression model.

1.2 Domestic Hot Water

1.2.1 WATER HEATHER REPLACEMENT

1.2.1.1 Measure Description

This measure involves:

- The replacement of electric water heaters by ENERGY STAR heat pump water heaters (HPWH);
- The replacement of either electric or gas water heaters by ENERGY STAR certified solar water heaters.

Systems greater than 55 gallons in capacity have an efficiency requirement that necessitates installation of a heat pump water heater or tank-less system.

Water heating deemed savings values are measured on an annual per-unit basis. Deemed savings variables include tank volume, estimated water usage, and rated uniform energy factor. Fuel substitution is not eligible for deemed savings. This measure applies to all residential applications.

1.2.1.2 Baseline and Efficiency Standards

The current baseline for electric and gas water heaters is the US DOE energy efficiency standard (10 CFR Part 430), which is consistent with the International Energy Conservation Code (IECC) 2009. Residential water heaters manufactured on or after April 16, 2015, must comply with the amended standards found in the Code of Federal Regulations, 10 CFR 430.32(d)[51]. An abbreviated account of the regulations that apply to qualifying water heater units are found in the table below.

Table 1-36 Title 10: 430.32 (d) Water Heater Standards

Product Class	Rated Storage Volume	Draw Pattern	Uniform Energy Factor (UEF)
Electric Storage Water Heater	≥ 20 gal and ≤ 55 gal	Very Small	0.8808 − (0.0008 × Vr)
		Low	0.9254 − (0.0003 × Vr)
		Medium	0.9307 − (0.0002 × Vr)
		High	0.9349 − (0.0001 × Vr)
	> 55 gal and ≤ 120 gal	Very Small	1.9236 − (0.0011 × Vr)
		Low	2.0440 − (0.0011 × Vr)
		Medium	2.1171 − (0.0011 × Vr)
		High	2.2418 − (0.0011 × Vr)
Instantaneous Electric Water Heater (tankless)	< 2 gal	Very Small	0.91
		Low	0.91
		Medium	0.91
		High	0.92

Where Vr[52] is the Rated Storage Volume which equals the water storage capacity of a water heater, in gallons, as certified by the manufacturer.

The new code requires that a "draw pattern" is to be determined to better calculate the energy factor associated with a water heater. The draw pattern is based on the first hour rating (FHR) of an installed

[51] https://www.govinfo.gov/content/pkg/CFR-2018-title10-vol3/pdf/CFR-2018-title10-vol3-part430.pdf (pg. 480)

[52] Vr is the Rated Storage Volume (in gallons), as determined pursuant to 10 CFR 429.17

water heater and is defined as the number of gallons of hot water the heater can supply per hour. The following three tables (Table 1-37, Table 1-38 and Table 1-39) provide the FHR ranges and corresponding draw patterns for different equipment types.

Table 1-37 Tank Water Heater Draw Pattern

New FHR Greater Than or Equal to:	New FHR Less Than:	Draw pattern
0 gallons	18 gallons	Very Small
18 gallons	51 gallons	Low
51 gallons	75 gallons	Medium
75 gallons	No Upper Limit	High

Table 1-38 Instantaneous Water Heater Draw Pattern

New Max GPM Greater Than or Equal to:	New Max GPM Rating Less Than:	Draw pattern
0 gallons/minute	1.7 gallons/minute	Very Small
1.7 gallons/minute	2.8 gallons/minute	Low
2.8 gallons/minute	4 gallons/minute	Medium
4 gallons/minute	No Upper Limit	High

Table 1-39 Heat Pump Water Heater Draw Pattern

Draw Volume	Draw Pattern
10 gallons	Very Small
38 gallons	Low
55 gallons	Medium
84 gallons	High

Current baseline Uniform Energy Factors (efficiencies) for various tank size electric storage water heaters are calculated and shown in Table 1-40. The estimated annual hot water usage for electric storage water heaters of various sizes is shown in Table 1-41.

Table 1-40 Calculated Electric Storage Water Heater Baseline Uniform Energy Factors

Uniform Energy Factors by Tank Size		Capacity (Gallons)				
		30	40	50	65	80
		≥ 20 gal and ≤ 55 gal			> 55 gal and ≤ 120 gal	
Electric Storage Water Heater	Very Small	0.8568	0.8488	0.8408	1.8521	1.8356
	Low	0.9164	0.9134	0.9104	1.9725	1.956
	Medium	0.9247	0.9227	0.9207	2.0456	2.0291
	High	0.9319	0.9309	0.9299	2.1703	2.1538

Table 1-41 Estimated Annual Hot Water Use (Gallons)

Tank Size (gal) of Replaced Water Heater	30	40	50	65	80
Estimated Annual Hot Water Usage	12,761	16,696	18,973	22,767	27,320

1.2.1.3 Estimated Useful Life

The EUL of this measure is dependent on the type of water heating. According to DEER 2014, the following measure lifetimes should be applied:

- 13 years for electric storage tank water heaters
- 10 years for Heat Pump Water Heaters
- 20 years for tank-less electric water heaters
- 15 years for solar water heaters

1.2.1.4 Deemed Savings Values

1.2.1.4.1 Water Heater

(i) Energy Savings

Calculated deemed energy savings are shown in Table 1-42. Water heater replacements that have tank sizes that fall between the range of 30-gallon to 50-gallon in volume generally produce adequate energy savings.

Table 1-42 Deemed Energy Savings for Water Heater Replacement

Water Heater System Type	HVAC System Type	Draw Pattern	Capacity (Gallons)				
			30	40	50	65	80
Heat Pump Water Heater	Gas Furnace	Very Small	1,351	1,790	2,059	709	867
		Low	1,236	1,624	1,854	620	757
		Medium	1,221	1,602	1,826	570	697
		High	1,208	1,583	1,801	494	605
	Heat Pump	Very Small	1,220	1,618	1,864	475	586
		Low	1,105	1,452	1,658	386	477
		Medium	1,090	1,430	1,631	336	417
		High	1,077	1,411	1,606	260	324
	Electric Resistance	Very Small	1,130	1,501	1,731	315	394
		Low	1,015	1,335	1,525	226	285
		Medium	1,000	1,313	1,497	177	225
		High	987	1,294	1,473	100	132
	Unconditioned	Very Small	1,260	1,670	1,923	546	671
		Low	1,144	1,504	1,718	457	562
		Medium	1,130	1,483	1,690	408	502
		High	1,117	1,464	1,666	331	409
Solar with Electric Backup	N / A	Very Small	1,611	2,130	2,446	1,173	1,423
		Low	1,496	1,964	2,240	1,083	1,314
		Medium	1,481	1,942	2,212	1,034	1,254
		High	1,468	1,923	2,188	958	1,161

(ii) Demand Reductions

Calculated deemed demand reductions are shown in Table 1-43.

Table 1-43 Deemed Demand Reductions for Water Heater Replacement

Water Heater System Type	HVAC System Type	Draw Pattern	Capacity (Gallons)				
			30	40	50	65	80
Heat Pump Water Heater	Gas Furnace	Very Small	0.1185	0.1570	0.1806	0.0622	0.0760
		Low	0.1084	0.1424	0.1626	0.0543	0.0664
		Medium	0.1071	0.1405	0.1601	0.0500	0.0612
		High	0.1060	0.1388	0.1580	0.0433	0.0530
	Heat Pump	Very Small	0.1070	0.1419	0.1635	0.0417	0.0514
		Low	0.0969	0.1274	0.1455	0.0338	0.0418
		Medium	0.0956	0.1254	0.1430	0.0295	0.0365
		High	0.0944	0.1238	0.1409	0.0228	0.0284
	Electric Resistance	Very Small	0.0991	0.1316	0.1518	0.0276	0.0345
		Low	0.0890	0.1171	0.1338	0.0198	0.0250
		Medium	0.0877	0.1152	0.1313	0.0155	0.0197
		High	0.0866	0.1135	0.1292	0.0088	0.0116
	Unconditioned	Very Small	0.1105	0.1465	0.1687	0.0479	0.0589
		Low	0.1004	0.1319	0.1507	0.0401	0.0493
		Medium	0.0991	0.1300	0.1482	0.0357	0.0440
		High	0.0979	0.1284	0.1461	0.0291	0.0359
Solar with Electric Backup	N / A	Very Small	0.1413	0.1868	0.2145	0.1029	0.1248
		Low	0.1312	0.1722	0.1965	0.0950	0.1152
		Medium	0.1299	0.1703	0.1940	0.0907	0.1100
		High	0.1288	0.1687	0.1919	0.0840	0.1018

1.2.1.4.2 Heat Pump Water Heater

(i) Energy Savings

The residential heat pump water heater (HPWH) measure involves the installation of an integrated ENERGY STAR HPWH. The HPWHs available through the ENERGY STAR product finder have an average UEF of 3.22.

The variables affecting deemed savings are storage tank volume, HPWH Energy Factor (EF), HPWH installation location (in conditioned or unconditioned space), and weather zone. This measure considers an air-conditioning energy savings (“Cooling Bonus”) and an additional space heating energy requirement (“Heating Penalty”) associated with the HPWH when it is installed inside conditioned space.

$$kWh_{Savings} = \frac{\rho \times C_p \times V \times \left(T_{SetPoint} - T_{Supply}\right) \times \left(\frac{1}{EF_{pre}} - \left(\frac{1}{(EF_{post} \times (1 + PA\%)} \times Adj\right)\right)}{3{,}412\ Btu/kWh}$$

Where:

ρ = Water density = 8.33 lb/gal

C_p = Specific heat of water = 1 BTU/lb.·°F

V = Estimated annual hot water use (gal) from Table 1-41

$T_{SetPoint}$ = Water heater set point (value = 123.61°F, based on on-site testing of New Orleans homes)

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

EF_{pre} = Baseline Uniform Energy Factor from Table 1-40

EF_{post} = Uniform Energy Factor of new HPWH. ENERGY STAR average is 3.22

$PA\%$ = Performance Adjustment to adjust the HPWH EF relative to ambient air temperature per DOE guidance $= 0.00008 \times T_{amb}^3 + 0.0011 \times T_{amb}^2 - 0.4833 \times T_{amb} + 0.0857$. Assumed conditioned space, 73.4 degrees , PA% = 2.17%. For unconditioned space, 68.78 degrees , PA% = -1.92%

T_{amb}= Ambient temperature dependent on location of HPWH (Conditioned or Unconditioned Space) and Weather Zone from Table 1-44

Adj =HPWH-specific adjustment factor to account for Cooling Bonus and Heating Penalty on an annual basis, as well as backup electrical resistance heating which is estimated at 0.92 EF. Adjustment factors are listed in Table 1-45

$3{,}412\ Btu/kWh$ = conversion factor to convert BTU to kWh

The average ambient air temperatures listed in Table 1-44 are applicable to the installation locations for the HPWH. Unconditioned space is considered to be an unheated garage-like environment. This data is based on local ambient temperatures for each weather zone calculated from TMY3 weather data. The conditioned space temperatures assume thermostat settings of 78°F (cooling season) and 70°F (heating season), and a “balance point temperature” of 65°F. Unconditioned space ambient temperatures are adjusted from the local temperatures by seasonal factors to account for a garage-like setting.

Table 1-44 Average Ambient Temperatures and PA% Factors by Installation Location

	Conditioned Space	**Unconditioned Space**
$T_{ambient}$	73.4°F	68.9°F
PA% Factor	2.17%	- 1.91%

Table 1-45 HPWH Adjustment[53]

Water Heater Location	**Furnace Type**	**Adjustment Factor**
Conditioned Space	Gas	0.917
	Heat Pump	1.201
	Elec. Resistance	1.395
Unconditioned Space	N/A	1.070

[53] In order to facilitate an algorithmic approach: a spreadsheet model was created which modeled savings accounting for Cooling Bonus and Heating Penalty on an annual basis, as well as backup electrical resistance heating; HPWH Adjustment factors were derived to equate the results of this more extensive model to a simpler algorithm.

As an example, the following deemed electricity savings are applicable for the replacement of a 50-gallon electric storage tank water heater having a medium draw pattern, with a 50-gallon heat pump water heater using an ENERGY STAR model with an EF of 3.22 in conditioned space for a household using a gas furnace in New Orleans:

$$kWh_{Savings} = \frac{8.33 \times 1 \times 18{,}973 \times (123.61 - 74.8) \times \left(\frac{1}{0.9207} - \left(\frac{1}{3.22 \times (1 + 0.0217355)} \times 0.917\right)\right)}{3{,}412\ Btu/kWh}$$

$$= 1{,}825.758 kWh$$

(ii) Demand Reductions

$$kW_{savings} = kWh_{savings} \times Ratio_{Annual\ kWh}^{Peak\ kW}$$

Where:

$Ratio_{Annual\ kWh}^{Peak\ kW}$ Demand savings were calculated using the US DOE "Building America Performance Analysis Procedures for Existing Homes" combined domestic hot water use profile. Based on this profile, the ratio of Peak kW to Annual kWh for domestic hot water usage was estimated to be 0.0000877 kW per annual kWh savings

For the HPWH example shown in equation above, peak demand savings is 1,826 kWh × 0.0000877 = 0.160 kW.

1.2.1.4.3 Solar Water Heating with Electric Backup

(i) Energy Savings

The residential solar water heater measure involves the installation of an ENERGY STAR certified solar water heater rated by the Solar Rating and Certification Corporation (SRCC). Solar water heaters available through the ENERGY STAR product finder have an average Solar Energy Factor (SEF) of 8.7 for electric backup.

The variables affecting deemed savings are SEF, LF, and weather zone.

The SRCC determines SEF based on standardized 1,500 Btu/ft^2-day solar radiation profile across the U.S. As solar insolation varies widely depending on geographic location, in order to derive more accurate estimates for a given locale, Localization Factors (LF) are used to adjust the SEF. The LF for the New Orleans weather zone have been calculated. The LF is based on the daily total insolation (1,598 in New Orleans), averaged annually, per a Satellite Solar Radiation model developed by the State University of New York (SUNY).

$$kWh_{Savings} = \frac{\rho \times C_p \times V \times (T_{SetPoint} - T_{Supply}) \times \left(\frac{1}{EF_{pre}} - \frac{1}{SEF\ x\ LF}\right)}{3412 \frac{Btu}{kWh}}$$

Where:

ρ = Water density = 8.33 lb./gal

C_p = Specific heat of water = 1 BTU/lb·°F

V = Estimated annual hot water use (gal) from Table 1-41

$T_{SetPoint}$ = Water heater set point (default value = 122.24°F)

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

EF_{pre} = Baseline Energy Factor

SEF = Solar Energy Factor of new water heater, default of 8.7

LF = Localization Factor for SEF of new water heater in New Orleans, 1.068

As an example, the following deemed electricity savings are applicable for replacement of a 50-gallon (High Draw) electric storage tank water heater with a 50-gallon solar water heater with electric backup using a model with an EF of 8.7 for a household in New Orleans:

$$kWh_{Savings} = \frac{8.33 \times 1 \times 18{,}973 \times (123.61 - 74.8) \times \left(\frac{1}{0.9209} - \frac{1}{(8.7\ \times\ 1.068)}\right)}{3{,}412\ Btu/kWh}$$

$$= 2{,}212.30\ kWh/yr$$

(ii) Demand Reductions

$$kW_{savings} = kWh_{savings} \times Ratio\,\frac{Peak\ kW}{Annual\ kWh}$$

Where:

$Ratio\,\frac{Peak\ kW}{Annual\ kWh}$ For the above example, peak demand savings is 2,188.00 kWh x 0.0000877 = 0.194 kW.

1.2.1.5 Incremental Cost

Incremental costs are as follows.

Table 1-46 Incremental Costs

Replacement Type	Size Category				
	30	**40**	**50**	**65**	**80**
Storage Tank - HPWH[54]	$582.99	$493.74	$404.37	$100.00	$138.38
Solar with Gas Back-up	$8,401[55]				

[54] CA DEER Workpaper SWWH014 – HPWH Res. (2019)

[55] California Solar Thermal Program: 2012 reported project costs.

1.2.1.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure has been implemented in Energy Smart programs. However, participation for this measure is currently too low to create reliable averages of measure characteristics. As a result, savings are calculated using ENERGY STAR default values.

If participation reached 1% of residential Energy Smart program savings, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents and the TPE recommends a metering study to support usage assumptions. Further, the TPE recommends a review of sizing changes from baseline to post-retrofit and an assessment of whether there needs to be consideration of snapback effects in HPWH retrofits.

If the measure is under consideration for increased emphasis in Energy Smart, the TPE recommends a market assessment to provide guidance as to the needs of New Orleans residents and plumbing contractors and to address savings potential.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant.

1.2.2 WATER HEATER JACKETS

1.2.2.1 Measure Description

This measure involves water heater jackets (WHJ) installed on water heaters located in an unconditioned space. These estimates apply to all weather regions. This measure applies to all residential applications.

1.2.2.2 Baseline and Efficiency Standards

Baseline is assumed to be the post-1991, storage-type water heater. WHJ must be installed on storage water heaters having a capacity of 30 gallons or greater. The manufacturer's instructions on the WHJ and the water heater itself should be followed. If electric, thermostat and heating element access panels must be left uncovered. If gas, follow WHJ installation instructions regarding combustion air and flue access.

Table 1-47 Water Heater Jackets – Baseline and Efficiency Standards

Baseline	Efficiency Standard
Un-insulated water heater	Minimum insulation of R-6.7

1.2.2.3 Estimated Useful Life

The EUL of this measure is 13 years according to NEAT v.8.6.

1.2.2.4 Deemed Savings Values

Deemed savings are per installed jacket based on the jacket thickness, the type of water heating and the tank size.

Table 1-48 Water Heater Jackets – Electric Heating Deemed Savings Values

Approximate Tank Size (gal)	**Electric Water Heating**					
	kWh Savings			**kW Savings**		
	40	**52**	**80**	**40**	**52**	**80**
2" WHJ savings kWh	68	76	101	0.005	0.006	0.008
3" WHJ savings kWh	94	104	139	0.007	0.008	0.011

1.2.2.4.1 Calculation of Deemed Savings

Energy consumption for baseline units, with and without insulation jackets, was calculated using industry-standard energy-use calculation methodologies for residential domestic water heating. Variables in the calculations include the following:

- Water heater fuel type (electric or gas/propane)
- Baseline EF
- Estimated U-value of baseline unit
- Ambient temperature
- Tank volume
- Tank surface area
- Tank temperature

- Estimated hot water consumption

To estimate peak energy consumption, a load profile for residential water heating was developed from individual load profiles for the following end-uses: clothes washer, dishwasher, faucet, shower, sink-filling, bath, and other miscellaneous end-uses.

This end-use load shape data was calibrated using metered end-used data obtained from several utility end-use metering studies.

1.2.2.5 Incremental Cost

The incremental cost of a Water Heater Jacket is equal to the full installed cost. If the cost is unknown, use $35.

1.2.2.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on NEAT v.8.6 estimates.

In the PY13 evaluation of the Home Performance with Energy Star program, it is recommended that the percent of unjacketed water heaters is documented in order to inform whether water heater jackets warrant inclusion as a direct install measure.

1.2.3 WATER HEATER PIPE INSULATION

1.2.3.1 Measure Description

This measure requires water heater pipe insulation. Water heaters plumbed with heat traps are not eligible to receive incentives for this measure. New construction and water heater retrofits are not eligible for this measure, because they must meet current code requirements. This measure applies to all residential applications.

1.2.3.2 Baseline and Efficiency Standards

Baseline is assumed to be the typical gas or electric water heater with no heat.

All hot and cold vertical lengths of pipe should be insulated, plus the initial length of horizontal hot and cold water pipe, up to three feet from the transition, or until wall penetration, whichever is less.

Table 1-49 Water Heater Pipe Insulation – Baseline and Efficiency Standards

Baseline	Efficiency Standard
Un-insulated hot water pipes	Minimum insulation thickness of ½”

1.2.3.3 Estimated Useful Life

The EUL of this measure is dependent on the type of water heater it is applied to. According to DEER 2014, the following measure lifetimes should be applied:

- 13 years for electric storage water heating
- 11 years for gas storage water heating
- 10 years for heat pump water heaters

1.2.3.4 Deemed Savings Values

The deemed savings per linear foot are detailed below.

Pipe Wrap – Deemed Savings Per Linear Foot

R-value	Pipe Diameter	kWh	kW
3	½”	25.32	.0029
	¾”	37.99	.0043

1.2.3.4.1 Energy Savings

$$Energy\ Savings = \left(U_{pre} - U_{post}\right) \times A \times \left(T_{Pipe} - T_{ambient}\right) \times \left(\frac{1}{RE}\right) \times \frac{Hours_{Total}}{Conversion\ Factor}$$

Where:

U_{pre}= 1/(2.03[56]) = 0.49 BTU/h sq. ft. degree F

[56] 2.03 is the R-value representing the film coefficients between water and the inside of the pipe and between the surface and air. Mark’s Standard Handbook for Mechanical Engineers, 8th edition.

U_{post}= 1/(2.03+$R_{Insulation}$)

$R_{Insulation}$= R-value of installed insulation

$A =$ Surface area in square feet (πDL) with L (length) and D pipe diameter in feet

$T_{Pipe}(°\mathrm{F}) =$ Average temperature of the pipe. Default value = 90 °F (average temperature of pipe between water heater and the wall)

$T_{ambient}(°\mathrm{F}) =$ 68.78°F (New Orleans)

RE = Recovery Efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance water heaters, 0.79 for natural gas water heaters, or 2.2 for heat pump water heaters[57]

$Hours_{Total}$ = 8,760 hr per year[58,59]

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/Therm for gas water heating.

1.2.3.4.2 Demand Savings

Peak demand savings for hot water heaters installed in conditioned space can be calculated using the following formula for electric:

$$kW_{savings} = \left(U_{pre} - U_{post}\right) \times A \times \left(T_{Pipe} - T_{ambientMAX}\right) \times \left(\frac{1}{RE}\right) \times \frac{1}{3{,}412\ Btu/kWh}$$

Where:

U_{pre} = 1/(2.03) =0.49 BTU/h sq ft degree F

U_{post} = 1/(2.03+$R_{Insulation}$)

$R_{Insulation}$ = R-value of installed insulation

$A =$ Surface area in square feet (πDL) with L (length) and D pipe diameter in feet

$T_{Pipe}(°\mathrm{F}) =$ Average temperature of the pipe. Default value = 90 °F (average temperature of pipe between water heater and the wall)

$T_{ambientMAX}(°\mathrm{F}) =$For water heaters installed in unconditioned basements, use an average ambient temperature of 75°F; for water heaters inside the thermal envelope, use an average ambient temperature of 78 °F

---

[57] Default values based on median recovery efficiency of residential water heaters by fuel type in the AHRI database, at https://www.ahridirectory.org/ahridirectory/pages/rwh/defaultSearch.aspx

[58] Ontario Energy's Measures and Assumptions for Demand Side Management (DSM) Planning www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/Navigant_Appendix_C_substantiation_sheet_20090429.pdf

[59] New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs Residential, Multi-Family, and Commercial/Industrial Measures http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/06f2fee55575bd8a852576e4006f9af7/$FILE/TechManualNYRevised10-15-10.pdf

RE = Recovery efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance or 2.2 for heat pump water heaters.

1.2.3.5 Incremental Cost

The incremental cost of a Water Heater Pipe Insulation is equal to the full installed cost. If the cost is unknown, use $3 per linear foot of insulation .

1.2.3.6 Future Studies

In the PY13 evaluation of the Home Performance with Energy Star program, it is recommended that the percent of uninsulated hot water lines is documented in order to inform whether pipe insulation warrant inclusion as a direct install measure

1.2.4 FAUCET AERATORS

1.2.4.1 Measure Description

This measure involves retrofitting aerators on kitchen and bathroom water faucets. The savings values are per faucet aerator installed. It is not a requirement that all faucets in a home be treated for the deemed savings to be applicable. This measure applies to all residential applications.

1.2.4.2 Baseline and Efficiency Standards

The 2.2 gallons per minute (GPM) baseline faucet flow rate is based upon the Energy Policy Act of 1992 (EPAct 92) and subsequent EPAct actions which limited faucet flows to 2.2 GPM . The US EPA WaterSense specification for faucet aerators is 1.5 GPM .

Table 1-50 Faucet Aerators – Baseline and Efficiency Standards

Baseline	Efficiency Standard
2.2 GPM	1.5 GPM maximum

The deemed savings values are for residential, retrofit-only installation of kitchen and bathroom faucet aerators.

1.2.4.3 Installation Requirements for Contractors / Trade Allies

Aerators that have been defaced so as to make the flow rating illegible are not eligible for replacement. For direct install programs, all aerators removed shall be collected by the contractor and held for possible inspection by the utility until all inspections for invoiced installations have been completed.

1.2.4.4 Estimated Useful Life

The EUL of this measure is 10 years according to DEER 2014.

1.2.4.5 Deemed Savings Values

The table below summarizes the deemed kWh and kW for 1.5 GPM and 1.0 GPM faucet aerators, based on the algorithms in the subsections to follow.

Table 1-51 Faucet Aerators – Deemed Savings

Efficient GPM Rating	Water Heater Type	kWh	kW
1.5 GPM	Electric Resistance	26.80	0.0028
	Heat Pump	11.94	0.0012
1.0 GPM	Electric Resistance	44.66	0.0046
	Heat Pump	19.90	0.0021

1.2.4.5.1 Effect of Weather Zones on Water Usage and Water Main Temperature

Average water main temperatures for the New Orleans are 74.8°F. The water main temperature data was approximated using the following formula .

$$T\ of\ water\ main = T_{avg\ ambient} + R \times \Delta T_{amb}$$

Where:

$T_{avg\ ambient}$ = the average annual ambient dry bulb temperature, 68.8°F in New Orleans

R = 0.05

ΔT_{amb} = the average of maximum and minimum ambient air-dry bulb temperature for the month (Tmax + Tmin)/2 where Tmax = maximum ambient dry bulb temperature for the month, and Tmin = minimum ambient dry bulb temperature for the month

Baseline and efficiency-standard water usages per capita were derived from an analysis of metered studies of residential water efficiency retrofit projects conducted for Seattle, WA.; the East Bay Municipal Utility District (CA); and Tampa, FL.[60, 61, 62]

1.2.4.5.2 Estimated Hot Water Usage Reduction

$$Water\ consumption = \frac{\frac{Faucet\ Use\ per\ Person}{Day} \times Occupants\ per\ Home \times \frac{365\ Days}{Year}}{Faucets\ per\ Home}$$

Applying the formula to the values from Table 1-50 returns the following baseline and post water consumption.

- Baseline (2.2 GPM): 9.7 x 2.37 x 365 / 3.86 = 2,174
- Post (1.5 GPM): 8.2 x 2.37 x 365 / 3.86 = 1,838
- Post (1.0 GPM): 7.2 x 2.37 x 365 / 3.86 = 1,614

Gallons of water saved per year can be found by subtracting the post consumption in gallons per year per aerator from the baseline consumption.

- Gallons of water saved per year (1.5 GPM): 2,174 – 1,838 = 336
- Gallons of water saved per year (1.0 GPM): 2,174 – 1,614 = 560

Table 1-52 Estimated Aerator Hot Water Usage Reduction

Assumption Type	Seattle Study[63]	Tampa Study[64]	East Bay Study	Average	Value used for New Orleans
Faucet use gallons/person/day (baseline)	9.2	9.4	10.5	9.7	9.7
Faucet use gallons/person/day (1.5 GPM)	8.0	6.2	10.5	8.2	8.2

[60] Seattle Home Water Conservation Study, 2000. "The Impacts of High Efficiency Plumbing Fixture Retrofits in Single-Family Homes." December. http://www.allianceforwaterefficiency.org/mainsearch.aspx?searchtext=Seattle%20Home%20Water%20Conservation%20Study

[61] Residential Indoor Water Conservation Study, 2003 "Evaluation of High Efficiency Indoor Plumbing Fixture Retrofits in Single-Family Homes in the East Bay Municipal Utility District Service Area." July. www.allianceforwaterefficiency.org/WorkArea/DownloadAsset.aspx?id=868

[62] Tampa Water Department Residential Water Conservation Study, 2004, "The Impacts of High Efficiency Plumbing Fixture Retrofits in Single-Family Homes." January 8. https://www.cuwcc.org/Portals/0/Document%20Library/Resources/Water%20Efficient%20Product%20Information/End%20Use%20Studies%20-%20Multiple%20Technologies/Tampa-Residential-Water-Conservation-Final-Report.pdf

[63] Average of pre-retrofit percent faucet hot water 72.7% on page 35, and post-retrofit percent faucet hot water 79.5% on page 53.

[64] Average of pre-retrofit percent faucet hot water 65.2% on page 31 and post-retrofit faucet hot water percentage 50.0% on page 54.

Assumption Type	Seattle Study[63]	Tampa Study[64]	East Bay Study	Average	Value used for New Orleans
Faucet use gallons/person/day (1.0 GPM)[65]	--	--	--	--	7.2
Occupants per home	2.54	2.92	2.56	2.67	2.37[66]
Faucets per home[67]	--	--	--	--	3.86
Gal./yr./faucet (baseline)	--	--	--	--	2,174
Gal./yr./faucet (1.5 GPM)	--	--	--	--	1,838
Gal./yr./faucet (1.0 GPM)	--	--	--	--	1,614
Percent hot water	76.10%[4]	Not listed	57.60%5	66.90%	66.9%
Water gallons saved/yr./faucet (1.5 GPM)	--	--	--	--	336
Water gallons saved/yr./faucet (1.0 GPM)	--	--	--	--	560

Based on the average percentage hot water shown in the table above, the average mixed water temperature across all weather zones was determined. The hot water temperature was found to be 122°F in a sample of 144 homes in New Orleans tested by the TPE. The mixed water temperature used in the energy savings calculation can be seen in the table below.

Table 1-53 Mixed Water Temperature Calculation

Average Water Main Temperature (°F)	Average Water Heater Setpoint Temperature (°F)	Percent Hot Water	Mixed Water Temperature (°F)
74.8	122.695	66.9%	106.8

1.2.4.5.3 Energy Savings

$$Annual\ Energy\ Savings\ = \frac{\rho \times C_P \times V \times \left(T_{Mixed} - T_{Supply}\right) \times \left(\frac{1}{RE}\right)}{Conversion\ Factor}$$

Where:

ρ = Water density = 8.33 lb/gal

C_P = Specific heat of water = 1 BTU/lb·°F

V = Gallons of water saved per year per faucet from Table 1-52

[65] This value is a linear extrapolation of gallons per person per day from the baseline (2.2 GPM) and the 1.5 GPM case.

[66] 2010-2014, US Census Bureau. http://www.census.gov/quickfacts/table/PST045215/2255000

[67] Faucets per home assumed to be equal to one plus the number half bathrooms and full bathrooms per home, taken from 2009 RECS, Table HC2.10.

T_{Mixed} = Mixed water temperature, 106.8°F, from Table 1-53

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

RE = Recovery Efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance water heaters, 2.2 for heat pump water heaters, or 0.79 for natural gas water heaters[68].

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/Therm for gas water heating

1.2.4.5.4 Demand Reductions

Demand reductions for homes with electric water heating were calculated using the following formula:

$$kW_{savings} = kWh_{savings} \times Ratio_{Annual\ kWh}^{Peak\ kW}$$

Where:

$Ratio_{Annual\ kWh}^{Peak\ kW}$

This value is taken from the DOE domestic hot water use study. The DOE domestic hot water use study provided values for the share of daily water use per hour in a profile for shower bath and sink hot water use. An average was calculated using peak hours of 3 PM to 6 PM to generate an average hourly share of daily water use during peak hours. That value was divided by 365 to generate a ratio of peak share to annual use.

1.2.4.5.5 Example Calculation of Deemed Savings Values

Deemed savings values are per faucet aerator installed.

Table 1-54 Example -Replacing 2.2 GPM with 1.5 GPM Faucet Aerator

Faucet Aerator, New Orleans Weather Zone		
Water Usage Reduction (gal)	336	
T_{Supply}	74.8°F	
T_{Mixed}	106.8°F	
Water heater RE (excluding standby losses)	0.98 (Electric) / 2.2 (Heat Pump)	
Energy Savings	Electric: 26.8 kWh	Heat Pump: 11.94 kWh
Demand Savings	Electric: 0.0028 kW	Heat Pump: 0.0012 kW

1.2.4.6 In-Service Rates

Table 1-55 In-Service Rates

Delivery Channel	ISR
Direct Install	0.98

[68] Default values based on median recovery efficiency of residential water heaters by fuel type in the AHRI database, at https://www.ahridirectory.org/ahridirectory/pages/rwh/defaultSearch.aspx

Mailer Kit[69]	0.45

1.2.4.7 Future Studies

Metering studies for water use are exceedingly expensive. In past metering efforts, the TPE has found costs to exceed $750 per site. As such, we do not advise a metering study for this measure unless savings exceed 5% of residential program savings.

[69] Based on primary data collection from 4,572 PY5-9 program participants.

1.2.5 LOW-FLOW SHOWERHEADS

1.2.5.1 Measure Description

This measure consists of removing existing showerheads and installing low-flow showerheads in residences. This measure applies to all residential applications.

1.2.5.2 Baseline and Efficiency Standards

The baseline average flow rate of the existing stock of showerheads is based on the current US DOE standard.

The incentive is for replacement of an existing showerhead with a new showerhead rated at 2.0, 1.75 or 1.5 gallons per minute (GPM). The only showerheads eligible for installation are those that are not easily modified to increase the flow rate.

1.2.5.3 Installation Requirements for Trade Allies / Contractors

Existing showerheads that have been defaced so as to make the flow rating illegible are not eligible for replacement. All showerheads removed shall be collected by the contractor and held for possible inspection by the utility until all inspections for invoiced installations have been completed.

Table 1-56 Low-Flow Showerhead – Baseline and Efficiency Standards

Measure	New Showerhead Flow Rate[70] (GPM)	Existing Showerhead Baseline Flow Rate (GPM)
2.0 GPM showerhead	2.00	2.50
1.75 GPM showerhead	1.75	2.50
1.5 GPM showerhead	1.50	2.50

The U.S. EPA WaterSense Program has implemented efficiency standards for showerheads requiring a maximum flow rate of 2.0 GPM .

1.2.5.4 Estimated Useful Life

The EUL of this measure is 10 years according to DEER 2014.

1.2.5.5 Effect of Weather Zones on Water Usage and Water Main Temperature

Average water main temperature is 74.8°F. The water main temperature data was approximated using the following formula .

$$T\ of\ water\ main = T_{avg\ ambient} + R \times \Delta T_{amb}$$

Where:

[70] All flow rate requirements listed here are the rated flow of the showerhead measured at 80 pounds per square inch of pressure (psi).

R = 0.05

$T_{avg\ ambient}$ = the average annual ambient air dry-bulb temperature

ΔT_{amb} = 74.8 (New Orleans), the average of maximum and minimum ambient air dry-bulb temperature for the month (Tmax + Tmin)/2 where Tmax = maximum ambient dry bulb temperature for the month and Tmin = minimum ambient dry bulb temperature for the month

1.2.5.6 Estimated Hot Water Usage Reduction

Baseline and efficiency standard water usages per capita were derived from an analysis of metered studies of residential water efficiency retrofit projects conducted for Seattle, WA.; the East Bay Municipal Utility District (CA); and Tampa, FL . See Table 1-57 for derivation of water usage values.

To determine water consumption, the following formula was used:

$$\frac{Gallons}{Shower} \times \frac{Showers\ per\ Person}{Day} \times \frac{365\ Days}{Year} \times \frac{Occupants\ per\ Home}{Showerheads\ per\ Home}$$

Applying the formula to the values from Table 1-57 returns the following baseline and post water consumption.

- Baseline (2.5 GPM): 20.7 x 0.69 x 365 x 2.37 / 1.62 = 7,627
- Post (2.0 GPM): 16.5 x 0.72 x 365 x 2.37 / 1.62 = 6,344
- Post (1.5 GPM): 12.4 x 0.72 x 365 x 2.37 / 1.62 = 4,767

Although the referenced studies do not provide data on 1.75 GPM showerheads, the consumption values for 2.5, 2.0, and 1.5 GPM roughly follow a linear pattern. Taking a simple average of the consumption for 2.0 and 1.5 GPM showerheads returns a value for a 1.75 GPM showerhead:

- Post (1.75 GPM): (6,344 + 4,767) / 2 = 5,556

Gallons of water saved per year can be found by subtracting the post consumption in gallons per year per showerhead from the baseline consumption. These values are also in Table 1-57.

- Gallons of water saved per year (2.0 GPM): (7,627 – 6,344) = 1,283
- Gallons of water saved per year (1.75 GPM): (7,627 – 5,556) = 2,071
- Gallons of water saved per year (1.5 GPM): (7,627 – 4,767) = 2,860

Table 1-57 Estimated Showerhead Hot Water Usage Reduction

Assumption Type	Seattle Study[71]	Tampa Study	East Bay Study[72]	Average	Value used for New Orleans
Gallons/shower @ 2.5 GPM (baseline)	19.8	20.0	22.3	20.7	20.7

[71] Seattle Study: Average of pre-retrofit percent shower hot water 73.1% on page 35, and post-retrofit percent shower hot water 75.5% on p. 53.

[72] East Bay Study: Average of pre-retrofit percent shower hot water 71.9% on page 31 and post-retrofit shower hot water percentage 60.0% on p. 54.

Assumption Type	Seattle Study[71]	Tampa Study	East Bay Study[72]	Average	Value used for New Orleans
Gallons/shower @ 2.0 GPM	15.8	16.0	17.8	16.5	16.5
Gallons/shower @ 1.5 GPM	11.9	12.0	13.4	12.4	12.4
Showers/person/day (baseline)	0.51	0.92	0.65	0.69	0.69
Showers/person/day (post)	0.59	0.82	0.74	0.72	0.72
Occupants per home	2.54	2.92	2.56	2.67	2.37[73]
Showerheads per home[74]	not listed	not listed	not listed	not listed	1.62
Water gal./yr./showerhead @ 2.0 GPM saved	not listed	not listed	not listed	not listed	1,283
Water gal./yr./showerhead @ 1.75 GPM saved	not listed	not listed	not listed	not listed	2,071
Water gal./yr./showerhead @ 1.5 GPM saved	not listed	not listed	not listed	not listed	2,860
Percent hot water	74.3%	not listed	66%	70.1%	70.1%

Based on the average percentage hot water shown in the table above, the average mixed water temperature across all weather zones was determined. The hot water temperature was found to be 122.24°F in a sample of 144 homes in New Orleans tested by the TPE. The mixed water temperature used in the energy savings calculation can be seen in the table below.

Table 1-58 Mixed Water Temperature Calculation

Weather Zone	Average Water Main Temperature (°F)	Average Setpoint Temperature (°F)	Percent Hot Water	Mixed Water Temperature (°F)
New Orleans	74.8	122.695	66.9%	106.8

1.2.5.7 Deemed Savings Values

1.2.5.7.1 Energy Savings

$$Annual\ Energy\ Savings\ =\ \frac{\rho \times C_P \times V \times (T_{Mixed} - T_{Supply}) \times \left(\frac{1}{RE}\right)}{Conversion\ Factor}$$

Where:

[73] 2010-2014, US Census Bureau. http://www.census.gov/quickfacts/table/PST045215/2255000

[74] Showerheads per home assumed to be equal to the number of full bathrooms per home, taken from 2009 RECS, Table HC2.10.

ρ = Water density = 8.33 lb/gallon

C_P = Specific heat of water = 1 BTU/lb·°F

V = 2.0, 1.75, or 1.5 GPM showerhead water gallons saved per year from Table 1-57

T_{Mixed} = Mixed water temperature, 106.8°F, from Table 1-57

T_{Supply}= Average New Orleans area supply water temperature, 74.8°F

RE = Recovery Efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance water heaters, 2.2 for heat pump water heaters,

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/Therm for gas water heating

1.2.5.7.2 Demand Reductions

Demand reductions were calculated using the US DOE “Building America Performance Analysis Procedures for Existing Homes” combined domestic hot water use profile which resulted in a ratio of 0.000104 Peak kW to Annual kWh . The DOE domestic hot water use study provided values for the share of daily water use per hour in a profile for shower, bath, and sink hot water use. An average was calculated using peak hours of 3pm to 6pm to generate an average hourly share of daily water use during peak hours. That value was divided by 365 to generate a ratio of peak share to annual use.

$$kW_{savings} = kWh_{\ savings} \times Ratio_{Annual\ kWh}^{Peak\ kW}$$

Table 1-59 Low Flow Showerhead Retrofit Deemed Energy Savings

<table>
<tr><th colspan="3">2.0 GPM Showerhead</th></tr>
<tr><td>Water gal. saved /year/showerhead @ 2.0 GPM</td><td colspan="2">1,283</td></tr>
<tr><td>T_{Supply}</td><td colspan="2">74.8°F</td></tr>
<tr><td>T_{Mixed}</td><td colspan="2">106.8°F</td></tr>
<tr><td>Water heater RE</td><td colspan="2">0.98 (Electric Resistance) / 2.2 (Heat Pump)</td></tr>
<tr><td>Energy Savings</td><td>Electric: 102 kWh</td><td>Heat Pump: 46 kWh</td></tr>
<tr><td>Demand Savings</td><td>Electric: 0.0106 kW</td><td>Heat Pump: 0.0047 kW</td></tr>
<tr><th colspan="3">1.75 GPM Showerhead</th></tr>
<tr><td>Water gal. saved /year/showerhead @ 1.5 GPM</td><td colspan="2">2,071</td></tr>
<tr><td>T_{Supply}</td><td colspan="2">74.8°F</td></tr>
<tr><td>T_{Mixed}</td><td colspan="2">106.8°F</td></tr>
<tr><td>Water heater EF (excluding standby losses)</td><td colspan="2">0.98 (Electric Resistance) / 2.2 (Heat Pump)</td></tr>
<tr><td>Energy Savings</td><td>Electric: 165 kWh</td><td>Heat Pump: 74 kWh</td></tr>
<tr><td>Demand Savings</td><td>Electric: 0.0172 kW</td><td>Heat Pump:0.0076 kW</td></tr>
<tr><th colspan="3">1.50 GPM Showerhead</th></tr>
<tr><td>Water gal. saved /year/showerhead @ 1.5 GPM</td><td colspan="2">2,860</td></tr>
<tr><td>T_{Supply}</td><td colspan="2">74.8°F</td></tr>
<tr><td>T_{Mixed}</td><td colspan="2">106.8°F</td></tr>
<tr><td>Water heater EF (excluding standby losses)</td><td colspan="2">0.98 (Electric Resistance) / 2.2 (Heat Pump)</td></tr>
<tr><td>Energy Savings</td><td>Electric: 228 kWh</td><td>Heat Pump: 102 kWh</td></tr>
</table>

Demand Savings	Electric: 0.0237 kW	Heat Pump: 0.0106 kW

1.2.5.8 In-Service Rates

Table 1-60 In-Service Rates

Delivery Channel	ISR
Direct Install	0.98
Mailer Kit[75]	0.62

1.2.5.9 Future Studies

The TPE has found costs to exceed $750 per site. As such, we do not advise a metering study for this measure unless savings exceed 5% of residential program savings.

[75] Based on primary data collection from 4,572 PY5-9 program participants.

1.2.6 SHOWERHEAD THERMOSTATIC RESTRICTOR VALVES

1.2.6.1 Measure Description

This measure consists of installing a thermostatic restrictor valve (TRV) between the existing shower arm and showerhead. The valve will reduce behavioral water waste by restricting water flow when the water reaches a set temperature (generally 95˚F). Restricting the flow when the water reaches the temperature set point, reduces the amount of water that goes down the drain prior to the user entering the shower.

1.2.6.2 Baseline and Efficiency Standards

The baseline condition is the residential shower arm and standard (2.5 gpm) showerhead without a thermostatic restrictor valve installed. The baseline average flow rate of the existing stock of showerheads is based on the current US DOE standard.

To qualify for thermostatic restrictor valve deemed savings, the installed equipment must be a thermostatic restrictor valve installed on a residential shower arm and showerhead with either a standard (2.5 gpm) or low-flow (2.0, 1.75, or 1.5 gpm) showerhead. If this measure is installed in conjunction with a low-flow showerhead, refer to 1.2.5 *Low-Flow Showerheads* and claim additional savings as outlined in that measure.

For direct install applications, the residence must have electric resistance water heating.

1.2.6.3 Estimated Useful Life

The EUL of this measure is 10 years according to DEER 2008 .

1.2.6.4 Effect of Weather Zones on Water Usage and Water Main Temperature

Average water main temperatures for the New Orleans is 74.8°F. The water main temperature data was approximated using the following formula .

$$T\ of\ water\ main = T_{avg\ ambient} + R \times \Delta T_{amb}$$

Where:

$T_{avg\ ambient}$ = the average annual ambient dry bulb temperature, 68.8°F in New Orleans

R = 0.05

ΔT_{amb} = the average of maximum and minimum ambient air-dry bulb temperature for the month (Tmax + Tmin)/2 where Tmax = maximum ambient dry bulb temperature for the month, and Tmin = minimum ambient dry bulb temperature for the month

1.2.6.4.1 Estimated Hot Water Usage Reduction

Water usages per capita were derived from an analysis of metered studies of residential water efficiency retrofit projects conducted for Seattle, WA.; the East Bay Municipal Utility District (CA); and Tampa, FL.

Table 1-61 Estimated Showerhead Hot Water Usage Reduction

Assumption Type	Seattle Study	Tampa Study	East Bay Study	Average	Value used for New Orleans
Showers/person/day	0.51	0.92	0.65	0.69	0.69
Occupants per home	2.54	2.92	2.56	2.67	2.37[76]
Showerheads per home[77]	not listed	not listed	not listed	not listed	1.62
Percent hot water	76.1%	Not listed	57.6%	66.9%	66.9%

To determine gallons of behavioral waste (defined as hot water that goes down the drain before the user enters the shower) per year, the following formula was used in conjunction with values from Table 1-61.

$$Annual\ Showerhead\ Behavioral\ Waste = SHFR \times BW \times n_S \times 365_{days/year} \times \%_{HW} \times \frac{n_O}{n_{SH}}$$

Where:

$SHFR$ = Showerhead flow rate, gallons per minute (2.5, 2.0, 1.75 and 1.5 gpm)

BW = Behavioral waste, minutes per shower (0.783)

n_S = Number of showers per day (0.69)

n_O = Number of occupants per home (2.37)

n_{SH} = Number of showerheads per home (1.62)

$\%_{HW}$ = Percent hot water (.669)

Applying the formula to the values from Table 1-61 returns the following values for baseline behavioral waste in gallons per showerhead per year:

- 2.5 GPM (baseline): 2.5 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 483 gal
- 2.0 GPM: 2.0 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 386 gal
- 1.75 GPM: 1.75 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 338 gal
- 1.5 GPM: 1.5 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 290 gal

Table 1-62 Gallons of Hot Water Saved per Year

2.5 gpm	2.0 gpm	1.75 gpm	1.5 gpm
483	386	338	290

[76] 2010-2014, US Census Bureau. http://www.census.gov/quickfacts/table/PST045215/2255000

[77] Showerheads per home assumed to be equal to the number of full bathrooms per home, taken from 2009 RECS, Table HC2.10.

1.2.6.5 Deemed Savings Values

1.2.6.5.1 Energy Savings

$$Annual\ Energy\ Savings\ = \frac{\rho \times C_P \times V \times (T_{Setpoint} - T_{Supply}) \times \left(\frac{1}{RE}\right)}{Conversion\ Factor}$$

Where:

$\rho =$ Water density = 8.33 lb/gal

$C_P =$ Specific heat of water = 1 BTU/lb·°F

$V =$ Gallons of hot water saved per year (see Table 1-62)

$T_{Setpoint} =$ Water heater setpoint temperature (122.695°F)

$T_{Supply} =$ Average New Orleans area supply water temperature, 74.8°F

$RE =$ Recovery Efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance water heaters, 2.2 for heat pump water heaters[78].

$Conversion\ Factor =$ 3,412 Btu/kWh for electric water heating or 100,000 Btu/Therm for gas water heating

1.2.6.5.2 Demand Reductions

Demand reductions for homes with electric water heating were calculated using the following formula:

$$kW_{savings} = kWh_{savings} \times Ratio_{Annual\ kWh}^{Peak\ kW}$$

Where:

$Ratio_{Annual\ kWh}^{Peak\ kW}$

The table below summarizes the deemed kWh and kW for TRVs installed on 2.5, 2.0, 1.75 and 1.5 gpm showerheads, using methods above.

Table 1-63 Deemed Savings for TRVs – Showerheads

Showerhead GPM Rating	Water Heater Type	kWh	kW
2.5 gpm	Electric Resistance	58	0.006
	Heat Pump	26	0.003
2.0 gpm	Electric Resistance	46	0.005
	Heat Pump	21	0.002
1.75 gpm	Electric Resistance	40	0.004
	Heat Pump	18	0.002

[78] Default values based on median recovery efficiency of residential water heaters by fuel type in the AHRI database, at https://www.ahridirectory.org/ahridirectory/pages/rwh/defaultSearch.aspx

1.50 gpm	Electric Resistance	35	0.004
	Heat Pump	15	0.002

1.2.6.6 Incremental Cost

The incremental cost of the measure should be the actual program cost (including labor if applicable) or $29.95 plus $15.47 labor if not available.

1.2.6.7 Future Studies

Metering studies for water use are exceedingly expensive. In past metering efforts, the TPE has found costs to exceed $750 per site. As such, we do not advise a metering study for this measure unless savings exceed 5% of residential program savings.

1.2.7 TUB SPOUT DIVERTERS AND THERMOSTATIC RESTRICTOR VALVES ON SHOWERHEADS

1.2.7.1 Measure Description

This measure consists of replacing existing tub spouts and shower heads with an automatically diverting tub spout and showerhead system with a thermostatic restrictor valve (TRV) between the existing shower arm and showerhead. When the water temperature reaches a set point (generally 95˚F), the thermostatic restrictor valve will engage the anti-leak diverter. The water will divert from the spout to a showerhead with a closed valve, which prevents the hot water from flowing down the drain prior to use.

1.2.7.2 Baseline and Efficiency Standards

The baseline condition is the residential shower arm and standard (2.5 gpm) showerhead without a thermostatic restrictor valve installed.

To qualify for deemed savings, the installed equipment must be a thermostatic restrictor valve installed on a residential shower arm and showerhead with either a standard (2.5 gpm) or low-flow (2.0, 1.75, or 1.5 gpm) showerhead. If this measure is installed in conjunction with a low-flow showerhead, refer to the Low-Flow Showerheads measure (Section 1.2.5 Low-Flow Showerheads) and claim additional savings as outlined in that measure.

1.2.7.3 Estimated Useful Life

The EUL of this measure is 10 years according to DEER 2008[79].

1.2.7.4 Effect of Weather Zones on Water Usage and Water Main Temperature

Average water main temperatures for the New Orleans area is 74.8°F. The water main temperature data was approximated using the following formula .

$$T\ of\ water\ main = T_{avg\ ambient} + R \times \Delta T_{amb}$$

Where:

$T_{avg\ ambient}$ = the average annual ambient dry bulb temperature, 68.8°F in New Orleans

R = Decreased efficiency offset (0.05)[208]

ΔT_{amb} = the average of maximum and minimum ambient air-dry bulb temperature for the month (Tmax + Tmin)/2 where Tmax = maximum ambient dry bulb temperature for the month, and Tmin = minimum ambient dry bulb temperature for the month

[79] This value is consistent with the low flow showerhead EUL, DEER 2014.

1.2.7.5 Estimated Hot Water Usage Reduction

Water usages per capita were derived from an analysis of metered studies of residential water efficiency retrofit projects conducted for Seattle, WA.; the East Bay Municipal Utility District (CA); and Tampa, FL[80, 81, 82].

Table 1-64 Estimated Showerhead Hot Water Usage Reduction

Assumption Type	Seattle Study	Tampa Study	East Bay Study	Average	Value used for New Orleans
Showers/person/day	0.51	0.92	0.65	0.69	0.69
Occupants per home	2.54	2.92	2.56	2.67	2.37[83]
Showerheads per home[84]	not listed	not listed	not listed	not listed	1.62
Percent hot water	76.1%	Not listed	57.6%	66.9%	66.9%

This system provides savings in two parts: elimination of behavioral waste (hot water that goes down the drain prior to the user entering the shower) and elimination of tub spout diverter leakage. Total gallons of water saved are the sum of these two parts.

Part 1: To determine gallons of behavioral waste (defined as hot water that goes down the drain before the user enters the shower) per year, the following formula was used in conjunction with values from Table 1-64.

$$Annual\ Showerhead\ Behavioral\ Waste = \%WUE_{SH} \times SHFR \times BW \times n_S \times 365_{days/year} \times \%_{HW} \times \frac{n_O}{n_{SH}}$$

$$Annual\ Tub\ Spout\ Behavioral\ Waste = \%WUE_{TS} \times TSFR \times BW \times n_S \times 365_{days/year} \times \%_{HW} \times \frac{n_O}{n_{SH}}$$

[80] Seattle Home Water Conservation Study, 2000. "The Impacts of High Efficiency Plumbing Fixture Retrofits in Single-Family Homes." December. http://www.allianceforwaterefficiency.org/mainsearch.aspx?searchtext=Seattle%20Home%20Water%20Conservation%20Study Average of pre-retrofit percent shower hot water 73.1% on page 35, and post-retrofit percent shower hot water 75.5% on p. 53.

[81] Residential Indoor Water Conservation Study, 2003 "Evaluation of High Efficiency Indoor Plumbing Fixture Retrofits in Single-Family Homes in the East Bay Municipal Utility District Service Area." July. www.allianceforwaterefficiency.org/WorkArea/DownloadAsset.aspx?id=868 Average of pre-retrofit percent shower hot water 71.9% on page 31 and post-retrofit shower hot water percentage 60.0% on p. 54.

[82] Tampa Water Department Residential Water Conservation Study, 2004, "The Impacts of High Efficiency Plumbing Fixture Retrofits in Single-Family Homes." January 8. https://www.cuwcc.org/Portals/0/Document%20Library/Resources/Water%20Efficient%20Product%20Information/End%20Use%20Studies%20-%20Multiple%20Technologies/Tampa-Residential-Water-Conservation-Final-Report.pdf

[83] 2010-2014, US Census Bureau. http://www.census.gov/quickfacts/table/PST045215/2255000

[84] Showerheads per home assumed to be equal to the number of full bathrooms per home, taken from 2009 RECS, Table HC2.10.

Where:

$\%WUE_{SH}$ = Showerhead percentage of warm-up events (0.6)

$\%WUE_{TS}$ = Showerhead percentage of warm-up events (0.4[8])

$SHFR$ = Showerhead flow rate, gallons per minute (2.5, 2.0, 1.75 and 1.5 gpm)

$TSFR$ = Tub Spout flow rate, gallons per minute (4 gpm)

BW = Behavioral waste, minutes per shower (0.783)

n_S = Number of showers per day (0.69)

n_O = Number of occupants per home (2.37)

n_{SH} = Number of showerheads per home (1.62)

$\%_{HW}$ = Percent hot water (.669)

Applying the formula to the values used for New Orleans from returns the following values for baseline behavioral waste in gallons per showerhead and tube spout per year:

Showerheads:

- 2.5 GPM (baseline): 0.6 x 2.5 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 290 gal
- 2.0 GPM: 0.6 x 2.0 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 232 gal
- 1.75 GPM: 0.6 x 1.75 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 203 gal
- 1.5 GPM: 0.6 x 1.5 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 174 gal

Tub Spout:

- 5.0 GPM: 0.4 x 5.0 x 0.783 x 0.69 x 365 x .669 x 2.37/1.62 = 386 gal

Table 1-65 Water Savings by Flow Rate (gallons)

2.5 gpm	**2.0 gpm**	**1.75 gpm**	**1.5 gpm**	**Tub Spout**
290	232	203	174	386

Part 2: To determine the baseline gallons of diverted leakage per year, the following formula was used:

$$Annual\ Diverter\ Waste = DLR \times t_S \times n_S \times 365_{days/year} \times \%_{HW} \times \frac{n_O}{n_{SH}}$$

Where:

DLR = Showerhead percentage of warm-up events

t_s = Shower time (mins/shower) (5.68)

n_S = Number of showers per day (0.69)

n_O = Number of occupants per home (2.37)

n_{SH} = Number of showerheads per home (1.62)

$\%_{HW}$ = Diverter water percentage (.669)

Applying the formula to the values used for New Orleans from Table 1-64 returns the following values:

Diverter (0.8 gpm): 0.8 x 5.68 x 0.69 x 365 x 2.37/1.62 x .737= 1,270 *gal*

Total water saved: To determine gallons of water saved per year can be found by adding the total waste from previous calculations:

$$Gallons\ Hot\ Water\ Saved = SHBW + TSBW + DW$$

Where:

$SHBW$ = Showerhead behavioral waste (see Table 1-65) (gal)

$TSBW$ = Tub spout behavioral waste (386 gal)

DW = Diverter waste (1,270 gal)

1.2.7.6 Deemed Savings Values

1.2.7.6.1 Energy Savings

$$Annual\ Energy\ Savings = \frac{\rho \times C_P \times V \times \left(T_{Setpoint} - T_{Supply}\right) \times \left(\frac{1}{RE}\right)}{Conversion\ Factor}$$

Where:

ρ = Water density = 8.33 lb/gal

C_P = Specific heat of water = 1 BTU/lb·°F

V = Total gallons of water saved per year (see steps 1 and 2)

$T_{Setpoint}$ = Water heater setpoint temperature (122.695°F)

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

RE = Recovery Efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance water heaters, 2.2 for heat pump water heaters[85].

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating

1.2.7.6.2 Demand Savings

Demand savings for homes with electric water heating were calculated using the following formula:

$$kW_{savings} = kWh_{savings} \times Ratio_{Annual\ kWh}^{Peak\ kW}$$

Where:

$Ratio_{Annual\ kWh}^{Peak\ kW}$

[85] Default values based on median recovery efficiency of residential water heaters by fuel type in the AHRI database, at https://www.ahridirectory.org/ahridirectory/pages/rwh/defaultSearch.aspx

The table below summarizes the deemed kWh and kW for TRVs installed on 2.5, 2.0, 1.75 and 1.5 gpm showerheads, using methods above.

Table 1-66 Deemed Savings for TRVs – Showerheads

Showerhead GPM Rating	Water Heater Type	kWh	kW
2.5 gpm	Electric Resistance	232	0.024
	Heat Pump	103	0.011
2.0 gpm	Electric Resistance	225	0.023
	Heat Pump	100	0.010
1.75 gpm	Electric Resistance	222	0.023
	Heat Pump	99	0.010
1.50 gpm	Electric Resistance	218	0.023
	Heat Pump	97	0.010

1.2.7.7 Incremental Cost

The incremental cost of the measure should be the actual program cost (including labor if applicable) or $91.38 plus $20 labor if not available.

1.2.7.8 Future Studies

Metering studies for water use are exceedingly expensive. In past metering efforts, the TPE has found costs to exceed $750 per site. As such, we do not advise a metering study for this measure unless savings exceed 5% of residential program savings.

1.3 Heating, Ventilation & Air Conditioning

1.3.1 CENTRAL AIR CONDITIONER REPLACEMENT

1.3.1.1 Measure Description

This measure involves a residential retrofit with a new central air conditioning system or the installation of a new central air conditioning system in a residential new construction (packaged unit, or split system consisting of an indoor unit with a matching remote condensing unit). Maximum cooling capacity per unit is 65,000 Btu/hour. This measure applies to all residential applications.

1.3.1.2 Baseline and Efficiency Standards[86]

The Department of Energy (DOE) is changing the way HVAC systems are tested and modifying its rating system, replacing SEER, EER and HSPF ratings with SEER2, EER2 and HSPF2, respectively. All systems sold must meet new efficiency minimums using the new "M1" testing procedure which is designed to better reflect field conditions.

The following conversion factors are recommended for use if the efficient equipment is not rated under the new testing procedure, but the stipulated baseline is:

- $SEER2 = SEER \times 0.95$
- $EER2 = EER \times 0.95$

The new guidelines affect HVAC equipment manufactured prior to December 31, 2022 and installed in the Southwest region after January 1, 2023. EER ratings for the New Orleans region are subject to EER2 classification but required efficiency levels do not change.

For new construction (NC) and replace on burnout (ROB) projects, the cooling baseline is 14.3 SEER2 (15.0 SEER) for split systems and 13.4 SEER2 (14.0 SEER) for packaged systems, consistent with the current federal minimum standard .

For early retirement (ER) projects, the cooling baseline is reduced to 13.0 SEER (12.4 SEER2) for systems manufactured before January 1, 2015, and 14.0 (13.3 SEER2) for systems manufactured after. For ER HSPF baselines please see Table 1-67 below.

For Early Replacement, the maximum lifetime age of an eligible piece of equipment is capped at the point at which it is expected that 75 percent of the equipment has failed. Where the age of the unit exceeds the 75 percent failure age, ROB savings should be applied. This cap prevents early retirement savings from being applied to projects where the age of the equipment greatly exceeds the estimated useful life of the measure.

Air conditioning equipment shall be properly sized to the dwelling, based on ASHRAE or ACCA Manual J standards. Manufacturer data sheets on installed air conditioning equipment or the AHRI reference number must be provided to the utility. The installed central air conditioning equipment must be AHRI certified.

[86] https://www.federalregister.gov/documents/2022/03/30/2022-06450/energy-conservation-program-energy-conservation-standards-for-air-cooled-three-phase-small

Table 1-67 Central Air Conditioner – Baseline and Efficiency Levels

System Type	SEER	New SEER2	EER	New EER2
Split System AC (AC <45,000 Btu/h)	15.0	14.3	12.2 (< 15.2 SEER2)	11.7 (< 15.2 SEER2)
			10.2 (≥ 15.2 SEER2)	9.8 (≥ 15.2 SEER2)
Split System AC (AC ≥45,000 Btu/h)	14.5	13.8	12.2 (< 15.2 SEER2)	11.7 (< 15.2 SEER2)
			10.2 (≥ 15.2 SEER2)	9.8 (≥ 15.2 SEER2)
Single Packaged Units (ACs, Heat Pumps, Gas, Electric and Dual-Fuel HPs)	14.0	13.4	11.0	10.45

1.3.1.3 *Estimated Useful Life*

The EUL of this measure is 19 years according to the US DOE.[87]

1.3.1.4 *Deemed Savings Values*

Nameplate data should be used when collected. If not available, deemed savings values for NC and ROB are provided in Table 1-68 through Table 1-73 These values reflect the per-ton and per-dwelling averages from the PY5 through to-date PY9 program years. For systems where tonnage is unknown, deemed values have been provided based on 3.65 average capacity (TONs).

1.3.1.4.1 Split Systems

(i) Split Systems <45,000 Btu, or <3.75 TONs cooling

Table 1-68 Deemed kWh for Split Systems <45,000 Btu, or <3.75 TONs cooling

Efficiency	kWh Saved per Ton	kWh if Tonnage Unknown
15 SEER2	64	234
16 SEER2	146	533
17 SEER2	218	796
18 SEER2	282	1,031
19 SEER2	340	1,240
20 SEER2	392	1,429

[87] U.S. DOE, 2011 Technical Support Document: "Residential Central Air Conditioners, Heat Pumps, and Furnaces, 8.2.3.5 Lifetime." June www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/75.

Table 1-69 Deemed kW for Split Systems <45,000 Btu, or <3.75 TONs cooling

Efficiency	kW Saved per Ton	kW if Tonnage Unknown
12 EER2	0.020	0.07
13 EER2	0.079	0.29
14 EER2	0.130	0.47
15 EER2	0.174	0.63
16 EER2	0.212	0.77
17 EER2	0.246	0.90

(ii) Split Systems ≥45,000 Btu, or ≥3.75 TONs cooling

Table 1-70 Deemed kWh for Split Systems ≥45,000 Btu, or ≥3.75 TONs cooling

Efficiency	kWh Saved per Ton	kWh if Tonnage Unknown
14 SEER2	20	74
15 SEER2	114	416
16 SEER2	196	714
17 SEER2	268	978
18 SEER2	332	1,212
19 SEER2	390	1,422
20 SEER2	441	1,611

Table 1-71 Deemed kW for Split Systems ≥45,000 Btu, or ≥3.75 TONs cooling

Efficiency	kW Saved per Ton	kW if Tonnage Unknown
10 EER2	0.019	0.07
11 EER2	0.103	0.38
12 EER2	0.173	0.63
13 EER2	0.232	0.85
14 EER2	0.283	1.03
15 EER2	0.327	1.19

(iii) Packaged Systems

Table 1-72 Deemed kWh for Packaged Systems

Efficiency	kWh Saved per Ton	kWh if Tonnage Unknown
14 SEER2	63	229
15 SEER2	156	571
16 SEER2	238	870
17 SEER2	310	1,133
18 SEER2	375	1,367
19 SEER2	432	1,577
20 SEER2	484	1,766

Table 1-73 Deemed kW for Packaged Systems

Efficiency	kW Saved per Ton	kW if Tonnage Unknown
11 EER2	0.044	0.16
12 EER2	0.114	0.42
13 EER2	0.173	0.63
14 EER2	0.224	0.82
15 EER2	0.268	0.98
16 EER2	0.307	1.12
11 EER2	0.044	0.16

1.3.1.4.2 Deemed Savings Calculations

(i) Replace-on-Burnout

$$kWh_{Savings} = CAP_c \times \frac{1}{1{,}000} W/_{kW} \times \left(\frac{1}{SEER2_{base}} - \frac{1}{SEER2_{Eff}}\right) \times EFLH_C$$

$$kW_{Savings} = CAP_c \times \frac{1}{1{,}000} W/_{kW} \times \left(\frac{1}{EER2_{base}} - \frac{1}{EER2_{Eff}}\right) \times \%CF$$

Where,

CAP_c = Cooling capacity (in BTU)

$SEER2_{base}$ = Seasonal efficiency of baseline equipment (see Table 1-67)

$SEER2_{eff}$ = Seasonal efficiency of efficient equipment (see Table 1-67)

$EER2_{base}$ = Full-load efficiency of baseline equipment (see Table 1-67)

$EER2_{eff}$ = Full-load efficiency of baseline equipment (see Table 1-67)

$EFLH_c$ = Equivalent Full-Load Cooling Hours

$\%CF$ = Peak Coincidence Factor

1.3.1.4.3 Equivalent Full-Load Hours

Equivalent Full-Load Cooling Hours (EFLHc) measures the total annual runtime of HVAC equipment. To support development of this value, the usage of 68 HVAC systems in New Orleans was metered. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans.

The resulting EFLHc is 1,637.

1.3.1.4.4 Peak Coincidence Factor

The Peak Coincidence Factor is defined as the percent time during the ENO peak period where the residential central air conditioner is operational. Peak hours were defined as:

- Weekdays
- Non-holidays
- 4:00-5:00 PM
- Average ambient temperature exceeding 90 degrees Fahrenheit.

The average central AC runtime during qualified hours was 77%. This peak coincidence factor is applied to calculate peak kW demand reductions from this measure.

1.3.1.4.5 Uncertainty Analysis

The uncertainties associated with the two key parameters collected in EM&V are as follows:

- EFLHc: ±7.81%
- % Coincidence: ±2.11%

1.3.1.5 Incremental Cost

The incremental cost of high central air conditioners is detailed in Table 1-74.

Table 1-74 High Efficiency Central AC Replacement Incremental Costs

Product Type	Incremental Cost Per Ton
16 SEER2	$119
17 SEER2	$238
18 SEER2	$358
19 SEER2	$477
20 SEER2	$596
21 SEER2	$670

1.3.2 WINDOW AIR CONDITIONER REPLACEMENT

1.3.2.1 Measure Description

This measure involves the replacement of a window air conditioner in a residential building.

1.3.2.2 Baseline and Efficiency Standards[88]

The baseline is a new air conditioning unit with a combined energy efficiency ratio (CEER) that meets federal standards established on June 1, 2014 .

Efficient units must meet ENERGY STAR standards, requiring 10% efficiency above federal minimum requirements.

Table 1-75 Window Air Conditioner – Baseline and Efficiency Levels

Reverse Cycle?	Louvered Sides?	Capacity	Baseline CEER	Efficient CEER	kWh	kW
No	Yes	< 8,000	11.0	12.1	46.4	0.0445
		≥ 8,000 and < 14,000	10.9	12.0	74.2	0.0453
		≥ 14,000 and < 20,000	10.7	11.8	118.8	0.0470
		≥ 20,000	9.4	10.3	171.5	0.0501
	No	< 8,000	10.0	11.0	51.0	0.0490
		≥ 8,000	9.6	10.6	78.8	0.0530
Yes	Yes	< 20,000	9.8	10.8	113.7	0.0509
		≥ 20,000	9.3	10.2	190.3	0.0511
	No	< 14,000	9.3	10.2	83.7	0.0511
		≥ 14,000	8.7	9.6	146.9	0.0581

1.3.2.3 Estimated Useful Life

According to the DOE's Technical Support Document, Chapter 8: Life Cycle Cost and Payback Period Analyses 2011, the EUL is 10.5 years.

1.3.2.4 Deemed Savings Values

1.3.2.4.1 Replace-on-Burnout

$$kWh_{Savings} = CAP_c \times \frac{1}{1{,}000} {}^{W}/_{kW} \times \left(\frac{1}{CEER_{base}} - \frac{1}{CEER_{Eff}}\right) \times EFLH_C \times RAF$$

$$kW_{Savings} = CAP_c \times \frac{1}{1{,}000} {}^{W}/_{kW} \times \left(\frac{1}{CEER_{base}} - \frac{1}{CEER_{Eff}}\right) \times \%CF$$

Where:

CAP_c = Cooling capacity (in BTU)

$CEER_{base}$ = Full-load efficiency of baseline equipment (see Table 1-75)

$CEER_{eff}$ = Full-load efficiency of baseline equipment (see Table 1-75)

$CEER_{base}$ = Seasonal efficiency of baseline equipment (see Table 1-75)

$CEER_{eff}$ = Seasonal efficiency of efficient equipment (see Table 1-75)

EFLHc = Equivalent Full-Load Cooling Hours, 1,637

%CF = Peak Coincidence Factor, 77%

RAF = Room AC Adjustment Factor, .49

1.3.2.5 Equivalent Full-Load Hours

Equivalent Full-Load Cooling Hours (EFLHc) measures the total annual runtime of HVAC equipment. To support development of this value, the usage of 68 HVAC systems in New Orleans was metered. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans.

1.3.2.6 Peak Coincidence Factor

The Peak Coincidence Factor is defined as the percent time during the ENO peak period where the residential central air conditioner is operational. Peak hours were defined as:

- Weekdays
- Non-holidays
- 4:00-5:00 PM
- Average ambient temperature exceeding 90 degrees Fahrenheit.

The average central AC runtime during qualified hours was 77%. This peak coincidence factor is applied to calculate peak kW demand reductions from this measure.

1.3.2.7 Uncertainty Analysis

The uncertainties associated with the two key parameters collected in EM&V are as follows:

- EFLHc: ±7.81%
- % Coincidence: ±2.11%

1.3.2.8 Incremental Cost

The incremental cost of high central air conditioners is $50 .

1.3.2.9 Net-to-Gross Ratio

The NTGR for this measure is 62% .

1.3.3 ELECTRONICALLY COMMUTATED MOTORS ON FURNACE FANS

1.3.3.1 Measure Description

Electronically Commutated Motors (ECMs) are motors that provide the power to furnace blowers to circulate the heated air required for space conditioning. This measure focuses on ECMs installed on residential furnace fans and is not applicable for ECMs on separate air handling units. ECMs operate using a built-in inverter and magnetic rotor to vary the torque and/or air flow rate required by the HVAC system. These motors are able to maintain their high efficiency at a variety of operation points thus improving their desirability compared to baseline motors.

1.3.3.2 Baseline and Efficiency Standards

The baseline equipment for this measure is different depending on if the measure is retrofit or new construction. Two types of baseline equipment exist; Shaded-pole (SP) motors and permanent split capacitor (PSC) motors on residential furnaces.

1.3.3.2.1 Retrofit (Early Replacement)

The baseline equipment for retrofit is the existing motor type.

1.3.3.2.2 New Construction (Includes Major Remodel & ROB)

The baseline equipment for new construction is a PSC motor.

1.3.3.3 Deemed Savings Values

The algorithms below are to be used to calculate electric energy and demand reductions for this measure:

$$kWh_{savings} = \left(\frac{hp_{base}}{Eff_{base}} - \frac{hp_{ECM}}{Eff_{ECM}}\right) \times 0.746 \times EFLH_h \times y$$

$$kW_{savings} = \left(\frac{hp_{base}}{Eff_{base}} - \frac{hp_{ECM}}{Eff_{ECM}}\right) \times 0.746 \times CF$$

Where:

hp_{base} = Rated horsepower of baseline motor, hp

hp_{ECM} = Rated horsepower of installed ECM, hp

Eff_{pre} = Efficiency of baseline motor as found in Table 1-76Table 1-76 Furnace Fan Efficiency Valuesthe table below, %

Eff_{ECM} = Efficiency of ECM as found in Table 1-76 below, %

$EFLH_h$ = Equivalent full load hours of heating, 1,118

Y = Ratio of fan motor on to burner on as calculated below,

CF = Coincidence Factor, 0.71

The ratio of blower on time to furnace burner on time can be taken as 1.39 based on DOE estimated values or calculated based on the DOE furnace test procedure shown below[89] if the relevant parameters are known.

$$y = \frac{t^{+} - t^{-}}{t_{ON}}$$

Where:

---

[89] U.S. Department of Energy (2014, June). TECHNICAL SUPPORT DOCUMENT: ENERGY EFFICIENCY PROGRAM FOR CONSUMER PRODUCTS AND COMMERCIAL AND INDUSTRIAL EQUIPMENT: RESIDENTIAL FURNACE FANS.

t^+ = off-period between burner shutdown and blower shutdown (blower off delay), min

t^- = on-period between burner shutdown and blower shutdown (blower off delay), min

t_{ON} = average burner on-time, min

1.3.3.3.1 Calculation Variables

Typical motor efficiency values were obtained for HVAC applications from a DOE report and can be found below. The original report provided a range; however, the median value of the range was extracted for use in calculating savings.

Table 1-76 Furnace Fan Efficiency Values

Motor Type	**Efficiency (%)**
Shaded-Pole	30
Permanent Split Capacitor	60
Electronically Commutated	75

1.3.3.4 Estimated Useful Life

The EUL of this measure is 15 years[90].

1.3.3.5 Incremental Cost

Actual material and labor costs should be used when available. When not available, the incremental cost of this measure should be $475 .

1.3.3.6 Future Studies

There are no future studies planned for this measures at this time.

[90] DEER 2008

1.3.4 HEAT PUMP REPLACEMENT

1.3.4.1 Measure Description

This measure involves a residential retrofit with a new heat pump system or the installation of a new heat pump system in a residential new construction (packaged unit, or split system consisting of an indoor unit with a matching remote condensing unit). Maximum cooling capacity per unit is 65,000 BTU/hour. This measure applies to all residential applications.

1.3.4.2 Baseline and Efficiency Standards[91]

The DOE is changing the way HVAC systems are tested and modifying its rating system, replacing SEER, EER and HSPF ratings with SEER2, EER2 and HSPF2, respectively. All systems sold must meet new efficiency minimums using the new "M1" testing procedure which is designed to better reflect field conditions.

The following conversion factors are recommended for use if the efficient equipment is not rated under the new testing procedure, but the stipulated baseline is:

- $SEER2 = SEER \times 0.95$
- $HSPF2 = HSPF \times 0.85$

The new guidelines affect system heat pump (HP) equipment manufactured prior to December 31, 2022, and installed in the Southwest region after January 1, 2023. Further, SEER/SEER2 and HSPF/HSPF2 requirements have been increased. EER ratings for the New Orleans region are subject to EER2 classification but required efficiency levels do not change.

For new construction (NC) and replace on burnout (ROB) projects, the cooling baseline is 14.3 SEER2 (15.0 SEER) and 7.5 HSPF2 (8.8 HSPF) for split systems, and 13.4 SEER2 (14.0 SEER) and 6.7 HSPF2 (8.0 HSPF) for packaged systems, consistent with the current federal minimum standard .

For early retirement (ER) projects, the cooling baseline is reduced to 13.0 SEER (12.4 SEER2) for systems manufactured before January 1, 2015, and 14.0 (13.3 SEER2) for systems manufactured after. For ER HSPF baselines please see Table 1-77 below.

For Early Replacement, the maximum lifetime age of an eligible piece of equipment is capped at the point at which it is expected that 75 percent of the equipment has failed. Where the age of the unit exceeds the 75 percent failure age, ROB savings should be applied. This cap prevents early retirement savings from being applied to projects where the age of the equipment greatly exceeds the estimated useful life of the measure.

Heat Pump equipment shall be properly sized to the dwelling, based on ASHRAE or ACCA Manual J standards. Manufacturer data sheets on installed air conditioning equipment or the AHRI reference number must be provided to the utility. The installed central air conditioning equipment must be AHRI certified.

---

[91] https://www.federalregister.gov/documents/2022/03/30/2022-06450/energy-conservation-program-energy-conservation-standards-for-air-cooled-three-phase-small

Table 1-77 Heat Pump – Baseline and Efficiency Levels

Characterization	System Type	SEER	New SEER2	HSPF	New HSPF2
New Construction and Normal Replacement	Split	15.0	14.3	8.8	7.5
	Packaged	14.0	13.4	8.0	6.7
Early Retirement (< Jan 1, 2015)	Both	13.0	12.4	7.7	6.6
Early Retirement (≥ Jan 1, 2015)	Split	14.0	13.3	8.2	7.0
	Packaged[92]			8.0	6.8

The heating baseline for early retirement of an electric resistance furnace is 3.41 HSPF.

1.3.4.3 *Estimated Useful Life*

The EUL of this measure is 16 years, according to the US DOE.[93]

1.3.4.4 *Deemed Savings Values*

Nameplate data should be used when collected. If not available, deemed savings values for NC and ROB are provided in Table 1-78 through Table 1-83. These values reflect the per-ton and per-dwelling averages from the PY5 through to-date PY9 program years. For systems where tonnage is unknown, deemed values have been provided based on 3.01 average capacity (TONs). The baseline EER2 used is 10.45.

1.3.4.4.1 Deemed kWh and kW for Package Systems

Table 1-78 Deemed Cooling kWh Savings for Packaged Systems

Efficiency	kWh Saved per Ton	kWh if Tonnage Unknown
14 SEER2	63	189
15 SEER2	156	470
16 SEER2	238	716
17 SEER2	310	933
18 SEER2	375	1,126
19 SEER2	432	1,299
20 SEER2	484	1,455

Table 1-79 Deemed Heating kWh Savings for Packaged Systems

Efficiency	kWh Saved per Ton	kWh if Tonnage Unknown
7 HSPF2	46	138
8 HSPF2	175	525
9 HSPF2	275	826
10 HSPF2	355	1,066

[92] ACs, Heat Pumps, Gas, Electric and Duel-Fuel HPs

[93] US U.S. DOE, 2011. *Technical Support Document: "Residential Central Air Conditioners, Heat Pumps, and Furnaces, 8.2.3.5 Lifetime*". June. www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/75.

11 HSPF2	420	1,263
12 HSPF2	475	1,427
13 HSPF2	521	1,566

1.3.4.4.2 Deemed kWh and kW for Split Systems

Table 1-80 Deemed Cooling kWh Savings for Split Systems

Efficiency	kWh Saved per Ton	kWh if Tonnage Unknown
15 SEER2	64	193
16 SEER2	146	439
17 SEER2	218	656
18 SEER2	282	849
19 SEER2	340	1,022
20 SEER2	392	1,177
21 SEER2	438	1,318

Table 1-81 Deemed Heating kWh Savings for Split Systems

Efficiency	kWh Saved per Ton	kWh if Tonnage Unknown
8 HSPF2	60	180
9 HSPF2	160	481
10 HSPF2	240	722
11 HSPF2	305	918
12 HSPF2	360	1,082
13 HSPF2	406	1,221
14 HSPF2	446	1,340

1.3.4.4.3 Deemed kWh for Electric Resistance to Heat Pump Conversion

Table 1-82 Deemed Cooling kWh Savings for Electric Resistance to Heat Pump Conversion[94]

Efficiency	kWh Saved per Ton	kWh if Tonnage Unknown
4 HSPF2	206	618
5 HSPF2	443	1,332
6 HSPF2	602	1,809
7 HSPF2	715	2,149
8 HSPF2	800	2,404
9 HSPF2	866	2,602
10 HSPF2	918	2,761
11 HSPF2	962	2,891
12 HSPF2	998	2,999
13 HSPF2	1,028	3,091
14 HSPF2	1,054	3,169

[94] COP = HSPF × 1,055 J/BTU / 3,600 J/W-hr. For Electric Resistance, heating efficiency is 1 COP. Therefore, HSPF = 1 × 3,600 / 1,055 = 3.41.

1.3.4.4.4 Deemed kW Reductions

Table 1-83 Deemed kW Savings for Split Systems

Efficiency	kW Saved per Ton	kW if Tonnage Unknown
12 EER2	0.11	0.34
13 EER2	0.17	0.52
14 EER2	0.22	0.67
15 EER2	0.27	0.81
16 EER2	0.31	0.92
17 EER2	0.34	1.02
18 EER2	0.37	1.12

1.3.4.4.5 Replace-on-Burnout

(i) Cooling Savings

$$kWh_{Savings} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{SEER2_{base}} - \frac{1}{SEER2_{Eff}}\right) \times EFLH_C$$

$$kW_{Savings} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{EER2_{base}} - \frac{1}{EER2_{Eff}}\right) \times \%CF$$

Where:

CAP_c = Cooling capacity (in BTU)

$EER2_{base}$ = Full-load efficiency of baseline equipment (see Table 1-77)

$EER2_{eff}$ = Full-load efficiency of baseline equipment (see Table 1-77)

$SEER2_{base}$ = Seasonal efficiency of baseline equipment (see Table 1-77)

$SEER2_{eff}$ = Seasonal efficiency of efficient equipment (see Table 1-77)

EFLHc = Equivalent Full-Load Cooling Hours

%CF = Peak Coincidence Factor

(ii) Heating Energy Savings

Heating savings are calculated with the following formula:

$$kWh_{Savings} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{HSPF2_{base}} - \frac{1}{HSPF2_{Eff}}\right) \times EFLH_h$$

Where:

CAP_c = Cooling capacity (in BTU)

$EER2_{base}$ = Full-load efficiency of baseline equipment (see Table 1-77)

$EER2_{eff}$ = Full-load efficiency of baseline equipment (see Table 1-77)

$HSPF2_{base}$ = Heating Season Performance Factor of baseline equipment (see Table 1-77)

$HSPF2_{eff}$ = Heating Season Performance Factor of efficient equipment (see Table 1-77)

$EFLH_h$ = Equivalent Full-Load Heating Hours, 600

%CF = Peak Coincidence Factor

(iii) Derivation of Equivalent Full-Load Hours and Peak Coincidence Factor

(iv) Cooling Hours

Equivalent Full-Load Cooling Hours (EFLHc) measures the total annual runtime of HVAC equipment. To support development of this value, the usage of 68 HVAC systems in New Orleans was metered over the course of three years. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans.

The resulting EFLHc is 1,637.

(v) Peak Coincidence Factor

The Peak Coincidence Factor is defined as the percent time during the ENO peak period where the residential central air conditioner is operational. Peak hours were defined as:

- Weekdays
- Non-holidays
- 4:00-5:00 PM
- Average ambient temperature exceeding 90 degrees Fahrenheit.

The average central AC runtime during qualified hours was 77%. This peak coincidence factor is applied to calculate peak kW demand reductions from this measure.

(vi) Heating Hours

Equivalent Full-Load Heating Hours ($EFLH_h$) measures the total annual runtime of heating equipment. To support development of this value, the usage of 295 electric heating systems in New Orleans was estimated using a billing analysis. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans. In addition, the $EFLH_h$ was multiplied by a scaling factor of 1.51 to account for differences in usage for heat pump vs. electric resistance heating types.

The heat pump scaling factor was calculated using the following equation:

$Scaling\ Factor_{HP} = ((\frac{\frac{kWh}{HDD}}{Ton}_{HP}) * COP_{HP})/((\frac{\frac{kWh}{HDD}}{Ton}_{ER}) * COP_{ER})$ Where:

> *$kWh/HDD/Ton_{HP}$*= Weighted average of predicted kWh/HDD/Ton for heat pump heating types for single and multi-family homes = 0.3282
>
> *$kWh/HDD/Ton_{ER}$*= Weighted average of predicted kWh/HDD/Ton for electric resistance heating types for single and multi-family homes = 0.4348
>
> *COP_{HP}* = Coefficient of performance for heat pumps = 2.0
>
> *COP_{HP}* = Coefficient of performance for electric resistance = 1.0

The resulting $EFLH_H$ for Electric Resistance systems 396.

The resulting $EFLH_H$ for Heat Pumps is 600.

(vii) Uncertainty Analysis

The uncertainties associated with the four key parameters collected in EM&V are as follows:

- EFLHc: ±5.10%
- % Coincidence: ±2.11%
- EFLHh: Electric Resistance ±5.10%
- EFLHh: Heat Pumps ±37.10%

1.3.4.5 Incremental Cost

The incremental cost of high efficiency heat pump is detailed in Table 1-84 .

Table 1-84 Replacement Incremental Costs (HP Baseline)

Efficiency	Incremental Cost Per Ton
15 SEER2	$184
16 SEER2	$319
17 SEER2	$605
18 SEER2	$605

The incremental costs of retiring an electric resistance heating system early and replacing it with a high efficiency heat pump are detailed in the Table 1-85 table below.

Table 1-85 Replacement Incremental Costs (ER Baseline)

Efficiency	Incremental Cost Per Ton
15 SEER2	$1,605
16 SEER2	$1,740
17 SEER2	$2,026
18 SEER2	$2,026

1.3.4.6 Future Studies

There are no future studies planned for this measure at this time.

1.3.5 GROUND SOURCE HEAT PUMP REPLACEMENT

1.3.5.1 Measure Description

This measure involves the installation of water-to-air ground source heat pump as a replacement for an existing air-source heat pump. Maximum cooling capacity per unit is 65,000 BTU/hour. This measure applies to all residential applications.

1.3.5.2 Baseline and Efficiency Standards[95]

The Department of Energy (DOE) is changing the way HVAC systems are tested and modifying its rating system, replacing SEER, EER and HSPF ratings with SEER2, EER2 and HSPF2, respectively. All systems sold must meet new efficiency minimums using the new “M1” testing procedure[96] which is designed to better reflect field conditions.

The new guidelines affect system heat pump (HP) equipment manufactured prior to December 31, 2022 and installed in the Southwest region after January 1, 2023. Further, SEER/SEER2 and HSPF/HSPF2 requirements have been increased. EER ratings for the New Orleans region are subject to EER2 classification but required efficiency levels do not change.

For new construction (NC) and replace on burnout (ROB) projects, the cooling baseline is 14.3 SEER2 (15.0 SEER) and 7.5 HSPF2 (8.8 HSPF) for split systems, and 13.4 SEER2 (14.0 SEER) and 6.7 HSPF2 (8.0 HSPF) for packaged systems, consistent with the current federal minimum standard .

Due to the high cost of this equipment, all projects are assumed to be replacement on burnout or new construction.

Heat Pump equipment shall be properly sized to the dwelling, based on ASHRAE or ACCA Manual J standards. Manufacturer data sheets on installed air conditioning equipment or the AHRI reference number must be provided to the utility. The installed central air conditioning equipment must be AHRI certified.

Table 1-86 Heat Pump – Baseline and Efficiency Levels

	SEER2	EER2	HSPF2
New Construction and Normal Replacement	14.3	11.7 (< 15.2 SEER2) 9.8 (≥ 15.2 SEER2)	7.5 (split)
			6.7 (packaged)
ENERGY STAR Criteria – Water-to-Air[97]		Closed Loop: 16.2	Closed Loop: 10.3
		Open Loop: 20.0	Open Loop: 11.8
ENERGY STAR Criteria – Water-to-Water		Closed Loop: 15.3	Closed Loop: 8.9
		Open Loop: 19.1	Open Loop: 10.0
		DGX: 15.2	DGX: 10.3

[96] https://www.energy.gov/sites/prod/files/2016/08/f33/Central%20Air%20Conditioners%20and%20Heat%20Pumps%20TP%20SNOPR_4.pdf

[97] EER and COP values given by the ENERGY STAR website have been converted into EER2 and HSPF2 vales for this table.

1.3.5.3 Estimated Useful Life

The EUL of this measure is 25 years, according to the US DOE.[98]

1.3.5.4 Calculation of Deemed Savings

1.3.5.4.1 Replace-on-Burnout

(i) Cooling Savings

$$kWh_{Savings} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{SEER2_{base}} - \frac{1}{SEER2_{Eff}}\right) \times EFLH_C$$

$$kW_{Savings} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{EER2_{base}} - \frac{1}{EER2_{Eff}}\right) \times \%CF$$

Where:

CAP_c = Cooling capacity (in BTU)

$EER2_{base}$ = Full-load efficiency of baseline equipment (see Table 1-86)

$EER2_{eff}$ = Full-load efficiency of baseline equipment (see Table 1-86)

$SEER2_{base}$ = Seasonal efficiency of baseline equipment (see Table 1-86)

$SEER2_{eff}$ = Seasonal efficiency of efficient equipment (see Table 1-86)

$EFLHc$ = Equivalent Full-Load Cooling Hours

$\%CF$ = Peak Coincidence Factor

(ii) Heating Energy Savings

Heating savings are calculated with the following formula:

$$kWh_{Savings} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{HSPF2_{base}} - \frac{1}{HSPF2_{Eff}}\right) \times EFLH_h$$

Where:

CAP_c = Cooling capacity (in BTU)

$EER2_{base}$ = Full-load efficiency of baseline equipment (see Table 1-86)

$EER2_{eff}$ = Full-load efficiency of baseline equipment (see Table 1-86)

$HSPF2_{base}$ = Heating Season Performance Factor of baseline equipment (see Table 1-86)

$HSPF2_{eff}$ = Heating Season Performance Factor of efficient equipment (see Table 1-86)

[98] Source DOE Energy Savers website: www.energysavers.gov/your_home/space_heating_cooling/index.cfm/mytopic=12640 .

$EFLH_h$ = Equivalent Full-Load Heating Hours, 600

%CF = Peak Coincidence Factor

1.3.5.5 Incremental Cost

New Construction and Time of Sale: The actual installed cost of the Ground Source Heat Pump should be used (default of $3838 per ton[99]), minus the assumed installation cost of the baseline equipment ($1,262 per ton for ASHP[100] or $2,011 for a new baseline 80% AFUE furnace or $3,424 for a new 82% AFUE boiler[101] and $833 per ton[102] for new baseline Central AC replacement).

Early Replacement: The full installation cost of the Ground Source Heat Pump should be used (default provided above). The assumed deferred cost (after 8 years) of replacing existing equipment with a new baseline unit is assumed to be $1,399 per ton for a new baseline Air Source Heat Pump, or $2,784 for a new baseline 90% AFUE furnace or $3,926 for a new 82% AFUE boiler and 928 per ton for new baseline Central AC replacement[103]. This future cost should be discounted to present value using the nominal societal discount rate.

1.3.5.6 Future Studies

There are not future studies planned for this measures at this time.

---

[99] Based on data provided in 'Results of Home geothermal and air source heat pump rebate incentives documented by IL electric cooperatives.

[100] Baseline cost per ton derived from DEER 2008 Database Technology and Measure Cost Data. See 'ASHP_Revised DEER Measure Cost Summary.xls' for calculation.

[101] Furnace and boiler costs are based on data provided in Appendix E of the Appliance Standards Technical Support Documents including equipment cost and installation labor.

[102] Based on 3 ton initial cost estimate for a conventional unit from ENERGY STAR Central AC calculator.

[103] All baseline replacement costs are consistent with their respective measures and include inflation rate of 1.91%.

1.3.6 DUCTLESS HEAT PUMP

1.3.6.1 Measure Description

This measure involves the installation of ductless mini-split heat pumps (DMSHP). These systems have increased savings over efficient air source heat pumps as they use less fan energy to move heat and cooled air and don't incur distribution losses.

1.3.6.2 Baseline and Efficiency Standards

For new construction (NC) and ROB projects, the cooling baseline is 14 SEER and 8.0 HSPF, consistent with the current federal minimum standard . Due to the high cost of this equipment, all projects are assumed to be replacement on burnout or new construction.

A DMSHP must be a high-efficiency, variable-capacity system that exceeds program minimum efficiency requirements. Qualified systems will typically have an inverter-driven DC motor.

Heat Pump equipment shall be properly sized to the dwelling, based on ASHRAE or ACCA Manual J standards. Manufacturer data sheets on installed air conditioning equipment or the AHRI reference number must be provided to the utility. The installed central air conditioning equipment must be AHRI certified.

Table 1-87 Heat Pump – Baseline and Efficiency Levels

Replacement Type	SEER	New SEER2	HSPF	New HSPF2
New Construction and Replace on Burnout	15.0	14.3	8.8	7.5
Early Retirement	14.0	13.3	8.2	7.0

1.3.6.3 Estimated Useful Life

The EUL of this measure is 18 years.[104]

1.3.6.4 Deemed Savings Values

Savings are calculated in the same manner as for Heat Pump Replacement. See Section 1.3.4.4.4. According to the current AHRI database , the average efficiency of ENERGY STAR-rated ductless units that are currently in production is as follows:

- SEER: 21.17
- EER: 12.79
- HSPF: 10.43

The average capacity of these units is 2.28 tons.

[104] Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, Inc., June 2007

The resulting average unit energy savings for a ductless mini-split are detailed in the Table 1-88 below. This is per-unit installed in a residence; a retrofit may constitute installation of multiple units, and if so, the calculation is performed separately for each and the savings added.

Table 1-88 Ductless Mini-Split Average Savings

	kWh Per Ton	kW per Ton	Average Tons	kWh per Unit	kW per Unit
New Construction and Normal Replacement	598	0.064	3.01	1,801	0.19

1.3.6.5 Incremental Cost

New Construction and Time of Sale: The actual installed cost of the DMSHP should be used (defaults are provided below), minus the assumed installation cost of the baseline equipment ($1,381 per ton for ASHP[105] or $2,011 for a new baseline 80% AFUE furnace or $3,543 for a new 82% AFUE boiler[106] and $952 per ton[107] for new baseline Central AC replacement).

Default full cost of the DMSHP is provided below. Note, for smaller units a minimum cost of $2,000 should be applied .

Table 1-89 Ductless Mini-Split Full Installed Cost

Efficiency (HSPF2)	Full Install Cost ($/ton)
8-8.9	$1,443
9-9.9	$1,605
10-10.9	$1,715
12+	$2,041

The incremental cost of the DSMHP compared to a baseline minimum efficiency DSMHP is provided in the Table 1-90 below .

Table 1-90 Ductless Mini-Split Incremental Cost

Efficiency (HSPF2)	Incremental Cost ($/ton) over HSPF 8.0 DHP
8-8.9	$62
9-9.9	$224
10-10.9	$334
12+	$660

Early Replacement/retrofit (replacing existing equipment): The full installation cost of the DMSHP should be used (default provided above). The assumed deferred cost (after 8 years) of replacing existing equipment with a new baseline unit is assumed to be $1,518 per ton for a new baseline Air Source Heat

[105] Baseline cost per ton derived from DEER 2008 Database Technology and Measure Cost Data. See 'ASHP_Revised DEER Measure Cost Summary.xls' for calculation.

[106] Furnace and boiler costs are based on data provided in Appendix E of the Appliance Standards Technical Support Documents including equipment cost and installation labor. Where efficiency ratings are not provided, the values are interpolated from those that are.

[107] Based on 3 ton initial cost estimate for a conventional unit from ENERGY STAR Central AC calculator

Pump, or $2,903 for a new baseline 90% AFUE furnace or $4,045 for a new 82% AFUE boiler and $1,047 per ton for new baseline Central AC replacement . If replacing electric resistance heat, there is no deferred replacement cost. This future cost should be discounted to present value using the nominal societal discount rate.

Where the DMSHP is a supplemental HVAC system, the full installation cost of the DMSHP should be used (default provided above) without a deferred replacement cost.

1.3.6.6 Future Studies

The baseline for ductless systems may vary widely. Program implementers and the TPE should coordinate to ensure collection of baseline data for these projects.

1.3.7 CENTRAL AC AND HEAT PUMP TUNE-UP

1.3.7.1 Measure Description

This measure applies to central air conditioners and heat pumps. An AC tune-up, in general terms, involves checking, adjusting, and resetting the equipment to factory conditions, such that it operates closer to the performance level of a new unit. This measure applies to all residential applications.

For this measure, the service technician must complete the following tasks according to industry best practices:

- Air Conditioner Inspection and Tune-Up Checklist[108]
- Inspect and clean condenser, evaporator coils, and blower.
- Inspect refrigerant level and adjust to manufacturer specifications.
- Measure the static pressure across the cooling coil to verify adequate system airflow and adjust to manufacturer specifications.
- Inspect, clean, or change air filters.
- Calibrate thermostat on/off set points based on building occupancy.
- Tighten all electrical connections, and measure voltage and current on motors.
- Lubricate all moving parts, including motor and fan bearings.
- Inspect and clean the condensate drain.
- Inspect controls of the system to ensure proper and safe operation. Check the starting cycle of the equipment to assure the system starts, operates, and shuts off properly.
- Provide documentation showing completion of the above checklist to the utility or the utility's representative.

1.3.7.2 Baseline and Efficiency Standards

The baseline is a system with demonstrated imbalances of refrigerant charge.

After the tune-up, the equipment must meet airflow and refrigerant charge requirements. To ensure the greatest savings when conducting tune-up services, the eligibility minimum requirement for airflow is the manufacturer specified design flow rate, or 350 CFM/ton, if unknown. Also, the refrigerant charge

[108] Based on ENERGY STAR HVAC Maintenance Checklist. www.energystar.gov/index.cfm?c=heat_cool.pr_maintenance

must be within +/- 3 degrees of target sub-cooling for units with thermal expansion valves (TXV) and +/- 5 degrees of target super heat for units with fixed orifices or a capillary.

The efficiency standard, or efficiency after the tune-up, is assumed to be the manufacturer specified energy efficiency ratio (EER) of the existing central air conditioner or heat pump. The efficiency improvement resulting from the refrigerant charge adjustment depends on the pre-adjustment refrigerant charge.

1.3.7.3 Estimated Useful Life

The EUL for a full tune-up with refrigerant change is 10 years . If no refrigerant charge adjustment is made, the EUL is 3 years .

1.3.7.4 Deemed Savings Values

The methodologies in this chapter detail the approach program staff should take to capture data needed to calculate savings from AC tune-ups. However, this data may not always be readily available or measurable. The values in Table 1-91 and Table 1-92 reflect the per-ton and per-unit averages from the PY5 through to-date PY9 program years and should be used when test data cannot be collected. HSPF and EER gains used in deemed calculations were derived from the same data.

Table 1-91 AC Tune-Up Deemed Savings by Capacity

System Type	kWh/Ton	kW/Ton
Central AC	283.3	0.133
Central HP	603.2	0.133

Table 1-92 AC Tune-Up Deemed Savings by Dwelling

System Type	Average Single Family Capacity (Tons)	kWh/SF Dwelling	kW/SF Dwelling	Average Multifamily Capacity (Tons)	kWh/MF Dwelling	kW/MF Dwelling
Central AC	3.28	929.1	0.437	2.46	696.8	0.328
Central HP	3.28	1,978.4	0.437	2.46	1,483.8	0.328

1.3.7.4.1 Partial Deemed Savings Based on Tune Up Component

Partial savings may be claimed if the tune-up does not require all components. These are additive if condenser cleaning, evaporator cleaning and refrigerant charge correction are performed.

Partial savings may be claimed if the tune-up does not require all components (e.g. a coil cleaning is required by a refrigerant charge is not). These are additive if condenser cleaning, evaporator cleaning and refrigerant charge correction are performed. See Table 1-93 below for percentage savings that can be claimed. See Table 1-94 and Table 1-95 for per-residence deemed savings values by component, followed by an example.

Table 1-93 Savings by Component[109]

Tune-Up Component	% Savings
Condenser Cleaning	6.10%
Evaporator Cleaning	0.22%
Refrigerant Charge Off. ≤ 20%	0.68%
Refrigerant Charge Off. > 20%	8.44%
Combined (Refrigerant Off. ≤ 20%)	7.00%
Combined (Refrigerant Off.> 20%)	14.76%

Table 1-94 Deemed Savings by Component[110] for Single Family

Tune-Up Component	Central AC		Heat Pump	
	kWh/Dwelling	kW/Dwelling	kWh/Dwelling	kW/Dwelling
Condenser Cleaning	56.7	0.027	120.7	0.027
Evaporator Cleaning	2.0	0.001	4.4	0.001
Refrigerant Charge Off. ≤ 20%	6.3	0.003	13.5	0.003
Refrigerant Charge Off. > 20%	78.4	0.037	166.9	0.037
Combined (Refrigerant Off. ≤ 20%)	65.0	0.031	138.5	0.031
Combined (Refrigerant Off.> 20%)	137.1	0.065	292.0	0.065

Table 1-95 Deemed Savings by Component for Multifamily[111]

Tune-Up Component	Central AC		Heat Pump	
	kWh/Dwelling	kW/Dwelling	kWh/Dwelling	kW/Dwelling
Condenser Cleaning	42.5	0.020	90.5	0.020
Evaporator Cleaning	1.5	0.001	3.3	0.001
Refrigerant Charge Off. ≤ 20%	4.7	0.002	10.1	0.002
Refrigerant Charge Off. > 20%	58.8	0.028	125.2	0.028
Combined (Refrigerant Off. ≤ 20%)	48.8	0.023	103.9	0.023
Combined (Refrigerant Off.> 20%)	102.9	0.048	219.0	0.048

Example: A central AC at a single family dwelling only requires a condenser cleaning and evaporator cleaning as service. Using Table 1-94 above, we see these components provide 56.7 kWh and 2.0 kWh of savings, respectively. A total savings of 58.7 kWh and 0.028 kW can be claimed for this project.

---

[109] Savings estimates are determined by applying the findings from DNV-GL "Impact Evaluation of 2013-2014 HVAC3 Commercial Quality Maintenance Programs", April 2016, to simulate the inefficient condition within select eQuest models and across climate zones. The percent savings were consistent enough across building types and climate zones that it was determined appropriate to apply a single set of assumptions for all. See 'eQuest C&I Tune up Analysis.xlsx' for more information.

[110] Savings estimates are determined by applying the findings from DNV-GL "Impact Evaluation of 2013-2014 HVAC3 Commercial Quality Maintenance Programs", April 2016, to simulate the inefficient condition within select eQuest models and across climate zones. The percent savings were consistent enough across building types and climate zones that it was determined appropriate to apply a single set of assumptions for all. See 'eQuest C&I Tune up Analysis.xlsx' for more information.

[111] Savings estimates are determined by applying the findings from DNV-GL "Impact Evaluation of 2013-2014 HVAC3 Commercial Quality Maintenance Programs", April 2016, to simulate the inefficient condition within select eQuest models and across climate zones. The percent savings were consistent enough across building types and climate zones that it was determined appropriate to apply a single set of assumptions for all. See 'eQuest C&I Tune up Analysis.xlsx' for more information.

1.3.7.4.2 Deemed Savings Calculations

There are two ways in which deemed savings can be calculated for this measure:

- Test-in and test-out efficiency; or
- Application of a stipulated reduction in annual use.

(i) Test-in and Test-out Efficiency

$$kWh_{Savings\_Cooling} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{EER_{pre}} - \frac{1}{EER_{post}}\right) \times EFLH_C$$

$$kWh_{Savings\_Heating} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{HSPF_{pre}} - \frac{1}{HSPF_{post}}\right) \times EFLH_H$$

$$kW_{Savings} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{EER_{pre}} - \frac{1}{EER_{post}}\right) \times \%CF$$

$$kWh_{Central\ AC} = kWh_{Savings\_Cooling}$$

$$kWh_{Heat\ Pumps} = kWh_{Savings\_Cooling} + kWh_{Savings\_Heating}$$

Where:

CAP_c = Cooling capacity (in BTU)

EER_{pre} = Efficiency of the equipment prior to tune-up

EER_{post}= Nameplate efficiency of the existing equipment

EFLHc = Equivalent Full-Load Cooling Hours = 1,637

EFLHh = Equivalent Full-Load Heating Hours = 600

$HSPF_{pre}$ = Measured efficiency of the heating equipment before tune-up

$HSPF_{post}$ = Measured efficiency of the heating equipment after tune-up

%CF = Peak Coincidence Factor

(ii) Baseline Efficiency

Baseline efficiency is calculated as:

$$EER_{pre} = (1 - EL) \times EER_{post}$$

EL is the Efficiency Loss based on the current refrigerant charge level. The EL values are summarized in Table 1-96 and Table 1-97.

Table 1-96 Efficiency Loss by Refrigerant Charge Level (Fixed Orifice)

% Charged	EL
≤70	.37
75	.29
80	.20
85	.15

90	.10
95	.05
100	0
≥120	.03

Table 1-97 Efficiency Loss by Refrigerant Charge Level (TXV)

% Charged	EL
≤70	.12
75	.09
80	.07
85	.06
90	.05
95	.03
100	.00
≥120	.04

(iii) Equivalent Full-Load Hours

Equivalent Full-Load Cooling Hours (EFLHc) measures the total annual runtime of HVAC equipment. To support development of this value, the usage of 68 HVAC systems in New Orleans was metered. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans.

The resulting EFLHc is 1,637.

Equivalent Full-Load Heating Hours ($EFLH_h$) measures the total annual runtime of heating equipment. To support development of this value, the usage of 295 electric heating systems in New Orleans was estimated using a billing analysis. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans. In addition, the $EFLH_h$ was multiplied by a scaling factor of 1.51 to account for differences in usage for heat pump vs. electric resistance heating types.

The heat pump scaling factor was calculated using the following equation:

$$Scaling\ Factor_{HP} = ((\frac{\frac{kWh}{HDD}}{Ton}_{HP}) * COP_{HP})/((\frac{\frac{kWh}{HDD}}{Ton}_{ER}) * COP_{ER})$$

Where:

kWh/HDD/Ton$_{HP}$= Weighted average of predicted kWh/HDD/Ton for heat pump heating types for single and multi-family homes = 0.3282

kWh/HDD/Ton$_{ER}$= Weighted average of predicted kWh/HDD/Ton for electric resistance heating types for single and multi-family homes = 0.4348

COP_{HP} = Coefficient of performance for heat pumps = 2.0

COP_{HP} = Coefficient of performance for electric resistance = 1.0

(iv) Peak Coincidence Factor

The Peak Coincidence Factor is defined as the percent time during the ENO peak period where the residential central air conditioner is operational. Peak hours were defined as:

- Weekdays
- Non-holidays
- 4:00-5:00 PM
- Average ambient temperature exceeding 90 degrees Fahrenheit.

The average central AC runtime during qualified hours was 77%. This peak coincidence factor is applied to calculate peak kW demand reductions from this measure.

(v) % Off Annual Use

Alternatively, program administrators may elect to claim savings based off of a percent reduction in annual use.

$$kWh_{Savings} = CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{EER_{pre}}\right) \times EFLH_C \times \%Reduction\; kWh_{Savings} =$$

$$CAP_c \times 1kW/1{,}000W \times \left(\frac{1}{EER_{pre}}\right) \times EFLH_C \times \%Reduction\; kW_{Savings} = CAP_c \times 1kW/1{,}000W \times$$

$$\left(\frac{1}{EER_{pre}}\right) \times \%CF\%Reduction$$

In this, EERpre is assumed to be 10.164 . Percent reduction is 17.2%. This value is derived with PY7 through PY9 Residential Heating & Cooling Program data.

$$kWh_{Central\ AC} = kWh_{Savings\_Cooling}\; kWh_{Heat\ Pumps} = kWh_{Savings\_Cooling} + \; kWh_{Savings\_Heating}$$

Partial savings may also be claimed by applying values in Table 1-93.

(vi) Uncertainty Analysis

The uncertainties associated with the two key parameters collected in EM&V are as follows:

- EFLHc: ±7.81%
- EFLHh: Heat Pumps ±37.10%
- % Coincidence: ±2.11%

1.3.7.5 Incremental cost

The incremental cost of an AC Tune-Up is $175 .

1.3.7.6 Net-to-Gross

The NTG for this measure is 82% .

1.3.7.7 Future Studies

The incremental cost value is very sensitive to labor costs, and as such a New Orleans-specific cost study should be conducted to revise this value.

1.3.8 DUCT SEALING

1.3.8.1 Measure Description

This measure is comprised of performing duct sealing using mastic sealant or metal tape to the distribution system of homes with a central air conditioning system. Materials should be long-lasting materials such as UL 181A or UL 181 B-approved foil tape. Fabric-based duct tape is not allowed.

In calculating savings for this measure, program administrators are to use the leakage-to-unconditioned space metric, entailing a blower-door subtraction test method. this technique is described in detail on p.44 of the Energy Conservatory Blower Door Manual; which can be found on the Energy Conservatory website .

1.3.8.2 Baseline and Efficiency Standards

The baseline for this measure is unsealed ductwork, with a maximum pre-installation leakage rate of 40% of total fan flow . This cap is imposed because interior temperature in homes that exceed 40 percent total leakage would be above the thermally acceptable comfort levels published by ASHRAE in its 2009 Fundamentals publication. Historically, homeowners would remedy a situation in such a state of disrepair, and out of concern for the validity of baseline test measurements performed by duct sealing contractors and to ensure that the savings are program attributable, program administrators must cap baseline leakage at 40% of fan flow and report the extent to which contractors' baseline leakage measurements exceed this fan flow.

1.3.8.3 Estimated Useful Life

According to DEER 2014, the EUL for duct sealing is 18 years.

1.3.8.4 Deemed Savings Values

The methodologies in this chapter detail the approach program staff should take to capture data needed to calculate savings from duct sealing. However, this data may not always be readily available or measurable. The average leakage values in Table 1-98 and Table 1-99 reflect the average per-home leakage reductions from 5,163 residential single and multifamily duct sealing projects, spanning PY5 though PY9 with correction factors resulting from on-site testing applied . Additional deemed inputs which have been created from program data averages and used in savings calculations are detailed in Section 1.3.8.4.1, *Cooling Savings* below.

Table 1-98 Duct Sealing Deemed Savings Values – Single Family

System Type	Average Leakage Reduction[112]	kWh	kW
AC with Gas Heat	471	2,465	1.159
Heat Pump	471	2,879	1.159
AC with Electric Resistance Heat	471	4,106	1.159
Electric Resistance Heat, no AC	471	1,641	0.000

Table 1-99 Duct Sealing Deemed Savings Values – Multifamily

System Type	Average Leakage Reduction[113]	kWh	kW
AC with Gas Heat	443	2,317	1.090
Heat Pump	443	2,707	1.090
AC with Electric Resistance Heat	443	3,860	1.090
Electric Resistance Heat, no AC	443	1,543	0.000

The following formulas shall be used to calculate deemed savings for duct sealing.

1.3.8.4.1 Cooling Savings

$$kWh_{cooling} = \frac{\left(DL_{pre} - DL_{post}\right) \times EFLH_c \times \left(h_{out}\rho_{out-}h_{in}\rho_{in}\right) \times 60}{1000 \times SEER}$$

Where:

DL_{pre} = Pre-measurement of leakage to unconditioned space

DL_{post} = Post-measurement of leakage to unconditioned space

[112] Based on average results from 4,939 SF participants over PY5-9.

[113] Based on average results from 325 MF participants over PY5-9.

$EFLH_c$ = Equivalent Full Load Cooling Hours, 1,637, based on the TPE's metering of New Orleans homes

H_{out} = Outdoor design enthalpy, 40 BTU/lb.

H_{in} = Indoor design enthalpy, 30 BTU/lb.

P_{out} = Density of outdoor air at 95 deg. F, .0740 lb./ft.^{3}

P_{in} = Density of outdoor air at 95 deg. F, .0756 lb./ft.^{3}

SEER = Seasonal Efficiency Rating of existing systems (BTU/W*hr.). Default of 13

1,000 = W/kW conversion factor

60 = Minutes/hour conversion factor

The default of 13 SEER is based on the inspection of 182 program participants in Home Performance with ENERGY STAR and Assisted Home Performance with ENRGY STAR. These 182 participants had 135 unique model numbers, with an average SEER of 12.98. The minimum code prior to 2015 was 13 SEER and given how close the mean value is to that code value, we recommend a default SEER of 13.

1.3.8.4.2 Heating Savings (Heat Pump)

Heating savings are calculated as:

$$kWh_{Heating,Heat\ Pump} = \frac{(DL_{pre} - DL_{post})/((CAP/12{,}000) * 400) * EFLH_h * CAP * TRFheat}{\eta\text{Heat} / 3{,}412}$$

Where:

DL_{pre} = Pre-measurement of leakage to unconditioned space

DL_{post} = Post-measurement of leakage to unconditioned space

CAP = Heating output capacity (Btuh) of electric heat = Actual. Use 72,829 Btu/hr if CAP unavailable.

12,000 = Btu/ton conversion factor

400 = CFM/ton conversion factor

$EFLH_h$ = Equivalent full load heating hours of heat pumps = 600

TRFheat = Thermal Regain Factor for heating by space type = 1.0 for Unconditioned Spaces = 0.40 for Semi-Conditioned Spaces

ηHeat = Efficiency in COP of Heating equipment = Actual. If unavailable, use 2.40.

3,412 = Conversion of BTU/kWh.

The default CAP of 72,829 is based on average capacity found for 2,022 residential customers who participated in a residential program PY5-PY9.

1.3.8.4.3 Heating Savings (Electric Resistance)

Heating savings are calculated as:

$$kWh_{Heating,Electric\ Resistance} = \frac{\left(DL_{pre} - DL_{post}\right)/((CAP/12{,}000) * 400) * EFLH_h * CAP * TRFheat}{\eta\text{Heat / 3,412}}$$

Where:

DL_{pre} = Pre-measurement of leakage to unconditioned space

DL_{post} = Post-measurement of leakage to unconditioned space

CAP = Heating output capacity (Btu/hr) of electric heat = Actual. Use 72,829 Btu/hr if CAP unavailable.

12,000 = Btu/ton conversion factor

400 = CFM/ton conversion factor

$EFLH_h$ = Equivalent full load heating hours = 396

TRFheat = Thermal Regain Factor for heating by space type = 1.0 for Unconditioned Spaces = 0.40 for Semi-Conditioned Spaces

ηHeat = Efficiency in COP of Heating equipment = Actual. If unavailable, use 1.0.

3,412 = Conversion of BTU/kWh.

1.3.8.4.4 Demand Savings (Cooling)

Demand savings are calculated by applying peak coincidence to the Cooling kWh savings. If the residence does not have central air conditioning (i.e., the ductwork is used only for heating distribution) then demand savings are 0.

$$kW = \frac{kWh_{cooling}}{EFLH_c} \times Coincidence\%$$

Where:

$kWh_{cooling}$ = Calculated kWh cooling savings

$EFLH_c$ = Equivalent Full Load Cooling Hours, 1,637, based on the TPE metering of New Orleans homes

Coincidence% = 77%, calculated based on the TPE metering of New Orleans homes.

1.3.8.4.5 Derivation of Equivalent Full-Load Hours and Peak Coincidence Factor

(i) Cooling Hours

Equivalent Full-Load Cooling Hours (EFLHc) measures the total annual runtime of HVAC equipment. To support development of this value, the usage of 68 HVAC systems in New Orleans was metered over. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans.

The resulting EFLHc is 1,637.

1. Peak Coincidence Factor

The Peak Coincidence Factor is defined as the percent time during the ENO peak period where the residential central air conditioner is operational. Peak hours were defined as:

- Weekdays
- Non-holidays
- 4:00-5:00 PM
- Average ambient temperature exceeding 90 degrees Fahrenheit.

The average central AC runtime during qualified hours was 77%. This peak coincidence factor is applied to calculate peak kW demand reductions from this measure.

(ii) Heating Hours

Equivalent Full-Load Heating Hours ($EFLH_h$) measures the total annual runtime of heating equipment. To support development of this value, the usage of 295 electric heating systems in New Orleans was estimated using a billing analysis. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans. In addition, the $EFLH_h$ was multiplied by a scaling factor of 1.51 to account for differences in usage for heat pump vs. electric resistance heating types.

The heat pump scaling factor was calculated using the following equation:

$$Scaling\ Factor_{HP} = ((\frac{\frac{kWh}{HDD}}{Ton}_{HP}) * COP_{HP})/((\frac{\frac{kWh}{HDD}}{Ton}_{ER}) * COP_{ER})$$

Where:

$kWh/HDD/Ton_{HP}$= Weighted average of predicted kWh/HDD/Ton for heat pump heating types for single and multi-family homes = 0.3282

$kWh/HDD/Ton_{ER}$= Weighted average of predicted kWh/HDD/Ton for electric resistance heating types for single and multi-family homes = 0.4348

COP_{HP} = Coefficient of performance for heat pumps = 2.0

COP_{HP} = Coefficient of performance for electric resistance = 1.0

The resulting $EFLH_H$ for Electric Resistance systems 396.

The resulting $EFLH_H$ for Heat Pumps is 600.

1.3.8.5 Uncertainty Analysis

The uncertainties associated with the four key parameters collected in EM&V are as follows:

- EFLHc: ±5.10%
- % Coincidence: ±2.11%
- EFLHh: Electric Resistance ±5.10%
- EFLHh: Heat Pumps ±37.10%

1.3.8.6 Incremental cost

The incremental cost of this measure is the full installed cost. If this is not available than the PY6 average cost of $368 may be used instead.

1.3.8.7 Net-to-Gross

The NTG for this measure is 95%.

1.3.8.8 Future Studies

This is a high impact measure, regularly constituting a large percent of Energy Smart program savings. The TPE recommends that savings estimates for Duct Sealing be validated with a billing analysis of the past three years of program participants.

1.3.9 SMART THERMOSTATS

1.3.9.1 Measure Description

The Smart Thermostats measure involves the replacement of a manually operated or programmable thermostat with a smart programmable thermostat. This measure applies to all residential applications.

Recent research indicates that today's programmable thermostat is evolving into a more usable, capable, and connected device. Smart thermostats are the next generation of programmable thermostats, which provide an array of features including automatic occupancy sensing and set-point adjustment. An energy management system that includes a communicating climate control will provide energy users with vastly improved and potentially real-time information on heating, ventilation, and air conditioning (HVAC) consumption and cost. Armed with these capabilities, consumers are able to take immediate action to reduce energy use and see the results in real-time.

The location of the smart thermostat can affect its performance and efficiency. To operate properly, a thermostat must be installed on an interior wall away from direct sunlight, drafts, doorways, skylights, and windows. Additionally, thermostats should be installed in a location with the house that is regularly occupied while residents are home.

For homes with a heat pump, smart thermostats must be professionally installed and commissioned. Smart thermostats on heat pumps must be capable of controlling heat pumps to optimize energy use and minimize the use of backup electric resistance heat.

Smart thermostats have capabilities beyond those found in a traditional programmable thermostat. To qualify as a smart thermostat, the units installed, at a minimum, should have the following capabilities and installation parameters:

- Successful connection to existing WIFI
- Remote adjustment via smart phone or online
- Automatic scheduling
- Energy history
- Occupancy sensing (set "on" as a default)

Other optional features include:

- Early on function to allow desired set points to be met at onset of occupancy
- Filter reminders
- On screen indication when temperature is set to an energy saving value
- For heat pumps, smart thermostat must be able to control heat pump to optimize energy use and minimize the use of backup electric resistance heat

1.3.9.2 Baseline and Efficiency Standards

The baseline condition is a manually operated or properly programmed thermostat.

1.3.9.3 Estimated Useful Life

According to DEER 2014, the EUL for thermostats is 11 years.[114]

1.3.9.4 Deemed Savings Values

The deemed savings values for this measure is 343 kWh per household.

Savings are based on the results of the Smart Thermostat Direct Install Pilot Program, comprised of 894 multifamily dwellings, with 749 used in the estimation of final savings.

Billing data was used from program participants and supplemented with a matched control group. The evaluation used a pre-post fixed effects model with a vector of control variables for each month to capture seasonal effects. This is called a model specification allows the model to capture much of the baseline differences across customers while obtaining reliable estimates of the impact of the thermostat installation. The reductions are calculated in terms of kWh per day.

The model is shown below in Equation 1:

Equation 1 P Pre-Post Fixed Effects Model

$$kWh\ Usage_{it} = \alpha_0 + \beta_1 * Post_i + \beta_2 * Post_i * Treatment_i$$

$$+ \beta_3 * Month_t + \beta_4 * Post_i * Month_t + \beta_5 * Post_i * Treatment_i * Month_t$$

$$+\beta_6 * Customer_i + \varepsilon_{it}$$

Where:

i = ith customer

t = the first, second, third, etc. month of the post-treatment period

$kWh\ Usage_{it}$ = the average daily use during month t for household i in the post-treatment period

$Post_i$ = a dummy indicator for whether an observation for household i occurs pre- or post-installation of the thermostat

$Treatment_i$ = a dummy indicator for whether the household was a participant household with a Nest thermostat installed

$Month_t$ = the month of the billing period t

$Post_i * Treatment_i$ = an interaction term between the Post and Treatment variables

$Post_i * Month_t$ = an interaction term between the Post and Month variables

$Post_i * Treatment_i * Month_t$ = an interaction term between the Post, Treatment and Month variables

[114] Database for Energy Efficient Resources (2014). www.deeresources.com/.

$Customer_i$ = a customer-specific dummy variable which account for exogenous heterogeneity that cannot be explicitly controlled for (for a Fixed Effects Model)

α_0 = an intercept term

ε_{it} = an error term

In this specification, the predicted participant savings in the post-period are calculated as in Equation 2.

Equation 2: Participant Annual Savings

$$Participant\ Annual\ Savings = \sum_{t=1}^{12\ months} \left\{\beta_{2t} * \frac{Days}{Month_t} + \beta_{5t} * \frac{Days}{Month_t}\right\}$$

Where:

β_2 = the coefficient for Post*Treatment parameter

β_5 = the coefficient for the Post*Treatment*Month parameter, which captures the seasonal factors following the installation of the thermostat

$\frac{Days}{Month_t}$ = the total number of days during billing period t

Below, Table 1-100 shows the model results and average annual savings per household.

Table 1-100 Model Results and Annual Savings

	Average Annual Usage (kWh)	Average Annual kWh Savings	kWh Savings (%)	Average kWh Savings Variance	Error	90% Confidence Interval	R^2
Average	12,821.58	343.13	2.68%	3,300.19	94.50	(248.63, 437.63)	0.6797

1.3.9.5 *Incremental Cost*

For HPwES and other programs for which installation services are provided, the actual material, labor, and other costs should be used. If this is not available, use $394.17 for retrofit, $199.12 for new construction.

1.3.9.6 *Future Studies*

This sample from the program pilot was sufficient to provide statistically valid savings on a per-dwelling basis, but not sufficient to provide robust savings based on annual household energy use. These results, and savings estimates, will be updated with PY12 M&V results.

1.4 Envelope Measures

1.4.1 ATTIC KNEE WALL INSULATION

1.4.1.1 Measure Description

This measure involves adding attic knee wall insulation to un-insulated knee wall areas in residential dwellings of existing construction. A wall with an insulation value of R-0 has no insulation but does have a nominal wall R-value made up of interior and exterior wall materials, air film and wood studs. This measure applies to all residential applications.

1.4.1.2 Baseline and Efficiency Standards

This measure applies to existing construction only.

Table 1-101 Attic Knee Wall Insulation – Baseline and Efficiency Standards

Baseline	Efficiency Standard
Uninsulated knee wall	Minimum R-19 or R-30

1.4.1.3 Estimated Useful Life

The EUL of this measure is 20 years based on NEAT v. 8.6.

1.4.1.4 Deemed Savings Values

This measure has not been included in Energy Smart programs to-date. To provide an estimate of per-project savings, we use PY6 average project size for attic insulation. The average project in PY6 Home Performance with Energy Star was 1,633 square feet. For this estimation, we assume a square attic (40.41 feet per wall side). The assumed knee-wall height is three feet. The resulting surface area to be insulated is:

$$\text{Knee} - \text{Wall Area} = 40.41_{\text{Wall length}} \times 4_{\#\text{walls}} \times 3_{\text{Wall height}} = 496.92 \text{ ft.}^2$$

Table 1-102 Knee Wall Insulation – Deemed Savings Values Per Residence

Ceiling Insulation Base R-Value	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	AC Peak Savings (kW)
R-19	1,789	487	3,328	1,155
R-30	2,225	302	3,747	1,297

Table 1-103 Knee Wall Insulation – Deemed Savings Values Per Square Foot

Ceiling Insulation Base R-Value	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	AC Peak Savings (kW)
R-19	3.600	6.698	2.324	0.000
R-30	4.477	7.540	2.610	0.000

The deemed savings are dependent on the R-value of the attic knee wall, pre- and post-retrofit.

BEoptTM was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since attic knee wall insulation savings are sensitive to weather, available TMY3 weather data specific to each of the four Arkansas weather regions was used for the analysis. The prototype home characteristics used in the BEoptTM building model are outlined in Volume 3, *Appendices*.

1.4.1.5 Incremental Cost

The incremental cost for this measure is the total cost. The cost is $0.035 per sq. ft. per "R" unit of insulation . For the average project size of 496.92 square feet, the resulting cost is:

- R-19: $330
- R-49: $522

1.4.1.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on simulation results. If this measure is added to Energy Smart programs and exceeds 1% of residential savings, then the simulation model should be updated to align with the billed use of customers that install the measure.

1.4.2 CEILING INSULATION

1.4.2.1 Measure Description

This measure requires adding ceiling insulation above a conditioned area in a residential dwelling of existing construction to a minimum ceiling insulation value of R-38, as well as additional insulation above R-38 in new construction applications. In both scenarios, Savings are estimated for a final insulation level of R-38 for retrofit applications and R-49 for both. This measure pertains to residential ceiling insulation only (attic floor).

1.4.2.2 Baseline and Efficiency Standards

In existing construction, ceiling insulation levels vary greatly, depending on the age of the home, type of insulation, and attic space utilization (such as using the attic for storage and HVAC equipment). The average pre-retrofit insulation level of the treated area will be determined and documented by the insulation contractor according to the ranges in Table 1-104. Degradation due to age and condition of the existing insulation will need to be considered by the insulation contractor.

IECC 2021 specifies an R-value of R-38 for ceiling insulation. Therefore, the eligibility standard for retrofit applications of this measure (minimum final R-value) is R-38. For new construction applications, R-38 is the baseline value.

Table 1-104 Ceiling Insulation – Baseline and Efficiency Standards

Baseline	Efficiency Standard
R-0 to R-1	R-38 or R-49
R-2 to R-4	
R-5 to R-8	
R-9 to R-14	
R-15 to R-22	

1.4.2.3 Estimated Useful Life

The EUL of this measure is 20 years according to DEER 2014.

1.4.2.4 Deemed Savings Values

Deemed savings values have been calculated for four major HVAC configurations: AC with electric resistance heating, AC with gas heating, heat pumps and spaces heated with electric resistance heating, but not cooled. The deemed savings are based on the R-value of the ceiling insulation pre-retrofit and a combined post-retrofit R-value (R-values of the existing insulation and the insulation being added) of at least R-38.

Note that the savings per square foot is a factor to be multiplied by the square footage of the ceiling area over a conditioned space that is being insulated.

For deemed savings for installation between the range of R-38 to R-49, linear interpolation can be used to determine the value that can be claimed as savings.

When providing per-residence estimates, we have included the following parameters from ceiling insulation projects from the PY9 through PY12 Energy Smart residential programs which offer ceiling insulation.

- Average project size: 1,539 ft^2 for single family, 953 ft^2 for multifamily
- Average baseline R-value: R-3.84[115] for single family, R-0 for multifamily

The tables below provide savings multipliers per dwelling ceiling insulation installed. Values are differentiated by dwelling type and HVAC configuration.

Table 1-105 Deemed Savings for R-38 – Per-Residence

Dwelling Type	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	Electric Resistance w/o AC	kW
Single Family	1,202	3,139	1,580	1,937	3.920
Multifamily	744	1,944	979	1,200	2.428

Table 1-106 Deemed Savings for R-49 – Per-Residence

Dwelling Type	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	Electric Resistance w/o AC	kW
Single Family	1,256	3,281	1,651	2,026	1,256
Multifamily	778	2,032	1,023	1,255	778

The tables below provide savings multipliers per square foot of ceiling insulation installed. These values are applicable to both single family and multifamily dwellings.

Table 1-107 Deemed Savings for R-38 – Per $ft.^2$

Beginning R-Value	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	Electric Resistance w/o AC	kW
0 to 4	0.7808	2.0397	1.0267	1.2589	0.0025
5 to 8	0.5389	1.4174	0.7149	0.8785	0.0020
9 to 14	0.3164	0.8189	0.4096	0.5025	0.0011
15 to 22	0.1496	0.4017	0.2039	0.2521	0.0010

Table 1-108 Deemed Savings for R-49 – Per $ft.^2$

Beginning R-Value	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	Electric Resistance w/o AC	kW
0 to 4	0.8159	2.1323	1.0730	1.3163	0.0027
5 to 8	0.5740	1.5100	0.7612	0.9360	0.0021
9 to 14	0.3515	0.9115	0.4559	0.5600	0.0013
15 to 22	0.1847	0.4942	0.2502	0.3095	0.0011

[115] This value is the average starting R-value for 632 projects between PY9 through PY12.

Below, Table 1-109 and Table 1-110 provide savings multipliers per dwelling ceiling insulation installed. Values are differentiated by dwelling type and HVAC configuration.

Table 1-109: New Construction Deemed Savings for R-49 – Per-Residence

Dwelling Type	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	Electric Resistance w/o AC	kW
Single Family	54	142	71	88	0.211
Multifamily	33	88	44	55	0.131

Table 1-110: New Construction Deemed Savings for R-49 – Per ft.^{2}

Beginning R-Value	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	Electric Resistance w/o AC	kW
38	0.0351	0.0925	0.0463	0.0575	0.0001

The algorithms below may be used for the calculation of deemed savings in retrofit applications only. For New Construction, use provided per-ft^2 or per-dwelling figures

BEoptTM was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine; available TMY3 weather data specific to the New Orleans area was used for the analysis. The prototype home characteristics used in the BEoptTM building model are outlined in Volume 3, *Appendices*.

1.4.2.4.1 Energy Savings

$$\text{Savings}_{\text{kWh}} = \text{Installed Square Footage} \times \left[(I_1 \times R_{\text{Final}}) - (C_1 \times R_{\text{initial}}) + \left(C_2 \times {R_{\text{initial}}}^2\right) - \left(C_3 \times {R_{\text{initial}}}^3\right) + \left(C_4 \times {R_{\text{initial}}}^4\right) + I_2\right]$$

Where:

Installed Square Footage = Total installed square footage of insulation

R_{final} = Ending R-value of insulation

$R_{initial}$ = Starting R-value of insulation

I_1, I_2, C_1, C_2, C_3, C_4 = Coefficients as found in Table 1-111 below

Table 1-111 Coefficients for kWh Savings Calculations

Coefficient	AC/Gas Heat	AC/Electric Resistance	Heat Pump	No AC/Electric Resistance
I1	0.0031887755	0.0084122935	0.0042112083	0.0052235180

C1	0.2388320100	0.5693145100	0.2753752100	0.3304825000
C2	0.0204054900	0.0451657500	0.0210182200	0.0247602600
C3	0.0008743000	0.0018119600	0.0008110100	0.0009376600
C4	0.0000143100	0.0000281000	0.0000121400	0.0000137900
I2	1.3226049300	3.3375076800	1.6578403600	2.0149027600

Rounding is not permitted.

1.4.2.4.2 Demand Reductions

$$\text{Savings}_{\text{kW}} = \text{Installed Square Footage} \times \left[(\text{I}_1 \times \text{R}_{\text{Final}}) - (\text{C}_1 \times \text{R}_{\text{initial}}) + (\text{C}_2 \times {\text{R}_{\text{initial}}}^2) - (\text{C}_3 \times {\text{R}_{\text{initial}}}^3) + (\text{C}_4 \times {\text{R}_{\text{initial}}}^4) - (\text{C}_5 \times {\text{R}_{\text{initial}}}^5) + (\text{C}_6 \times {\text{R}_{\text{initial}}}^6) + \text{I}_2\right]$$

Where:

Installed Square Footage = Total installed square footage of insulation

R_{final} = Ending R-value of insulation

$R_{initial}$ = Starting R-value of insulation

I_1, I_2, C_1, C_2, C_3, C_4, C_5, C_6 = Coefficients as found in Table 1-112 below

Table 1-112 Coefficients for kW Savings Calculations

Coefficient	AC/Gas Heat	AC/Electric Resistance	Heat Pump	No AC/Electric Resistance
I1	0.00001246	0.00001246	0.00001157	0.00000564
C1	0.00413666	0.00413666	0.00414756	0.00239700
C2	0.00100819	0.00100819	0.00100863	0.00053761
C3	0.00012807	0.00012807	0.00012790	0.00006509
C4	0.00000857	0.00000857	0.00000855	0.00000423
C5	0.00000029	0.00000029	0.00000029	0.00000014
C6	0.00000000	0.00000000	0.00000000	0.00000000
I2	0.00870883	0.00870883	0.00878639	0.00565800

Rounding is not permitted.

1.4.2.5 Incremental Cost

The incremental cost for this measure is the total cost. The average cost is $0.040/ft^2 per "R" unit of insulation for SF applications and $0.025/ft^2 per "R" unit of insulation for MF applications . For the average single family project size of 1,539 ft^2, and multifamily project of 953 ft^2, the resulting costs are in the table below.

Table 1-113 Incremental Cost

Dwelling Type	Final R-Value	
	R-38	**R-49**
SF	$2,321	$2,993
MF	$889	$1,146

1.4.2.6 Future Studies

This measure should have its simulation model recalibrated to the billed use of the past three years of program participants.

1.4.3 WALL INSULATION

1.4.3.1 Measure Description

This measure consists of adding wall insulation in the wall cavity in residential dwellings of existing construction. This measure applies to all residential applications.

1.4.3.2 Baseline and Efficiency Standards

In order to qualify for this measure, there must be no existing wall cavity insulation. Post-retrofit condition will be a wall cavity filled with either fiberglass or cellulose insulation (R-13 nominal value), open cell insulation (R-13 nominal value), or closed cell foam insulation (R-23 nominal value). Each type of insulation's nominal R-value depends on a full thickness application within the cavity of a wall with 2x4 inch studs.

Table 1-114 Wall Insulation – Baseline and Efficiency Standards

Baseline	Efficiency Standard (Nominal R-Values)	
Uninsulated wall cavity	Fiberglass/Cellulose	R-13
	Open Cell Foam	R-13
	Closed Cell Foam	R-23

1.4.3.3 Estimated Useful Life

The EUL of this measure is 20 years according to DEER 2014.

1.4.3.4 Deemed Savings Values

The savings per square foot is a factor to be multiplied by the square footage of the net wall area insulated. Wall area must be part of the thermal envelope of the home and shall not include window or door area.

Deemed savings for R-13 can be achieved with either fiberglass, cellulose, or open cell foam insulation. Deemed savings for R-23 is only applicable to closed cell insulation. The R-value represents the nominal value of the cavity insulation and not the R-value of the wall assembly.

For deemed savings for installation between the range of R-13 to R-23, linear interpolation can be used to determine the value that can be claimed as savings.

To calculate savings per-residence, the following assumptions are used:

Average square feet of insulation: 1,501[116]

Table 1-115 Wall Insulation – Deemed Savings Values Per-Residence

Ceiling Insulation Base R-Value	kWh Savings / SQFT		kW Peak Savings / SQFT	
	R-13	R-23	R-13	R-23
Electric Cooling w Gas Heat	0.78286	0.82574	0.00033	0.00060

[116] ENERGY STAR guidance. https://www.energystar.gov/ia/partners/bldrs_lenders_raters/downloads/Savings_and_Cost_Estimate_Summary.pdf

Electric Cooling W Electric Resistance Heat	3.33772	3.74885	0.00033	0.00060
Electric Cooling w Electric Heat Pump	1.05252	1.13064	0.00033	0.00051

Table 1-116 Wall Insulation – Deemed Savings Values Per-Ft.[2]

Ceiling Insulation Base R-Value	**kWh Savings / SQFT**		**kW Peak Savings / SQFT**	
	R-13	**R-23**	**R-13**	**R-23**
Electric Cooling with Gas Heat	0.78286	0.82574	0.00033	0.00060
Electric Cooling with Electric Resistance Heat	3.33772	3.74885	0.00033	0.00060
Electric Cooling with Electric Heat Pump	1.05252	1.13064	0.00033	0.00051

Deemed savings values have been calculated for each of the four weather zones. The deemed savings are dependent on the R-value of the wall pre- and post-retrofit. BEoptTM was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since wall insulation savings are sensitive to weather, available TMY3 weather data specific to each of the four Arkansas weather regions were used for the analysis. The prototype home characteristics used in the BEoptTM building model are outlined in Volume 3, *Appendices*.

1.4.3.5 Incremental Cost

The incremental cost of this measure is equal to the full installed cost. If this is not available, use $.92 per square foot[117]. For the average project size of 1,501 square feet, this results in an incremental cost of $1,381.

1.4.3.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on simulation results. If this measure is added to Energy Smart programs and exceeds 1% of residential savings, then the simulation model should be updated to align with the billed use of customers that install the measure.

If there is adequate participation, the assumed default square foot value should be revised.

[117] Midpoint value for floor insulation specified on Home Advisor. http://www.homeadvisor.com/cost/insulation/

1.4.4 FLOOR INSULATION

1.4.4.1 Measure Description

This measure presents two eligible scenarios for retrofitting a crawl space underneath an uninsulated floor[118]:

- Insulating the underside of the floor (above the vented crawl space), where the floor previously had no insulation
- "Encapsulating" the crawl space – sealing and insulating the vented perimeter skirt or stem wall between the ground (finished grade) and the first floor of the house, leaving the underside of the first floor structure uninsulated

This measure applies to all residential applications.

1.4.4.2 Baseline and Efficiency Standards

The baseline is considered to be a house with pier and beam construction, no insulation under the floor of the conditioned space, and a vented crawl space. In order to qualify for deemed savings, either the floor can be insulated to a minimum of R-19 or the crawl space can be encapsulated as described below. Deemed savings are provided for each option.

- Option 1 – Insulating the underside of the floor to a minimum of R-19.
- Option 2 – Encapsulating the crawl space: The crawl space perimeter skirt or stem walls are sealed in a sound and durable manner and the ground (floor of the crawl space) is sealed with a heavy plastic vapor barrier. The skirt or stem wall interior surfaces are insulated to R-13 (minimum) with closed cell foam[119]. The underside of the floor above the crawlspace is left uninsulated. A small flow of conditioned air to the crawl space is recommended to moderate humidity levels[120].

OSHA standards and applicable versions of the IECC and IRC codes will be pertinent to the installation. Note that this will include ensuring that any oil or gas-fueled furnaces or water heaters located in the crawlspace be provided with dedicated combustion air supply or be sealed-combustion units equipped with a powered combustion system.[121]

Table 1-117 Floor Insulation – Baseline and Efficiency Standards

Baseline	**Efficiency Standard**
No insulation under floor	R-19 installed under floor; or encapsulated crawl space with air-sealed perimeter having R-13 insulation on the interior side, no floor insulation under the floor above, and moisture-sealed grade under the crawl space

[118] U.S. DOE publication "Building America Best Practices Series, Vol 17, "Insulation" found at http://apps1.eere.energy.gov/buildings/publications/pdfs/building_america/insulation_guide.pdf (accessed 7-8-15) has extensive building science and code conformance information regarding insulating floors as well as sealing and insulating crawl spaces.

[119] IECC 2012, Table R402.1

[120] U.S. DOE publication "Building America Best Practices Series, Vol 17, "Insulation" found at http://apps1.eere.energy.gov/buildings/publications/pdfs/building_america/insulation_guide.pdf (accessed 7-8-15), p. 58, 1 cfm per every 50 sq. ft. of floor area.

[121] *Ibid* (p. 59).

1.4.4.3 Estimated Useful Life

The average lifetime of this measure is 20 years according to DEER 2014.

1.4.4.4 Deemed Savings Values

The deemed savings values listed below are per square foot of first level floor area above the crawl space.

For the per-residence savings, we assume the same square feet as attic insulation (1,633 ft.2), due to a lack of participation in this measure. This is to be updated when there is adequate participation to support an estimate.

Table 1-118 R-19 Floor Insulation – Deemed Savings Values Per-Residence

Equipment Type	kWh Savings / residence	kW Peak Savings / residence
Electric Cooling with Gas Heat	-393.226	Negligible
Electric Cooling with Electric Resistance Heat	108.5945	n/a
Electric Cooling with Electric Heat Pump	807.5185	Negligible

Table 1-119 R-19 Floor Insulation – Deemed Savings Values Per-Ft.2

Equipment Type	kWh Savings / sq. ft.	kW Peak Savings / sq. ft.
Electric Cooling with Gas Heat	-0.2408	Negligible
Electric Cooling with Electric Resistance Heat	0.4945	Negligible
Electric Cooling with Electric Heat Pump	0.0952	Negligible

Deemed savings values have been calculated for each of the four weather zones. BEoptTM was used to estimate energy savings for both options using the same base case model (uninsulated floor) and the DOE EnergyPlus simulation engine. Savings are sensitive to weather; therefore, available TMY3 weather data specific to New Orleans used for the analysis. The prototype home characteristics used in the BEoptTM building model are outlined in Volume 3 *Appendices*.

1.4.4.5 Incremental Cost

The incremental cost of this measure is equal to the full installed cost.

1.4.4.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on simulation results. If this measure is added to Energy Smart programs and exceeds 1% of residential savings, then the simulation model should be updated to align with the billed use of customers that install the measure. If there is adequate participation, the assumed default square foot value should be revised.

1.4.5 ENERGY STAR WINDOWS, DOORS & SKYLIGHTS

1.4.5.1 Measure Description

This measure involves the replacement of windows with an ENERGY STAR window(s), door(s) or skylight(s) in an existing home. This measure applies to all residential applications and are calculated on per square foot of window basis, inclusive of frame and sash. All windows must be in a metal frame. Converted residences are not eligible.

ENEGRY STAR U-factor and Solar Heat Gain Coefficient (SHGC) qualification criteria vary based on climate zone. Figure 1-3 displays the fours zones, with New Orleans appearing in the 'Southern' zone. Relevant required efficiency levels are shown in Table 1-120.

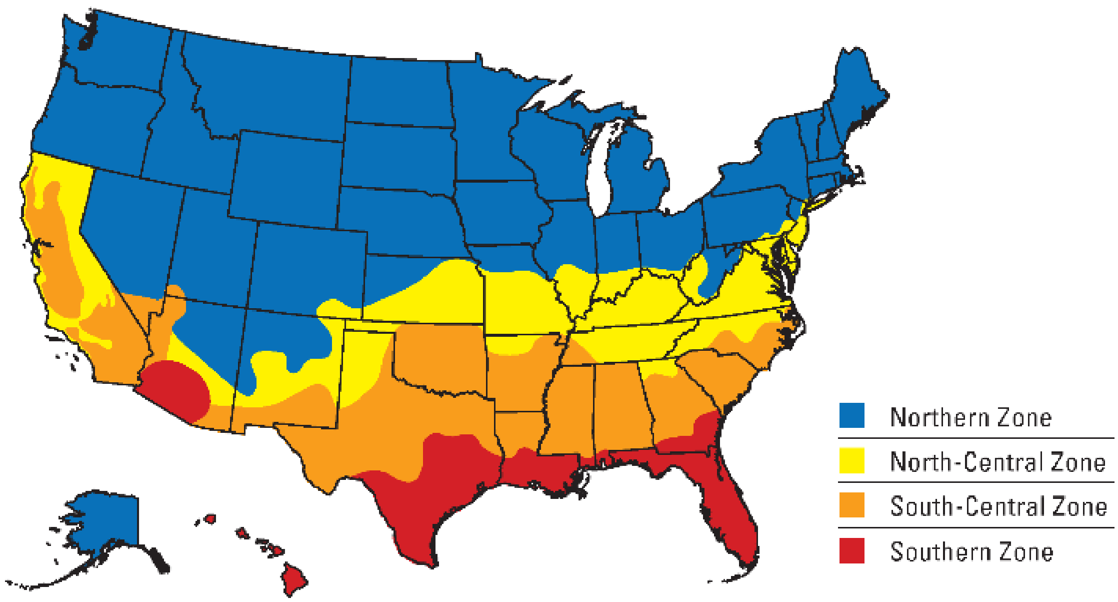


Figure 1-3 ENERGY STAR Window Program Climate Map

Table 1-120 ENERGY STAR Efficiency Requirements for New Orleans[122, 123, 124]

New Orleans - Southern	U-Factor	SHGC
Windows	≤ 0.40	≤ 0.25
Doors (Opaque)	≤ 0.17	No Rating
Doors (≤ ½ Glass)	≤ 0.25	≤ 0.25
Doors (> ½ Glass)	≤ 0.30	≤ 0.25
Skylights	≤ 0.60	≤ 0.28

[122] Effective as of January 1, 2016: https://www.energystar.gov/sites/default/files/asset/document/Windows_Doors_and_Skylights_Program_Requirements%20v6.pdf

[123] Btu/(h*ft2 *°F)

[124] Solar Heat Gain Coefficient

1.4.5.2 Baseline and Efficiency Standards

For this measure, there are two separate baseline assumptions and two sets of deemed savings values for both single and double pane windows. Prototypical U-Values and SHGCs for baseline windows are presented in Table 1-121.

Table 1-121 Baseline Windows

Number of Panes	U-Factor BTU/ (h*FT^2 *°F)	Solar Heat Gain Coefficient (SHGC)
1	1.12	0.79
2	0.81	0.64

1.4.5.3 Estimated Useful Life

The EUL of an ENERGY STAR window is 20 years[125].

1.4.5.4 Deemed Savings Values

1.4.5.4.1 Windows

Table 1-122 and Table 1-123 provide per-square foot deemed savings values for single pane and double pane windows.

Table 1-122 ENERGY STAR Replacement for Single-Pane Window[126]

Equipment Type	kWh Savings / sq. ft.	kW Savings / sq. ft.
Electric AC with Gas Heat	5.847	0.0024
Elec. AC with Resistance Heat	6.149	0.0024
Heat Pump	5.975	0.0024

Table 1-123 ENERGY STAR Replacement for Double-Pane Window[127]

Equipment Type	kWh Savings / sq. ft.	kW Savings / sq. ft.
Electric AC with Gas Heat	3.931	0.0017
Elec. AC with Resistance Heat	3.990	0.0017
Heat Pump	4.035	0.0017

Table 1-124 and Table 1-125 show savings for a typical window, 11.06ft^2 (approximately 35.6" x 44.5").[128]

[125] DEER 2008, 2014.

[126] Modeled at 202 ft^2 area

[127] Modeled at 202 ft^2 area

[128] Based on an inventory of the 100 highest-selling windows in local stores.

Table 1-124 Average Savings for Single-Pane Windows

Equipment Type	kWh Savings	kW Savings
Electric AC with Gas Heat	64	0.027
Elec. AC with Resistance Heat	68	0.027
Heat Pump	66	0.027

Table 1-125 Average Savings for Double-Pane Windows

Equipment Type	kWh Savings	kW Savings
Electric AC with Gas Heat	43	0.019
Elec. AC with Resistance Heat	44	0.019
Heat Pump	44	0.019

1.4.5.4.2 Doors

Table 1-126 through Table 1-128 provide per-square foot deemed savings values for doors.

Table 1-126 ENERGY STAR Replacement for Doors (Opaque)[129]

Equipment Type	kWh Savings / sq. ft.	kW Savings / sq. ft.
Electric AC with Gas Heat	0.725	0.0171
Elec. AC with Resistance Heat	3.725	0.0171
Heat Pump	1.750	0.0171

Table 1-127 ENERGY STAR Replacement for Doors (≤ ½-Lite)[130]

Equipment Type	kWh Savings / sq. ft.	kW Savings / sq. ft.
Electric AC with Gas Heat	1.400	0.0262
Elec. AC with Resistance Heat	4.100	0.0262
Heat Pump	2.275	0.0262

Table 1-128 ENERGY STAR Replacement for Doors (> ½-Lite)[131]

Equipment Type	kWh Savings / sq. ft.	kW Savings / sq. ft.
Electric AC with Gas Heat	3.000	0.0523
Elec. AC with Resistance Heat	6.225	0.0523
Heat Pump	4.175	0.0523

1.4.5.4.3 Skylights

Table 1-129 provides per-square foot deemed savings values for skylights.

Table 1-129 ENERGY STAR Replacement for Skylights[132]

Equipment Type	kWh Savings / sq. ft.	kW Savings / sq. ft.
Electric AC with Gas Heat	0.842	0.0322
Elec. AC with Resistance Heat	0.842	0.0322
Heat Pump	0.901	0.0322

[129] 40 ft^2 area, no glass

[130] 40 ft^2 area, 25% glass

[131] 40 ft^2 area, 75% glass

[132] 101 ft^2 area

BEoptTM was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since ENERGY STAR window, skylight and door savings are sensitive to weather, available TMY3 weather data specific to New Orleans was used for the analysis. The prototype home characteristics used in the BEoptTM building model are outlined in Volume 3, *Appendices*.

1.4.5.5 Incremental Costs

- Windows: ENERGY STAR[133] estimates window incremental costs for the New Orleans climate zone to be \$0.61/ft2, or \$6.74 for a typical 11.06ft^2 window.
- Doors: ENERGY STAR[134] estimates incremental costs for doors to be \$13 for ≤ 1/2 lite doors and \$30 for >1/2 lite doors. The average cost increase over best-selling opaque doors is \$0, thus the incremental cost for opaque doors is \$0.
- Skylights: ENERGY STAR[134] estimates incremental costs for skylights to be \$20-\$40 for a typical skylight.

1.4.5.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure has not yet been implemented in Energy Smart programs. As a result, savings are calculated using Texas values which have been weather-normalized for New Orleans. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents.

If participation reached 1% of residential Energy Smart program savings, the TPE recommends a simulation models be calibrated with utility metering data and deemed savings estimates be updated at that time.

[133] https://www.energystar.gov/sites/default/files/asset/document/Savings_and_Cost_Estimate_Summary.pdf

[134] https://www.energystar.gov/ia/partners/prod_development/revisions/downloads/windows_doors/Draft6_V1_Criteria_Analysis_Report.pdf

1.4.6 ENERGY STAR LOW EMISSIVITY STORM WINDOWS

1.4.6.1 Measure Description

This measure involves the installation of interior or exterior ENERGY STAR low emissivity (low-e) storm windows over existing windows. Savings is achieved through lowering structure emissivity, solar gain and air leakage. This measure applies residential applications including low-rise multifamily buildings. ENEGRY STAR U-factor and Solar Heat Gain Coefficient (SHGC) qualification criteria vary based on climate zone. Figure 1-3 displays the fours zones, with New Orleans appearing in the 'Southern' zone. Relevant required efficiency levels are shown in Table 1-130.

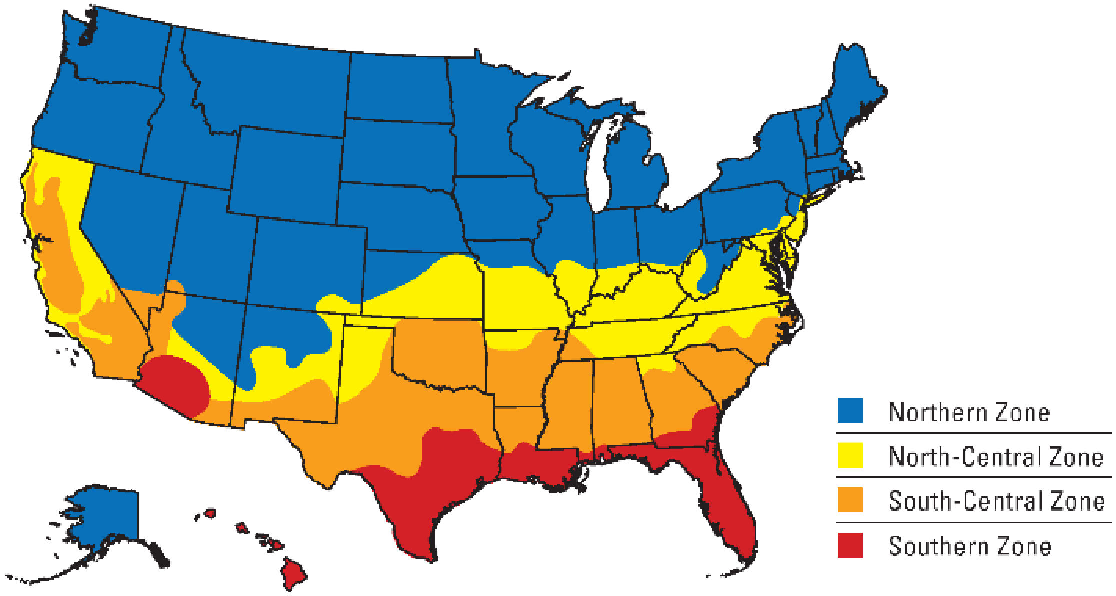


Figure 1-4 ENERGY STAR Window Program Climate Map

Table 1-130 ENERGY STAR Requirements for Storm Windows (Southern Region)

Emissivity	Solar Transmission	Air Leakage
≤ 0.22	≤ 0.55	≤ 1.5 (exterior) ≤ 0.5 (interior)

1.4.6.2 Baseline and Efficiency Standards

The baseline for this measure is an existing single or double pane glass window with no existing storm window.

1.4.6.3 Estimated Useful Life

The lifetime of an ENERGY STAR window is 20 years[135].

[135] DEER 2008, 2014.

1.4.6.4 Deemed Savings Values

The table below provide deemed savings values for interior and exterior ENERGY STAR storm windows.

Table 1-131 ENERGY STAR Interior Storm Window Deemed Savings

Equipment Type	kWh Savings/ ft.^{2}	kW Savings/ ft.^{2}
Gas & AC	1.51	0.0007
AC & Elec Resistance	2.98	0.0007
Heat Pump	1.96	0.0007

Table 1-132 ENERGY STAR Exterior Storm Window Deemed Savings

Equipment Type	kWh Savings/ ft.^{2}	kW Savings/ ft.^{2}
Gas & AC	1.38	0.0006
AC & Elec Resistance	2.10	0.0006
Heat Pump	1.62	0.0006

BEopt™ was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since ENERGY STAR storm window savings are sensitive to weather, available TMY3 weather data specific to New Orleans was used for the analysis. The prototype home characteristics used in the BEopt™ building model are outlined in the NO TRM V6.0 Volume 3 Appendices.

1.4.6.5 Incremental Costs

The incremental cost of this measure is equal to the full installed cost. If this is not available, the incremental costs for low-E storm windows are assumed to be $1/SQFT[136].

1.4.6.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure has not yet been implemented in Energy Smart programs. As a result, savings are calculated using national values which have been weather-normalized for New Orleans. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents. If participation reached 1% of residential Energy Smart program savings, the TPE recommends running simulation models be calibrated with utility metering data and deemed savings estimates be updated at that time.

[136] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-24826.pdf

1.4.7 AIR INFILTRATION

1.4.7.1 Measure Description

This measure reduces air infiltration into the residence, using pre- and post-treatment blower door air pressure readings to quantify the air leakage reduction. There is no post-retrofit minimum infiltration requirement, however, installations must comply with the prevailing Arkansas mechanical code. This measure applies to all residential applications.

1.4.7.2 Baseline and Efficiency Standards

1.4.7.2.1 Existing Buildings

The baseline for this measure is the existing leakage rate of the residence to be treated. The existing leakage rate should be capped to account for the fact that the deemed savings values per CFM50 leakage reduction are only applicable up to a point where the existing HVAC equipment would run continuously. Beyond that point, energy use will no longer increase linearly with an increase in leakage.

Baseline assumptions used in the development of these deemed savings are based on the 2013 ASHRAE Handbook of Fundamentals, Chapter 16, which provides typical infiltration rates for residential structures. In a study of low income homes reported in ASHRAE, approximately 95 percent of the home infiltration rates were below 3.0 ACHNat.[137] Therefore, to avoid incentivizing homes with envelope problems not easily remedied through typical weatherization procedures, or improperly conducted blower door tests, these savings should only be applied starting at a baseline ACHNat of 3.0 or lower.

To calculate the maximum allowable CFM50, pre-value for a particular house, use the following equation:

$$CFM_{50,pre}/ft^2 = \frac{ACH_{Nat,pre} \times h \times N}{60}$$

Where:

$CFM_{50,pre}/ft^2$ = Per square foot pre-installation infiltration rate ($CFM50/ft^2$)

$ACH_{Nat,pre}$ = Maximum pre-installation air change rate (ACH_{Nat}) = 3.0

60 = Constant to convert from minutes to hours

h = Ceiling height (ft.) = 8.5 (default)[138]

N = N factor (Table 1-133)

[137] 2013 ASHRAE Handbook of Fundamentals, Chapter 16, pp. 16.18, Figure 12.

[138] Typical ceiling height of 8 feet adjusted to account for greater ceiling heights in some areas of a typical residence.

Table 1-133 Air Infiltration – N Factor[139]

Wind Shielding	Number of Stories		
	Single Story	Two Story	Three + Story
Well Shielded	25.8	20.6	18.1
Normal	21.5	17.2	15.1
Exposed	19.4	15.5	13.5

- Well Shielded is defined as urban areas with high buildings or sheltered areas, and buildings surrounded by trees, bermed earth, or higher terrain.
- Normal is defined as buildings in a residential neighborhood or subdivision, with yard space between buildings. Approximately 80-90 percent of houses fall in this category.
- Exposed is defined as buildings in an open setting with few buildings or trees around and buildings on top of a hill or ocean front, exposed to winds.

Maximum CFM50 per square foot values are available in Table 1-134. Pre-retrofit leakage rates are limited to fa maximum per $ft.^2$ value specified in the table, as this generally indicates severe structural damage not repairable by typical infiltration reduction techniques.

Table 1-134 Pre-Retrofit Infiltration Cap ($CFM50/ft^2$)

Wind Shielding	Number of Stories		
	Single Story	Two Story	Three + Story
Well Shielded	11.0	8.8	7.7
Normal	9.1	7.3	6.4
Exposed	8.2	6.6	5.7

1.4.7.2.2 New Construction

The maximum ACH50 allowable under IECC2021 is 5.0. The maximum CFM50 is partially determined by the total volume of the sealed space. To calculate the maximum allowable CFM50, pre-value for a particular house, use the following equation:

$$ACH_{50} = \frac{CFM_{50} \times Volume}{60}$$

Using a maximum ACH50 of 5.0 and rearranging the equation, the maximum allowable air leakage, and thus the baseline for NC is:

$$CFM_{50} = \frac{Volume}{12}$$

[139] Krigger, J. & Dorsi, C. 2005, Residential Energy: Cost Savings and Comfort for Existing Buildings, 4th Edition. Version RE. Volume 3, *Appendices*-11: Zone 3 Building Tightness Limits, p. 284., December 20. www.waptac.org/data/files/Website_docs/Technical_Tools/Building%20Tightness%20Limits.pdf

Where:

ACH_{50}= Air Exchanges per Hour (maximum 5.0)

CFM_{50}= Air Flow (ft^3 at 50 pascals)

Volume = Volume of sealed space

1.4.7.3 Estimated Useful Life

According to DEER 2014 the Estimated Useful Life for air infiltration is 11 years.

1.4.7.4 Deemed Savings Values

Programs should calculate savings based on pre- and post-retrofit leakage testing. If this data is not available, default estimates may be applied. The following assumptions based on PY6 evaluation results of the Home Performance with ENERGY STAR program are used in providing per-residence savings estimates:

- Leakage reduction: 2,045 CFM

Table 1-135 Air Infiltration Reduction – Retrofit Deemed Savings Values Per-Residence

Equipment Type	kWh Savings/ CFM50 (ESF)	kW Savings/ CFM50 (DSF)
Electric AC with Gas Heat	840	0.6769
Elec. AC with Resistance Heat	2,082	0.6789
Heat Pump	1,474	0.6789

The following formulas shall be used to calculate deemed savings for infiltration efficiency improvements. The formulas apply to all building heights and shielding factors.

$$kWh_{savings} = CFM_{50} \times ESF$$

$$kW_{savings} = CFM_{50} \times DSF$$

Where:

CFM_{50} = Air infiltration reduction in Cubic Feet per Minute at 50 pascals, as measured by the difference between pre- and post-installation blower door air leakage tests

ESF = corresponding energy savings factor (Table 1-136)

DSF = corresponding demand savings factor (Table 1-136)

Table 1-136 Air Infiltration Reduction – Deemed Savings Values Per-Ft.2

Equipment Type	kWh Savings/ CFM50 (ESF)	kW Savings/ CFM50 (DSF)
Electric AC with Gas Heat	0.4108	0.000331
Elec. AC with Resistance Heat	1.018	0.000332
Heat Pump	0.721	0.000332

BEoptTM was used to estimate energy savings for a series of models using the US DOE EnergyPlus simulation engine. Since infiltration savings are sensitive to weather, available TMY3 weather data specific to New Orleans was used for the analysis. The prototype home characteristics used in the BEoptTM building model are outlined in Volume 3, *Appendices*.

The deemed savings are dependent on the pre- and post-CFM50 leakage rates of the home and are presented as annual savings / CFM50 reduction. A series of model runs was completed in order to establish the relationship between various CFM50 leakage rates and heating and cooling energy consumption. The resulting analysis of model outputs was used to create the deemed savings tables of kWh and kW per CFM50 of air infiltration reduction.

1.4.7.5 Incremental Cost

The incremental cost of this measure is equal to the full installed cost. If this is not available, a default value of $0.25 per square foot of conditioned floor area may be applied[140]. This should use a default of 1,762 square feet, based on PY6 program tracking for the Home Performance with ENERGY STAR program.

The resulting per-project incremental cost is $441.

1.4.7.6 Net-to-Gross

The NTG for this measure is 95%[141].

1.4.7.7 Future Studies

This measure should have its simulation model recalibrated to the billed use of the past three years of program participants.

---

[140] ENERGY STAR guidance. https://www.energystar.gov/ia/partners/bldrs_lenders_raters/downloads/Savings_and_Cost_Estimate_Summary.pdf

[141] Based on primary data collection from 78 PY6-9 program participants.

1.4.8 WINDOW FILM

1.4.8.1 Measure Description

This measure consists of adding solar film to east, west and south-facing windows. This measure applies to all residential applications.

1.4.8.2 Baseline and Efficiency Standards

This measure is applicable to existing homes only. Low E windows and tinted windows are not applicable for this measure. To qualify for deemed savings, solar film should be applied to east, west and south-facing facing glass.

Table 1-137 Window Film – Baseline and Efficiency Standards

Baseline	Efficiency Standard
Single- or double-pane window with no existing solar films, solar screens, or low-e coating	Solar Film with SHGC <0.50

1.4.8.3 Estimated Useful Life

The average lifetime of this measure is 10 years according to DEER 2014.

1.4.8.4 Deemed Savings Values

The savings per square foot is a factor to be multiplied by the square footage of the window area to which the films are being added. For the per-residence values, we assume 330 total window SQFT.

Table 1-138 Window Film – Deemed Savings Values Per-Residence

Existing Windowpane Type	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	AC Peak Savings (kW)
Single Pane	1,391	-218	531	0.33
Double Pane	813	-75	273	0.33

Table 1-139 Window Film – Deemed Savings Values Per-SqFt.[2]

Existing Windowpane Type	AC/Gas Heat kWh	AC/Electric Resistance kWh	Heat Pump kWh	AC Peak Savings (kW)
Single Pane	4.216	-0.661	1.610	0.001
Double Pane	2.465	-0.226	0.826	0.001

The deemed savings are dependent on the SHGC of pre- and post-retrofit glazing. BEopt™ was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since window film savings are sensitive to weather, available TMY3 weather data specific to New Orleans was used for the analysis. The prototype home characteristics used in the BEopt building model are outlined in Volume 3 Appendices.

1.4.8.5 Incremental Cost

The incremental cost of this measure is equal to the full installed cost. If this is not available, the default cost is:

- $2.00 per square foot[142]
- $660 per residence

1.4.8.6 Future Studies

At the time of authorship of the TRM, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on simulation results. If this measure is added to Energy Smart programs and exceeds 1% of residential savings, then the simulation model should be updated to align with the billed use of customers that install the measure.

If there is adequate participation, the assumed default square foot value should be revised.

[142] Energize Connecticut cost documentation. http://www.uinet.com/wps/wcm/connect/193bba80476e1bc19d6c9d02c80795ac/FINAL-C0118-2017-UI-CI-Incentive-Matrix-Gas-Caps-Rev.+02.17.pdf?MOD=AJPERES&CACHEID=193bba80476e1bc19d6c9d02c80795ac

1.4.9 RADIANT BARRIERS

1.4.9.1 Measure Description

Radiant barriers are designed to block radiant heat transfer between a building roof and the attic space insulation. They typically consist of a metallic foil material (usually aluminum) and are generally installed on the roof decking or beneath roof sheathing. Radiant barriers are most effective at reducing cooling consumption by reflecting heat away from a home.

1.4.9.2 Baseline and Efficiency Standards

This measure applies to existing construction that does not have a radiant barrier installed on the roof decking.

The efficiency requirements for radiant barriers must meet the standards set by the Reflective Insulation Manufacturers Association International (RIMA) to include proper attic ventilation. The following table displays the requirements for radiant barriers.

Table 1-140: Required Substantiation

Required Substantiation		
Physical Property	Test Method or Standard	Requirement
Surface Emittance	ASTM C 1371	0.1 or less
Water Vapor Transmission	ASTM E 96: Procedure A Desiccant Method	0.02 for Vapor Retarder 0.5 or greater for perforated products
Surface Burning		
Flame Spread	ASTM E 84	25 or less
Smoke Density	ASTM E 84	450 or less
Corrosivity	ASTM D 3310	Corrosion on less than 2% of the affected surface
Tear Resistance	ASTM D 2261	
Adhesive Performance		
Bleeding	Section 10.1 of ASTM C 1313	Bleeding or delamination of less than 2% of the surface area
Pliability	Section 10.2 of ASTM C 1313	No cracking or delamination
Mold and Mildew	ASTM C 1338	No growth when visually examined under 5X magnification

Interior radiation control coatings are not applicable for the deemed savings derived. A study performed by RIMA found that none of the coating-type products currently on the market had an emittance of 0.10 or lower as required by the standards set by the American Society for Testing and Materials (ASTM) for a product to be considered a radiant barrier.[143] Therefore, all coating materials and spray application materials are ineligible for application of these savings values.

All radiant barriers should be installed according to the RIMA Handbook, Section 7.4.[144] However, horizontal installation is not eligible, due to the likelihood of dust buildup and wear-and-tear damage to the radiant barrier.

A radiant barrier cannot be in contact with any other materials on its underside or else it becomes defective. Therefore, once a radiant barrier is installed on the roof decking, no roof deck insulation can be installed.

1.4.9.3 Estimated Useful Life

The average lifetime of this measure is estimated to be about 25 years for downward facing radiant barriers, based on the DOE's Radiant Barrier Fact Sheet.[145]

1.4.9.4 Deemed Savings Values

Deemed savings values have been calculated for New Orleans. The calculations for deemed savings values are based on the addition of a radiant barrier to the roof decking where a radiant barrier did not previously exist. Please note that the savings per square foot is a factor to be multiplied by the square footage of the ceiling area over a conditioned space to which the radiant barrier is applied. Gas Heat (no AC) kWh applies to forced air furnace systems only.

Table 1-141 Deemed Savings Values

Addition of Radiant Barrier with existing attic insulation level	AC/Gas Heat kWh	Gas Heat (no AC) kWh	AC/Electric Resistance kWh	Heat Pump kWh	AC Peak Savings kW
	(/ sq. ft.)	(/ sq. ft.)	(/ sq. ft.)	(/ sq. ft.)	(/ sq. ft.)
Attic insulation ≤R-19	0.2142	0.006	0.3238	0.1794	0.0001
Attic insulation >R19	0.1361	0.0039	0.1853	0.0993	0.0001

1.4.9.5 Incremental Cost

The incremental cost is $0.15 to $0.45 per square feet.[146]

1.4.9.6 Future Studies

There are no future studies planned for this measures at this time.

[143] Study by RIMA that found no radiant coating on the market having a low enough emittance to be considered a radiant barrier: http://www.rimainternational.org/technical/ircc.html

[144] RIMA Handbook available online: http://www.rimainternational.org/technical/handbook.html

[145] http://web.ornl.gov/sci/ees/etsd/btric/RadiantBarrier/RBFactSheet2010.pdf

[146] Oak Ridge National Laboratory. https://web.ornl.gov/sci/buildings/tools/radiant/rb2/rb-tables/index.shtml#table1

1.5 Lighting

1.5.1 ENERGY STAR LIGHTING

1.5.1.1 Measure Description

This chapter provides energy and demand savings calculations for the replacement of residential lighting equipment with energy efficient lamps or fixtures. The operating hours and demand factors are based on primary research in the New Orleans market. This chapter now incorporates the 2007 Energy Independence & Security Act (EISA) Phase II standards (also known as the "EISA Backstop").

This chapter applies to omnidirectional, directional and specialty lamps. Using ANSI C79.1-2002 nomenclature this includes omnidirectional lamps with A, BT, P, PS, S, and T[147] shapes. Reflector and specialty lamps covered are PAR, R, BR, MR, and similar lamp shapes, as well as other specialty lamps such as 3-way lamps, globes and candelabra base lamps which now fall under the expanded General Service Lamp (GSL) definition. It is applicable only to manually controlled (switches and dimmers) residential lighting, and not LED fixtures or connected, 'smart' or otherwise automatically controlled lighting.

1.5.1.2 Baseline and Efficiency Standards

The baseline equipment was originally assumed to be an incandescent or halogen lamp with adjusted baseline wattages compliant with EISA 2007 Regulations. The first of two advances of lighting standards from EISA 2007 Regulations were phased in from January 2012 to January 2014 and dictated higher efficiency for General Service Lamps (GSLs).

Phase II takes effect on July 25, 2022, stipulating that all GSLs sold in the United States (US) must achieve a minimum efficacy of 45 lumens/watt[148]. The ruling also significantly expands the definition of GSLs, extending the covered lumen range, base types, and shapes, while reducing the types of bulbs exempted[149].

"General Service Lamp means a lamp that it:

- Has an [American National Standards Institute] (ANSI) base;
- Is able to operate at a voltage of 12 volts or 24 volts, at or between 100 to 130 volts, at or between 220 to 240 volts, or at 277 volts for integrated lamps, or is able to operate at any voltage for non-integrated lamps;
- Has an initial lumen output of greater than or equal to 310 lumens (or 232 lumens for modified spectrum general service incandescent lamps) and less than or equal to 3,300 lumens;
- Is not a light fixture;

[147] According to ENERGY STAR, omni-directional LED products "…shall have an even distribution of luminous intensity (candelas) within the 0° to 135° zone (vertically axially symmetrical). Luminous intensity at any angle within this zone shall not differ from the mean luminous intensity for the entire 0° to 135° zone by more than 20%. At least 5% of total flux (lumens) must be emitted in the 135°-180° zone. Distribution shall be vertically symmetrical as measured in three vertical planes at 0°, 45°, and 90°."

http://www.energystar.gov/ia/partners/product_specs/program_reqs/Integral_LED_Lamps_Program_Requirements.pdf.

[148] Federal Registrar document, page 27440: https://www.govinfo.gov/content/pkg/FR-2022-05-09/pdf/2022-09477.pdf

[149] Ibid.

- Is not an LED downlight retrofit kit; and
- Is used in general lighting applications."

Previously exempt lamps that are now subject to regulations under the expanded GSL definition include:

- Reflectors: The following three reflector lamp types (which represent most reflectors) are no longer exempt from GSL standards:
    - (A) Lamps rated at 50 watts or less that are ER30, BR30, BR40, or ER40 lamps;
    - (B) Lamps rated at 65 watts that are BR30, BR40, or ER40 lamps; or
    - (C) R20 incandescent reflector lamps rated 45 watts or less;
- Lumen maximums: The lumen maximum subject to the EISA GSL definition has been increased from 2,600 to 3,300 lumens;
- Base types: All standard bulb bases are included (small screw base and candelabra); and
- Others lamp types: 3-way, decorative (including globes <5", flame shapes and candelabra shapes), T-lamps (≤40w OR ≥ 10"), vibration service, rough service, and shatter resistant bulb exemptions are also discontinued.

The 45 lumen/watt efficacy requirement inherently disallows incandescent and halogen lamps, but the EISA backstop does not directly specify a technological standard to satisfy the efficacy requirement. LEDs are well beyond 45 lumens/W (very often operating at greater than 60 lumens/watt), and alternative technologies all fall below the new EISA backstop, effectively meaning that general service lamps which operate at 45 lumens/watts for common lighting categories are not available for purchase[150].

This precludes savings from being claimed in most circumstances such as time of sale, new construction, and kits distribution channels. Savings can still be realized through early replacement direct install program channels, where existing incandescent, halogen, CFL and other inefficient technologies can be directly identified. To claim savings, implementation staff must record as-found lamp types and wattages and use the tables below to determine the baseline.

Table 1-142 Baseline Wattage by Lumen Output for Omni-Directional Lamps[151]

Minimum Lumens	Maximum Lumens	EISA Phase I W_{base}	EISA Phase II W_{base}
310	749	29	12
750	1,049	43	20
1,050	1,489	53	28
1,490	2,600	72	45

[150] Notable exceptions include some compact fluorescent bulbs (CFL).

[151] Wattages developed using the 45 LPW standard.

Table 1-143 Baseline Wattage by Lumen Output for Directional/Reflector Lamps[152]

Lamp Type	Incandescent Equivalent (Pre-EISA)	EISA Phase I W_{base}	EISA Phase II W_{base}
PAR20	50	35	23
PAR30	50	35	23
R20	50	45	29
PAR38	60	55	35
BR30	65	EXEMPT	38
BR40	65	EXEMPT	38
ER40	65	EXEMPT	38
BR40	75	65	42
BR30	75	65	42
PAR30	75	55	35
PAR38	75	55	35
R30	75	65	42
R40	75	65	42
PAR38	90	70	45
PAR38	120	70	45
R20	≤ 45	EXEMPT	23
BR30	≤ 50	EXEMPT	EXEMPT
BR40	≤ 50	EXEMPT	EXEMPT
ER30	≤ 50	EXEMPT	EXEMPT
ER40	≤ 50	EXEMPT	EXEMPT

Table 1-144 Baseline Wattage by Lumen Output for Exempt Lamps[153]

Minimum Lumens	Maximum Lumens	Incandescent Equivalent (W_{base})
310	749	40
750	1,049	60
1,050	1,489	75
1,490	2,600	100

1.5.1.3 Allowable Distribution Channels

Table 1-145 below shows the application of the backstop by delivery channel.

[152] Based on manufacturer available reflector lighting products as available in August 2013; using 45 lumens/watt.

[153] Lumen bins and incandescent equivalent wattages from ENERGY STAR labeling requirements, Version 1.0 http://www.energystar.gov/products/specs/sites/products/files/ENERGY%20STAR%20Lamps%20V1.0%20Final%20Draft%20Specification.pdf EISA Standards from: United States Department of Energy. Impact of EISA 2007 on General Service Incandescent Lamps: FACT SHEET.

Table 1-145 Application of Backstop by Delivery Channel

Delivery Channel	Description	Application of EISA Backstop
Retail Markdown	Incentives to retailers that reduce the cost of LEDs at point of sale.	Savings for purchases made after June 30, 2023, will be disallowed. Program administrators may process incentives for purchases made prior to the effective date until September 30, 2023.
Online Marketplace	Online store run by Entergy or the TPA that sells LEDs at a discounted price.	Savings for purchases made after June 30, 2023, will be disallowed. Program administrators may process incentives for purchases made prior to the effective date until September 30, 2023.
School Kits	Program-provided school kits which incorporate self-install energy efficiency measures and educational materials for fifth-grade students. These kits have traditionally included LEDs, low flow showerheads, and faucet aerators.	The TPE acknowledges that school kits may warrant greater interest as a matter of education. However, EISA impacts need to be accounted. To retain any savings from school kits after June 30, 2023, the TPA must include survey questions in the student questionnaire developed by the TPE that address what the replaced bulb. The questionnaire must be submitted to the TPE before use in the program. The TPE will incorporate survey responses from the student questionnaire, creating a weighted baseline for savings. Responses that indicate having replaced a CFL or LED will have savings reduced accordingly. This differs from past evaluations in that minimum code was applied to all school kit LEDs irrespective of preexisting lamp type.
Direct Install	TPA staff or their trade allies directly remove old lamps and install LEDs in customer homes.	Direct install activities may continue after June 30, 2023. However, all projects that occur after June 30, 2023, will require that the TPA "bag and tag" the old lamps, to be stored until a quarterly verification inspection is conducted by TPE staff. Direct install may be used to replace incandescent, halogen, or CFL lamps, with savings adjusted accordingly.
Mailer Kit	TPA staff ship kits that include LEDs to residential customers. This may manifest as "push" (kits sent to customers unprompted) or "pull" (kits requested by customers).	Savings for shipments made after June 30, 2023, will be disallowed (determined by postmark date). Program administrators may process incentives for distributions made prior to the effective date until September 30, 2023.

1.5.1.4 Efficiency Standard

Lamps must be a standard ENERGY STAR qualified lighting.

Exceptions to the ENERGY STAR label are allowed for unlisted lamps, fixtures or other lighting-related devices that have been submitted to ENERGY STAR for approval. If the lamp or fixture does not achieve ENERGY STAR approval within the New Orleans program year, however, then the lamp or fixture would have to be immediately withdrawn from the program.

1.5.1.5 Effective Useful Life

The EUL for LED replacement under the auspices of EISA Phase II is based on the remaining useful life of the baseline lamp. The EUL for incandescent and halogen lamps is two years. With a final sale date of June 30, 2023, this puts the “savings ending date” for savings with an incandescent or halogen baseline on June 30, 2025.

If a CFL baseline is used, the EUL will assume a CFL with an 8,000-hour rated life, which results in an EUL of five years[154]. With a final sale date of June 30, 2023, this puts the “savings ending date” for savings with an incandescent or halogen baseline on June 30, 2028.

To simplify implementation, single values based on implementation year may be used. This is summarized in Table 1-146.

Table 1-146 EUL by Implementation Year and Baseline Type

Implementation Year	Incandescent / Halogen Baseline	CFL Baseline
2023	2.5	5.5
2024	1.5	4.5
2025	0.5	3.5

1.5.1.6 Lighting Hours of Use (HOU) Metering

Hours of use (HOU) were estimated through direct monitoring of lighting in the on-site sample homes. Each logger was extrapolated to full annual usage by using a linear model with day length as the predictor, where day length varies inversely with the number of HOU. Latitude and longitude coordinates for New Orleans, Louisiana were used in the computation of day length (29.9511, -90.0715). The regression used to extrapolate the meter data to a full year is shown in the equation below.

$$H_d = \alpha + \beta * \text{Day Length} + \varepsilon_d$$

Where:

H_d = hours of use on day d

Day Length = number of daylight hours on day d

α and β are coefficients determined by the regression

ε_d = residual error

A similar model was run which added room type as an explanatory variable to estimate hours of use for each room type.

[154] EUL based on 8,000 hours and 2.38 hours per day, with a .526 “switching degradation factor” for CFL.

1.5.1.6.1 Hours of Use (HOU) Results

Results of the regressed logger data provided the TPE with overall efficient lighting hours of use, as well as breakdowns of hours of use by room type as shown in. In total 355 lighting loggers were used, and all results were found to meet precision requirements. Overall daily HOU are 2.38, which corresponds to 871 annual HOU. The coefficients from the overall model and the model which adds room type are also shown below.

Table 1-147 Hours of Use by Area

Area/Room	HOU Annual	HOU Daily	# Loggers	Precision
Kitchen	855	2.34	83	0.04
Living Room	841	2.3	81	0.04
Bedroom	796	2.18	49	0.06
Bath	1,121	3.07	62	0.04
Dining Room	769	2.11	80	0.05
Overall	871	2.38	355	0.02

Table 1-148 Lighting Model Coefficients

Coefficient	Estimate	SE	T-Stat	P-value
Intercept	4.263	0.561	7.594	3.26E-14
Day Length	-0.154	0.043	-3.567	0.000362

Figure 1-5 below is a scatterplot showing average HOU for all the loggers in the M&V sample and the corresponding day length (based on New Orleans, LA). The fitted line shows a slightly negative relationship between average daily hours and day length, which an expedited pattern ex-ante. The day length coefficients for both models also confirm this relationship, as they are both negative, although neither is statistically significant.

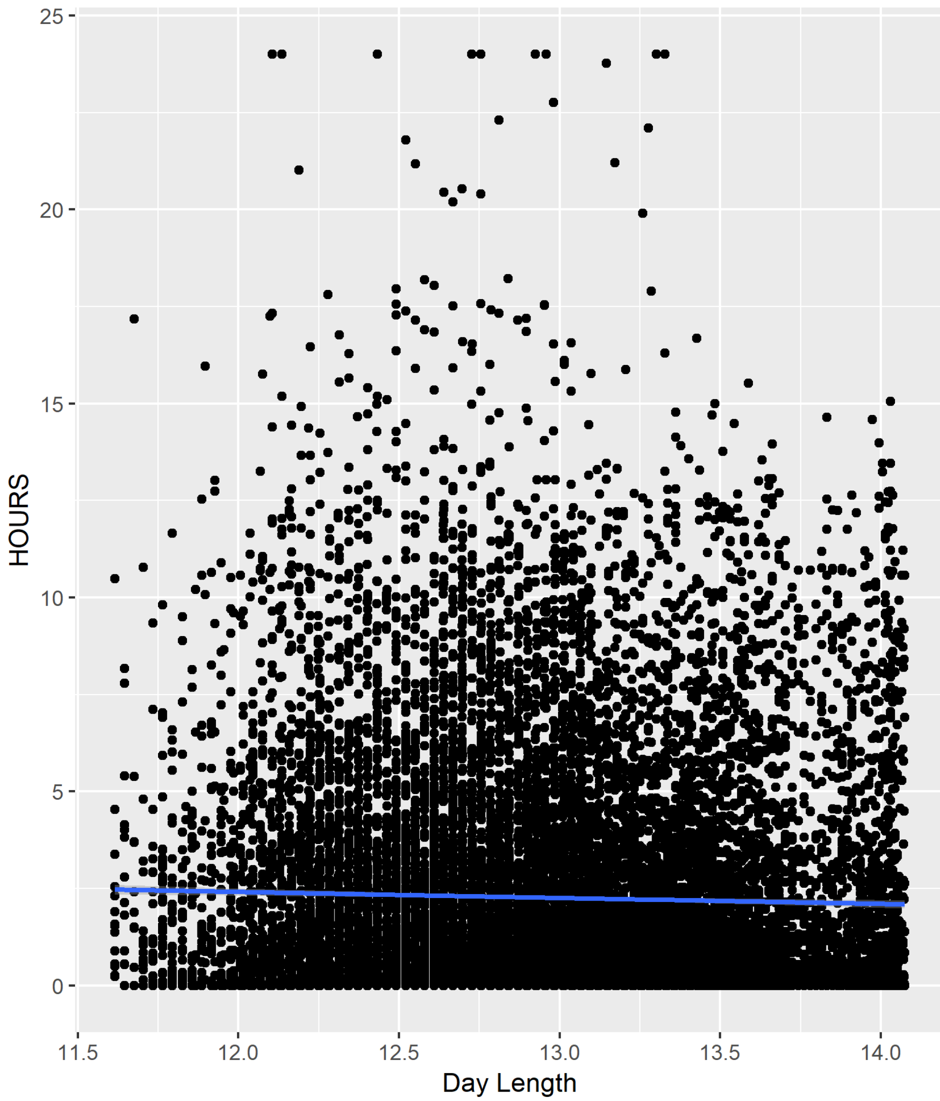


Figure 1-5 Scatterplot Showing Average Hours of Use

1.5.1.6.2 Coincident Factor

The TPE calculated the coincident factor (CF) based on actual lighting logger data in July through September between the hours of 4 and 5 pm as 11.12%.

1.5.1.6.3 Exterior Lighting

Annual hours of operation for exterior lighting, which operates during non-daylight hours, was calculated using dusk-to-dawn data taken from the National Oceanic and Atmospheric Administration website. Savings for lamps installed in exterior areas of residences should be calculated using 4,319 hours annually, and 0% CF.

1.5.1.7 Deemed Savings Values

$$kWh_{savings} = \left((W_{base} - W_{post})/1000\right) \times Hours \times ISR \times IEF_E$$

Where:

W_{base} = Based on wattage equivalent of the lumen output of the lamp (see Table 1-142,

Table 1-143, and Table 1-144)

W_{post} = Actual wattage of lamp installed

Hours = Average hours of use per year (see Table 1-149)

IEF_E = Interactive Effects Factor to account for cooling energy savings and heating energy penalties; this factor also applies to outdoor and unconditioned spaces (Table 1-151)

ISR = In Service Rate, or percentage of rebate units that get installed, to account for units purchased but not immediately installed (see Table 1-150)

When the EISA 2007 standard goes into effect for lighting, the reduced wattage savings should be claimed for the rest of the EUL.

Table 1-149 Average Hours of Use Per Year

Installation Location	Hours
Indoor[155]	870.5
Outdoor[156]	4,319

Table 1-150 In-Service Rate (ISR)

Delivery Channel	ISR
Retail (TOS) and Direct Install[157]	0.98

Table 1-151 IEF_E for Cooling/Heating Savings

Heating Type	Interactive Effects Factor (IEF_E)[158]
Gas Heat with AC	1.10
Gas Heat with no AC	1.00
Electric Resistance Heat with AC	0.83
Electric Resistance Heat with no AC	0.73
Heat Pump	0.96
Heating/Cooling Unknown[159]	0.91

[155] Indoor Hours based off aggregated lighting study performed by TPE with lighting logger data from 80 homes.

[156] Calculated using dusk-to-dawn data taken from the National Oceanic and Atmospheric Administration website.

[157] Dimetrosky, S. et al, 205, "Residential Lighting Evaluation Protocol – The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures." January. ISR for upstream programs, including storage lamps installed within four years of purchase.

[158] Refer to Appendix I, Arkansas TRM V8.2 Volume 3.

[159] Unknown factors are based on ENERGY STAR Interactive effects, weighted by primary data collected on New Orleans typical HVAC arrangements.

$$kW_{savings} = \left(\left(W_{base} - W_{post}\right)/1000\right) \times CF \times ISR \times IEF_D$$

Where:

CF = Coincidence Factor (see Table 1-152)

IEF_D = Interactive Effects Factor to account for cooling demand savings; this factor also applies to outdoor and unconditioned spaces (see Table 1-153).

Table 1-152 Summer Peak Coincidence Factor

Lamp Location	CF
Indoor[160]	11.12%
Outdoor	0.00%

Table 1-153 IEF for Cooling Demand Savings

Heating Type	Interactive Effects Factor (IEF_D)[161]
Gas Heat with AC	1.29
Gas Heat with no AC	1.00
Electric Resistance Heat with AC	1.29
Electric Resistance Heat with no AC	1.00
Heat Pump	1.29
Heating/Cooling Unknown[162]	1.21

1.5.1.7.1 Annual kWh, Annual kW, and Lifetime kWh Savings Calculation Examples

1.5.1.7.2 Early Replacement of an Incandescent Lamp

A 9W 850lm LED is installed by an implementer in program year (PY) 2023 and directly replaces a 43W incandescent lamp (i.e., an EISA Phase I-compliant incandescent lamp). Per Table 1-142, this is eligible as early replacement and can use the 43W baseline. Other necessary inputs for calculating the kWh savings include the EUL (2.5 years), IEFD (1.25 for unknown heating/cooling type), IEFE (0.97 for unknown cooling/heating type), ISR (0.98), summer coincidence factor (0.1112), and HOU per Year (870.50 hours). All kWh values are rounded to the second decimal place.

First Year Savings:

$$kWh\ Savings = \left(\frac{[43-9]}{1000}\right) \times 870.50 \times 0.97 \times 0.98 = 28.13\ {\scriptstyle kWh}\ kW\ Savings = \left(\frac{[43-9]}{1000}\right) \times 0.1112 \times$$

$$1.21 \times 0.98 = 0.004\ kW$$

Lifetime Savings: This LED has a rated life of 15,000 hours but is capped at 2.5 years because the incandescent lamp it is replacing will burn out within two years of the final sale date of June 30, 2023.

---

[160] Based off TPE light metering study, detailed in this chapter.

[161] Refer to Appendix I, Arkansas TRM V8.2 Volume 3.

[162] Unknown factors are based on ENERGY STAR Interactive effects, weighted by primary data collected on New Orleans typical HVAC arrangements.

$$Claimable\ Lifetime\ kWh\ Savings\ = 28.13\ kWh \times 2.5\ EUL\ = 70.34\ kWh$$

1.5.1.7.3 Early Replacement of a CFL Lamp

A 9W 850lm LED is installed by an implementer in program year (PY) 2023 and directly replaces a 14W CFL lamp. The CFL meets EISA Phase II efficacy requirements, but there are still marginal savings achieved via installation of an LED. The EUL is 5.5 years. The other inputs are the same as specified in the incandescent example presented above.

First Year Savings:

$$kWh\ Savings = \left(\frac{[14-9]}{1000}\right) \times 870.50 \times 0.97 \times 0.98 = 4.14\ kWh$$

$$kW\ Savings = \left(\frac{[14-9]}{1000}\right) \times 0.1112 \times 1.21 \times 0.98 = 0.0005\ kW$$

Lifetime Savings: This LED has a rated life of 15,000 hours but is capped at 5.5 years because the incandescent lamp it is replacing will burn out within five years of the final sale date of June 30, 2023.

$$Claimable\ Lifetime\ kWh\ Savings\ = 4.14\ kWh \times 2.5\ EUL\ = 22.76\ kWh$$

1.5.1.8 Incremental Cost

Prices for LEDs decrease each year. Given this, actual lighting costs should be compared to a stipulated baseline cost where feasible. If that information is not available, use $1.45

1.5.1.9 Net-to-Gross

The NTG for this measure is 62% for direct install applications.

1.5.1.10 Future Studies

At the time of authorship of this chapter, the TPE could not identify lighting options that are broadly available that are set to meet 45 lumens/watt. Available options tend to vastly exceed this (with LEDs typically exceeding 60 lumens/watt). The TPE will conduct an annual market review to address whether low-cost options designed to meet and not exceed EISA Phase II efficacy requirements become available and will reassess baselines in response to relevant market developments in this area.

1.5.2 ENERGY STAR OMNI-DIRECTIONAL LEDS (RETIRED)

This measure has been retired based upon Tier II EISA legislation. Remaining relevant information has been transferred to the 'ENERGY STAR Lighting' chapter.

1.5.3 ENERGY STAR DIRECTIONAL AND SPECIALTY LEDS (RETIRED)

This measure has been retired based upon Tier II EISA legislation. Remaining relevant information has been transferred to the 'ENERGY STAR Lighting' chapter.

1.5.4 ENERGY STAR OMNI-DIRECTIONAL COMPACT FLUORESCENT LAMPS (CFLS) (RETIRED)

This measure has been retired based upon Tier II EISA legislation. Remaining relevant information has been transferred to the 'ENERGY STAR Lighting' chapter.

1.5.5 ENERGY STAR SPECIALTY COMPACT FLUORESCENT LAMPS (CFLS) (RETIRED)

This measure has been retired based upon Tier II EISA legislation. Remaining relevant information has been transferred to the 'ENERGY STAR Lighting' chapter.

2. NON-RESIDENTIAL MEASURES

This chapter presents commercial and industrial (C&I), or non-residential measures.

2.1 Motors

2.1.1 Electronically Commutated Motors for Refrigeration and HVAC Applications

2.1.1.1 Measure Description

An electronically commutated motor (ECM) is a fractional horsepower direct current (DC) motor used most often in commercial refrigeration applications such as display cases, walk-in coolers/freezers, refrigerated vending machines, and bottle coolers. ECMs can also be used in HVAC applications, primarily as small fan motors for packaged terminal units or in terminal air boxes. ECMs generally replace shaded pole (SP) or permanent split-capacitor (PSC) motors and offer energy savings of at least 50 percent.

2.1.1.2 Baseline and Efficiency Standards

The standard motor type for this application is a shaded pole or permanent split-capacitor motor.

Any ECM up to 1 HP in size will meet the minimum requirements for both retrofit and new construction installations.

2.1.1.3 Estimated Useful Life

In accordance with DEER 2014 the EUL is 15 years.

2.1.1.4 Deemed Savings Values

The table below summarizes deemed kWh and kW by facility type for this measure. The following assumptions are used: baseline watts are 102; this is the average of SP motors (132W) and PSC motors (72W).

Hours:

- HVAC: 4,386
- Refrigeration: 8,760
- Unknown: 6,573

COP:

- HVAC: 3.45 (assumes 11.8 EER)
- Refrigeration: 1.90 (average of refrigerator and freezer)
- Unknown: 2.67

Duty Cycle:

- HVAC, medium-temp refrigeration: 1.00
- Freezer: .94
- Unknown: .985

Table 2-1 Deemed Savings by Facility Type

End-Use	HVAC		Refrigeration (Med. temps)		Refrigeration (Freezers)		Unknown	
	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Assembly	351	0.066	829	0.095	779	0.089	552	0.07
College	351	0.066	829	0.095	779	0.089	552	0.069
Fast Food	351	0.067	829	0.095	779	0.089	552	0.071
Full Menu	351	0.062	829	0.095	779	0.089	552	0.066
Grocery	351	0.068	829	0.095	779	0.089	552	0.071
Health Clinic	351	0.072	829	0.095	779	0.089	552	0.076
Large Office	351	0.068	829	0.095	779	0.089	552	0.071
Lodging	351	0.067	829	0.095	779	0.089	552	0.071
Religious Worship	351	0.062	829	0.095	779	0.089	552	0.065
Retail	351	0.066	829	0.095	779	0.089	552	0.069
Unknown	351	0.07	829	0.095	779	0.089	552	0.074

2.1.1.4.1 Energy Savings

$$kWh_{savings} = (W_{base} - W_{ECM}) \times Hrs \times DC \times (1 + \frac{1}{COP})/1000 \, ^{W}/_{kW}$$

Where:

kW_{base} = Power of the motor being replaced; use known wattage of motor, or if unknown, use 132W (SP motors)[163] or 72W (PSC motors)[164]

kW_{ECM} = Power of the replacement EC motor; use known wattage of motor, or if unknown, use 40W[165]

The motor’s power for either Base or ECM can be calculated using the following equation if power is not known. The values for rated wattage and phase can be found on motor’s nameplate:

$$kW_{motor} = \frac{Volts \ \times Amperage}{1000} \times \sqrt{Phase} \times Power\ Factor$$

Hrs = Hours of yearly operation, use 8,760 hours for refrigeration and 4,386 for HVAC

---

[163] http://www.fishnick.com/publications/appliancereports/refrigeration/GE_ECM_revised.pdf

[164] The Massachusetts TRM specifies a load factor of 54% for SP motors and a load factor of 29% for PSC motors, as specified by National Resource Management (NRM). Multiplying the 132 W default value for SP motors by the ratio of PSC load factor to SP load factor results in a default PSC motor wattage of 72 watts.

[165] http://www.fishnick.com/publications/appliancereports/refrigeration/GE_ECM_revised.pdf

DC = Duty cycle, only use a value of 0.94 if the application of the motor being replaced is for a freezer system. This is because the freezer will complete four 20-min defrost cycles per day where the evaporator fan will not be used. Use a value of 1 if the application is for a cooler refrigeration or HVAC.

$PowerFactor$ = Power factor of the motor, if not known an average value of 0.55 can be used for ECM in refrigeration, 0.7 for ECM in HVAC, and 0.85 for base motor in both applications.[166]

COP = Coefficient of Performance for the motor's operation based on application. COP value depends on the end temperature of the refrigeration process. The COP values to use for refrigeration analysis are 1.3 for freezers and 2.5 for coolers[167]. For HVAC, use the EER value from install spec sheet and the conversion COP = EER/3.412.

2.1.1.4.2 Demand Reductions

$$kW_{HVAC\ reduction} = (kW_{base} - kW_{ECM}) \times CF \times (1 + \frac{1}{COP})$$

$$kW_{Refrigeration\ reduction} = (kW_{base} - kW_{ECM}) \times DC \times CF \times (1 + \frac{1}{COP})$$

Where:

CF = Coincidence Factor, use values from Table 2-2 for HVAC applications; default value of 1.0 for refrigeration applications[168]

DC = Duty cycle, only use a value of 0.94 if the application of the motor being replaced is for a freezer refrigeration. This is because the freezer will complete four 20-min defrost cycles per day where the evaporator fan will not be used. Use a value of 1 if the application is for a cooler refrigeration of HVAC.

Table 2-2 Commercial Coincidence Factors by Building Type[169]

Building Type	Coincidence Factor
Assembly	0.82
College	0.84
Fast Food	0.78
Full Menu	0.85
Grocery	0.90
Health Clinic	0.85
Large Office	0.84

[166] http://www.ecw.org/sites/default/files/230-1.pdf

[167] PSC of Wisconsin, Focus on Energy Evaluation, Business Programs: Deemed Savings Manual V1.0, pp. 4-103 -4-106.

[168] CF set to 1.0 for refrigeration applications based on annual run-time assumption of 8,760 hours

[169] Values for Assembly and Religious Worship building types developed using an adjustment factor derived through a comparison of average CFs for College/University and Assembly/Religious Worship building types from the Texas state Technical Reference Manual. College/University was selected as a reference building type due to average alignment with Assembly/Religious worship building types in other TRMs, inclusion of a summer session, and increased evening usage.

Lodging	0.77
Religious Worship	0.82
Retail	0.88
School	0.71
Small Office	0.84

2.1.1.5 Incremental Cost

Incremental cost by end-use type is $177.[170]

2.1.1.6 Future Studies

There are no future studies planned for this measure at this time.

[170] Difference in the fully installed cost ($468) for ECM motor and controller, listed in Work Paper PGE3PREF126, "ECM for Walk-In Evaporator with Fan Controller," June 20,2012, and the measure cost specified in 4.6.6 ($291)

2.1.2 PREMIUM EFFICIENCY MOTORS

2.1.2.1 Measure Description

Currently a wide variety of NEMA premium efficiency motors from 1-500 HP are available. Deemed values for demand and energy savings associated with this measure must be for motors with an equivalent operating period (hours x Load Factor) over 1,000 hours.

2.1.2.2 Baseline and Efficiency Standards

2.1.2.2.1 Replace on Burnout

The EISA 2007 Sec 313 adopted the new federal standard and required that electric motors that are manufactured and sold in the United States meet the new standard by December 19, 2010. The standards can also be found in sections 431.25(c)-(f) of the Code of Federal Regulations (10 CFR Part 431).

With these changes, any 1-500 HP motor bearing the “NEMA Premium" trademark will align with national energy efficiency standards and legislation. The Federal Energy Management Program (FEMP) has already adopted NEMA MG 1-2006 Revision 1 2007 in its Designated Product List for federal customers.

In addition to the new standards for 200-500 HP motors, additional motors in the 1-200 HP range are now included in the NEMA Premium standard. These new motors are referred to as “General Purpose Electric Motors (Subtype II)”. These additional types of motors include:

- U-Frame Motors
- Design C Motors
- Close-coupled pump motors
- Footless motors
- Vertical solid shaft normal thrust (tested in a horizontal configuration)
- 8-pole motors
- All poly-phase motors with voltages up to 600 volts other than 230/460 volts (230/460-volt motors are covered by EPAct-92)

2.1.2.2.2 Early Retirement

The baseline for early retirement projects is the nameplate efficiency of the existing motor to be replaced, if known. If the nameplate is illegible and the in-situ efficiency cannot be determined, then the baseline should be based on the minimum efficiency allowed under the Federal Energy Policy Act of 1992 (EPAct), as listed in

NEMA Premium Efficiency motor levels continue to be industry standard for minimum-efficiency levels. The savings calculations assume that the minimum motor efficiency for both replace on burnout and early retirement projects exceeds that listed in Table 2-3.

The maximum age of an eligible for early retirement is capped at the point at which it is expected that 75 percent of the equipment has failed. Where the age of the unit exceeds the 75 percent failure age, ROB savings should be applied. This cap prevents early retirement savings from being applied to projects where the age of the equipment greatly exceeds the estimated useful life of the measure.

Table 2-3 Premium Efficiency Motors – Replace on Burnout Baseline[171]

hp	$\eta_{baseline, Open Motors}$			$\eta_{baseline, Closed Motors}$		
	6-Pole	4-Pole	2-Pole	6-Pole	4-Pole	2-Pole
1	82.5	85.5	77.0	82.5	85.5	77.0
1.5	86.5	86.5	84.0	87.5	86.5	84.0
2	87.5	86.5	85.5	87.5	86.5	85.5
3	88.5	89.5	85.5	89.5	89.5	86.5
5	89.5	89.5	86.5	89.5	89.5	88.5
7.5	90.2	91.0	88.5	91.0	91.7	89.5
10	91.7	91.7	89.5	91.0	91.7	90.2
15	91.7	93.0	90.2	91.7	92.4	91.0
20	92.4	93.0	91.0	91.7	93.0	91.0
25	93.0	93.6	91.7	93.0	93.6	91.7
30	93.6	94.1	91.7	93.0	93.6	91.7
40	94.1	94.1	92.4	94.1	94.1	92.4
50	94.1	94.5	93.0	94.1	94.5	93.0
60	94.5	95.0	93.6	94.5	95.0	93.6
75	94.5	95.0	93.6	94.5	95.4	94.1
100	95.0	95.4	93.6	95.0	95.4	94.1
125	95.0	95.4	94.1	95.0	95.4	95.0
150	95.4	95.8	94.1	95.8	95.8	95.0
200	95.4	95.8	95.0	95.8	96.2	95.4
250	94.5	95.4	94.5	95.0	95.0	95.4
300	94.5	95.4	95.0	95.0	95.4	95.4
350	94.5	95.4	95.0	95.0	95.4	95.4
400	n/a	95.4	95.4	n/a	95.4	95.4
450	n/a	95.8	95.8	n/a	95.4	95.4
500	n/a	95.8	95.8	n/a	95.8	95.4

Table 2-4 Premium Efficiency Motors – Early Retirement Baseline[172]

hp	$\eta_{baseline, Open Motors}$			$\eta_{baseline, Closed Motors}$		
	6-Pole	4-Pole	2-Pole	6-Pole	4-Pole	2-Pole
1	80.0	82.5	75.5	80.0	82.5	75.5
1.5	84.0	84.0	82.5	85.5	84.0	82.5
2	85.5	84.0	84.0	86.5	84.0	84.0
3	86.5	86.5	84.0	87.5	87.5	85.5
5	87.5	87.5	85.5	87.5	87.5	87.5
7.5	88.5	88.5	87.5	89.5	89.5	88.5
10	90.2	89.5	88.5	89.5	89.5	89.5
15	90.2	91.0	89.5	90.2	91.0	90.2
20	91.0	91.0	90.2	90.2	91.0	90.2
25	91.7	91.7	91.0	91.7	92.4	91.0
30	92.4	92.4	91.0	91.7	92.4	91.0
40	93.0	93.0	91.7	93.0	93.0	91.7
50	93.0	93.0	92.4	93.0	93.0	92.4

[171] Federal Standards for Electric Motors, Table 1: Full Load Efficiencies for Standard Electric Motors, http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/50. Accessed June 2013.

[172] Federal Standards for Electric Motor Efficiency from the Federal Energy Policy Act of 1992 (EPACT). http://www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/e-pact92.pdf . Accessed June 2013.

60	93.6	93.6	93.0	93.6	93.6	93.0
75	93.6	94.1	93.0	93.6	94.1	93.0
100	94.1	94.1	93.0	94.1	94.5	93.6
125	94.1	94.5	93.6	94.1	94.5	94.5
150	94.5	95.0	93.6	95.0	95.0	94.5
200	94.5	95.0	94.5	95.0	95.0	95.0
250	94.5	95.4	94.5	95.0	95.0	95.4
300	94.5	95.4	95.0	95.0	95.4	95.4
350	94.5	95.4	95.0	95.0	95.4	95.4
400	n/a	95.4	95.4	n/a	95.4	95.4
450	n/a	95.8	95.8	n/a	95.4	95.4
500	n/a	95.8	95.8	n/a	95.8	95.4

2.1.2.3 Estimated Useful Life

According to DEER 2014 the EUL is 15 years.

2.1.2.4 Deemed Savings Values

Actual motor operating hours are expected to be used to calculate savings. Every effort should be made to capture the estimated operating hours. Short and/or long-term metering can be used to verify estimates. If metering is not possible, interviews with facility operators and review of operations logs should be conducted to obtain an estimate of actual operating hours. If there is not sufficient information to accurately estimate operating hours, then the annual operating hours in Table 2-5 or

Table 2-6.

Table 2-5 Premium Efficiency Motors – Operating Hours, Load Factor (HVAC)

Building Type	Load Factor[173]	HVAC Fan Hours[174]
College/ University	0.75	4,581
Fast Food Restaurant		6,702
Full Menu Restaurant		5,246
Grocery Store		6,389
Health Clinic		7,243
Lodging		4,067
Large Office (>30k SqFt)		4,414
Small Office (≤30k SqFt)		3,998
Retail		5,538
School		4,165

[173] Itron 2004-2005 DEER Update Study, Dec 2005; Table 3-25. Accessed May 2013.http://www.deeresources.com/deer2005/downloads/DEER2005UpdateFinalReport_ItronVersion.pdf .

[174] Fan schedule operating hours taken as the average of operating hours from the Connecticut, Maine, and Pennsylvania Technical Reference Manuals: CL&P and UI Program Savings Documentation for 2008 Program Year, Connecticut Lighting & Power Company; Efficiency Maine Technical Reference User Manual No. 2007-1; Pennsylvania Utility Commission Technical Reference Manual June 2012.

Table 2-6 Premium Efficiency Motors – Operating Hours, Load Factor (Non-HVAC)

Industrial Processing	Load Factor[175]	Hours[176]					
		Chem	Paper	Metals	Petroleum Refinery	Food Production	Other
1-5 hp	0.54	4,082	3,997	4,377	1,582	3,829	2,283
6-20 hp	0.51	4,910	4,634	4,140	1,944	3,949	3,043
21-50 hp	0.60	4,873	5,481	4,854	3,025	4,927	3,530
51-100 hp	0.54	5,853	6,741	6,698	3,763	5,524	4,732
101-200 hp	0.75	5,868	6,669	7,362	4,170	5,055	4,174
201-500 hp	0.58	5,474	6,975	7,114	5,311	3,711	5,396
501-1,000 hp		7,495	7,255	7,750	5,934	5,260	8,157
>1,000 hp		7,693	8,294	7,198	6,859	6,240	2,601

2.1.2.4.1 Measure/Technology Review

Premium efficiency motors are a mature technology, and a wealth of information exists on the measure. A summary of the key resources is included in Table 2-7.

Table 2-7 Premium Efficiency Motors- Review of Motor Measure Information

Resource	Notes
PG&E 2006[177]	Savings for common motor retrofits
Xcel Energy 2006[178]	Program level savings estimates for high-efficiency motors
DEER 2014[179]	Savings and cost for common motor retrofit
KEMA 2010[180]	Motor savings included in comprehensive potential study
CEE[181]	Industrial motor efficiency initiative
RTF[182]	Savings for common motor retrofit
ITP[183]	Savings for common motor retrofit
NPCC 2010[184]	Market information and overview of savings potential
NEMA 2009[185]	Minimum efficiency level for premium efficiency motors

---

175 United States Industrial Electric Motor Systems Market Opportunities Assessment, Dec 2002; Table 1-19. Accessed May 2013. www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/mTRMkt.pdf

176 United States Industrial Electric Motor Systems Market Opportunities Assessment, Dec 2002; Table 1-15. Accessed May 2013. www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/mTRMkt.pdf

177 Pacific Gas & Electric (PG&E). 2006. *2006 Motors Unit Savings Workpapers.V14.*

178 Xcel Energy. 2006. 2007/2008/2009 *Triennial Plan Minnesota Natural Gas and Electric Conversation Improvement Program.*

179 Consortium of Energy Efficiency. Commercial Lighting Program. http://library.cee1.org/content/commercial-lighting-qualifying-products-lists

180 KEMA. 2010. *Measurement Manual*. Prepared for Tennessee Valley Authority.

181 Consortium for Energy Efficiency. 2010. Industrial Motors & Motor Systems. http://library.cee1.org/content/cee-2012-summary-member-programs-motors-motor-systems

182 Regional Technical Forum (RTF). http://rtf.nwcouncil.org/measures/

183 Industrial Technologies Program http://www1.eere.energy.gov/industry/

184 Northwest Power and Conservation Council (NPCC). 2010. *The Sixth Northwest Electric Power and Conservation Plan.*

185 National Electrical Manufacturers Association (NEMA). 2009. *Motors and Generators. NEMA* MG 1-2009.

MotorMaster+[186]	Comprehensive resource of motor efficiencies and tools to calculate savings
PacifiCorp 2009[187]	Motor savings included in comprehensive potential study

Deemed electric motor demand and energy savings should be calculated by the following formulas.

2.1.2.4.2 Replace on Burnout (ROB)

$$kWh_{savings} = Rated\ Horsepower\ \times Conversion\ Factor\ \times LF\ \times \left(\frac{1}{\eta_{baseline}} - \frac{1}{\eta_{post}}\right) \times hours$$

$$kW_{reduction} = Rated\ Horsepower\ \times Conversion\ Factor\ \times LF\ \times \left(\frac{1}{\eta_{baseline}} - \frac{1}{\eta_{post}}\right) \times CF$$

Where:

$Rated\ HorsePower$ = Nameplate horsepower data of the motor

$Conversion\ Factor$ = 0.746 kW/hp

LF = Estimated load factor for the motor; if load factor is not available, deemed load factors in Table 2-5 or

Table 2-6 can be used.

$\eta_{baseline}$= Efficiencies listed in Table 2-3 should be used (in the case of rewound motors, in situ efficiency may be reduced by a percentage as found in Table 2-9)

η_{post}= Efficiency of the newly installed motor

Hours= Estimated annual operating hours for the motor; if unavailable, annual operating hours in Table 2-5 or

Table 2-6 be used.

CF = Coincidence Factor = 0.74[188]

2.1.2.4.3 Early Retirement (ER)

Annual kWh and kW savings must be calculated separately for two time periods:

- The estimated remaining life (RUL, see Table 2-8) of the equipment that is being removed, designated the first N years, and
- Years EUL - N through EUL, where EUL is 15 years.

[186] MotorMaster+. 2010. https://www1.eere.energy.gov/manufacturing/tech_assistance/software_motormaster.html

[187] PacifiCorp. 2009. *FinAnswer Express Market Characterization and Program Enhancements Utah Service Territory.*

[188] Itron 2004-2005 DEER Update Study, Dec 2005; Table 3-25. http://www.deeresources.com/deer2005/downloads/DEER2005UpdateFinalReport_ItronVersion.pdf Accessed May 2013.

Table 2-8 Premium Efficiency Motors – Remaining Useful Life (RUL) of Replaced Systems[189,190]

Age of Replaced System (Years)	RUL (Years)
5	10.0
6	9.1
7	8.2
8	7.3
9	6.5
10	5.7
11	5.0
12	4.4
13	3.8
14	3.3
15	2.8
16	2.5
17	2.2
18	1.9
19	0.0

For the first N years:

$$kWh_{savings} = Rated\ Horsepower\ \times Conversion\ Factor\ \times LF\ \times \left(\frac{1}{\eta_{baseline}} - \frac{1}{\eta_{post}}\right) \times hours$$

$$kW_{reduction} = Rated\ Horsepower\ \times Conversion\ Factor\ \times LF\ \times \left(\frac{1}{\eta_{baseline}} - \frac{1}{\eta_{post}}\right) \times CF$$

Where:

$Rated\ HorsePower$ = Nameplate horsepower data of the motor

$Conversion\ Factor$ = 0.746 kW/hp

LF = Estimated load factor for the motor; if load factor is not available, deemed load factors in Table 2-5 or

Table 2-6 can be used

$\boldsymbol{\eta_{baseline}}$= In situ efficiency of the baseline motor; if unavailable, efficiencies listed in Table 2-3

can be used (in the case of rewound motors, in situ efficiency may be reduced by a percentage as found in Table 2-9).

η_{post}=Efficiency of the newly installed motor

---

189 Because the motor EUL is 15 years, it is consistent for use with the RUL determined using the Weibull distribution offered in the DOE's Life Cycle Cost Analysis Spreadsheet, "lcc_cuac_hourly.xls".

http://www1.eere.energy.gov/buildings/appliance_standards/standards_test_procedures.html.

190 Use of the early retirement baseline is capped at 18 years, representing the age at which 75 percent of existing equipment is expected to have failed. Systems older than 18 years should use the ROB baseline.

$Hours$= Estimated annual operating hours for the motor; if unavailable, annual operational hours in Table 2-5 or

Table 2-6 can be used

CF = Coincidence Factor = 0.74[191]

Table 2-9 Rewound Motor Efficiency Reduction Factors[192]

Motor Horsepower	Efficiency Reduction Factor
<40	0.01
≥40	0.005

For Years EUL - N through EUL: Savings should be calculated exactly as they are for replace on burnout projects, referred to as $kWh_{SavingsROB}$.

Total lifetime savings for early retirement projects are then determined by adding the savings calculated under the two preceding equations.

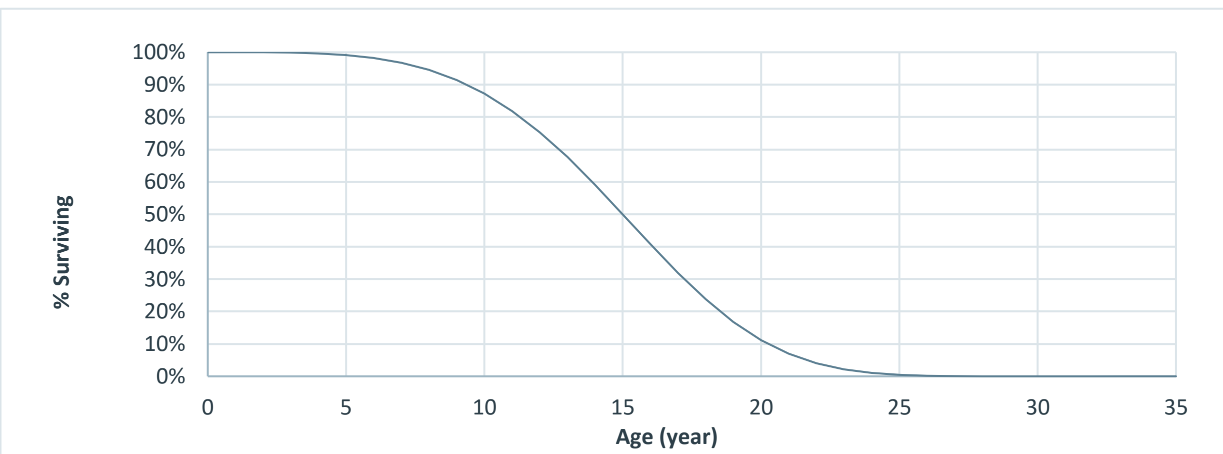
$$Lifetime\ kWh\ savings\ for\ Early\ Retirement\ Projects$$

$$= \left(kWh_{savingsRUL} \times RUL\right) + \left[kWh_{savingsROB} \times (EUL - RUL)\right]$$

Where:

RUL= The Remaining Useful Life of the equipment, in years, see Table 2-8.

EUL = The Estimated Useful Life of the equipment, deemed at 15 years



[191] Itron 2004-2005 DEER Update Study, Dec 2005; Table 3-25. http://www.deeresources.com/deer2005/downloads/DEER2005UpdateFinalReport_ItronVersion.pdf. Accessed May 2013.

[192] U.S. DOE, Preliminary Technical Support Document, "Energy Efficiency Program for Commercial Equipment: Energy Conservation Standards for Electric Motors, 2.7.2 Impact of Repair on Efficiency." July 23, 2012. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/50. Download TSD at: http://www1.eere.energy.gov/buildings/appliance_standards/pdfs/em_preanalysis_tsdallchapters.pdf .

Figure 2-1 Survival Function for Premium Efficiency Motors[193]

The method used for estimating the RUL of a replaced system uses the age of the existing system to re-estimate the survival function shown in Figure 2-1. The age of the system being replaced is found on the horizontal axis and the corresponding percentage of surviving systems is determined from the chart. The surviving percentage value is then divided in half, creating a new percentage. Then the age (year) that corresponds to this new percentage is read from the chart. RUL is estimated as the difference between that age and the current age of the system being replaced.

2.1.2.5 Incremental Cost

Table 2-10 Motor Incremental Cost by Size[194]

Motor Horsepower	Incremental Cost
5	$918
7.5	$918
10	$918
15	$918
20	$933
25	$1,012
30	$1,091
40	$1,300
50	$1,497
60	$1,796
75	$1,943
100	$2,389
125	$3,087
150	$3,784
200	$4,555
250	$4,655
300	$4,755
350	$4,855
400	$4,955
450	$5,055
500	$5,155

2.1.2.6 Future Studies

In Energy Smart and other utility portfolios, this is typically a low-volume measure. High-saving motor applications are more commonly found in custom applications. As a result, the TPE does not advise funding future measure research, and recommend that the measure receive updated only when applicable codes or standards warrant it.

[193] Source: Weibull distribution based on the Life Cycle Cost Analysis Spreadsheet, "lcc_cuac_hourly.xls". http://www1.eere.energy.gov/buildings/appliance_standards/standards_test_procedures.html.

[194] Comprehensive Process and Impact Evaluation of the (Xcel Energy) Colorado Motor and Drive Efficiency Program, FINAL, March 28, 2011,TetraTech

2.2 Water Heating

2.2.1 WATER HEATER REPLACEMENT

2.2.1.1 Measure Description

This measure includes:

- The replacement of electric water heaters in commercial buildings by high efficiency electric resistance water heaters
- The replacement of electric water heaters in commercial buildings by heat pump water heaters
- The replacement of small (< 12 kW) electric water heaters in commercial buildings by electric tankless water heaters

Commercial water heater savings are measured per location and are calculated for new construction or replace-on-burnout. Storage tank models and tankless models, utilizing electricity are eligible.

2.2.1.2 Baseline and Efficiency Standards

The baseline standards for IECC 2009 are detailed in Table 2-11.

Table 2-11 Water Heaters – Water Heater Performance Requirements

Equipment Type	Size Category (Input)	Subcategory or Rating Condition	Performance Required[195],[196]	Test Procedure
Water heaters, electric	≤ 12 kW	Resistance	IECC 2009: 0.97 - 0.00132V, EF	DOE 10 CFR Part 430
	> 12 kW		1.73V + 155, SL (Btu/hr)	ANSI Z21.10.3
	≤ 24 amps and ≤ 250 volts	Heat Pump	0.93 - 0.00132V, EF	DOE 10 CFR Part 430

For smaller water heaters where energy factor (EF) is used, EF considers the overall efficiency, including combustion efficiency and standby loss (SL). Regulated by DOE as “residential water heaters”, these smaller water heaters manufactured on or after April 16, 2015, must comply with the amended standards found in the Code of Federal Regulations, 10 CFR 430.32(d), detailed in Table 2-12.

[195] Energy factor (EF) and thermal efficiency (Et) are minimum requirements. In the EF equation, V is the rated volume in gallons.

[196] Standby loss (SL) is the maximum Btu/hr based on a nominal 70°F temperature difference between stored water and ambient requirements. In the SL equation, Q is the nameplate input rate in Btu/hr. In the SL equation for electric and gas water heaters and boilers, V is the rated volume in gallons.

Table 2-12 Small Commercial Water Heaters – Standards and their Compliance Dates[197]

Product Class	Energy Factor as of April 16, 2015
Electric Water Heater	For Vs < 55 gallons: 0.960 – (0.0003V) For Vs > 55 gallons: 2.057 – (0.00113V)

For larger water heaters, thermal efficiency (Et) is used and does not factor into SL; however, a limitation on SL is noted.

The savings calculations consider the minimum water heater efficiency requirements listed in Table 2-11 to be the baseline.

2.2.1.3 Estimated Useful Life

The EUL of this measure is dependent on the type of water heating. According to DEER 2014, the following measure lifetimes should be applied.[198]

- 10 years for Heat Pump Water Heater (HPWH)
- 15 years for High Efficiency Commercial Storage Water Heater
- 20 years for Commercial Tankless Water Heater

2.2.1.4 Deemed Savings Values

Program staff should endeavor to collect unit-specific information to support energy savings calculations. However, if such data is not available the tables below may be used. The assumptions are as follows:

- Electric Resistant Water Heating:
    - Assume full facility load met by a series of 50-gallon units
    - Resulting baseline EF is .945
    - Efficient EF is .98
- Heat Pump Water Heating:
    - Assume full facility load met by a series of 200-gallon units
    - Resulting baseline EF is 2.00
    - Efficient EF is 2.20

[197] Where V is the rated storage volume, which equals the water storage capacity of a water heater (in gallons), as certified by the manufacturer.

[198] http://www.deeresources.com/files/deer2008exante/downloads/EUL_Summary_10-1-08.xls

Table 2-13 Deemed Savings: Electric Resistant Water Heaters

Building Type	Annual Hot Water/1,000 ft.²	Average ft.²	kWh Savings	kW Savings
Convenience Store	4,255	2,800	50	0.0057
Education	6,746	45,000	1,267	0.1446
Grocery	646	21,300	57	0.0065
Health	22,734	72,000	6,829	0.7796
Large Office	1,686	95,000	668	0.0763
Large Retail	1,254	80,000	419	0.0478
Lodging	27,399	76,500	8,745	0.9983
Nursing	28,279	72,000	8,495	0.9697
Restaurant	41,224	3,850	662	0.0756
Small Office	1,428	6,000	36	0.0041
Small Retail	5,660	6,400	151	0.0172
Warehouse	1,148	14,000	67	0.0076
Other Commercial	3,652	4,000	61	0.0070

Table 2-14 Deemed Savings: Heat Pump Water Heaters

Building Type	Annual Hot Water/1,000 ft.²	Average ft.²	kWh Savings	kW Savings
Convenience Store	4,255	2,800	60	0.0068
Education	6,746	45,000	1,523	0.1739
Grocery	646	21,300	69	0.0079
Health	22,734	72,000	8,214	0.9376
Large Office	1,686	95,000	804	0.0917
Large Retail	1,254	80,000	503	0.0575
Lodging	27,399	76,500	10,518	1.2007
Nursing	28,279	72,000	10,217	1.1663
Restaurant	41,224	3,850	796	0.0909
Small Office	1,428	6,000	43	0.0049
Small Retail	5,660	6,400	182	0.0207
Warehouse	1,148	14,000	81	0.0092
Other Commercial	3,652	4,000	73	0.0084

Typically, two types of ratings exist for water heaters: energy factor (EF) for smaller units, and thermal efficiency (Et) for larger water heaters. Large heat pump water heaters may also be rated by a third method, coefficient of performance (COP), which is the ratio of heat energy output to electrical energy input and is analogous to thermal efficiency. EF includes standby losses, while Et and COP only consider the amount of energy required to heat the water. Therefore, in the formulas below, the baseline and energy efficiency measure may be compared for each type of water heater.

The electricity savings for this measure are highly dependent on the estimated hot water consumption, which varies significantly by building type. The following tables list estimated hot water consumption for various building types by number of units, occupants, or building size.

Table 2-15 Hot Water Requirements by Building Type and System Capacity[199]

Building Type	Annual Hot Water Consumption Per Gallon of Rated Capacity
Convenience Store	489
Education	526
Grocery	489
Health	730
Large Office	474
Large Retail	489
Lodging	663
Nursing	623
Restaurant	577
Small Office	474
Small Retail	489
Warehouse	316
Other Commercial	316

Table 2-16 converts the values from Table 2-15 into per-1,000 square feet value based on the same CBECS 2012 data.

Table 2-16 Hot Water Requirements by Building Size[200]

Building Type	Annual Hot Water Consumption Per 1,000 SQFT
Convenience Store	4,255
Education	6,746
Grocery	646
Health	22,734
Large Office	1,686
Large Retail	1,254
Lodging	27,399
Nursing	28,279
Restaurant	41,224
Small Office	1,428
Small Retail	5,660
Warehouse	1,148
Other Commercial	3,652

2.2.1.4.1 Small Electric Storage Water Heaters

As small (≤ 12 kW) electric water heaters are typically rated by EF, this section of this measure includes both higher-efficiency resistance water heaters and small (≤ 24 amps and ≤ 250 volts) heat pump water heaters. Deemed annual energy savings for small electric water heater replacements are calculated by the following formula.

[199] Methodology based on TPE analysis. Annual hot water usage in gallons based on CBECS (2012) and RECS (2009) consumption data of West South Central (removed outliers of 1,000 kBtuh or less) to calculate hot water usage. Annual hot water gallons per tank size gallons based on the tank sizing methodology found in ASHRAE 2011 HVAC Applications. Chapter 50 Service Water Heating. Demand assumptions (gallons per day) for each building type based on ASHRAE Chapter 50 and to LBNL White Paper. LBL-37398 Technology Data Characterizing Water Heating in Commercial Buildings: Application to End Use Forecasting. Assumes hot water heater efficiency of 80.

[200] This is a conversion of the capacity values to a per-square foot value based on average building size in the CBECS.

$$kWh_{Savings} = \frac{\rho \times C_p \times V \times (T_{SetPoint} - T_{Supply}) \times (EF_{pre} - EF_{post})}{3{,}412\ Btu/kWh}$$

Where:

ρ = Water density = 8.33 lb/gal

C_p = Specific heat of water = 1 BTU/lb.·°F

V = Average annual hot water use (gallons). See for Table 2-15 and Table 2-16

estimates of water consumption.

$T_{SetPoint}$ = Water heater set point (default value = 120°F)

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F[201]

EF_{pre} = Calculated energy factor of existing water heater, based on the water heater tank volume; Table 2-11.

EF_{post} = Energy Factor of replacement water heater (taken from nameplate); the replacement water heater may be either a high efficiency electric storage water heater or a heat pump water heater

$Conversion\ Factor$ = 3,412 Btu/kWh

Deemed demand reduction for small electric water heater replacements are calculated by formula as follows:

$$kW_{reduction} = \frac{\rho \times C_p \times V \times (T_{SetPoint} - T_{Supply}) \times (EF_{pre} - EF_{post})}{3{,}412\ Btu/kWh} \times 1/24 \times 1/365$$

Where all variables are the same as in the energy equation and the average hourly ratio is a best estimate of peak coincidence for commercial hot water heater replacements.[202]

2.2.1.4.2 Large Electric Storage Water Heaters

Large (> 12 kW) electric resistance water heaters can be replaced with heat pump water heaters.

For replacement of large electric resistance water heaters with a heat pump water heater, deemed annual energy savings are calculated by the following formula.

[201] Calculated using area groundwater data. See Volume 3, *Appendices.*

[202] For replacement with high-efficiency electric storage water heaters and tankless water heaters, the 1/24 peak coincidence factor accurately reflects that improvements in the efficiency of electric resistance storage water heaters are driven almost entirely by reductions in storage losses (conversion efficiency, RE, is close to 1), which are distributed evenly throughout the day.

$$kWh_{Savings} = \frac{\rho \times C_p \times GPD \times (T_{SetPoint} - T_{Supply}) \times \left(\frac{1}{E_{t,base}} - \frac{1}{COP_{post}}\right) \times Days/Year}{3{,}412\ Btu/kWh}$$

Where:

ρ = Water density = 8.33 lb/gal

C_p = Specific heat of water = 1 BTU/lb·°F

V = Average daily hot water use (gallons). See Table 2-15 and Table 2-16 for estimates of water consumption

$T_{SetPoint}$ = Water heater set point (default value = 120°F)

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

$E_{t,base}$ = .98

COP_{post} = Coefficient of performance of new heat pump water heater

2.2.1.4.3 Demand Savings

Deemed demand reduction for replacement of large electric resistance water heaters with a heat pump water heater are calculated by the following formula.

$$kW_{reduction} = \frac{\rho \times C_p \times GPD \times (T_{SetPoint} - T_{Supply}) \times (EF_{pre} - EF_{post})}{3{,}412\ Btu/kWh} \times 1/24$$

Where all variables are the same as in the energy equation and the 1/24 ratio is a best estimate of peak coincidence for commercial hot water heater replacements.

2.2.1.5 Incremental Cost

The incremental cost for heat pump water heaters are as follows[203]:

- 50 Gallon: $1,050
- 80 Gallon: $1,050
- 100 Gallon: $1,950

2.2.1.6 Future Studies

Current DHW load estimates are based off of CBECS data for the West South region. If there is significant participation, we recommend updating with actual participant loads. Further, a study of commercial DHW setpoints would be warranted.

[203] Cost information is based upon data from "2010-2012 WA017 Ex Ante Measure Cost Study Draft Report", Itron, February 28, 2014. See "NR HW Heater_WA017_MCS Results Matrix - Volume I.xls" for more information.

2.2.2 FAUCET AERATORS

2.2.2.1 Measure Description

This measure consists of installing low-flow faucet aerators in commercial facilities which reduce water usage and save energy associated with heating the water.

2.2.2.2 Baseline and Efficiency Standards

The baseline faucet aerators are assumed to have a flow rate of 2.2 gallons per minute.[204] To qualify for this measure, the flow rate of installed low-flow faucet aerators must be ≤1.5 gallon per minute.[205]

2.2.2.3 Estimated Useful Life

The EUL of this measure is 10 years according to DEER 2014.

2.2.2.4 Deemed Savings Values

Table 2-17 presents the savings for 1.5, 1.0, and 0.5 GPM aerators. The "unknown" category being an average of the listed facility types.

Table 2-17 Faucet Aerator Deemed Savings

Building Type	**Days per Year**	**Minutes per Day**	**kWh Savings**			**kW Savings**		
			1.5 GPM	**1.0 GPM**	**0.5 GPM**	**1.5 GPM**	**1.0 GPM**	**0.5 GPM**
Hospital, nursing home	365	3	86	148	210	0.0071	0.0122	0.0172
Dormitory	274	30	648	1,111	1,574	0.0946	0.1622	0.2298
Multifamily	365	3	86	148	210	0.0071	0.0122	0.0172
Lodging	365	3	86	148	210	0.0047	0.0081	0.0115
Commercial	250	30	591	1,014	1,436	0.1892	0.3244	0.4596
School	200	30	473	811	1,149	0.1183	0.2028	0.2873
Unknown	303	17	329	563	798	0.0702	0.1203	0.1704

Annual kWh electric and peak kW savings can be calculated using the following equations:

$$kWh\ Savings = \frac{\rho \times C_P \times U \times (F_B - F_P) \times \left(T_H - T_{Supply}\right) \times \frac{1}{E_t} \times Days/Year}{3{,}412\ Btu/kWh}$$

$$kW_{reduction} = \frac{\rho \times C_P \times U \times (F_B - F_P) \times \left(T_H - T_{Supply}\right) \times \frac{1}{E_t} \times P}{3{,}412\,\frac{Btu}{kWh}}$$

---

[204] Maximum flow rate for lavatories and aerators set in Federal Energy Policy Act of 1992 and codified at 2.2 GPM at 60 psi in 10CFR430.32.

[205] "High-Efficiency Lavatory Faucet Specification." WaterSense. EPA. October 1, 2007. http://www.epa.gov/watersense/partners/faucets_final.html

Table 2-18 Commercial Aerator Savings Parameters

Parameter	Description	Value
F_B	Average baseline flow rate of aerator (GPM)	2.2
F_P	Average post measure flow rate of aerator (GPM)	≤1.5
Days/Year	Annual Building type operating days for the applications:	
	1.Hospital, Nursing home	365
	2. Dormitory	274[206]
	3. Multifamily	365
	4. Lodging	365
	5. Commercial	250
	6. School	200
T_{supply}	Average supply (cold) water temperature (^oF)	74.8
T_H	Average mixed water (after aerator) temperature (^oF)	120[207]
U	Baseline water usage duration, following applications	
	1. Hospital, Nursing home	3 min/day/unit
	2. Dormitory	30 min/day/unit
	3. Multifamily	3 min/day/unit
	4. Lodging	3 min/day/unit
	5. Commercial	30 min/day/unit
	6. School	30 min/day/unit
ρ	Unit conversion: 8.33 pounds/gallon	8.33
C_p	Heat capacity of water - 1 Btu/lb. ^oF	1
E_t	Thermal Efficiency of water heater	Default Values: 0.98 for ER, 2.2 (COP) for HP
	Hourly water consumption during peak period as a fraction of average daily consumption for applications:	
	1. Hospital, Nursing home	0.03
	2. Dormitory	0.04
	3. Multifamily	0.03
	4. Lodging	0.02
	5. Commercial	0.08
	6. School	0.05

Example: The following is an electric example calculation for a 1.0 GPM aerator replacement for a school using the previous equations and information. Example electric savings are based on heating water with a conventional electric resistance storage tank water heater.

[206] Dormitories with few occupants in the summer: 365 x (9/12) = 274.

[207] Calculated based on area groundwater temps.

$\Delta kWh = [8.33\ x\ 30minday\ x\ (2.2 - 1.0)\ GPM\ x\ (120 - 74.8°\text{F})\ x\ (1/.98) * 200dayyear]/3412$

$Btu/kWh = 811\ kWh$

$\Delta kW = [8.33\ x\ 30minday\ x\ (2.2 - 1.0)\ GPM\ x\ (120 - 74.8°\text{F})\ \text{x}\ (1/.98)\ x\ .05]/3412\ Btu/kWh$

$= 0.202\ kW$

2.2.2.5 Incremental Cost

Program-actual costs should be used where available. If not available, the incremental cost of a faucet aerator is $8.00[208].

2.2.2.6 Future Studies

If there is significant participation, we recommend updating with actual participant loads. Further, a study of commercial DHW setpoints would be warranted.

[208] Direct-install price per faucet assumes cost of aerator and install time. (2011, Market research average of $3 and assess and install time of $5 (20min @ $15/hr)

2.2.3 LOW-FLOW SHOWERHEADS

2.2.3.1 Measure Description

This measure consists of removing existing showerheads and installing low-flow showerheads at the following commercial building types: hospitals and nursing homes, lodging facilities, commercial facilities (offices or other commercial buildings in which showers are provided for employees), fitness centers, and schools.[209]

2.2.3.2 Baseline and Efficiency Standards

The savings values for low-flow showerheads are for the retrofit of existing operational showerheads with a flow rate of 2.5 gallons per minute (GPM) or higher.[210] Facilities must have electric water heating to qualify for this measure.

The baseline showerhead has an average flow rate of 2.5 GPM based on the current DOE standard. To qualify for the deemed savings, replacement showerheads must have a flow rate of 2.0 GPM or less.[211]

Existing showerheads that have been defaced so as to make the flow rating illegible are not eligible for replacement. Low flow shower heads that are easily tampered with should not be used. Removed showerheads shall be collected by the contractor and held for possible inspection by the utility until all inspections for invoiced installations have been completed.

Table 2-19 Low-Flow Showerhead – Baseline and Efficiency Standards

Measure	New Showerhead Flow Rate[212] (GPM)	Existing Showerhead Baseline Flow Rate (GPM)
2.0 GPM showerhead	2.0	2.5
1.75 GPM showerhead	1.75	2.5
1.5 GPM showerhead	1.5	2.5

The U.S. EPA WaterSense Program has implemented efficiency standards for showerheads requiring a maximum flow rate of 2.0 GPM[213].

2.2.3.3 Estimated Useful Life

The EUL of this measure is 10 years according to DEER 2014.

---

[209] This measure draws from multiple sources, including the residential low flow showerhead measure and commercial faucet aerator measure. Information specific to hot water use in commercial market sectors was drawn from CLEAResult, Inc. draft white paper: *Work Papers for Low Flow Shower Heads with Gas or Electric Water Heaters: Savings Calculation Methodology for Application in Arkansas Energy Efficiency Programs*, February 2014.

[210] 10 CFR Part 430, Energy Conservation Program for Consumer Products: Test Procedures and Certification and Enforcement Requirements for Plumbing Products; and Certification and Enforcement Requirements for Residential Appliances; Final Rule, March 1998. Online. Available: http://www.regulations.gov/#!documentDetail;D=EERE-2006-TP-0086-0003.

[211] The U.S. Environmental Protection Agency (EPA) WaterSense Program has a thorough specification for showerheads that meet a maximum flow rate of 2.0 gpm. The specification is available on the EPA website at: www.epa.gov/WaterSense/partners/showerhead_spec.html

[212] All flow rate requirements listed here are the rated flow of the showerhead measured at 80 pounds per square inch of pressure (psi).

[213] http://www1.eere.energy.gov/femp/program/waterefficiency_bmp7.html.

2.2.3.4 *Deemed Savings Values*

Table 2-20 through Table 2-22 present the default savings for 1.5, 1.0, and 0.5 GPM aerators, respectively. The results are presented by facility type, with the "unknown" category being an average of the listed facility types. For the "unknown" facility type, the values are the average of all other facilities excluding Fitness Center; this facility is a high outlier in savings and the TPE has opted to exclude it from the "unknown" category due to the risk of this facility skewing results.

Table 2-20 Showerhead Deemed Savings – 2.0 GPM

Building Type	Hot Water Reduction	kWh Savings	kW Savings
Hospital / Nursing Home	232	26.11	0.7844
Hospitality	326	36.67	0.7345
Commercial Employee Shower	253	28.46	2.2798
Fitness Center	5203	584.96	46.8656
Schools	344	38.72	1.9390
Unknown	288.75	32.49	1.4642

Table 2-21 Showerhead Deemed Savings – 1.75 GPM

Building Type	Hot Water Reduction	kWh Savings	kW Savings
Hospital / Nursing Home	348	39.16	1.1766
Hospitality	489	55.01	1.1017
Commercial Employee Shower	380	42.68	3.4197
Fitness Center	7,804	877.44	70.2984
Schools	517	58.09	2.9085
Unknown	433.5	48.73	2.1963

Table 2-22 Showerhead Deemed Savings – 1.5 GPM

Building Type	Hot Water Reduction	kWh Savings	kW Savings
Hospital / Nursing Home	464	52.22	1.5688
Hospitality	652	73.34	1.4690
Commercial Employee Shower	506	56.91	4.5596
Fitness Center	10,405	1169.93	93.7312
Schools	689	77.45	3.8780
Unknown	577.75	64.98	2.9284

Energy and demand reduction are estimated as functions of the reduction in daily water use (ΔV) attributable to installation of low flow showerheads in a given commercial building type. Reduction in water use and deemed savings calculations make use of the data provided by building type in Table 2-23 and the New Orleans average water main temperature, 74.8.

Table 2-23 Showers per Day (per Showerhead) and Days of Operation by Building Type

Building Type	**Showers/Day**	**Days/Year**
Hospital/Nursing Home	0.89	365
Hospitality	1.25	365
Commercial	0.97	250
Fitness Center	19.94	365
School	1.32	200

2.2.3.4.1 Estimated Hot Water Usage Reduction

Reduction in annual hot water usage is estimated based on the typical duration of a shower and the expected number of showers per year for an installed showerhead in a given facility.

Reduction in daily hot water consumption is estimated on a per-showerhead basis using the following formula.

$$\Delta V = U \times N \times (Q_B - Q_P) \times F_{HW}$$

Where:

ΔV = Reduction in daily hot water use in gallons per day (GPD)

U = Typical shower duration of 7.8 (minutes/shower)

N = Number of showers per day (per showerhead); (N) is a function of the commercial building type, values for N are provided in Table 2-25.

Q_B = Baseline showerhead flow rate, 2.5 GPM

Q_P = Flow rate of installed showerhead (in GPM)

F_{HW} = Hot Water Fraction (share of water flowing through showerhead from the water heater, %)

The fraction of hot water is a function of the inlet water temperature (T_{supply}) the temperature of water from the hot water heater (T_{HW} = 120 ^oF), and the desired temperature at the showerhead (T_{mixed} = 105 ^oF).

Reduction in daily hot water usage is provided for reference in Table 2-24.

Table 2-24 Reduction in Daily Hot Water Usage, ΔV (GPD)

Flow Rate of Installed Showerhead	Building Type				
	Hospital / Nursing home	Hospitality	Commercial - Employee Shower	Fitness Center	Schools
2.0 GPM	232	326	253	5,203	344
1.75 GPM	348	489	380	7,804	517
1.5 GPM	464	652	506	10,405	689

2.2.3.4.2 Energy Savings

The deemed energy savings are calculated as follows:

$$kWh_{savings} = \frac{\rho \times C_P \times \Delta V \times \left(T_{HW} - T_{Supply}\right) \times \left(\frac{1}{E_t}\right)}{Conversion\ Factor}$$

Where:

ρ = Water density = 8.33 lb/gallon

C_P = Specific heat of water = 1 Btu/lb·°F

ΔV = gallons of hot water saved per day (GPD, calculated above identified in Table 2-24)

T_{HW} = Temperature to which water is heated in the water heater, 120°F

T_{Supply}= Average inlet water temperature (water mains temperature), 74.8.

E_t = Thermal efficiency of water heater (or in the case of heat pump water heaters, COP); if unknown, use 0.98 as a default for electric resistance water heaters, 2.2 for heat pump water heaters[214]

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/therm for gas water heating

2.2.3.4.3 Demand Savings

The deemed demand reduction is calculated as follows.

$$kW_{reduction} = \frac{\rho \times C_P \times \Delta V \times \left(T_{HW} - T_{Supply}\right) \times \left(\frac{1}{E_t}\right)}{Conversion\ Factor}\ x\ P$$

[214] Default values based on median recovery efficiency of commercial water heaters by fuel type in the AHRI database as cited in previous iterations of the AR TRM. Online: available at http://cafs.ahrinet.org/gama_cafs/sdpsearch/search.jsp?table=CWH.

Where:

All inputs are the same as described in the Energy Savings Equation; and

P = electric peak coincidence factors, as provided for each building type in Table 2-25. [215]

Parameters for savings calculations can be found in the table below.

Table 2-25 Parameters for Annual Energy and Peak Demand Savings Calculations

Parameter	Description	Value
U	Baseline shower duration[216] (min/shower)	7.8
N	Number of showers per day per showerhead[217] Hospital, Nursing Home Lodging Commercial 24-Hour Fitness Center Schools	 0.89 1.25 0.97 19.94 1.32
Q_B	Average baseline flow rate of showerhead (GPM)	2.5
Q_P	Flow rate of installed showerhead (GPM)	≤ 2.0
F_{HW}	Share of water flowing through showerhead coming from the water heater (%)	66.9
ρ	Density of water (lb./gal)	8.33
Cp	Heat capacity of water (Btu/lb.-ºF)	1
T_{HW}	Temperature to which water is heated by the water heater (ºF)[218]	120
T_{supply}	Average supply (cold) water temperature (ºF)	74.8
E_t	Thermal Efficiency of hot water heater: Conventional Electric Storage Water Heater Heat Pump Water Heater (COP) Gas Storage Water Heater	 0.98 2.2 0.80

215 For all building types except 24-Hour Fitness Centers, derived from *ASHRAE Handbook 2011. HVAC Applications.* American Society of Heating Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) 2011. ASHRAE, Inc., Atlanta, GA. The peak factor is the ratio of the gallons of hot water used during the peak times of 3pm to 6pm, to the total amount of hot water used during the day. 24-Hour Fitness Center is assigned the same value as Commercial.

216 Hendron, R., & Engebrech, C. 2010, "*Building America Research Benchmark Definition, Updated December 2009, Technical Report NREL/TP-550-47246,* January. National Renewable Energy Laboratory The average shower duration taken from Table 12, p. 20.

217 Primary source is Northwest Power and Conservation Council ProCost V2.3. The number of showers per day per showerhead is back-calculated for hospitals and nursing homes, lodging and commercial building types, coefficients from annual minutes per showerhead estimates. N = (Minutes/year) x (year/days) x (Shower/minutes) = Showers/day. For 24-hour fitness centers, minutes per year were taken from informal telephone survey of Fitness Centers in the Northwest, conducted by Northwest Power and Conservation Council Regional Technical Forum staff in June, 2013. The estimate for schools is derived from Water consumption from Planning and Management Consultants, Ltd., Aquacraft, Inc. and John Olaf Nelson, Water Resources Management. "*Commercial and Institutional End Uses of Water,*" American Water Works Association Research Foundation, 2000.

218 ASHRAE Handbook 2011. HVAC Applications. American Society of Heating Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE), Inc., Atlanta, GA.

Parameter	Description	Value
$Days/year$	Annual building type operating days for the applications:[219] Hospital, Nursing Home Lodging Commercial 24-Hour Fitness Center School	 365 365 250 365 200
P	Peak Factor:[220] Hospital, Nursing Home Lodging Commercial 24-Hour Fitness Center School	 0.03 0.02 0.08 0.08 0.05

2.2.3.5 *Incremental Cost*

Program-actual costs should be used where available. If not available, the incremental cost of a low flow showerhead is $12[221].

2.2.3.6 *Future Studies*

If there is significant participation, we recommend updating with actual participant loads. Further, a study of commercial DHW setpoints would be warranted.

---

[219] All values except 24-Hour Fitness Center from Osman , S. & Koomey, J. Lawrence Berkeley National Laboratory 1995. *Technology Data Characterizing Water Heating in Commercial Buildings: Application to End-Use Forecasting.* December 1995. Value for 24-Hour Fitness Center based on observation.

[220] Derived from *ASHRAE Handbook 2011. HVAC Applications.* American Society of Heating Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) 2011. ASHRAE, Inc., Atlanta, GA. The peak factor is the ratio of the gallons of hot water used during the peak times of 3 pm to 6pm, to the total amount of hot water used during the day.

[221] Direct-install price per showerhead assumes cost of showerhead (Market research average of $7 and assess and install time of $5 (20min @ $15/hr)

2.2.4 WATER HEATER PIPE INSULATION

2.2.4.1 Measure Description

This measure consists of installing water heater pipe insulation exceeding the IECC mandated standard (0.5-inch of insulation that delivers an R-value of at least 3.7 per inch) over at least the first 8 feet of exposed pipe in small commercial settings. Water heaters plumbed with heat traps or automatic-circulating systems are not eligible to receive incentives for this measure.[222]

2.2.4.2 Baseline and Efficiency Standards

Baseline insulation is R = 1.85 sq. ft. h °F/Btu, the mandated standard since IECC 2000.

2.2.4.3 Estimated Useful Life

The EUL of this measure is the remaining service life of the water heater. If unknown, use one-third of the life of an electric resistant water heater, rounded down. This is a measure life of 4 years.[223]

2.2.4.4 Deemed Savings Values

The TPE assume three feet of R-3 insulation in providing an estimate of per-project savings. Program administrators are encouraged to incorporate facility-specific inputs when possible. Deemed savings are:

- 112 kWh; and
- 0.0128 kW

2.2.4.4.1 Energy Savings

$$kWh_{savings} = \left(U_{pre} - U_{post}\right) \times A \times \left(T_{Pipe} - T_{ambient}\right) \times \left(\frac{1}{E_t}\right) \times \frac{Hours_{Total}}{Conversion\ Factor}$$

Where:

U_{pre}= 1/(2.03[224]) = 0.49 BTU/h sq. ft. degree F

$U_{post} = 1/(2.03 + R_{Insulation})$

$R_{Insulation}$= R-value of installed insulation

$A =$ Surface area in square feet (πDL) with L (length) and D pipe diameter in feet

$T_{Pipe}(°\mathrm{F}) =$ Average temperature of the pipe. Default value $= 90$ °F (average temperature of pipe between water heater and the wall)

$T_{ambient}(°\mathrm{F}) =$ 68.78°F (New Orleans TMY3 average hourly temperature)

---

[222] A survey of several large online home-improvement retailers shows three general classes of commercially available pipe insulation: one around R-2.3 (typically 5/8" thick foam), another around R-3 (typically 1/2" thick rubber) and lastly high-end insulation in the R-6 to R-7 range (1" thick rubber).

[223] To see water heater EUL, go to Section 2.2.1.3.

[224] 2.03 is the R-value representing the film coefficients between water and the inside of the pipe and between the surface and air. *Mark's Standard Handbook for Mechanical Engineers, 8th edition*.

Et = Thermal efficiency (or in the case of heat pump water heaters, COP); if unknown, use 0.98 as a default for electric water heaters, 2.2 for a heat pump water heater.[225]

$Hours_{Total}$ = 8,760 hr per year[226,227]

$Conversion\ Factor$ = 3,412 Btu/kWh

For example, deemed savings for water heater pipe insulation with an R-value of 3 installed on an electric water heater in New Orleans would be as follows.

$$kWh_{savings} = (0.49 - 0.20) \times 2.1 \times (90 - 74.8) \times \left(\frac{1}{0.98}\right) \times \frac{8{,}760}{3{,}412} = 24.3\ kWh/yr$$

2.2.4.4.2 Demand Savings

Peak demand reduction for hot water heaters installed in conditioned space can be calculated using the following formula for electric demand reduction.

$$kW_{reduction} = \left(U_{pre} - U_{post}\right) \times A \times \left(T_{Pipe} - T_{ambientMAX}\right) \times \left(\frac{1}{E_t}\right) \times \frac{1}{3{,}412\ Btu/kWh}$$

Where:

U_{pre} = 1/(2.03) =0.49 BTU/h SQFT °F

$U_{post} = 1/(2.03 + R_{Insulation})$

$R_{Insulation}$ = R-value of installed insulation

$A =$ Surface area in SQFT (πDL) with L (length) and D pipe diameter in feet

$T_{Pipe}(°\mathrm{F}) =$ Average temperature of the pipe. Default value = 90 °F (average temperature of pipe between water heater and the wall)

$T_{ambientMAX}(°\mathrm{F}) =$ Installed in unconditioned basements use 68.8°F; Inside thermal envelope uses 78 °F

Et = Thermal efficiency (or in the case of heat pump water heaters, COP); if unknown, use 0.98 as a default for electric water heaters, 2.2 for a heat pump water heater.

---

[225] Default values based on median recovery efficiency of residential water heaters by fuel type in the AHRI database, at https://www.ahridirectory.org/ahridirectory/pages/rwh/defaultSearch.aspx

[226] Ontario Energy's Measures and Assumptions for Demand Side Management (DSM) Planning www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/Navigant_Appendix_C_substantiation_sheet_20090429.pdf

[227] New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs Residential, Multi-Family, and Commercial/Industrial Measures http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/06f2fee55575bd8a852576e4006f9af7/$FILE/TechManualNYRevised10-15-10.pdf

2.2.4.5 Incremental Cost

The incremental cost of a Water Heater Pipe Insulation is equal to the full installed cost. If the cost is unknown, use $4.45 for ¾” pipe and $4.15 for ½” pipe per linear foot of insulation[228].

2.2.4.6 Future Studies

This measure is not anticipated to contribute significant savings. Future updates for this measure will be limited to applicable code revisions.

[228] Illinois TRM

2.2.5 WATER COOLER TIMERS

2.2.5.1 Measure Description

This measure involves installing a timer on an existing water cooler to shut down operation during unoccupied hours. It is applicable to both ENERGY STAR and non-ENERGY STAR-certified models to the following system types:

- Cold Only
- Cook and Cold
- Hot and Cold
- Hot, Cook and Cold

2.2.5.2 Baseline and Efficiency Standards

The baseline is an existing water cooler without a timer, integral or otherwise. The efficient condition is the cooler with a properly programmed timer installed.

2.2.5.3 Estimated Useful Life

According to DEER 2014, this measure has an EUL of 5 years[229].

2.2.5.4 Deemed Savings Values

Deemed savings are provided by cooler type and program delivery channel.

Table 2-26 Deemed Savings for Water Cooler Timers

Cooler Type	Efficiency level	kWh Savings	kW Savings
Cold only	Non-ENERGY STAR	46	0.00
	ENERGY STAR	28	0.00
Hot/Cold	Non-ENERGY STAR	251	0.00
	ENERGY STAR	159	0.00

2.2.5.5 Incremental Cost

The incremental cost for a digital weekly timer controller, inclusive of install cost, is $24.46 for mail-by-request and $22.13 for direct install[230].

2.2.5.6 Future Studies

There are currently no future studies planned for this measure at this time.

[229] "EUL_Summary_10-1-08.xlsx" (available at http://www.deeresources.com/)

[230] https://nwcouncil.box.com/v/ComWaterCoolerTimerv2-0

2.3 Heating, Ventilation & Air Conditioning

2.3.1 PACKAGED TERMINAL AC/HP EQUIPMENT

2.3.1.1 Measure Description

This measure requires the installation of a PTAC or PTHP. AHRI Test Standard 310/380-2004 defines a PTAC or PTHP as "a wall sleeve and a separate non-encased combination of heating and cooling assemblies specified by the manufacturer and intended for mounting through the wall. It includes refrigeration components, separable outdoor louvers, forced ventilation, and heating availability by purchaser's choice of, at least, hot water, steam, or electrical resistance heat." These definitions are consistent with federal code (10 CFR Part 431.92).

PTAC/PTHP equipment is available in standard and non-standard sizes. Standard size refers to PTAC/PTHP equipment with wall sleeve dimensions having an external opening greater than or equal to 16 inches high or greater than or equal to 42 inches wide, and a cross-sectional area greater than or equal to 672 square inches. Non-standard size refers to PTAC/PTHP equipment with existing wall sleeve dimensions having an external wall opening of less than 16 inches high or less than 42 inches wide, and a cross-sectional area less than 672 square inches.

2.3.1.2 Baseline and Efficiency Standards

The baseline for units that are used in new construction or are replaced on burnout is energy code IECC 2021, which goes into effect in Louisiana on July 1, 2023. The baseline for early replacement is the previous Louisiana energy code, IECC 2009.

IECC 2021 leverages new DOE testing methods and associated metrics. The following conversion factors are recommended for use if the efficient equipment is not rated under the new testing procedure, but the stipulated baseline is:[231]

$$SEER2 = SEER \times Conversion\ Factor$$

$$EER2 = EER \times Conversion\ Factor$$

$$HSPF2 = HSPF \times Conversion\ Factor$$

Where:

Table 2-27: Efficiency Rating Conversion Factors (Ducted and Ductless)

System Type	SEER2	EER2	HSPF2
Ducted	0.95	0.95	0.91
Ductless	1.00	1.00	0.95
Packaged	0.95	0.95	0.84

[231] Consortium for Energy Efficiency (CEE), Testing, Testing, M1, 2, 3, Transitioning to New Federal Minimum Standards, CEE Summer Program Meeting, June 10, 2022.

Table 2-28 displays relevant NC and ROB baselines.

Table 2-28 PTAC/PTHP Equipment – Baseline Efficiency Levels

Equipment Type	Operation Mode	Size	Capacity	Minimum Efficiency
PTAC	Cooling Mode	Standard Size	< 7,000	EER = 11.9
			7,000 – 15,000	EER = 14.0 – (0.300 x CAP/1,000)
			> 15,000	EER = 9.5
		Nonstandard Size	< 7,000	EER = 9.4
			7,000 – 15,000	EER = 10.9 – (0.213 x CAP/1,000)
			> 15,000	EER = 7.7
PTHP	Cooling Mode	Standard Size	< 7,000	EER = 11.9
			7,000 – 15,000	EER = 14.0 – (0.300 x CAP/1,000)
			> 15,000	EER = 9.5
		Nonstandard Size	< 7,000	EER = 9.3
			7,000 – 15,000	EER = 10.8 – (0.213 x CAP/1,000)
			> 15,000	EER = 7.6
PTHP	Heating Mode	Standard Size	< 7,000	COP = 3.3
			7,000 – 15,000	COP = 3.7 – (0.052 x CAP/1,000)
			> 15,000	COP = 2.90
		Nonstandard Size	< 7,000	COP = 2.7
			7,000 – 15,000	COP = 2.9 – (0.026 x CAP/1,000)
			> 15,000	COP = 2.5

2.3.1.3 *Estimated Useful Life*

The EUL of the measure is 10 years in accordance with the DOE Packaged Terminal Air Conditioners and Heat Pumps Energy Conservation Standard Technical Support Document.[232]

2.3.1.4 *Deemed Savings Values*

For the deemed savings values, the TPE assume a Standard size category, and a capacity of 11,000 BTU (midpoint of the central size category) and a 13 EER/3.4 COP system.

[232] U.S. DOE, Technical Support Document: "*Packaged Terminal Air Conditioners and Heat Pumps, 3.2.7 Equipment Lifetime*". http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/45.

Table 2-29 Deemed Savings by Building Type - PTAC

Building Type	kWh	kW
Fast Food	432	0.142
Grocery	278	0.164
Health Clinic	362	0.155
Large Office	270	0.153
Lodging	381	0.140
Full Menu Restaurant	363	0.155
Retail	580	0.160
School	424	0.129
Small Office	375	0.153
University	275	0.153
Unknown	432	0.142

Table 2-30 Deemed Savings by Building Type - PTHP

Building Type	kWh	kW
Fast Food	507	0.142
Grocery	320	0.164
Health Clinic	394	0.155
Large Office	378	0.153
Lodging	494	0.140
Full Menu Restaurant	409	0.155
Retail	722	0.160
School	462	0.129
Small Office	445	0.153
University	442	0.153
Unknown	507	0.142

Deemed peak demand and annual energy savings for PTAC/PTHP equipment should be calculated using the following formulas.

$$kWh_{Savings,PTAC} = CAP_C \times \frac{1\ kW}{1{,}000\ W} \times EFLH_C \times \left(\frac{1}{\eta_{base}} - \frac{1}{\eta_{post}}\right)$$

$$kWh_{Savings,PTHP,C} = CAP_C \times \frac{1\ kW}{1{,}000\ W} \times EFLH_C \times \left(\frac{1}{\eta_{base,C}} - \frac{1}{\eta_{post,C}}\right)$$

$$kWh_{Savings,PTHP,H} = CAP_H \times \frac{1\ kWh}{3{,}412\ \mathrm{BTU}} \times EFLH_H \times \left(\frac{1}{\eta_{base,H}} - \frac{1}{\eta_{post,H}}\right)$$

$$kW_{Savings} = CAP_C \times \frac{1\ kW}{1{,}000\ W} \times \left(\frac{1}{\eta_{base}} - \frac{1}{\eta_{post}}\right) \times CF$$

Where:

CAP_C= Rated equipment cooling capacity of the new unit (BTU/hr.)

CAP_H= Rated equipment heating capacity of the new unit (BTU/hr.)

$\eta base$,C = Baseline energy efficiency rating of the baseline cooling equipment (EER)

$\eta post$,C = Nameplate energy efficiency rating of the installed cooling equipment (EER)

$\eta post$,H = Nameplate energy efficiency rating of the installed heating equipment (COP)

Note: heating efficiencies expressed as a heating seasonal performance factor (HSPF) will need to be converted to a coefficient of performance (COP) using the following equation:

$$\text{COP} = \frac{HSPF}{3.412}$$

3.412 = Constant to convert from BTU/hr. to kWh

CF= Coincidence factor (Table 2-31)

EFLHc = Equivalent full-load hours for cooling (Table 2-31)

EFLHh= Equivalent full-load hours for heating (Table 2-31)

Table 2-31 Equivalent Full-Load Hours by Building Type

Building Type	**$EFLH_C$**	**$EFLH_H$**	**Coincidence Factor**
Fast Food	2,375	272	0.78
Grocery	1,526	153	0.90
Health Clinic	1,989	115	0.85
Large Office	1,483	392	0.84
Lodging	2,095	409	0.77
Full Menu Restaurant	1,997	166	0.85
Retail	3,191	513	0.88
School	2,329	140	0.71
Small Office	2,060	255	0.84
University	1,510	604	0.84

2.3.1.5 Incremental Cost

The incremental cost for this equipment is $84/ton[233]. The average tonnage is assumed to be .92 if unknown, resulting in an incremental cost of $77.

2.3.1.6 Future Studies

Though eligible for Energy Smart, this measure has had little-to-no participation. Until such time as participation produces a minimum of 500,000 kWh in a program year, it is recommended that updates be limited to those needed to reflect code changes. If this threshold is met, we recommend focusing M&V to update EFLH estimates.

[233] DEER 2014.

2.3.2 UNITARY AND SPLIT SYSTEM AC/HP EQUIPMENT

2.3.2.1 Measure Description

This measure requires the installation of packaged or split system air conditioners (AC) or heat pumps (HP), excluding PTACs/PTHPs. Unitary or split system ACs/HPs consist of one or more factory-made assemblies that normally include an evaporator or cooling coil(s), compressor(s), and condenser(s). They provide the function of air cooling, and may include the functions of air heating, air circulation, air cleaning, dehumidifying, or humidifying.

2.3.2.2 Baseline and Efficiency Standards[234]

The baseline for units that are used in new construction or are replaced on burnout is energy code IECC 2021, which goes into effect in Louisiana on July 1, 2023. The baseline for early replacement is the previous Louisiana energy code, IECC 2009.

IECC 2021 leverages new DOE testing methods and associated metrics. The following conversion factors are recommended for use if the efficient equipment is not rated under the new testing procedure, but the stipulated baseline is:[235]

$$SEER2 = SEER \times Conversion\ Factor$$

$$EER2 = EER \times Conversion\ Factor$$

$$HSPF2 = HSPF \times Conversion\ Factor$$

Where:

Table 2-32 Efficiency Rating Conversion Factors[236]

System Type	SEER2	EER2	HSPF2
Ducted	0.95	0.95	0.91
Ductless	1.00	1.00	0.95
Packaged	0.95	0.95	0.84

The table below shows the new minimum efficiency levels. All types are Split System and Package System unless otherwise noted.

---

[234] 2010 U.S. Code: Title 42, Chapter 77, Subchapter III, Part A-1, Section 6313.

[235] Consortium for Energy Efficiency (CEE), Testing, Testing, M1, 2, 3, Transitioning to New Federal Minimum Standards, CEE Summer Program Meeting, June 10, 2022.

[236] IECC 2012, Table C403.2.3(1) & C403.2.3(2); full-load efficiencies consistent with ASHRAE 90.1-2010, Table 6.8.1A & 6.8.1B and compliant with the federal standard.

Table 2-33 Unitary AC/HP Equipment – Baseline Efficiency Levels[237]

Equipment Type	Capacity (Btu/h)	Heating Section Type	Minimum Efficiency
Air Conditioners, Air Cooled	<65,000	All	13.4 SEER2
	≥65,000 & <135,000	Electric Resistance (or none)	11.2 EER
			14.8 IEER
		All Other	11 EER
			14.6 IEER
	≥ 135,000 & <240,000	Electric Resistance (or none)	11 EER
			14.2 IEER
		All Other	10.8 EER
			14 IEER
	≥240,000 & <760,000	Electric Resistance (or none)	10 EER
			13.2 IEER
		All Other	9.8 EER
			13 IEER
	≥760,000	Electric Resistance (or none)	9.7 EER
			12.5 IEER
		All Other	9.5 EER
			12.3 IEER
Air Conditioners, Water Cooled	<65,000	All	12.1 EER
			12.3 IEER
	≥65,000 & <135,000	Electric Resistance (or none)	12.1 EER
			13.9 IEER
		All Other	11.9 EER
			13.7 IEER
	≥ 135,000 & <240,000	Electric Resistance (or none)	12.5 EER
			13.9 IEER
		All Other	12.3 EER
			13.7 IEER
	≥240,000 & <760,000	Electric Resistance (or none)	12.4 EER
			13.6 IEER
		All Other	12.2 EER
			13.4 IEER
	≥760,000	Electric Resistance (or none)	12.2 EER
			13.5 IEER
		All Other	12 EER
			13.3 IEER
Air Conditioners, Evaporatively Cooled	<65,000	All	12.1 EER
			12.3 IEER
	≥65,000 & <135,000	Electric Resistance (or none)	12.1 EER
			12.3 IEER
		All Other	11.9 EER
			12.1 IEER

[237] IECC 2021, Table C403.2.3(1) & C403.2.3(2.

Equipment Type	Capacity (Btu/h)	Heating Section Type	Minimum Efficiency
	≥ 135,000 & <240,000	Electric Resistance (or none)	12 EER
			12.2 IEER
		All Other	11.8 EER
			12.2 IEER
	≥240,000 & <760,000	Electric Resistance	11.9 EER
			12.1 IEER
		All Other	11.7 EER
			11.9 IEER
	≥760,000	Electric Resistance	11.7 EER
			11.9 IEER
		All Other	11.5 EER
			11.7 IEER
Heat Pumps, Air Cooled (Cooling Mode)	<65,000	All	14.3 SEER2[238]
			13.4 SEER2[239]
	≥65,000 & <135,000	Electric Resistance	11 EER
			14.1 IEER
		All Other	10.8 EER
			13.9 IEER
	≥ 135,000 & <240,000	Electric Resistance	10.6 EER
			13.5 IEER
		All Other	10.4 EER
			13.3 IEER
	≥240,000 & <760,000	Electric Resistance	9.5 EER
			12.5 IEER
		All Other	9.3 EER
			12.3 IEER
Heat Pumps, Air Cooled (Heating Mode)	<65,000	All	7.5 HSPF2
			6.7 HSPF2
	≥65,000 & <135,000		3.4 COP[240]
			2.25 COP[241]
	≥ 135,000 & <240,000		3.3 COP[240]
			2.05 COP[241]
	≥240,000 & <760,000		3.2 COP[240]
			2.05 COP[241]

2.3.2.3 *Estimated Useful Life*

According to the DEER 2014 the EUL for this measure is 15 years.

[238] Split

[239] Package

[240] 47° db/43°F wb

[241] 17° db/15°F wb

2.3.2.4 Deemed Savings Values

Deemed peak demand and annual energy savings for unitary AC and HP equipment should be calculated as shown below. Note that these savings calculations are different depending on whether the measure is replace-on-burnout or early retirement.[242]

$$kWh_{Savings,AC} = CAP \times \frac{1\ kW}{1{,}000\ W} \times EFLH_C \times \left(\frac{1}{\eta_{base}} - \frac{1}{\eta_{post}}\right)$$

$$kWh_{Savings,HP} = CAP \times \frac{1\ kW}{1{,}000\ W} \times \left[\left(\frac{EFLH_C}{\eta_{base,AC}} + \frac{EFLH_H}{\eta_{base,HP}}\right) - \left(\frac{EFLH_C}{\eta_{post,AC}} + \frac{EFLH_H}{\eta_{post,HP}}\right)\right]$$

$$kW_{Savings} = CAP \times \frac{1\ kW}{1{,}000\ W} \times \left(\frac{1}{\eta_{base}} - \frac{1}{\eta_{post}}\right) \times CF$$

Where:

CAP = Rated equipment cooling capacity of the new unit (BTU/hr)

$\eta_{base,AC/HP}$ = Baseline energy efficiency rating of the cooling/heating equipment (Table 2-33)

$\eta_{post,AC/HP}$= Nameplate energy efficiency rating of the installed cooling/heating equipment

Note: Use EER for kW savings calculations and SEER/IEER and HSPF for kWh savings calculations.

CF = Coincidence factor (

Table 2-34)

$EFLH_c$ = Equivalent full-load hours for cooling (

[242] Early retirement baseline efficiencies differ because they are based on energy code IECC 2009 and new construction and replace on burnout projects are based on energy code IECC 2021.

Table 2-34)

$EFLH_h$ = Equivalent full-load hours for heating (

Table 2-34)

Table 2-34 Equivalent Full-Load Hours by building type

Building Type	**$EFLH_C$**	**$EFLH_H$**	**Coincidence Factor**
Fast Food	2,375	272	0.78
Grocery	1,526	153	0.90
Health Clinic	1,989	115	0.85

Large Office	1,483	392	0.84
Lodging	2,095	409	0.77
Full Menu Restaurant	1,997	166	0.85
Retail	3,191	513	0.88
School	2,329	140	0.71
Small Office	2,060	255	0.84
University	1,510	604	0.84

2.3.2.5 Incremental Cost

Incremental cost is detailed in Table 2-35 below.

Table 2-35 Unitary AC Incremental Cost

Capacity	**Cost Per Ton per 1.0 SEER above 14.0**
65,000 Btuh or less	$82
65,000 to 240,000 Btuh	$48
240,000 to 760,000 Btuh	$180
760,000 Btuh or more	$181

2.3.2.6 Future Studies

Though eligible for Energy Smart, this measure has had little-to-no participation. Until such time as participation produces a minimum of 500,000 kWh in a program year, it is recommended that updates be limited to those needed to reflect code changes. If this threshold is met, we recommend focusing M&V to update EFLH estimates.

2.3.3 AIR- AND WATER-COOLED CHILLERS

2.3.3.1 Measure Description

This measure requires the installation of any air-cooled or water-cooled chilling package, referred to as a chiller. AHRI Test Standard 550/590-2003 defines a water-chilling package as “a factory-made and prefabricated assembly of one or more compressor, condensers, and evaporators, with interconnections and accessories, designed for the purpose of cooling water. It is a machine specifically designed to make use of a vapor compression refrigeration cycle to remove heat from water and reject the heat to a cooling medium, usually air or water.”

The most common applications are for larger cooling loads (e.g., 50 to 100 tons and greater). Chiller types include centrifugal, rotary, screw, scroll, reciprocating, and gas absorption. Absorption chillers are subject to a different AHRI test standard and not reviewed as part of this analysis. When a water-cooled chiller is replacing an air-cooled chiller, the additional auxiliary electrical loads for the condenser water pump and the cooling tower fan have to be considered. Thus, a penalty factor is necessary as a downward adjustment to account for the peak demand and energy savings.

To qualify, the chiller must serve an HVAC load. Chillers used as part of industrial processes require custom analysis.

2.3.3.2 Baseline and Efficiency Standards

The baseline for units that are used in new construction or are replaced on burnout is the current state minimum standard[243] (Table 2-36). Two different paths are proposed. Path A involves installing a chiller that optimizes demand reduction (optimizes EER) whereas Path B involves optimizing total energy savings (optimizes IPLV). If the design path is unknown, use Path A efficiencies or deemed savings values.

Table 2-36 Chillers – Baseline Efficiency Levels for Chilled Water Packages[244]

Equipment Type	Chiller Type	Capacity (Tons)	Path A		Path B	
			IPLV (kW/TON)	EER (kW/Ton)	IPLV (kW/TON)	EER (kW/Ton)
Air Cooled	All	<150	0.960	1.255	0.960	1.255
		≥ 150	0.941	1.255	0.941	1.255
Water Cooled	Rotary/ Screw/Scroll/ Reciprocating	< 75	0.630	0.780	0.600	0.800
		≥ 75 and < 150	0.615	0.775	0.586	0.790
		≥ 150 and < 300	0.580	0.680	0.540	0.718
		≥ 300	0.540	0.620	0.490	0.639
Water Cooled	Centrifugal	< 300	0.596	0.634	0.450	0.639
		≥ 300 and < 600	0.549	0.576	0.400	0.600
		≥ 600	0.539	0.570	0.400	0.590

243 IECC 2009

244 The values in the table reflect IECC 2009, Table 503.2.3(7).

2.3.3.3 *Estimated Useful Life*

For high-efficiency chillers according to the DEER 2014 the EUL is 20 years.

2.3.3.4 *Deemed Savings Values*

This measure has significant variability in equipment capacity and thus a per-unit savings value is not likely to be usable by program administrators. Due to this we present savings in a per-ton basis, assuming IECC 2009 efficiencies are the baseline, and the proposed efficiencies are 10% better than the federal minimum EER and IPLV values[245,246].

Table 2-37 Deemed Savings – Air-Cooled Chillers

Building Type	Capacity (Tons)	Path A		Path B	
		Energy (kWh/Ton)	**Demand (kW/Ton)**	**Energy (kWh/Ton)**	**Demand (kW/Ton)**
Fast Food	<150	408	0.169	658	0.110
	> 150	403	0.177	642	0.110
Grocery	<150	262	0.195	423	0.127
	> 150	259	0.204	413	0.127
Health Clinic	<150	341	0.184	551	0.120
	> 150	338	0.192	538	0.120
Large Office	<150	255	0.182	411	0.119
	> 150	252	0.190	401	0.119
Lodging	<150	360	0.167	580	0.109
	> 150	356	0.174	566	0.109
Full Menu Restaurant	<150	343	0.184	553	0.120
	> 150	339	0.192	540	0.120
Retail	<150	548	0.191	884	0.125
	> 150	542	0.199	863	0.125
School	<150	400	0.154	645	0.101
	> 150	395	0.161	630	0.101
Small Office	<150	354	0.182	570	0.119
	> 150	350	0.190	557	0.119
University	<150	259	0.182	418	0.119
	> 150	256	0.190	408	0.119

[245] https://www.energy.gov/eere/femp/purchasing-energy-efficient-air-cooled-electric-chillers

[246] https://www.energy.gov/eere/femp/purchasing-energy-efficient-water-cooled-electric-chillers

Table 2-38 Deemed Savings – Water-Cooled Chillers – Positive Displacement[247]

Building Type	Capacity (Tons)	Path A		Path B	
		Energy (kWh/Ton)	Demand (kW/Ton)	Energy (kWh/Ton)	Demand (kW/Ton)
Fast Food	< 75	214	0.092	356	0.076
	> 75 and < 150	264	0.099	344	0.090
	> 150 and < 300	223	0.073	342	0.083
	> 300	192	0.073	319	0.060
Grocery	< 75	137	0.106	229	0.088
	> 75 and < 150	169	0.114	221	0.104
	> 150 and < 300	143	0.085	220	0.095
	> 300	124	0.084	205	0.069
Health Clinic	< 75	179	0.100	298	0.083
	> 75 and < 150	221	0.108	288	0.098
	> 150 and < 300	187	0.080	286	0.090
	> 300	161	0.079	268	0.065
Large Office	< 75	133	0.099	222	0.082
	> 75 and < 150	165	0.107	215	0.097
	> 150 and < 300	139	0.079	214	0.089
	> 300	120	0.079	199	0.064
Lodging	< 75	189	0.091	314	0.075
	> 75 and < 150	233	0.098	304	0.089
	> 150 and < 300	197	0.072	302	0.082
	> 300	170	0.072	282	0.059
Full Menu Restaurant	< 75	180	0.100	300	0.083
	> 75 and < 150	222	0.108	290	0.098
	> 150 and < 300	188	0.080	288	0.090
	> 300	162	0.079	269	0.065
Retail	< 75	287	0.103	479	0.086
	> 75 and < 150	354	0.112	463	0.101
	> 150 and < 300	300	0.083	460	0.093
	> 300	258	0.082	429	0.067
School	< 75	210	0.083	349	0.070
	> 75 and < 150	259	0.090	338	0.082
	> 150 and < 300	219	0.067	335	0.075
	> 300	189	0.066	313	0.054
Small Office	< 75	185	0.099	309	0.082
	> 75 and < 150	229	0.107	299	0.097
	> 150 and < 300	194	0.079	297	0.089
	> 300	167	0.079	277	0.064
University	< 75	136	0.099	227	0.082
	> 75 and < 150	168	0.107	219	0.097
	> 150 and < 300	142	0.079	217	0.089

[247] Rotary/Screw/Scroll/Reciprocating

	> 300	122	0.079	203	0.064

Table 2-39 Deemed Savings – Water-Cooled Chillers – Centrifugal

Building Type	**CAP**	**Path A**		**Path B**	
		Energy (kWh/Ton)	**Demand (kW/Ton)**	**Energy (kWh/Ton)**	**Demand (kW/Ton)**
Fast Food	< 300	240	0.066	171	0.032
	> 300 and < 600	214	0.056	127	0.054
	> 600	211	0.051	138	0.050
Grocery	< 300	154	0.077	110	0.036
	> 300 and < 600	137	0.065	82	0.062
	> 600	136	0.059	89	0.057
Health Clinic	< 300	201	0.072	143	0.034
	> 300 and < 600	179	0.061	106	0.059
	> 600	177	0.056	115	0.054
Large Office	< 300	150	0.071	107	0.034
	> 300 and < 600	133	0.060	79	0.058
	> 600	132	0.055	86	0.053
Lodging	< 300	212	0.065	151	0.031
	> 300 and < 600	189	0.055	112	0.053
	> 600	186	0.051	122	0.049
Full Menu Restaurant	< 300	202	0.072	144	0.034
	> 300 and < 600	180	0.061	107	0.059
	> 600	178	0.056	116	0.054
Retail	< 300	322	0.075	230	0.036
	> 300 and < 600	287	0.063	171	0.061
	> 600	284	0.058	185	0.056
School	< 300	235	0.060	168	0.029
	> 300 and < 600	210	0.051	125	0.049
	> 600	207	0.047	135	0.045
Small Office	< 300	208	0.071	148	0.034
	> 300 and < 600	185	0.060	110	0.058
	> 600	183	0.055	119	0.053
University	< 300	153	0.071	109	0.034
	> 300 and < 600	136	0.060	81	0.058
	> 600	134	0.055	88	0.053

Deemed peak demand and annual energy savings for chillers should be calculated using the following formulas:

$$kW_{Savings} = CAP \times (\eta_{base} - \eta_{post}) \times CF$$

$$kWh_{savings} = CAP \times EFLH_C \times (\eta_{base} - \eta_{post})$$

Where:

CAP = Rated equipment cooling capacity of the new unit (Tons)

η_{base} = Baseline energy efficiency rating of the baseline cooling equipment (kW/ton or EER converted to kW/ton)

η_{post}= Nameplate energy efficiency rating of the installed cooling equipment (kW/ton)

Note: use full-load efficiency (in units of kW/ton) for kW savings calculations and IPLV (in units of kW/ton) for kWh savings calculations. Cooling efficiencies expressed as an EER will need to be converted to kW/ton using the equation below.

$$\frac{kW}{Ton} = \frac{12}{EER}$$

CF= Coincidence factor (Table 2-40)

$EFLH_c$= Equivalent full-load hours for cooling (Table 2-40)

$EFLH_h$= Equivalent full-load hours for heating (Table 2-40)

Table 2-40 Equivalent Full-Load Hours by Building type

Building Type	**$EFLH_C$**	**$EFLH_H$**	**Coincidence Factor**
Fast Food	2,375	272	0.78
Grocery	1,526	153	0.90
Health Clinic	1,989	115	0.85
Large Office	1,483	392	0.84
Lodging	2,095	409	0.77
Full Menu Restaurant	1,997	166	0.85
Retail	3,191	513	0.88
School	2,329	140	0.71
Small Office	2,060	255	0.84
University	1,510	604	0.84

2.3.3.5 Incremental Cost

Incremental cost is detailed in Table 2-41 below.

Table 2-41 Chiller Incremental Cost

Equipment Type	Capacity	Cost Per Ton
Air-cooled	All capacities	\$127/ton[248]
Water-cooled – reciprocating	All capacities	\$22/ton[249]
Water-cooled – rotary & scroll	< 150 tons	\$351/ton[250]
	>=150 and < 300 tons	\$127/ton
	>= 300 tons	\$87/ton

2.3.3.6 Future Studies

This is a low-volume, high-savings measure. The TPE recommends that chiller projects be flagged for IPMVP Option C or D analysis when they occur.

[248] 2008 Database for Energy-Efficiency Resources (DEER), Version 2008.2.05, "Cost Values and Summary Documentation", California Public Utilities Commission, December 16, 2008. Calculated as the simple average of screw and reciprocating air-cooled chiller incremental costs from DEER2008. This assumes that baseline shift from IECC 2012 to IECC 2015 carries the same incremental costs. Values should be verified during evaluation

[249] 2008 Database for Energy-Efficiency Resources (DEER), Version 2008.2.05, "Cost Values and Summary Documentation"

[250] Incremental costs for water-cooled, positive displacement (rotary screw and scroll) from the W017 Itron California Measure Cost Study, accessed via http://www.energydataweb.com/cpuc/search.aspx. The data is provided in a file named "MCS Results Matrix – Volume I".

2.3.4 AIR CONDITIONER AND HEAT PUMP TUNE-UP

2.3.4.1 Measure Description

This measure applies to central air conditioners and heat pumps. An AC tune-up, in general terms, involves checking, adjusting, and resetting the equipment to factory conditions, such that it operates closer to the performance level of a new unit. For this measure, the service technician must complete the following tasks according to industry best practices:

- Inspect and clean condenser, evaporator coils, and blower.
- Inspect refrigerant level and adjust to manufacturer specifications.
- Measure the static pressure across the cooling coil to verify adequate system airflow and adjust to manufacturer specifications.
- Inspect, clean, or change air filters.
- Calibrate thermostat on/off setpoints based on building occupancy.
- Tighten all electrical connections, and measure voltage and current on motors.
- Lubricate all moving parts, including motor and fan bearings.
- Inspect and clean the condensate drain.
- Inspect controls of the system to ensure proper and safe operation. Check the starting cycle of the equipment to assure the system starts, operates, and shuts off properly.
- Provide documentation showing completion of the above checklist to the utility or the utility's representative.

2.3.4.2 Baseline and Efficiency Standards

The baseline is a system with demonstrated imbalances of refrigerant charge.

After the tune-up, the equipment must meet airflow and refrigerant charge requirements. To ensure the greatest savings when conducting tune-up services, the eligibility minimum requirement for airflow is the manufacturer specified design flow rate, or 350 CFM/ton, if unknown. Also, the refrigerant charge must be within +/- 3 degrees of target sub-cooling for units with thermal expansion valves (TXV) and +/- 5 degrees of target super heat for units with fixed orifices or a capillary.

The efficiency standard, or efficiency after the tune-up, is assumed to be the manufacturer specified energy efficiency ratio (EER) of the existing central air conditioner or heat pump. The efficiency improvement resulting from the refrigerant charge adjustment depends on the pre-adjustment refrigerant charge.

2.3.4.3 Estimated Useful Life

According to DEER 2014 the EUL for refrigerant charge correction is 10 years.

2.3.4.4 Deemed Savings Values

This measure has significant variability in equipment capacity and thus a per-unit savings value is not likely to be usable by program administrators. Due to this we present savings in a per-ton basis. Savings assume a 15% efficiency loss.

Table 2-42 Deemed Savings by Building Type – Commercial AC Tune-up

Building Type	**kWh/Ton**	**kW/Ton**
Fast Food	457	0.1502
Grocery	294	0.1733
Health Clinic	383	0.1636
Large Office	285	0.1617
Lodging	403	0.1482
Full Menu Restaurant	384	0.1636
Retail	614	0.1694
School	448	0.1367
Small Office	397	0.1617
University	291	0.1617
Unknown	396	0.159

Table 2-43 Deemed Savings by Building Type – Commercial Heat Pump Tune-up

Building Type	**kWh/Ton**	**kW/Ton**
Fast Food	538	0.1529
Grocery	340	0.1765
Health Clinic	420	0.1667
Large Office	395	0.1647
Lodging	519	0.151
Full Menu Restaurant	436	0.1667
Retail	761	0.1725
School	494	0.1392
Small Office	471	0.1647
University	456	0.1647
Unknown	483	0.162

Deemed peak demand and annual energy savings for unitary AC/HP tune-up should be calculated using the following formulas.

$$kW_{savings,C} = CAP_C \times \frac{1\ kW}{1{,}000\ W} \times \left(\frac{1}{EER_{pre}} - \frac{1}{EER_{post}}\right) \times CF$$

$$kWh_{savings,C} = CAP_C \times \frac{1\ kW}{1{,}000\ W} \times EFLH_C \times \left(\frac{1}{EER_{pre}} - \frac{1}{EER_{post}}\right)$$

$$kWh_{savings,H} = CAP_H \times \frac{1\ kW}{1{,}000\ W} \times EFLH_H \times \left(\frac{1}{HSPF_{pre}} - \frac{1}{HSPF_{post}}\right)$$

$$kWh_{savings,AC} = kWh_{savings,C}$$

$$kWh_{savings,HP} = kWh_{savings,C} + kWh_{savings,H}$$

Where:

CAP_c= Rated equipment cooling capacity (BTU/hr.)

CAP_h= Rated equipment heating capacity (BTU/hr.)

EER_{pre}= Adjusted efficiency of the equipment for cooling before tune-up (BTU/watt-hr)

EER_{post}= Nameplate efficiency of the existing equipment for cooling; if unknown, use default EER value (BTU/watt-hr) in Table 2-46 and Table 2-47.

Note: Site measurements may be substituted for EER_{pre} and EER_{post}, if the measurements are taken on the same site visit and under similar operating conditions using reliable, industry accepted techniques. If used for measures other than refrigerant charge, then the implementer should use an EUL of three years.

$HSPF_{pre}$ = Efficiency of the equipment for heating before tune-up (BTU/watt-hr)

$HSPF_{post}$ = Nameplate efficiency of the existing equipment for heating; if unknown, use default HSPF value from Table 2-48 (BTU/watt-hr)

CF = Coincidence factor (Table 2-50)

$EFLH_c$= Equivalent full-load hours for cooling (Table 2-49)

$EFLH_h$= Equivalent full-load hours for heating (Table 2-49)

The adjusted EER_{pre} can be calculated using the following equation.

$$EER_{pre} = (1 - EL) * EER_{post}$$

Where:

EL = Efficiency Loss (Fixed Orifice: Table 2-44; TXV:

Table 2-45) determined by averaging efficiency losses from multiple studies.[251,252,253,254,255] Interpolation is allowed, extrapolation is not allowed.

Using the COP, HSPF and EER can be calculated by multiplying the COP by 3.413.

Table 2-44 Efficiency Loss Percentage by Refrigerant Charge Level (Fixed Orifice)

% Charged	EL
≤ 70	0.37
75	0.29
80	0.20

[251] Architectural Energy Corporation, managed by New Buildings Institute. “Small HVAC System Design Guide.” Prepared for the California Energy Commission. October 2003. Figure 11.

[252] Davis Energy Group. “HVAC Energy Efficiency Maintenance Study,” California Measurement Advisory Council (CALMAC). December 29, 2010. Figure 14.

[253] Proctor Engineering Group. “Innovative Peak Load Reduction Program CheckMe! Commercial and Residential AC Tune-Up Project.” California Energy Commission. November 6, 2003. Table 6-3.

[254] Proctor Engineering Group. PEG Tune-Up Calculations spreadsheet.

[255] Pennsylvania Technical Reference Manual (TRM). June 2012. Measure 3.3.2, Table 3-96.

85	0.15
90	0.10
95	0.05
100	0.00
> 120	0.03

Table 2-45 Efficiency Loss Percentage by Refrigerant Charge Level (TXV)

% Charged	**EL**
< 70	0.12
75	0.09
80	0.07
85	0.06
90	0.05
95	0.03
100	0.00
> 120	0.04

Table 2-46 Default Air Conditioner EER per Size Category[256]

Size Category (BTU/hr.)	**EER (BTU/watt-hr)**[257]
< 65,000	11.0
> 65,000 and < 135,000	10.8
> 135,000 and < 240,000	9.8
> 240,000 and < 760,000	9.5

Table 2-47 Default Heat Pump EER per Size Category[258]

Size Category (BTU/hr.)	**EER (BTU/watt-hr)**
< 65,000	11.8
> 65,000 and < 135,000	10.8
> 135,000 and < 240,000	10.4
> 240,000	9.3

$$HSPF_{pre} = (HSPF_{post}) \times (1 - M)^{age}$$

Where:

> $HSPF_{post}$= HSPF of pre-tune up equipment when new (use nameplate or default value from Table 2-48)

---

[256] Code specified SEER or EER value from 2013 Addenda to ASHRAE 90.1-2010 (efficiency value effective January 1, 2015 for units < 65,000 Btu/hr and prior to January 1, 2010 for units > 65,000 Btu/hr).

[256] Code specified SEER or EER value from ASHRAE 90.1-2010 (efficiency value effective January 1, 2015

[257] SEER values converted to EER using EER = -0.02 x SEER^2 + 1.12 x SEER. National Renewable Energy Laboratory (NREL). "Building America House Simulation Protocols." U.S. DOE. Revised October 2010. http://www.nrel.gov/docs/fy11osti/49246.pdf.

[258] Code specified SEER or EER value from 2013 Addenda to ASHRAE 90.1-2010 (efficiency value effective January 1, 2015 for units < 65,000 Btu/hr and prior to January 1, 2010 for units > 65,000 Btu/hr).

M = Maintenance factor[259], use 0.01 if annual maintenance conducted or 0.03 if maintenance is seldom

Age = Age of equipment in years, up to a maximum of 20 years, use a default of 10 years if unknown.

Table 2-48 Default Heat Pump HSPF per Size Category[260]

Size Category (BTU/hr.)	Subcategory or Rating Condition	Default HSPF[261]
< 65,000	Split System	8.2
	Single Package	8.0
≥ 65,000 and < 135,000	47°F db/43°F wb Outdoor Air	11.3
	17°F db/15°F wb Outdoor Air	7.7
≥ 135,000	47°F db/43°F wb Outdoor Air	10.9
	17°F db/15°F wb Outdoor Air	7.0

Table 2-49 Equivalent Full-Load Hours by Building Type

Building Type	$EFLH_C$	$EFLH_H$
Fast Food	2,375	272
Grocery	1,526	153
Health Clinic	1,989	115
Large Office	1,483	392
Lodging	2,095	409
Full Menu Restaurant	1,997	166
Retail	3,191	513
School	2,329	140
Small Office	2,060	255
University	1,510	604
Unknown	2,056	268

Table 2-50 Commercial Coincidence Factors by Building Type[262]

Building Type	Coincidence Factor
Fast Food	0.78
Grocery	0.90
Health Clinic	0.85
Large Office	0.84
Lodging	0.77
Full Menu Restaurant	0.85

[259] "Building America House Simulation Protocols." U.S. DOE. Revised October 2010. Table 32. Page 40. http://www.nrel.gov/docs/fy11osti/49246.pdf.

[260] Code specified HSPF or COP value from 2013 Addenda to ASHRAE 90.1-2010 (efficiency value effective January 1, 2015 for units < 65,000 Btu/hr and prior to January 1, 2010 for units > 65,000 Btu/hr).

[261] COP values converted to HSPF using COP=HSPF÷3.412

[262] Values for Assembly and Religious Worship building types developed using an adjustment factor derived through a comparison of average CFs for College/University and Assembly/Religious Worship building types from the Texas state Technical Reference Manual. College/University was selected as a reference building type due to average alignment with Assembly/Religious worship building types in other TRMs, inclusion of a summer session, and increased evening usage.

Retail	0.88
School	0.71
Small Office	0.84
College	0.84
Unknown	0.83

2.3.4.4.1 Partial Savings Based on Tune Up Component

Partial savings may be claimed if the tune-up does not require all components (e.g., a coil cleaning is required but a refrigerant charge correction is not). These are additive if condenser cleaning, evaporator cleaning and refrigerant charge correction are performed. See the table below.

Table 2-51 Savings by Component[263]

Tune-Up Component	**% Savings**
Condenser Cleaning	6.10%
Evaporator Cleaning	0.22%
Refrigerant Charge Off. ≤ 20%	0.68%
Refrigerant Charge Off. > 20%	8.44%
Combined (Refrigerant Off. ≤ 20%)	7.00%
Combined (Refrigerant Off.> 20%)	14.76%

2.3.4.5 Incremental Cost

Full project cost should be used. If not available, use $35/ton[264].

2.3.4.6 Future Studies

The incremental cost value is very sensitive to labor costs, and as such a New Orleans-specific cost study should be conducted to revise this value. Further, due to past realization rate issues with residential AC tune-up if this offering is expanded to the commercial sector the TPE strongly recommends a whole-program billing analysis to support savings estimates.

---

[263] Savings estimates are determined by applying the findings from DNV-GL “Impact Evaluation of 2013-2014 HVAC3 Commercial Quality Maintenance Programs”, April 2016, to simulate the inefficient condition within select eQuest models and across climate zones. The percent savings were consistent enough across building types and climate zones that it was determined appropriate to apply a single set of assumptions for all. See ‘eQuest C&I Tune up Analysis.xlsx’ for more information.

[264] Act on Energy Commercial Technical Reference Manual No. 2010-4

2.3.5 GUEST ROOM ENERGY MANAGEMENT CONTROLS

2.3.5.1 Measure Description

Packaged terminal heat pumps (PTHP) and packaged terminal air conditioners (PTAC) are commonly installed in the hospitality industry to provide heating and cooling of individual guest rooms. Occupancy-based PTHP/PTAC controllers are a combination of a control unit and occupancy sensor that operate in conjunction with each other to provide occupancy-controlled heating and/or cooling. The control unit plugs into a wall socket and the PTHP/PTAC plugs into the control unit. The control unit is operated by an occupancy sensor that is mounted in the room and turns the PTHP/PTAC on and off. The most common application for occupancy-based PTHP/PTAC controls is hotel rooms.

To qualify for savings, equipment must have a setback of at least 5 degrees Fahrenheit. Setbacks greater than 8 degrees Fahrenheit are not recommended due to occupant comfort considerations.

2.3.5.2 Baseline and Efficiency Standards

There is no code requirement for installation of GREM systems. The baseline configuration is a PTAC/PTHP with a manually controlled thermostat.

2.3.5.3 Estimated Useful Life

The EUL of this measure is eight years in accordance with DEER 2014.

2.3.5.4 Deemed Savings Values

Estimated gross annual energy savings is 355 kWh/unit, based on numbers reported by Xcel Energy and scaled appropriately based on New Orleans weather data. There is no peak demand reduction associated with this measure. As these savings estimates are based on a single reference, it is recommended that New Orleans work with early program participants to conduct actual pre- and post-measurement of energy use to verify the accuracy of these values.

2.3.5.5 Incremental Cost

The incremental cost is the difference between a GREM system and a manual thermostat, $260[265].

2.3.5.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from other programs. If this measure is added to Energy Smart programs, the evaluation should include a metering study to support occupancy estimates.

[265] DEER 2014 value for energy management systems

2.3.6 DEMAND CONTROL VENTILATION

2.3.6.1 Measure Description

Commercial Demand Controlled Ventilation (DCV) entails installing CO_2 sensors within occupied zones in a commercial building in order to optimize the amount of outside air supplied to the space. This reduces energy use for space conditioning by reducing the amount of air supplied during unoccupied times. Furthermore, maintaining appropriate airflow can improve occupant health and productivity by ensuring adequate ventilation for pollutant and odor removal, as well as preventing excessive buildup of CO_2[266].

2.3.6.2 Baseline and Efficiency Standards

The baseline for this measure was modeled as a prototypical building for 7 different building types that would most benefit from installing DCV due to their high occupancy density as well as significant variability in occupancy patterns. These models were also modified to calculate separate savings for buildings with Gas heat and Air Conditioning, as well as buildings with Heat Pumps. This measure is also only appropriate for retrofit applications. The efficiency standard for this measure, in accordance with IECC 2009, is that DCV is "***required for spaces larger than 500 ft^2 . . . and with an average occupant load of 40 people per 1000 ft^2 of floor area***". Thus, savings cannot be claimed for new construction in spaces that meet this minimum criterion unless the space is exempt in accordance with the exemptions listed in section 503.2.5[267].

2.3.6.3 Estimated Useful Life

The EUL for this product is taken to be the life of a typical CO_2 sensor. This was determined to be 10 years[268].

2.3.6.4 Deemed Savings Values

The deemed savings values were calculated using DEER prototypical commercial building energy models in eQUEST. Occupant densities were modified in accordance with the DOE prototype buildings[269], and the standard airflow rate per person was input as 15 CFM. For the deemed savings values, the DEER Models assumed a minimum airflow of 0.40 CFM per ft^2, a COP of 3.5 for cooling and heating, and a furnace efficiency of 82%. These parameters can be found in the table below.

---

[266] D. P. Wyon. "Indoor Environmental Effects on Productivity." (1996). Johnson Controls Inc. Accessed September 5, 2018 from: 310404371_Indoor_environmental_effects_on_productivity_Proceedings_of_IAQ_1996_Paths_to_better_building_environments

267 IECC 2009 DCV Requirements https://up.codes/viewer/pennsylvania/iecc-2009/chapter/5/commercial-energy-efficiency#503.2.5.1

[268] During the course of conversations with vendors and Building Automation System (BAS) contractors, it was determined that sensors have to be functional for up to 10 years. It is recommended that they are part of a normal preventive maintenance program in which calibration is an important part of extending useful life. Although they are not subject to mechanical failure, they do fall out of tolerance over time. Illinois TRM 9.0 Vol. 2 (p285n566)

[269] "Commercial Prototype Building Models." U.S. Department of Energy & Pacific Northwest National Laboratory. Accessed August 27, 2018 from: https://www.energycodes.gov/development/commercial/prototype_models

Table 2-52 Occupant Density by Building Type

Building Type	Building Zones (ft^2)	Occupant Density (ft^2/Person)	Airflow Requirement (cfm/person)	Notes
Assembly	Auditorium: 33,235 Office: 765 Total: 34,000	50	15	DEER Default
Primary School (K-6)	Classroom: 31,500 Dining: 7,500 Gym: 7,500 Kitchen: 3,500 Total: 50,000	40		Office/Gym space densities unchanged
Secondary School (7-12)	Classroom: 31,500 Dining: 7,500 Gym: 7,500 Kitchen: 3,500 Total: 50,000	28.5		
Small Office (<30,000 ft^2)	Office:3,250 Conference:500 Other:6,250 Total:10,000	142		
Large Office (≥30,000 ft^2)	Office:101,500 Support Spaces 56,000 Lobby: 7,200 Mechanical/Electrical: 10,300 Total: 175,000	125		
Restaurant	Dining:2,000 Kitchen: 1,200 Lobby: 600 Restroom: 200 Total: 4,000	25		Kitchen and Bathroom density and airflow unchanged
Retail Stand-Alone	Retail: 6,400 Storage: 1,600 Total: 8,000	67		Storage space left at original occupancy density

Table 2-53 Deemed Savings by Building Type – PTAC

Building Type	kWh/Ton	kW/Ton
Assembly	523	0.100
Primary School (K-6)	73	0.047
Secondary School (7-12)	70	0.035
Small Office (<30,000 ft2)	48	-0.031
Large Office (≥30,000 ft2)	54	-0.035
Restaurant	160	0.017
Retail Stand-Alone	209	0.049

Table 2-54 Deemed Savings by Building Type - PTHP

Building Type	kWh/Ton	kW/Ton
Assembly	894	0.105
Primary School (K-6)	126	0.060
Secondary School (7-12)	125	0.044
Small Office (<30,000 ft2)	56	-0.031
Large Office (≥30,000 ft2)	63	-0.035
Restaurant	256	0.016
Retail Stand-Alone	293	0.356

Table 2-55 Deemed Savings by Building Type – Central AC

Building Type	kWh/1,000 ft^2	kW/1,000 ft^2
Assembly	165	0.170
Primary School (K-6)	148	0.003
Secondary School (7-12)	118	0.003
Small Office (<30,000 ft2)	231	0.000
Large Office (≥30,000 ft2)	260	0.131
Restaurant	485	0.003
Retail Stand-Alone	111	0.054

Table 2-56 Deemed Savings by Building Type – Roof Top Units

Building Type	kWh/1,000 ft^2	kW/1,000 ft^2
Assembly	54	0.140
Primary School (K-6)	139	0.003
Secondary School (7-12)	115	0.002
Small Office (<30,000 ft2)	209	0.000
Large Office (≥30,000 ft2)	210	0.106
Restaurant	387	0.002
Retail Stand-Alone	88	0.042

Deemed annual energy savings and peak demand reductions DCV applications should be calculated using the following equations. The energy savings and demand reductions are given as kWh/1,000 ft^2.

$kWh_{Savings} = Savings\ Multiplier \times$ Square footage covered by HVAC system

$kW_{Reduction} = Savings\ Multiplier \times$ Square footage covered by HVAC system

Where:

> *Savings Multiplier* = Savings per 1,000 ft^2 based on HVAC configuration/system from Table 2-53 to Table 2-56 above.

2.3.6.5 Incremental Cost

The deemed measure cost is assumed to be the full cost of installation of a DCV retrofit including sensor cost ($500) and installation ($1000 labor) for a total of $1,500[270].

2.3.6.6 Future Studies

This measure has had limited participation in Energy Smart. DCV projects should be over-sampled for targeted M&V if this measure has significant participation (at least 250,000 kWh).

[270] Discussion with vendors. Illinois TRM 9.0 Vol. 2 (p285n567)

2.3.7 SMART THERMOSTATS

2.3.7.1 Measure Description

This measure consists of replacing a manually operated or programmable thermostat with an ENERGY STAR certified[271] smart thermostat. If the thermostat is not ENERGY STAR-certified, it must have the following features:[272]

- Automatic scheduling.
- Occupancy sensing (set "on" as a default).
- For buildings with a heat pump, smart thermostats must be capable of controlling heat pumps to minimize the use of backup electric resistance heat.
- Ability to adjust settings remotely via a smart phone or online in the absence of connectivity to the thermostat service provider, retaining the ability for the facility to:
    - View the room temperature,
    - View and adjust the set temperature, and
    - Switch between off, heating and cooling.
- Have a static temperature accuracy ≤ ± 2.0 °F
- Have network standby average power consumption of ≤3.0 W average (including all equipment necessary to establish connectivity to the service provider's cloud, except those that can reasonably be expected to be present in the home, such as Wi-Fi routers and smart phones.)
- Enter network standby after ≤ 5.0 minutes from user interaction (on device, remote or occupancy detection)
- The following capabilities may be enabled through the connected thermostat (CT) device, CT service or any combination of the two. The CT product shall maintain these capabilities through subsequent firmware and software changes:
    - Ability for consumers to set and modify a schedule.
    - Provide feedback to occupants about the energy impact of their choice of settings.
    - Provide access to information relevant to their HVAC energy consumption (e.g., HVAC run time).

2.3.7.2 Baseline & Efficiency Standard

For retrofit projects, the baseline is the preexisting thermostat equipment configuration. For new construction projects, program administrators should assume a programmable thermostat as baseline (in accordance with IECC 2009).

[271] ENERGY STAR's qualified products list for smart thermostats: https://data.energystar.gov/dataset/ENERGY-STAR-Certified-Connected-Thermostats/7p2p-wkbf

[272] ENERGY STAR Smart Thermostat Specification:: https://www.energystar.gov/sites/default/files/ENERGY%20STAR%20Program%20Requirements%20for%20Connected%20Thermostats%20Version%201.0_0.pdf

2.3.7.3 Estimated Useful Life

The EUL for this measure is 11 years.[273]

2.3.7.4 Deemed Savings Values

Deemed savings are based off of a percent reduction of annual use compared to the equivalent full-load cooling and heating consumption for the facility. Savings are calculated as:

$$kWh\ Savings = Capacity(C) \times \frac{1}{SEER \times 1000} \times EFLH_C \times Savings\%_C$$
$$+ Capacity(H) \times \frac{1}{HSPF \times 1000} \times EFLH_H \times Savings\%_H$$

Where:

Capacity(C) = Cooling capacity (BTU)

SEER = Efficiency of controlled AC. Use current code requirements if nameplate actual is not available.

1000 = unit conversion

EFLH(C) = Equivalent Full Load Cooling Hours. See Table 2-57.

Capacity(H) = Heating capacity (BTU)

HSPF = Heating Efficiency of controlled HVAC system. Use current code requirements if nameplate actual is not available.

EFLH(H) = Equivalent Full Load Heating Hours. See Table 2-57.

Savings%(C) = Annual percent cooling savings

Savings%(H) = Annual percent heating savings

Capacity should be collected as part of the project application.

Table 2-57 Equivalent Full-Load Hours by Building Type

Building Type	**$EFLH_C$**	**$EFLH_H$**
Fast Food	2,375	272
Grocery	1,526	153
Health Clinic	1,989	115
Large Office	1,483	392
Lodging	2,095	409
Full Menu Restaurant	1,997	166
Retail	3,191	513
School	2,329	140
Small Office	2,060	255
University	1,510	604

[273] DEER 2014 EUL tables

Table 2-58 summarizes the annual percent savings for heating and cooling by baseline thermostat. Savings for natural gas are presented so as to allow program administrators to quantify the full benefit from installation of a smart thermostat in a facility with electric cooling and natural gas space heating.

Table 2-58 Savings Percent by Baseline Type

System	Baseline	
	Manual Thermostat[274]	**Programmable Thermostat**[275]
Electric Cooling	5%	3%
Electric Heating	4%	2%
Natural Gas Heating	5%	2%

2.3.7.4.1 Sample Calculation

For example, assume a small retail facility using an air source heat pump. The equipment is 60,000 BTU in capacity with efficiencies of 13 SEER and 7.7 HSPF. The associated EFLH values are 3,191 for cooling and 513 for heating. The facility uses a manual thermostat in the baseline configuration. The savings for this project would be:

$$Cooling\ Savings = 60{,}000 \times \frac{1}{13 \times 1000} \times 3{,}191 \times 5\% = 736\ kWh$$

$$Heating\ Savings = 60{,}000 \times \frac{1}{7.7 \times 1000} \times 513 \times 4\% = 160\ kWh$$

There are too many possible facility and equipment configuration combinations to provide pre-determined deemed savings. Program administrators should follow the algorithm specified above.

2.3.7.5 *Incremental Cost*

Actual measure cost should be used where available. If not available, the incremental cost of installing a smart thermostat is $154[276] for new construction and $208[277] for retrofit.

2.3.7.6 *Future Studies*

Current savings estimates for this measure cite existing studies from other climate zones. This measure should receive a detailed impact evaluation once sufficient participation has occurred.

---

[274] The savings percentages claimed for manual thermostats include the savings associated with upgrading from manual thermostats to programmable thermostats, which a 2015 MEMD study reported as about 3% savings for gas customers and 2% savings for electric customers. http://www.michigan.gov/documents/mpsc/CI_Programmable_TStats_MEMD_6_15_15_491808_7.pdf

[275] CLEAResult's "Guide to Smart Thermostats" reports the ranges of savings measured in recent residential evaluations, relative to a baseline that blended programmable and manual thermostats: 10–13% for gas savings; 14–18% for electric cooling savings; and 6–13% for electric heating. This finding is extrapolated to commercial facilities in this analysis. savings.https://www.clearesult.com/insights/whitepapers/guide-to-smart-thermostats

[276] From NEEP's 2016 Incremental Cost Study: http://www.neep.org/incremental-cost-emerging-technology-0, table 3-13 found range of incremental costs to be $80-195 (with baseline as $54 and using Nest/Ecobee at $249). NEEP's more recent list of home energy management systems products (http://neep.org/initiatives/high-efficiency-products/home-energy-management-systems) shows a straight average of 68 products at $210 for the cost of the smart thermostat, bringing the incremental cost assuming $54 for baseline down to $154.

[277] *Ibid.*

2.3.8 VARIABLE SPEED DRIVES

2.3.8.1 Measure Description

This measure is applied to variable speed drives (VSD) which are installed on the following HVAC system applications: chilled water pumps, cooling tower fans, hot water pumps and HVAC fans. All other VSD applications require custom analysis by the program administrator. The VSD will modulate the speed of the motor when it does not need to run at full load. Since the power of the motor is proportional to the cube of the speed for these types of applications, significant energy savings will result.

2.3.8.2 Baseline & Efficiency Standard

2.3.8.2.1 Definition of Baseline Equipment

The time of sale baseline is a new motor installed without a VSD or other methods of control. Retrofit baseline is an existing motor operating as is with no VSD. Retrofit baselines may or may not include inlet guide vanes, throttling valves or other methods of control. The motor is a standard efficiency motor based on ASHRAE Standard 90.1-2007 standards which are provided by horsepower. The AC unit has standard cooling efficiency based on IECC 2009. The part-load fan control is an outlet damper, inlet damper, inlet guide vane, or no control (constant volume systems).

Note IECC 2009 became effective July 20, 2011 and is the baseline for all New Construction permits from that date.[278] Installations of new equipment with VSDs which are required by IECC 2009 as adopted by New Orleans are not eligible for incentives.

2.3.8.2.2 Definition of Efficient Equipment

The VSD is applied to a motor which does not have a VSD. This measure is not applicable for replacing failed VSDs. The application must have a variable load and installation is to include the necessary controls. Savings are based on application of VSDs to a range of baseline load conditions including no control, inlet guide vanes, outlet guide vanes and throttling valves.

When applicable, the existing damper or inlet guide vane will be removed or set completely open permanently after installation. The VFD will maintain a constant static pressure by adjusting fan speed and delivering the same amount of air as the baseline condition.

2.3.8.3 Estimated Useful Life

The EUL for HVAC application is 15 years[279] and the EUL for process is 15 years.[280]

2.3.8.4 Deemed Savings Values

The deemed savings values were calculated using DEER prototypical commercial building energy models in eQUEST.

---

[278] Louisiana Energy Code and Links, http://sfm.dps.louisiana.gov/pr_energy.htm

[279] Efficiency Vermont TRM 10/26/11 for HVAC VSD motors

[280] DEER, 2008.

Table 2-59 Deemed Savings by Building Type – Chilled Water Pumps

Building Type	kWh/HP	kW/HP
Assembly	708	0.090
Primary School (K-6)	171	0.038
Secondary School (7-12)	171	0.038
Small Office (<30,000 ft^2)	558	0.087
Large Office (≥30,000 ft^2)	377	0.133
Restaurant	358	0.070
Retail Stand-Alone	377	0.074

Table 2-60 Deemed Savings by Building Type – Condenser Pumps

Building Type	kWh/HP	kW/HP
Assembly	613	0.073
Primary School (K-6)	143	0.034
Secondary School (7-12)	143	0.034
Small Office (<30,000 ft^2)	469	0.072
Large Office (≥30,000 ft^2)	688	0.152
Restaurant	327	0.072
Retail Stand-Alone	328	0.072

Table 2-61 Deemed Savings by Building Type – Cooling Tower Fans

Building Type	kWh/HP	kW/HP
Assembly	449	0.212
Primary School (K-6)	380	0.083
Secondary School (7-12)	380	0.083
Small Office (<30,000 ft^2)	955	0.193
Large Office (≥30,000 ft^2)	619	0.251
Restaurant	540	0.139
Retail Stand-Alone	802	0.136

Table 2-62 Deemed Savings by Building Type – Hot Water Heating Pumps

Building Type	kWh/HP	kW/HP
Assembly	1,251	0.152
Primary School (K-6)	299	0.073
Secondary School (7-12)	299	0.073
Small Office (<30,000 ft^2)	970	0.152
Large Office (≥30,000 ft^2)	306	0.073
Restaurant	595	0.152
Retail Stand-Alone	690	0.152

Table 2-63 Deemed Savings by Building Type – HVAC Fans

Building Type	kWh/HP	kW/HP
Assembly	8	0.001
Primary School (K-6)	2	0.000
Secondary School (7-12)	2	0.000
Small Office (<30,000 ft^2)	7	0.001
Large Office (≥30,000 ft^2)	3	0.001
Restaurant	4	0.001
Retail Stand-Alone	4	0.001

2.3.8.5 Deemed Savings Values

Deemed annual energy savings and peak demand reductions from VSD applications should be calculated using the following equations. The energy savings and demand reductions are given as kWh and kW per rated horsepower of the motor the VSD is controlling.

$kWh_{Savings} = Savings\ Multiplier \times$ Rated horsepower of motor VSD is controlling

$kW_{Reduction} = Savings\ Multiplier \times$ Rated horsepower of motor VSD is controlling

Where:

> *Savings Multiplier* = Savings per 1 HP HVAC configuration/system from Table 2-59 to Table 2-63 above.

2.3.8.6 Incremental Cost

Customer provided costs will be used when available. Default measure costs[281] are noted below for up to 20 hp motors. Custom costs must be gathered from the customer for motor sizes not listed below.

Table 2-64 Measure Cost by Horsepower

HP	Cost
1 -5 HP	$1,037
7.5 HP	$1,673
10 HP	$1,803
15 HP	$2,254
20 HP	$2,739

2.3.8.7 Future Studies

Current savings estimates for this measure cite existing studies from other climate zones. This measure should receive a detailed impact evaluation once sufficient participation has occurred.

[281] Material costs from Grainger.com, search for "Variable Frequency Drive" on 7/8/2020. RTF ‘https://nwcouncil.app.box.com/v/VariableSpeedDrivev2-0’

2.4 Refrigeration

2.4.1 VARIABLE REFRIGERANT FLOW SYSTEMS

2.4.1.1 Measure Description

This measure entails the installation of a variable refrigerant flow (VRF) multi-split heat pump system. There are numerous configurations of VRF systems. This chapter covers the two most common configurations in the market:

- Air-cooled VRF heat pumps; and
- Water-cooled VRF heat pumps.

2.4.1.2 Baseline and Efficiency Standards

The baseline for units that are used in new construction or are replaced on burnout is shown in Table 2-65. The format of the baseline table is taken from ASHRAE 90.1-2010 Table 6.8.1J Electrically Operated Variable Refrigerant Flow Air-to-Air and Applied Heat Pumps – Minimum Efficiency Requirements. This minimum efficiency requirement is based on applied heat pump baseline from Table 6.8.1B from ASHRAE 90.1-2010 where air-cooled VRF system with electric resistance heating references the baseline of applied heat pump with electric resistance heating and VRF with heat recovery with applied heat pump with all other heating types. However, water-cooled VRF baseline was stipulated in ASHRAE 90.1-2010. The current state building energy code is ASHRAE 90.1-2007 and the minimum baseline for applied heat pump from ASHRAE 90.1-2007 to 90.1-2010 didn't change, therefore the table from ASHRAE 90.1-2010 is applicable with an exception of air-cooled VRF system rated for 17°F dry-bulb and 43°F wet-bulb temperature which must comply the federal minimum standard[282] for heat pumps, which went into effect January 1, 2010.

Table 2-65 VRF Heat Pump System– Baseline Efficiency Standards

Equipment Type	Cooling Capacity (Btu/h)	Heating Section Type	Sub-Category	Minimum Efficiency
VRF, Air Cooled (Cooling Mode)	< 65,000	All	VRF Multi-split System	13 SEER
	≥65,000 & <135,000	Electric Resistance (or none)	VRF Multi-split System	11.0 EER
			VRF Multi-split System with Heat Recovery	10.8 EER
	≥135,000 & <240,000		VRF Multi-split System	10.6 EER

[282] 2013 U.S. Code: Title 10, Chapter 2, Subchapter D, Part 431, Subpart F, Table 1 to Page 431.97; Minimum Cooling Efficiency Standards for Air-Conditioning and Heating Equipment

Equipment Type	Cooling Capacity (Btu/h)	Heating Section Type	Sub-Category	Minimum Efficiency
		Electric Resistance (or none)	VRF Multi-split System with Heat Recovery	10.4 EER
	≥240,000	Electric Resistance (or none)	VRF Multi-split System	9.5 EER
			VRF Multi-split System with Heat Recovery	9.3 EER
VRF, Water Cooled (Cooling Mode)	< 65,000	All	VRF Multi-split system, 86°F entering water	12.0 EER
			VRF Multi-split system with Heat Recovery, 86°F entering water	11.8 EER
	≥65,000 & <135,000	All	VRF Multi-split system, 86°F entering water	12.0 EER
			VRF Multi-split system with Heat Recovery, 86°F entering water	11.8 EER
	≥135,000	All	VRF Multi-split system, 86°F entering water	10.0 EER
			VRF Multi-split system with Heat Recovery, 86°F entering water	9.8 EER
VRF, Air Cooled (Heating Mode)	< 65,000	All	VRF Multi-split system	7.7 HSPF
	≥65,000 & <135,000	All	VRF Multi-split system	3.3 COP
	≥135,000	All	VRF Multi-split system	3.2 COP
VRF, Water Cooled (Heating Mode)	<135,000	All	VRF Multi-split system, 68°F entering water	4.2 COP
	≥135,000	All	VRF Multi-split system, 68°F entering water	3.9 COP

2.4.1.3 Estimated Useful Life

The typical VRF system is a type of heat pump and the same 15 year EUL from DEER 2016 for commercial heat pumps applies to this measure.

2.4.1.4 Deemed Savings Values

This measure has significant variability in equipment efficiency based on system type and equipment capacity and thus we present savings on a per-ton basis. The measure efficiency is based on the average unit efficiency of all AHRI-certified VRF units[283] in the US market at three different cooling capacity bins.

The following tables present per-ton deemed savings.

Table 2-66 Deemed Savings by Building Type – VRF Air-Cooled Heat Pumps

Building Type	Cooling Capacity (tons)	VRF Multi-split System		VRF Multi-split System with Heat Recovery	
		kWh/Ton	kW/Ton	kWh/Ton	kW/Ton
Fast Food	< 11.25	615	0.1898	415	0.1257
	>=11.25 & < 20.00	240	0.0685	283	0.0845
	>= 20.00	300	0.0935	237	0.0746
Grocery	< 11.25	392	0.2190	264	0.1451
	>=11.25 & < 20.00	152	0.0790	180	0.0975
	>= 20.00	191	0.1078	152	0.0861
Health Clinic	< 11.25	500	0.2068	334	0.1370
	>=11.25 & < 20.00	188	0.0746	227	0.0921
	>= 20.00	245	0.1018	195	0.0813
Large Office	< 11.25	415	0.2044	286	0.1354
	>=11.25 & < 20.00	176	0.0737	198	0.0910
	>= 20.00	200	0.1006	156	0.0804
Lodging	< 11.25	566	0.1873	386	0.1241
	>=11.25 & < 20.00	232	0.0676	266	0.0835
	>= 20.00	274	0.0923	215	0.0737
Full Menu Restaurant	< 11.25	509	0.2068	342	0.1370
	>=11.25 & < 20.00	195	0.0746	232	0.0921
	>= 20.00	249	0.1018	197	0.0813
Retail	< 11.25	847	0.2141	575	0.1419
	>=11.25 & < 20.00	340	0.0773	395	0.0954
	>= 20.00	411	0.1054	324	0.0842
School	< 11.25	586	0.1727	392	0.1145
	>=11.25 & < 20.00	221	0.0623	266	0.0770
	>= 20.00	287	0.0851	228	0.0679
Small Office	< 11.25	536	0.2044	362	0.1354
	>=11.25 & < 20.00	211	0.0737	248	0.0910
	>= 20.00	261	0.1006	206	0.0804
University	< 11.25	450	0.2044	315	0.1354
	>=11.25 & < 20.00	203	0.0737	222	0.0910
	>= 20.00	215	0.1006	167	0.0804
Unknown	< 11.25	541	0.2009	367	0.1332
	>=11.25 & < 20.00	216	0.0725	252	0.0895
	>= 20.00	263	0.0990	208	0.0790

[283] 7,974 certified product information pulled from AHRI database on 7/1/2019; AHRI Directory of Certified Product Performance, https://www.ahridirectory.org/NewSearch?programId=72&searchTypeId=3

Table 2-67 Deemed Savings by Building Type – VRF Water Cooled Heat Pump

Building Type	Cooling Capacity (tons)	VRF Multi-split System		VRF Multi-split System with Heat Recovery	
		kWh/Ton	kW/Ton	kWh/Ton	kW/Ton
Fast Food	< 5.42	484	0.1443	N/A	N/A
	>=5.42 & < 11.25	509	0.1552	506	0.1527
	>= 11.25	716	0.2191	751	0.2319
Grocery	< 5.42	307	0.1666	N/A	N/A
	>=5.42 & < 11.25	324	0.1791	322	0.1762
	>= 11.25	456	0.2528	479	0.2676
Health Clinic	< 5.42	387	0.1573	N/A	N/A
	>=5.42 & < 11.25	411	0.1692	407	0.1664
	>= 11.25	579	0.2388	610	0.2528
Large Office	< 5.42	338	0.1554	N/A	N/A
	>=5.42 & < 11.25	347	0.1672	349	0.1645
	>= 11.25	486	0.2360	505	0.2498
Lodging	< 5.42	454	0.1425	N/A	N/A
	>=5.42 & < 11.25	471	0.1532	472	0.1508
	>= 11.25	661	0.2163	690	0.2290
Full Menu Restaurant	< 5.42	396	0.1573	N/A	N/A
	>=5.42 & < 11.25	419	0.1692	416	0.1664
	>= 11.25	591	0.2388	621	0.2528
Retail	< 5.42	674	0.1629	N/A	N/A
	>=5.42 & < 11.25	703	0.1751	702	0.1723
	>= 11.25	988	0.2472	1,033	0.2617
School	< 5.42	454	0.1314	N/A	N/A
	>=5.42 & < 11.25	482	0.1413	477	0.1390
	>= 11.25	679	0.1995	715	0.2111
Small Office	< 5.42	422	0.1554	N/A	N/A
	>=5.42 & < 11.25	444	0.1672	442	0.1645
	>= 11.25	624	0.2360	654	0.2498
University	< 5.42	377	0.1554	N/A	N/A
	>=5.42 & < 11.25	381	0.1672	387	0.1645
	>= 11.25	532	0.2360	548	0.2498
Unknown	< 5.42	429	0.1529	N/A	N/A
	>=5.42 & < 11.25	449	0.1644	448	0.1617
	>= 11.25	631	0.2321	661	0.2456

Deemed peak demand and annual energy savings for unitary AC and HP equipment should be calculated as shown below.

$$kW_{Savings} = CAP \times \frac{1\,kW}{1{,}000\,W} \times \left(\frac{1}{\eta_{base,Cooling}} - \frac{1}{\eta_{post,Cooling}}\right) \times CF$$

$$kWh_{Savings} = CAP \times \frac{1\,kW}{1{,}000\,W} \times \left[\left(\frac{EFLH_C}{\eta_{base,Cooling}} + \frac{EFLH_H}{\eta_{base,Heating} \times 3.413}\right) - \left(\frac{EFLH_C}{\eta_{post,Cooling}} + \frac{EFLH_H}{\eta_{post,Heating} \times 3.413}\right)\right]$$

Where:

CAP = Rated equipment cooling capacity of the new unit (BTU/hr)

$\eta_{base,Cooling/Heating}$ = Baseline energy efficiency rating of the cooling/heating equipment (Table 2-65), EER for cooling and COP for heating

$\eta_{post,Cooling/Heating}$= Nameplate energy efficiency rating of the installed cooling/heating equipment (Table 2-68), EER for cooling and COP for heating

CF = Coincidence factor

Table 2-70

$EFLH_c$ = Equivalent full-load hours for cooling (

Table 2-69)

$EFLH_h$ = Equivalent full-load hours for heating (

Table 2-69)

3.413 = kW to Btu/hr Conversion applied to heating COP to heating EER

Table 2-68 Measure Efficiency Assumptions[284]

Equipment Type	Cooling Capacity Category (Btu/h)	Cooling Capacity (Btu/h)	Sub-Category	Average Cooling Efficiency (EER)	Average Heating Efficiency (COP)
VRF, Air Cooled	< 65,000	65,000	All	N/A[285]	N/A[368]
	≥65,000 & <135,000	100,000	VRF Multi-split System	12.5	3.8
			VRF Multi-split System with Heat Recovery	12.6	3.7
	≥135,000 & <240,000	187,500	VRF Multi-split System	11.5	3.6
			VRF Multi-split System with Heat Recovery	11.5	3.5
	≥240,000	240,000	VRF Multi-split System	10.5	3.4
			VRF Multi-split System with Heat Recovery	10	3.3
VRF, Water Cooled	< 65,000	65,000	VRF Multi-split system	14.7	5.2
			VRF Multi-split system with Heat Recovery	N/A[368]	N/A[368]
	≥65,000 & <135,000	100,000	VRF Multi-split system	15	5
			VRF Multi-split system with Heat Recovery	14.9	5.1
	≥135,000	135,000	VRF Multi-split system	13.1	4.9
			VRF Multi-split system with Heat Recovery	12.9	4.8

[284] Average efficiency calculated from AHRI certified products available in US market

[285] Product not available in US in this category

Table 2-69 Equivalent Full-Load Hours by Building Type

Building Type	$EFLH_C$	$EFLH_H$
Fast Food	2,375	272
Grocery	1,526	153
Health Clinic	1,989	115
Large Office	1,483	392
Lodging	2,095	409
Full Menu Restaurant	1,997	166
Retail	3,191	513
School	2,329	140
Small Office	2,060	255
University	1,510	604

Table 2-70 Commercial Coincidence Factors by Building Type[286]

Building Type	Coincidence Factor
Fast Food	0.78
Grocery	0.90
Health Clinic	0.85
Large Office	0.84
Lodging	0.77
Full Menu Restaurant	0.85
Retail	0.88
School	0.71
Small Office	0.84
University	0.84

2.4.1.5 Incremental Cost

The incremental cost is $3 per square-foot of conditioned space[287] compared to baseline equipment.

2.4.1.6 Future Studies

VRF systems in certain applications has greater energy savings potential than the deemed savings in this version of TRM. For example, if the facility has vacant space that is not heated or cooled, the VRF unit will run in part-load which can operate with greater efficiency. Furthermore, if the facility installs more cooling capacity than required, they can increase their energy savings by running the unit on a lower part-load. Some VRF units can provide simultaneous heating and cooling which can improve overall unit

[286] Values for Assembly and Religious Worship building types developed using an adjustment factor derived through a comparison of average CFs for College/University and Assembly/Religious Worship building types from the Texas state Technical Reference Manual. College/University was selected as a reference building type due to average alignment with Assembly/Religious worship building types in other TRMs, inclusion of a summer session, and increased evening usage.

[287] CLEAResult 2016. "Utility Program Cost Effectiveness of Variable Refrigerant Flow Systems". ACEEE Summer Study on Energy Efficiency in Buildings 2016. https://aceee.org/files/proceedings/2016/data/papers/3_345.pdf

efficiency as well. An example of this application is to install VRF systems in lodging facilities where not all rooms are occupied so the unit will run on part load, as well as having some rooms request heating while other rooms request cooling. Both operational patterns present an opportunity for a VRF system to achieve greater savings. However, this version of TRM does not cover applications such as this as further is needed. It is advised that in large scale projects, program administrators should consider taking a custom savings approach rather than using this deemed savings approach to capture full potential savings.

2.4.2 DOOR HEATER CONTROL FOR REFRIGERATORS AND FREEZERS

2.4.2.1 Measure Description

This measure refers to the installation of anti-sweat door heater controls on glass doors for reach-in commercial refrigerators and freezers. The added control reduces both heater operation time and cooling load.

This measure only qualifies for retrofit applications. New construction applications are not allowed as this measure is standard practice for new construction and comes integrated on most modern glass-door refrigerators and freezers.

2.4.2.2 Baseline and Efficiency Standards

Qualifying equipment includes any controls that reduce the run time of door and frame heaters for refrigerated cases. The baseline efficiency case is a cooler or freezer door heater that operates 8,760 hours per year without any controls. The high efficiency case is a cooler (medium temperature) or freezer (low temperature) door heater connected to a heater control system. There are no state or federal codes or standards that govern the eligibility of equipment.

2.4.2.3 Estimated Useful Life

The EUL is 12 years as defined in the DEER database.[288]

2.4.2.4 Deemed Savings Values

2.4.2.4.1 Energy Savings

A door heater controller senses dew point (DP) temperature in the store and modulates power supplied to the heaters accordingly. DP inside a building is primarily dependent on the moisture content of outdoor ambient air. Because the outdoor DP varies between weather zones, weather data from each weather zone must be analyzed to obtain a DP profile.

Indoor dew point (t_{d-in}) is related to outdoor dew point (t_{d-out}) according to the following equation. Indoor dew point was calculated at each location for every hour in the year.[289]

$$t_{d-in} = 0.005379 \times t_{d-out}^2 + 0.171795 \times t_{d-out} + 19.870006$$

In the base case, the door heaters are all on and have a duty of 100% irrespective of the indoor DP temperature. For the post-retrofit case, the duty for each hourly reading was calculated by assuming a linear relationship between indoor DP and duty cycle for each bin reading. It is assumed that the door heaters will be all off (duty cycle of 0%) at 42.89°F or lower DP and all on (duty cycle of 100%) at 52.87°F or higher DP for a typical supermarket. Between these values, the door heaters' duty cycle changes proportionally:

[288] California's Database for Energy Efficiency Resources (DEER 2014).

[289] Work Paper PGEREF108: Anti-Sweat Heat (ASH) Controls. Pacific Gas & Electric Company. May 29, 2009.

$$Door\ Heater\ ON\% = \frac{t_{d-in} - All\ OFF\ Setpt\ (42.89°F)}{All\ ON\ Setpt\ (52.87°F) - All\ OFF\ Setpt\ (42.89°F)}$$

Because the controller only changes the run-time of the heaters, instantaneous door heater power (kW_{ASH}) as a resistive load remains constant per linear foot of door heater at:

$$kW_{ASH} = \frac{kW}{ft} \times L_{DH}$$

Where kW/ft. = 0.0368 for medium temperature and 0.0780 for low temperature applications.

Door heater energy consumption for each hour of the year is a product of power and run-time:

$$kWh_{ASH-Hourly} = kW_{Ash} \times Door\ Heater\ ON\% \times 1\ hour$$

Total annual door heater energy consumption (kWh_{ASH}) is the sum of all hourly reading values:

$$kWh_{ASH} = \sum kWh_{ASH-Hourly}$$

Energy savings were also estimated for reduced refrigeration loads using average system efficiency and assuming that 35% of the anti-sweat heat becomes a load on the refrigeration system.[290] The cooling load contribution from door heaters can be given by:

$$Q_{ASH}\left(\frac{ton}{h}\right) = 0.35 \times kW_{ASH} \times \frac{3{,}412\ \frac{Btu}{kWh}}{12{,}000\ \frac{Btu}{ton}} \times Door\ Heater\ ON\%$$

The compressor power requirements are based on calculated cooling load and energy-efficiency ratios obtained from the manufacturers' data. The compressor analysis is limited to the cooling load imposed by the door heaters, not the total cooling load of the refrigeration system.

The typical efficiency for a medium temperature case is 9 EER (1.33 kW/ton), and the typical efficiency for a low temperature case is 5 EER (2.40 kW/ton).[291]

Energy used by the compressor to remove heat imposed by the door heaters for each hourly reading is determined based on calculated cooling load and EER, as outlined below:

$$kWh_{Refrig-Hourly} = Q_{ASH} \times \frac{kW}{ton} \times 1\ hour$$

---

[290] Southern California Edison (SCE), 1999, *"A Study of Energy Efficient Solutions for Anti-Sweat Heaters."* Prepared for the Refrigeration Technology and Test Center (RTTC). December 14. https://www.sce.com/NR/rdonlyres/B1F7A3B4-719D-4CBB-87EB-E27F7CE7ECE0/0/Anti_Sweat_Heater_Report.pdf.

[291] Chapter 15 of the 2010 ASHRAE Handbook for Refrigeration

Total annual refrigeration energy consumption is the sum of all hourly reading values:

$$kWh_{Refrig} = \sum kWh_{Refrig-Hourly}$$

Total annual energy consumption (direct door heaters and indirect refrigeration) is the sum of all hourly reading values:

$$kWh_{Total} = kWh_{Refrig} + kWh_{ASH}$$

Once the annual energy consumption (direct door heaters and indirect refrigeration) has been determined for the baseline and post-retrofit case, the total energy savings are calculated by the following equation:

$$Annual\ Energy\ Savings = \Delta kWh = kWh_{Total-Baseline} - kWh_{Total-Post\ Retrofit}$$

2.4.2.4.2 Demand Savings

It is important to note that while there might be instantaneous demand reduction as a result of the cycling of the door heaters, peak demand reduction will only be due to the reduced refrigeration load. Peak demand reduction was calculated by the equation shown below:

$$Peak\ Demand\ Savings = \Delta kW = \frac{kWh_{Refrig-Baseline} - kWh_{Refrig-Post\ Retrofit}}{8{,}760\ hr/yr}$$

Annual and peak energy savings due to anti-sweat door heater controls in medium and low temperature refrigerated cases for New Orleans. Deemed savings is calculated using a ratio compared to El Dorado, AR (Zone 6) Savings provided in the table are per linear foot of glass door-controlled heater.

Table 2-71 Anti-Sweat Heater Controls – Savings per Linear Foot of Case by Location

Weather Zone	Med-Temperature		Low-Temperature	
	Annual kWh/ft. Savings	kW/ft. Savings	Annual kWh/ft. Savings	kW/ft. Savings
New Orleans	248	0.0046	259	0.0060

2.4.2.5 Incremental Cost

The full installed cost should be used for this measure. If not available, use $300 per circuit[292].

2.4.2.6 Future Studies

At the time, this measure had low participation in Energy Smart programs. As a result, savings are calculated using weather-adjusted default values from other programs. If participation exceeds 500,000 kWh, the evaluation should include a metering study to support runtime estimates.

292 Efficiency Vermont Technical Reference User Manual (TRM) Measure Savings Algorithms and Cost Assumptions, February, 19, 2010

2.4.3 ENERGY STAR REFRIGERATORS AND FREEZERS WITH SOLID DOORS

2.4.3.1 Measure Description

Commercial refrigerators and freezers are commonly found in restaurants and other food service industries. Reach-in, solid-door refrigerators and freezers are significantly more efficient than regular refrigerators and freezers due to better insulation and higher-efficiency components. These efficiency levels relate the volume of the appliance to its daily energy consumption. To qualify for this measure, new solid-door refrigerators and freezers must meet ENERGY STAR minimum efficiency requirements.

2.4.3.2 Baseline and Efficiency Standards

Baseline efficiency for commercial solid door refrigerators and freezers is defined by federal minimum efficiency levels that went into effect on March 28, 2014 (see Table 2-72 below). Also included are the minimum efficiency levels for the ENERGY STAR specifications version five, effective December 22, 2022.

Table 2-72 Solid-Door Refrigerators and Freezers – Efficiency Levels

Equipment	Baseline	Capacity	ENERGY STAR Max Daily Consumption (kWh/day)
Refrigerator	0.05V + 1.36	0<V<15	0.026V + .08
		15≤V<30	0.05V + 0.45
		30≤V<50	
		50≤V	0.025V + 1.6991
Freezer	0.22V + 1.38	0<V<15	0.21V + 0.9
		15≤V<30	0.12V + 2.248
		30≤V<50	0.2578V-1.8864
		50≤V	0.14V + 4.0

2.4.3.3 Estimated Useful Life

According to DEER 2014 the EUL is 12 years.

2.4.3.4 Deemed Savings Values

$$kWh\ Savings = annual\ kWh_{baseline} - annual\ kWh_{efficient}$$

$$kW\ Reduction = \frac{kWh\ Savings}{hours}$$

Where:

$hours$ = annual hours (365.25 x 24 = 8,766)[293]

[293] Refrigeration is assumed to operate continuously

Deemed measure savings for qualifying solid-door refrigerators and freezers are presented in Table 2-73.

Table 2-73 Solid-Door Refrigerators and Freezers – Deemed Savings Values

Type	Size Range (Cubic Ft)	Baseline Annual Energy Consumption (kWh/unit)	Efficient Annual Energy Consumption (kWh/unit)	Annual kWh Savings	Demand Reduction (kW/unit)
Refrigerator	0-15	634	100	533	0.061
	15-30	908	575	332	0.038
	30-50	1,227	895	332	0.038
	≥50[294]	1,775	1,260	515	0.059
Freezer	0-15	1,107	904	203	0.023
	15-30	2,312	1,807	505	0.058
	30-50	3,718	3,077	641	0.073
	≥50[294]	6,129	5,040	1,088	0.124

2.4.3.4.1 Measure Technology Review

Five primary resources contained data about solid-door refrigerators and freezers. The ENERGY STAR website and the CEE had the same maximum daily energy consumption levels for commercial food-grade refrigerators and freezers. The NPCC report and Ecotrope studies gave savings and cost estimates but did not include the volume of the appliances. NYSERDA's deemed savings and cost database (Nexant, 2005) contained data for both refrigerators and freezers at common sizes.

Table 2-74 Solid-Door Refrigerators and Freezers – Review of Measure Information

Available Resource	Notes
PG&E 2005[41]	Energy savings and cost estimates for refrigerators and freezers at common sizes
DEER 2014[65]	Energy savings and cost estimates for refrigerators and freezers at common sizes
KEMA 2010[24]	Energy savings and cost estimates for refrigerators and freezers at common sizes
CEE[64]	Maximum daily energy consumption levels (kWh/day) for CEE-qualified commercial qualified food-grade refrigerators and freezers
ENERGY STAR[69]	Maximum daily energy consumption levels (kWh/day) for commercial qualified food-grade refrigerators and freezers
NEXANT 2005[31]	Energy savings and cost estimates for refrigerators and freezers at common sizes
PacifiCorp 2009[44]	Unitary savings included in comprehensive potential study

[294] Solid-door refrigerators and freezers were evaluated for four different sizes or volumes (V), 7.5, 22.5, 40 and 70 cubic feet. The unit will be operated for 365.25 days per year.

2.4.3.5 Incremental Cost

The incremental cost is provided in Table 2-75[295].

Table 2-75 Solid-Door Refrigerators and Freezers Incremental Costs

Type	Incremental Cost
Refrigerator	$143
	$164
	$164
	$249
Freezer	$142
	$166
	$166
	$407

2.4.3.6 Future Studies

This measure applies known values from ENERGY STAR; the TPE does not recommend focused study for this measure. Parameters should be updated to correspond to the most recent ENERGY STAR specification.

[295] For the purposes of this characterization, assume and incremental cost adder of 5% on the full unit costs presented in Goldberg et al, State of Wisconsin Public Service Commission of Wisconsin, Focus on Energy Evaluation, Business Programs: Incremental Cost Study, KEMA, October 28, 2009.

2.4.4 ADD SOLID DOORS TO OPEN REFRIGERATED AND FREEZER CASES

2.4.4.1 Measure Description

Open display cases are typically found in grocery and convenience stores and have been a preference of store owners because they allow customers a clear view and easy access to refrigerated products. This measure is retrofitting existing vertical, open, refrigerated display cases by adding and installing doors. The baseline equipment is an open vertical display case with no doors or covering. The efficient equipment is the installation of solid doors on the existing display case. Replacement of open display cases with new display cases with doors is not covered under this measure characterization.

This measure is applicable to refrigerated case doors with and without anti-condensation heaters. Standard refrigerated case doors include anti-condensation heaters in the frames, doors, or within the glass to prevent condensation from forming and obstructing view of refrigerated products. High efficiency doors with no anti-condensation heaters use a combination of multiple layers of glass, low-conductivity filler gas, and low-emissivity glass coatings to prevent condensation. This calculation quantifies the infiltration savings seen by the compressor.

If the retrofitted door has LED fixtures and is recommended to leverage Section 2.6 for quantifying savings and measure benefits.

2.4.4.2 Baseline and Efficiency Standards

The baseline condition is an open, refrigerated, display case without any covering. The efficient condition is retrofitting an existing open, refrigerated, display case by adding doors, either standard efficiency or high efficiency. Savings for both efficient cases are provided.

2.4.4.3 Estimated Useful Life

The expected measure life is 15 years[296].

2.4.4.4 Deemed Savings Values

Deemed energy savings per linear foot of case are based on a project that compared a typical open refrigerated display case line-up to a typical glass-doored refrigerated display case line-up.[297]

$$kWh\ Savings = \Delta Energy\ \times Case\ Width\ \times \left(1 - \frac{hours_{cooling}}{8{,}766} \times \frac{COP_{ref}}{COP_{HVAC}}\right)$$

$$kW\ Reduction = \frac{Savings_{kWh}}{8{,}766}$$

[296] The measure life is sourced from the PG&E Workpaper, “Add Doors to Open Medium Temperature Cases – PGE3PREF116 R3”, June 2019.

[297] Fricke, Brian and Becker, Bryan, "Energy Use of Doored and Open Vertical Refrigerated Display Cases" (2010). International Refrigeration and Air Conditioning Conference. Paper 1154. Values derived from Table 1 and the relative width of the display cases used in the study (without anti-sweat heaters). Energy savings assume 365.25 days of annual operation. Demand savings assume flat energy savings throughout the day. http://docs.lib.purdue.edu/iracc/1154

Where:

$\Delta Energy$ =

Equipment	Efficiency Level	kWh/linear foot[298,299]
Refrigerator	Standard	477
	High	747
Freezer	Standard	183
	High	392

$Case\ Width$ = Case width in linear feet (taken from project application)

$hours_{cooling}$= 3,470[300]

8,766 = 24 hours x 365.25 days annually

COP_{ref} = Coefficient of Performance of refrigeration equipment. From application; COP = 3.517/(kW/ton), where kW/ton is the rated efficiency of the compressor in input kW per ton of refrigeration capacity.

COP_{HVAC} = Coefficient of Performance of facility HVAC equipment. From application; COP = EER/3.412. If unknown, use 2.93 for grocery stores, 3.57 for other facility types[301]

2.4.4.5 Incremental Cost

The incremental cost, which includes both material and labor, differs depending on whether or not the installed door is equipped with LED lighting. The estimated incremental cost for doors without LED lighting is $390 per linear foot. The incremental cost for doors with LED lighting is $419 per linear foot.[302]

2.4.4.6 Future Studies

There are no future studies planned for this measure at this time.

---

[298] Fricke, Brian and Becker, Bryan, "Energy Use of Doored and Open Vertical Refrigerated Display Cases" (2010). International Refrigeration and Air Conditioning Conference. Paper 1154. Values derived from Table 1 and the relative width of the display cases used in the study (without anti-sweat heaters). Energy savings assume 365.25 days of annual operation. Demand savings assume flat energy savings throughout the day. http://docs.lib.purdue.edu/iracc/1154

[299] Energy savings do not include savings from ASH controllers. See sections 'D.4.2 Door Heater Controls for Refrigerators and Freezers' for ASH controller savings.

[300] Calculated using New Orleans TMY3 data.

[301] ASHRAE 90.1 2010 Standard for Unitary HVAC: Grocery Store default assumes a 25-ton packaged RTU (cooling only); Other default assumes a 10-ton packaged RTU (cooling only)

[302] The incremental cost is sourced from the PG&E Workpaper, "Add Doors to Open Medium Temperature Cases – PGE3PREF116 R3", June 2019. The incremental cost for retrofitting new doors on existing refrigerated display cases is thematerial cost of the door and the labor cost required for installation. The material cost of the doors is $331 per linear foot with LED lighting and $301 per linear foot without LED lighting. And the installation cost is $88 per linear foot. 1225 The change in heat gain is sourced as the typical value for a medium temperature vertical display case adding doors from the PG&E Workpaper, "Add Doors to Open Medium Temperature Cases - PGE3PREF116 R3", June 2019. The workpaper assumes a net reduction in heat gain with the installation of doors on open refrigerated display cases. The primary benefits account for the decrease in excess heat entering the display case from air infiltration. Radiation and conduction heat gains were also included in the derivation of this value. Additionally, the net heat gain has built in assumptions on how often the refrigerated case doors will be used and the display case accessed by customers and site associates, reducing some of the air infiltration benefits of the new door.

2.4.5 REFRIGERATED CASE NIGHT COVERS

2.4.5.1 *Measure Description*

This measure applies to the installation of night covers on otherwise open vertical (multi-deck) and horizontal (coffin-type) low-temperature (L) and medium temperature (M) display cases to decrease cooling load of the case during the night. It is recommended that these film-type covers have small, perforated holes to decrease the build-up of moisture.

Cases may be either: Self Contained (SC) having both evaporator and condenser coils, along with the compressor as part of the unit or Remote Condensing (RC) where the condensing unit and compressor are remotely located. Refrigerated case categories[303] are as follows:

- Vertical Open (VO): Equipment without doors and an air-curtain angle ≥ 0° and < 10°
- Semi-vertical Open (SVO): Equipment without doors and an air-curtain angle ≥ 10° and < 80°
- Horizontal Open (HO): Equipment without doors and an air-curtain angle ≥ 80°

The measure is standard practice in new construction and is only eligible for retrofit applications.

2.4.5.2 *Baseline and Efficiency Standards*

The baseline standard for this measure is an open low-temperature or medium temperature refrigerated display case (vertical or horizontal) that is not equipped with a night cover.

The efficiency standard for this measure is any suitable material sold as a night cover. The cover must be applied for a period of at least six hours per night.

2.4.5.3 *Estimated Useful Life*

According to the CA DEER 2014, night covers are assigned an EUL of 5 years.

2.4.5.4 *Deemed Savings Values*

The following outlines the assumptions and approach used to estimate demand and energy savings due to installation of night covers on open low- and medium-temperature, vertical and horizontal, display cases. Heat transfer components of the display case include infiltration (convection), transmission (conduction), and radiation. This deemed savings approach assumes that installing night covers on open display cases will only reduce the infiltration load on the case. Infiltration affects cooling load in the following ways:

- Infiltration accounts for approximately 80% of the total cooling load of open vertical (or multi-deck) display cases.[304]

---

[303] U.S. DOE, Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial Industrial Equipment, Commercial Refrigeration Equipment, Washington DC, p3-15

[304] ASHRAE 2006. Refrigeration Handbook. Retail Food Store Refrigeration and Equipment. Atlanta, Georgia. pp. 46.1, 46.5, 46.10.

- Infiltration accounts for approximately 24% of the total cooling load of open horizontal (coffin or tub style) display cases.[305]

Installing night covers for a period of 6 hours per night can reduce the cooling load due to infiltration. This was modeled by the U.S. DOE for vertical and semi-vertical cases.

Table 2-76 Vertical & Semi-vertical Refrigerated Case Savings

Case Type[306]	VO.RC.M	VO.RC.L	VO.SC.M	SVO.RC.M	SVO.SC.M
kWh per day- before Night Curtain	50.52	118.44	38.98	38.48	32.82
kWh per day - with Night Curtain	46.84	111.58	36.99	35.74	31.05
Percent kWh Savings per Day	7%	6%	5%	7%	5%
Annual kWh Savings	1,343	2,504	726	1,000	646
Test Case Length (ft.)	12	12	4	12	4

Table 2-77 Horizontal Refrigerated Case Savings

Case Type[307]	HO.RC.M	HO.RC.L	HO.SC.M	HO.SC.L
kWh per day- before Night Curtain[308]	15.44	34.23	16.06	35.02
kWh per day - with Night Curtain	14.05	31.15	14.61	31.87
Percent kWh Savings per Day[309]	9%	9%	9%	9%
Annual kWh Savings	507	1,124	528	1,150
Test Case Length (ft.)	12	12	4	4

While the DOE also modeled the energy consumption for horizontal open cases, there was not an efficient case modeled with a night cover. The 9% energy savings as found by Faramarzi & Woodworth-Szleper[6] was used to determine the post kWh per day.

Due to the relatively consistent summer dry-bulb temperature across the New Orleans weather zone, deemed savings values are only provided for the average dry-bulb temperature of 96°F.

Table 2-78 Refrigerated Case Night Covers – Deemed Savings Values (per Linear Foot)[310]

Case Description	Temperature	kWh Savings	kW Savings

[305] *Ibid.*

[306] U.S. DOE, Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial Industrial Equipment, Commercial Refrigeration Equipment, Washington DC, pp.5-43- 5-47, 5A-5, 5A-6

[307] *Ibid.*

[308] *Ibid.*

[309] ASHRAE 1999 Effects of Low-E Shields on the Performance and Power Use of a Refrigerated Display Case. Faramarzi & Woodworth-Szleper, p.8

[310] Pacific Gas & Electric (PG&E), 2009, "Night Covers for Open Vertical and Horizontal Display Cases (Low and Medium Temperature Cases).

	Range (°F)	(kWh/ft.)	(kW/ft.)
Vertical Open, Remote Condensing Medium Temperature	10 – 35 °F	112	0.00
Vertical Open, Remote Condensing Low Temperature	< 10 °F	209	0.00
Vertical Open, Self-Contained Medium Temperature	10 – 35 °F	182	0.00
Semi-vertical Open, Remote Condensing Medium Temperature	10 – 35 °F	83	0.00
Semi-vertical Open, Self-Contained Medium Temperature	10 – 35 °F	162	0.00
Horizontal Open, Remote Condensing Medium Temperature	10 – 35 °F	42	0.00
Horizontal Open, Remote Condensing Low Temperature	< 10 °F	94	0.00
Horizontal Open, Self-Contained Medium Temperature	10 – 35 °F	132	0.00
Horizontal Open, Self-Contained Low Temperature	< 10 °F	288	0.00

Table 2-79 Refrigerated Case Night Covers – Deemed Savings Values (per Night Cover)[311]

Case Description	Temp Range (°F)	Length (ft.)	kWh Savings (per cover)	kW Savings (per cover)
Vertical Open, Remote Condensing Medium Temperature	10 – 35 °F	12	1,344	0.00
Vertical Open, Remote Condensing Low Temperature	< 10 °F	12	2,508	0.00
Vertical Open, Self-Contained Medium Temperature	10 – 35 °F	4	728	0.00
Semi-vertical Open, Remote Condensing Medium Temperature	10 – 35 °F	12	996	0.00
Semi-vertical Open, Self-Contained Medium Temperature	10 – 35 °F	4	648	0.00
Horizontal Open, Remote Condensing Medium Temperature	10 – 35 °F	12	504	0.00
Horizontal Open, Remote Condensing Low Temperature	< 10 °F	12	1,128	0.00
Horizontal Open, Self-Contained Medium Temperature	10 – 35 °F	4	528	0.00
Horizontal Open, Self-Contained Low Temperature	< 10 °F	4	1,152	0.00

2.4.5.5 *Incremental Cost*

The full measure cost should be used. When not available, use $42 per linear foot (CA DEER 2014). For projects that lack size information, use: remote Condensing: $504; self-contained: $168; and unknown: $336

[311] Pacific Gas & Electric (PG&E), 2009, "Night Covers for Open Vertical and Horizontal Display Cases (Low and Medium Temperature Cases), May 29.

2.4.5.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure had low participation in Energy Smart programs. As a result, savings are calculated using weather-adjusted default values from other programs. If participation exceeds 500,000 kWh, the evaluation should include a metering study to support coverage time estimates.

2.4.6 STRIP CURTAINS

2.4.6.1 Measure Description

This measure applies to the installation of strip curtains on walk-in coolers and freezers. This reduces the load on the refrigeration system through reduced infiltration of warm ambient air into the walk-in unit. This measure is only eligible for retrofit applications. The measure is standard practice in new construction.

2.4.6.2 Baseline and Efficiency Standards

The baseline standard for this measure is a walk-in cooler or freezer with no preexisting strip curtains or damaged strip curtains.

2.4.6.3 Estimated Useful Life

According to the California Database of Energy Efficiency Resources (DEER, 2014), refrigerated case night covers are assigned an EUL of 5 years.

2.4.6.4 Deemed Savings Values

Calculation of savings from strip curtains is based on Tamm's equation[312] and the ASHRAE handbook[313].

The formula or savings from strip curtains is as follows:

$$\frac{kWh\,Savings}{ft.^2} = \frac{365 \times t_{open} \times (Eff_{new} - E_{old}) \times 20 \times CD \times A \times \left\{\left[\frac{(T_i - T_r)}{T_i}\right] \times g \times h\right\}^{0.5} \times [p_i \times h_i - p_r \times h_r]}{3{,}412\,\frac{BTU}{kWh} \times COP_{adj} \times A}$$

[312] Kalterveluste durch kuhlraumoffnungen. Tamm W,. Kaltetechnik-Klimatisierung 1966;18;142-144

[313] ASHRAE 2010. ASHRAE Handbook, Refrigeration: 13.4, 13.6

The parameters are defined in the tables below. Infiltration accounts for approximately 80% of the total cooling load of open vertical (or multi-deck) display cases.[314] Table 2-80 summarizes assumptions that are universal across facility types.

Table 2-81 through Table 2-84.

Table 2-84 summarize assumptions for specific facilities.

Table 2-80 Strip Curtain Universal Input Assumptions

Parameter	Unit	Value	Source
kWh savings / ft.^{2}	kWh savings / ft.^{2}	Calculated	Calculated
kW savings / ft.^{2}	kW savings / ft.^{2}	Calculated	Calculated
20: product of 60 seconds and integration factor of 1/3	Seconds/minute	20	Tamms equation
g, gravitational constant	ft./seconds^2	32.174	Physics constant
1073,412	BTU/kWh	3,412	Physics constant

Table 2-81 Strip Curtain Input Assumptions for Supermarkets

Parameter	Unit	Value		Source
		Coolers	Freezers	
Eff-new: efficacy for new strip curtain.	% of infiltration blocked	.88	.88	http://www.calmac.org/publications/ComFac_Evaluation_V1_Final_Report_02-18-2010.pdf
Eff-old: efficacy for preexisting condition	% of infiltration blocked	Old curtain: .58 No curtain: .00 Unknown: .34	Old curtain: .58 No curtain: .00 Unknown: .30	
CD: Discharge Coefficient, an empirically determined scale factor that accounts for difference in infiltration rates predicted by Bernoulli's law and actual observed rates	None	.336	.415	
t-open, minutes/day walk-in door is open	Minutes/ day	132	102	

314 ASHRAE 2006. Refrigeration Handbook. Retail Food Store Refrigeration and Equipment. Pp. 46.1, 46.5, 46.10.

A, doorway area	ft.^{2}	35	35	
H, doorway height	ft.	7	7	
T_i Dry-bulb temp. of infiltrating air	Deg. F	71	67	
T_i Dry-bulb temp. of refrigerated air	Deg. F	37	5	
COP_{adj}, Coefficient of performance of refrigerators and freezers	Unitless ratio	3.07	1.95	
P, Density of infiltration air at 55% RH	lb./ft.^{2}	.074	.074	Psychometric equations based on dry bulb and RH
h, Enthalpy of infiltration air at 55% RH	BTU/ft.^{2}	26.935	24.678	
p_r Density of refrigerated air at 80% RH	lb./ft.^{2}	.079	.085	
h_r Enthalpy of refrigerated air at 80% RH	BTU/ft.^{2}	12.933	2.081	

Table 2-82 Strip Curtain Input Assumptions for Convenience Stores

Parameter	Unit	Value		Source
		Coolers	Freezers	
Eff-new: efficacy for new strip curtain.	% of infiltration blocked	.79	.83	http://www.calmac.org/publications/ComFac_Evaluation_V1_Final_Report_02-18-2010.pdf
Eff-old: efficacy for preexisting condition	% of infiltration blocked	Old curtain: .58 No curtain: .00 Unknown: .34	Old curtain: .58 No curtain: .00 Unknown: .30	
CD: Discharge Coefficient, an empirically determined scale factor that accounts for difference in infiltration rates predicted by Bernoulli's law and actual observed rates	None	.348	.421	
t-open, minutes/day walk-in door is open	Minutes/day	38	9	
A, doorway area	ft.^{2}	21	21	
H, doorway height	ft.	7	7	
T_i Dry-bulb temp. of infiltrating air	Deg. F	68	64	
T_i Dry-bulb temp. of refrigerated air	Deg. F	39	5	
COP_{adj}, Coefficient of performance of refrigerators and freezers	Unitless ratio	3.07	1.95	
P, Density of infiltration air at 55% RH	lb./ft.^{2}	.074	.074	Psychometric equations based on dry bulb and RH
h, Enthalpy of infiltration air at 55% RH	BTU/ft.^{2}	25.227	23.087	
p_r Density of refrigerated air at 80% RH	lb./ft.^{2}	.079	.085	

h_r Enthalpy of refrigerated air at 80% RH	BTU/ft.^{2}	13.750	2.081	

Table 2-83 Strip Curtain Input Assumptions for Restaurants

Parameter	Unit	Value		Source
		Coolers	Freezers	
Eff-new: efficacy for new strip curtain.	% of infiltration blocked	.80	.81	http://www.calmac.org/publications/ComFac_Evaluation_V1_Final_Report_02-18-2010.pdf
Eff-old: efficacy for preexisting condition	% of infiltration blocked	Old curtain: .58 No curtain: .00 Unknown: .33	Old curtain: .58 No curtain: .00 Unknown: .26	
CD: Discharge Coefficient, an empirically determined scale factor that accounts for difference in infiltration rates predicted by Bernoulli's law and actual observed rates	None	.383	.442	
t-open, minutes/day walk-in door is open	Minutes/day	45	38	
A, doorway area	ft.^{2}	21	21	
H, doorway height	ft.	7	7	
T_i Dry-bulb temp. of infiltrating air	Deg. F	70	67	
T_i Dry-bulb temp. of refrigerated air	Deg. F	39	8	
COP_{adj}, Coefficient of performance of refrigerators and freezers	Unitless ratio	3.07	1.95	
P, Density of infiltration air at 55% RH	lb./ft.^{2}	.074	.074	Psychometric equations based on dry bulb and RH
h, Enthalpy of infiltration air at 55% RH	BTU/ft.^{2}	26.356	24.678	
p_r Density of refrigerated air at 80% RH	lb./ft.^{2}	.079	.085	
h_r Enthalpy of refrigerated air at 80% RH	BTU/ft.^{2}	13.750	2.948	

Table 2-84 Strip Curtain Input Assumptions for Refrigerated Warehouses

Parameter	Unit	Value	Source
Eff-new: efficacy for new strip curtain.	% of infiltration blocked	.80	http://www.calmac.org/publications/ComFac_Evaluation_V1_Fin
Eff-old: efficacy for preexisting condition	% of infiltration blocked	Old curtain: .58 No curtain: .00 Unknown: .54	

CD: Discharge Coefficient, an empirically determined scale factor that accounts for difference in infiltration rates predicted by Bernoulli's law and actual observed rates	None	.425	al_Report_02-18-2010.pdf
t-open, minutes/day walk-in door is open	Minutes/day	494	
A, doorway area	ft.^{2}	80	
H, doorway height	ft.	10	
T_i Dry-bulb temp. of infiltrating air	Deg. F	59	
T_i Dry-bulb temp. of refrigerated air	Deg. F	28	
COP_{adj}, Coefficient of performance of refrigerators and freezers	Unitless ratio	1.91	
P, Density of infiltration air at 55% RH	lb./ft.^{2}	.076	Psychometric equations based on dry bulb and RH
h, Enthalpy of infiltration air at 55% RH	BTU/ft.^{2}	20.609	
p_r Density of refrigerated air at 80% RH	lb./ft.^{2}	.081	
h_r Enthalpy of refrigerated air at 80% RH	BTU/ft.^{2}	9.462	

Table 2-85 summarizes savings by system, baseline, and facility type for strip curtains on a per-square-foot basis.

Table 2-85 Strip Curtains – Deemed Savings Values (per Square Foot)[315]

Case Description	Preexisting Curtains	kWh Savings (kWh/ft.^{2})	kW Savings (kWh/ft.^{2})
Supermarket – Cooler	Yes	62	0.00708
Supermarket – Cooler	No	108	0.01233
Supermarket – Cooler	Unknown	37	0.00422
Supermarket – Freezer	Yes	179	0.02043
Supermarket – Freezer	No	349	0.03984
Supermarket – Freezer	Unknown	61	0.00696
Convenience Store - Cooler	Yes	5	0.00057
Convenience Store - Cooler	No	20	0.00228
Convenience Store - Cooler	Unknown	11	0.00126
Convenience Store - Freezer	Yes	8	0.00091
Convenience Store - Freezer	No	27	0.00308
Convenience Store - Freezer	Unknown	17	0.00194
Restaurant - Cooler	Yes	8	0.00091
Restaurant – Cooler	No	30	0.00342
Restaurant – Cooler	Unknown	18	0.00205
Restaurant - Freezer	Yes	34	0.00388
Restaurant - Freezer	No	119	0.01358
Restaurant - Freezer	Unknown	81	0.00925
Refrigerated Warehouse	Yes	254	0.02900
Refrigerated Warehouse	No	729	0.08322
Refrigerated Warehouse	Unknown	287	0.03276

[315] Pacific Gas & Electric (PG&E), 2009, "Night Covers for Open Vertical and Horizontal Display Cases (Low and Medium Temperature Cases).

Table 2-86 summarizes the deemed savings that should be used when project-specific data is not available.

These values are per-walk-in door and assume the following:

- Doorway area: Supermarket: 35; Convenience Store: 21; Restaurant: 21; and Refrigerated Warehouse: 80
- Preexisting curtains: Unknown

Table 2-86 Strip Curtains – Deemed Savings Values (per door)[316]

Case Description	Preexisting Curtains	kWh Savings (kWh/door)	kW Savings (kW/door)
Supermarket – Cooler	Unknown	1,295	0.1477
Supermarket – Freezer	Unknown	2,135	0.2436
Convenience Store - Cooler	Unknown	231	0.02646
Convenience Store - Freezer	Unknown	357	0.04074
Restaurant – Cooler	Unknown	378	0.04305
Restaurant - Freezer	Unknown	1,701	0.19425
Refrigerated Warehouse	Unknown	22,960	2.6208

2.4.6.5 Incremental Cost

The full measure cost should be used. When not available, use $10.22 per linear foot (DEER, 2014).

For projects that lack specific inputs for size, the default incremental costs are Supermarket: $358; Convenience Store: $215; Restaurant: $215; and Refrigerated Warehouse: $818

2.4.6.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure had low participation in Energy Smart programs. As a result, savings are calculated using weather-adjusted default values from other programs. If participation exceeds 500,000 kWh, the evaluation should include a metering study to support coverage time estimates.

[316] *Ibid.*

2.4.7 ZERO ENERGY DOORS

2.4.7.1 Measure Description

This measure applies to the installation of zero energy doors for refrigerated cases. Zero energy doors eliminate the need for anti-sweat heaters to prevent the formation of condensation on the glass surface by incorporating heat reflective coatings on the glass, gas inserted between the panes, non-metallic spacers to separate glass panes, and/or non-metallic frames.

This measure cannot be used in conjunction with anti-sweat heat (ASH) controls.

2.4.7.2 Baseline and Efficiency Standards

The baseline standard for this measure is a standard vertical reach-in refrigerated cooler or freezer with anti-sweat heaters on the glass surface of the doors.

The efficiency standard for this measure is a reach-in refrigerated cooler or freezer with special doors installed to eliminate the need for anti-sweat heaters. Doors must have either heat reflective treated glass, be gas-filled, or both.

2.4.7.3 Estimated Useful Life

According to the CA DEER, zero energy doors are assigned an EUL of 12 years.

2.4.7.4 Deemed Savings Values

$$kW_{savings} = kW_{door} \times BF$$

$$kWh_{savings} = kW_{savings} \times 8760$$

Where:

kW_{door} = Connected load kW of a typical reach-in cooler or freezer door with a heater

BF = Bonus factor for reducing cooling load from eliminating heat generated by the door heater from entering the cooler or freezer

8760 = Annual operating hours

Table 2-87 Assumptions for Savings Calculations

Variable	Deemed Values
kW_{door}[317]	Cooler: 0.075 Freezer: 0.200

[317] Based on range of wattages from two manufacturers and metered data (cooler 50-130W, freezer 200-320W). Efficiency Vermont Commercial Master Technical Reference Manual No. 2005-37.

BF[318]	Low-Temp Freezer: 1.3 Medium-Temp Cooler: 1.2 High-Temp Cooler: 1.1

Table 2-88 Zero Energy Doors – Deemed Savings Values (per door)[319]

Measure	kWh Savings	kW Savings	Measure
Low-Temperature Freezer (< 25°F)	2,278	0.26	Low-Temperature Freezer (< 25°F)
Medium-Temperature Cooler (25° - 40°F)	2,102	0.24	Medium-Temperature Cooler (25° - 40°F)
High-Temperature Cooler (41° - 65°F)	723	0.08	High-Temperature Cooler (41° - 65°F)

2.4.7.5 Incremental Cost

The incremental cost is $290 per door.[320]

2.4.7.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. If this measure is added to Energy Smart, The TPE recommends a baseline study to capture the market share of ASH-controlled doors versus uncontrolled doors.

[318] Bonus factor (1+0.65/COP) assumes 2.0 COP for low temp, 3.5 COP for medium temp, and 5.4 COP for high temp, based on the average of standard reciprocating and discuss compressor efficiencies with Saturated Suction Temperatures of -20ºF, 20ºF, and 45ºF, respectively, and a condensing temperature of 90ºF, and manufacturers assumption that 65% of heat generated by door enters the refrigerated case. Efficiency Vermont Commercial Master Technical Reference Manual No. 2005-37.

[319] Temperature ranges based on Commercial Refrigeration Rebate Form, p, 3. Efficiency Vermont. https://www.efficiencyvermont.com/Media/Default/docs/rebates/forms/efficiency-vermont-commercial-refrigeration-rebate-form.pdf.

[320] Vermont TRM

2.4.8 EVAPORATOR FAN CONTROLS

2.4.8.1 *Measure Description*

This measure applies to the installation of evaporator fan controls. As walk-in cooler and freezer evaporators often run continuously, this measure consists of a control system that turns the fan on only when the unit's thermostat is calling for the compressor to operate.

2.4.8.2 *Baseline and Efficiency Standards*

The baseline standard for this measure is an existing shaded pole evaporator fan motor with no temperature controls with 8,760 annual operating hours.

The efficiency standard for this measure is an energy management system (EMS) or other electronic controls to modulate evaporator fan operation based on temperature of the refrigerated space.

2.4.8.3 *Estimated Useful Life*

According to the CA DEER database evaporator fan controls are assigned an EUL of 16 years.[321]

2.4.8.4 *Deemed Savings Values*

Table 2-89 Evaporator Fan Controls Deemed Savings Values

Measure	kWh Savings	kW Savings
Low-Temperature Freezer (< 25°F)	543	0.062
Medium-Temperature Cooler (25° - 40°F)	501	0.057
High-Temperature Cooler (41° - 65°F)	463	0.053

The energy savings from the installation of evaporator fan controls are a result of savings due to the reduction in operation of the fan. The energy and demand reduction are calculated using the following equations:

$$kW_{savings} = \left[\left(kW_{evap} \times n_{fans}\right) - kW_{circ}\right] \times \left(1 - DC_{comp}\right) \times DC_{evap} \times BF$$

$$kWh_{savings} = kW_{savings} \times 8760$$

Where:

kW_{evap} = Nameplate connected load kW of each evaporator fan = 0.123 kW (default) [322]

kW_{circ} = Nameplate connected load kW of the circulating fan = 0.035 kW (default) [323]

[321] Database for Energy Efficient Resources (2014). http://www.deeresources.com/.

[322] Based on a weighted average of 80% shaded pole motors at 132 watts and 20% PSC motors at 88 watts.

[323] Wattage of fan used by Freeaire and Cooltrol.

n_{fans} = Number of evaporator fans

DC_{comp} = Duty cycle of the compressor = 50% (default) [324]

DC_{evap} = Duty cycle of the evaporator fan = Coolers: 100%; Freezers: 94% (default) [325]

BF = Bonus factor for reducing cooling load from replacing the evaporator fan with a lower wattage circulating fan when the compressor is not running = Low Temp.: 1.5, Medium Temp.: 1.3, High Temp.: 1.2 (default)[326]

8760 = Annual hours per year

2.4.8.5 Incremental Cost

The incremental cost is $291 per unit[327].

2.4.8.6 Future Studies

At the time of authorship, this measure had low participation in Energy Smart programs. As a result, savings are calculated using weather-adjusted default values from other programs. If participation exceeds 500,000 kWh, the evaluation should include a metering study to support energy savings estimates.

---

[324] A 50% duty cycle is assumed based on examination of duty cycle assumptions from Richard Traverse (35%-65%), Control (35%-65%), Natural Cool (70%), Pacific Gas & Electric (58%). Also, manufacturers typically size equipment with a built-in 67% duty factor and contractors typically adds another 25% safety factor, which results in a 50% overall duty factor.

[325] An evaporator fan in a cooler runs all the time, but a freezer only runs 8273 hours per year due to defrost cycles (4 20-min defrost cycles per day).

[326] Bonus factor (1+1/COP) assumes 2.0 COP for low temp, 3.5 COP for medium temp, and 5.4 COP for high temp, based on the average of standard reciprocating and discus compressor efficiencies with Saturated Suction Temperatures of -20°F, 20°F, and 45°F, respectively, and a condensing temperature of 90°F.

[327] CA DEER, 2014

2.5 Food Service

2.5.1 ENERGY STAR GRIDDLES

2.5.1.1 Measure Description

This measure applies to ENERGY STAR electric commercial griddles in retrofit and new construction applications. This appliance is designed for cooking food in oil or its own juices by direct contact with either a flat, smooth, hot surface or a hot channeled cooking surface where plate temperature is thermostatically controlled.

Energy-efficient commercial electric griddles reduce energy consumption primarily through application of advanced controls and improved temperature uniformity. Energy efficient commercial gas griddles reduce energy consumption primarily through advanced burner design and controls.

2.5.1.2 Baseline and Efficiency Standards

Key parameters for defining griddle efficiency are Heavy Load Cooking Energy Efficiency and Idle Energy Rate. There are currently no federal minimum standards for Commercial Griddles, however, the American Society of Testing and Materials (ASTM) publishes Test Methods[328] that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

ENERGY STAR efficiency requirements apply to single and double-sided griddles. The ENERGY STAR criteria should be reviewed on an annual basis to reflect the latest requirements.

Table 2-90 ENERGY STAR Criteria[329] for Electric and Gas Single- and Double-Sided Griddles

Performance Parameters	**Electric Griddles**
Heavy-Load Cooking Energy Efficiency	≥70%
Idle Energy Rate	≤320 watts per ft^2

2.5.1.3 Estimated Useful Life

According to the CA DEER commercial griddles are assigned an EUL of 12 years.[330]

2.5.1.4 Deemed Savings Values

Annual savings can be calculated by determining the energy consumed by a standard efficiency griddle as compared with an ENERGY STAR rated griddle.

$$\Delta kWh = kWhbase - kWheff$$

---

328 The industry standard for energy use and cooking performance of griddles are ASTM F1275-03: Standard Test Method for the Performance of Griddles and ASTM F1605-01: Standard Test Method for the Performance of Double-Sided Griddles

329 ENERGY STAR Commercial Griddles Program Requirements Version 1.1, effective May 2009 for gas griddles and effective January 1, 2011 for electric.

330 Database for Energy Efficient Resources, 2008, http://www.deeresources.com/deer0911planning/downloads/EUL_Summary_10-1-08.xls

$$kWh(base\ or\ eff) = kWhcooking + kWhidle + kWhpreheat$$

$$kWhcooking = \left(LBfood \times \frac{Efood}{CookEff}\right) \times Days$$

$$kWhidle = IdleEnergy\ \times\ (DailyHrs - \frac{LBfood}{Capacity} - \frac{PreheatTime}{60}) \times Days$$

$$kWhpreheat = PreheatEnergy\ \times Days$$

Key parameters used to compute savings are defined in Table 2-91.

Table 2-91 Energy Consumption Related Parameters for Commercial Griddles[331]

Parameter	Description	Value	Source
Daily Hrs.	Daily Operating Hours	12 hours	FSTC
Preheat Time	Time to Preheat (Min)	15 Minutes	FSTC
E_{food}	ASTM defined Energy to Food	0.139 kWh/lb., 475 Btu/lb	FSTC
Days	Number of Days of operation	365 Days	FSTC
CookEff	Cooking Energy Efficiency (%)	See Table 2-92	FSTC
IdleEnergy	Idle energy rate (kW), (Btu/h)		FSTC, ENERGY STAR
Capacity	Production capacity (lbs./hr)		FSTC
Preheat Energy	kWh/day, Btu/day		FSTC
LB_{Food}	Food cooked per day (lb/day)		FSTC

General assumptions used for deriving deemed electric and gas savings are values are taken from the Food Service Technology Center (FSTC) work papers.[332] These deemed values assume that the griddles are 3 x 2 feet in size. Parameters in the table are per linear foot, with an assumed depth of 2 feet.

[331] Assumptions based on PG&E Commercial Griddles Work Paper developed by FSTC, May 22, 2012.

[332] FSTC food service equipment work papers submitted to CPUC for Energy Efficiency 2013-2014 Portfolio; document titled EnergyEfficiency2013-2014-Portfolio_Test_PGE_20120702_242194.zip

https://www.pge.com/regulation/EnergyEfficiency2013-2014-Portfolio/Testimony/PGE/2012/EnergyEfficiency2013-2014-Portfolio_Test_PGE_20120702_242194.zip.

Table 2-92 Baseline and Efficient Assumptions for Electric Griddles

Parameter	Baseline Electric Griddles	Efficient Electric Griddles
Preheat Energy (kWh/ft.)	1.33	0.67
Idle Energy Rate (kW/ft.)	0.8	0.64
Cooking Energy Efficiency (%)	65%	70%
Production Capacity (lbs./h/ft.)	11.7	16.33
Lbs. of food cooked/day/ft.	33.33	33.33

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta kW = (\frac{\Delta kWh}{HOURS}) \times CF$$

Where:

ΔkWh = Annual energy savings (kWh)

4380 = Operating Equivalent hours = 365 x 12 = 4380 hours

0.84[333] = Coincidence Factor (CF)

Deemed savings based on the assumptions above are tabulated below per griddle, per linear foot.

Table 2-93 Deemed Savings for Electric and Gas Commercial Griddles per Linear Foot

Measure Description	Deemed Savings per Griddle per linear foot	
	kW	kWh
Griddle, Electric, ENERGY STAR	0.15	758

2.5.1.5 *Incremental Cost*

The incremental cost is $60 per linear foot of width of the unit[334].

2.5.1.6 *Future Studies*

At the time of authorship, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from FSTC. If this measure is added to Energy Smart programs, the evaluation should include an assessment of actual usage schedules to replace the default FSTC schedule values.

333 Coincidence factors utilized in other jurisdictions for Commercial Griddles vary from 0.84 to 1.0. The KEMA report titled “Business Programs: Deemed Savings Parameter Development,” November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

334 Measure cost from ENERGY STAR which cites reference as “EPA research on available models using AutoQuotes, 2010” http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COG

2.5.2 ENERGY STAR CONVECTION OVENS

2.5.2.1 Measure Description

High efficiency ovens exhibit better baking uniformity and higher production capacities while also including high-quality components and controls.

2.5.2.2 Baseline and Efficiency Standards

Efficient convection ovens are defined by ENERGY STAR or its equivalent and apply to electric full-size and half-size convection ovens and gas full-size convection ovens. Full size ovens accept a minimum of five pans measuring 18 x 26 x 1-inch. Half size ovens accept a minimum of five sheet pans measuring 18 x 13 x 1-inch. The ENERGY STAR criteria should be reviewed on an annual basis to reflect the latest requirements.

There are currently no federal minimum standards for Commercial Convection Ovens, however, the American Society of Testing and Materials (ASTM) publishes Test Methods[335] that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

Table 2-94: ENERGY STAR Criteria for Electric Convection Ovens[336]

Performance Parameters	Half Size Electric Ovens	Full Size Electric Ovens ≥ 5 Pans	Full Size Electric Ovens <5 Pans
Heavy-Load Cooking Energy Efficiency	≥71%	≥76%	
Idle Energy Rate	≤1.0 kW	≤1.4 kW	≤1.6 kW

2.5.2.3 Estimated Useful Life

According to the CA DEER, all commercial ovens are assigned an EUL of 12 years.[337]

2.5.2.4 Deemed Savings Values

Annual savings can be calculated by determining the energy consumed by a standard efficiency convection oven as compared with an ENERGY STAR rated convection oven.

$$\Delta kWh = kWhbase - kWheff$$

$$kWh(base\ or\ eff) = kWhcooking + kWhidle + kWhpreheat$$

[335] The industry standard for energy use and cooking performance of convection ovens is ASTM F-2861-10, Standard Test Method for Enhanced Performance of Combination Oven in Various Modes.

[336] ENERGY STAR Commercial Ovens Version 1.1, effective May 2009; Version 2.0 is currently under development to be released by 2013. New efficiency levels will be identified and scope will add Combination Ovens.

[337] Database for Energy Efficient Resources, 2008, http://www.deeresources.com/deer0911planning/downloads/EUL_Summary_10-1-08.xls

$$kWhcooking = \left(LB \times \frac{Efood}{CookEff}\right) \times Days$$

$$kWhidle = IdleEnergy \times \left(DailyHrs - \frac{LB}{Capacity} - \frac{PreheatTime}{60}\right) \times Days$$

$$kWhpreheat = PreheatEnergy \times Days$$

General assumptions in Table 2-95 are from the ENERGY STAR *Commercial Kitchen Equipment Savings Calculator – Convection Ovens* which refers to the Food Service Technology Center (FSTC) work papers and research.[338]

Table 2-95 Baseline and Efficient Assumptions for Electric Convection Ovens

Parameter	Half Size Electric Ovens		Full Size Electric Ovens	
	Baseline Model	Efficient Model	Baseline Model	Efficient Model
Preheat Energy (kWh/day)	0.89	0.7	1.563	1.389
Idle Energy Rate (kW)	1.03	1.00	2.00	< 5 pans: 1.0 ≥ 5 pans: 1.4
Cooking Energy Efficiency (%)	68%	71%	65%	76%
Production Capacity (lbs./hour)	45	50	90	90
Lbs. of food cooked/day	100	100	100	100
Efood (kWh/lb)	0.0732	0.0732	0.0732	0.0732
Days	365	365	365	365
Daily Hours	12	12	12	12
Preheat Time	9	8	9	9

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta kW = \left(\frac{\Delta kWh}{HOURS}\right) \times CF$$

338 FSTC food service equipment workpapers submitted to CPUC for Energy Efficiency 2013-2014 Portfolio; document titled EnergyEfficiency2013-2014-Portfolio_Test_PGE_20120702_242194.zip

Where:

ΔkWh = Annual energy savings (kWh)

$HOURS$ = Operating Equivalent hours = 365 x 12 = 4,380 hours[339]

CF = Coincidence Factor = 0.84[340]

Deemed savings based on the assumptions above are tabulated below for electric convection ovens.

Table 2-96 Deemed Savings Estimates for Electric Convection Ovens

Measure Description	Deemed Savings per Oven	
	kWh	kW
Half Size Electric Ovens	254	0.049
Full Size Electric Ovens < 5 Pans	4,578	0.878
Full Size Electric Ovens ≥ 5 Pans	3,010	0.577

2.5.2.5 Incremental Cost

The incremental cost for this measure is $1,022.[341]

2.5.2.6 Future Studies

There are currently no future studies planned for this measure at this time.

339 ENERGY STAR Commercial Kitchen Equipment Savings Calculator – Convection Ovens assumes an operating time of 12 hours.

340 KEMA report titled "Business Programs: Deemed Savings Parameter Development," November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

341 Measure cost from ENERGY STAR which references the "2016 IMC Analysis – For Cal TF (Energy Solutions)" document from: https://www.caetrm.com/media/reference-documents/2016_IMC_Analysis_-_For_Cal_TF_Energy_Solutions.xlsx

2.5.3 ENERGY STAR COMBINATION OVENS

2.5.3.1 Measure Description

Combination (“combi”) ovens are convection ovens with a steam cooking mode.

2.5.3.2 Baseline and Efficiency Standards

There are currently no federal minimum standards for Commercial Combination Ovens, however, the American Society of Testing and Materials (ASTM) publishes Test Methods611 that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

As of January 12, 2023, ENERGY STAR 3.0 specification applies to electric combination ovens. Combination ovens combines the function of hot air convection (oven mode), saturated and superheated steam heating (steam mode), and combination convection/steam mode for moist heating, to perform steaming, baking, roasting, rethermalizing, and proofing of various food products.

Table 2-97 High Efficiency Requirements for Electric Combination Ovens by Pan Capacity

Mode	Idle Rate	Cooking Efficiency (%)
Full and Half Size5-40 Pan Capacity (P)		
Steam Mode	≤ 0.133P + 0.64 kW	≥ 55%
Convection Mode	≤ 0.083P + 0.35 kW	≥ 78%
3 – 4 Pan Capacity and 2/3rd Size with 3-5 Pan Capacity		
Steam Mode	≤ 0.60P	≥ 51%
Convection Mode	≤ 0.05P + 0.55	≥ 70%

2.5.3.3 Estimated Useful Life

According to the CA DEER, all commercial ovens are assigned an EUL of 12 years.[342]

2.5.3.4 Deemed Savings Values

Annual savings can be calculated by determining the energy consumed by a standard efficiency combination oven as compared with a high efficiency combination oven.

$$\Delta kWh = kWhtotal,base - kWhtotal,eff$$

$$kWh(total,base\ or\ total,eff) = kWhoven + kWhsteam + kWhpreheat$$

$$kWh(oven\ or\ steam) = kWhcooking + kWhidle$$

[342] Database for Energy Efficient Resources, 2008, http://www.deeresources.com/deer0911planning/downloads/EUL_Summary_10-1-08.xls

$$kWhcooking\ (oven\ or\ steam) = (LBoven\ or\ steam \times \frac{Efood}{\text{CookEff}}) \times Days$$

Where:

LB$_{oven}$ = LB × (1-% Steam) and LB$_{steam}$ = LB × % Steam

$$kWhidle(oven)$$

$$= (1 - \%Steam) \times IdleEnergy \times (DailyHrs - LBovenCapacity$$

$$- nP \times PreheatTime60) \times Days$$

$$kWhidle(steam)$$

$$= (\%Steam) \times IdleEnergy\ \times\ (DailyHrs - LBsteamCapacity$$

$$- np \times PreheatTime60) \times Days$$

$$kWhpreheat = nP \times PreheatEnergy\ \times Days$$

For kWh$_{idle}$ calculations below, use the correct oven/steam specific parameters as outlined in **Error! Reference source not found.**.

$$kWh_{idle}\ (oven)$$

$$= (1 - \%Steam) \times IdleEnergy \times (DailyHrs - LBCapacity$$

$$- PreheatTime60) \times Days$$

$$kWh_{idle}\ (steam)$$

$$= (\%Steam) \times IdleEnergy\ \times\ (DailyHrs - LBCapacity$$

$$- PreheatTime60) \times Days$$

$$kWhpreheat = PreheatEnergy\ \times Days$$

Key parameters used to compute savings are listed in Table 2-98.

Table 2-98 Energy Consumption Parameters for Commercial Combination Ovens[343]

Parameter	Description	Baseline	Efficient
CookEffoven 3-4 pans	Cooking efficiency (%) Convection Mode	69%	70%
CookEffoven 5-40 pans	Cooking efficiency (%) Convection Mode	69%	78%
CookEffsteam 3-4 pans	Cooking efficiency (%) Steam Mode	45%	51%
CookEffsteam 5-40 pans	Cooking efficiency (%) Steam Mode	45%	55%
IdleEnergyoven	Idle energy rate (kW)	1.32	1.299
IdleEnergysteam		5.26	1.97
Capacityoven	Production capacity (lbs./hr)	79	119
Capacitysteam		126	177
PreheatTime	Time to Preheat (Min)	15	
PreheatEnergy	kWh/day	3	1.5
% Steam	Percent of time in Steam Mode	50%	
Efoodoven	ASTM defined Convection Oven Energy to Food (kWh/lb)	0.0732	
Efoodsteam	ASTM defined Energy to Food for Steam Cookers (kWh/lb)	0.0308	

343 All baseline and efficient data in this table are extracted from the ENERGY STAR Commercial Food Service Calculator and have been modified based on the ENERGY STAR V.3 Commercial Oven Program Requirements from: https://www.energystar.gov/sites/default/files/asset/document/ENERGY%20STAR%20Version%203.0%20Commercial%20Ovens%20Final%20Specification.pdf

LB	Food cooked per day (lb/day) in steam mode or oven mode	100
DailyHrs	Daily Operating Hours	12
Days	Number of days of operation	365

General assumptions used for deriving deemed savings are defined in the following tables. These values were taken from the ENERGY STAR Food Service Appliance Calculator as well as the Food Service Technology Center (FSTC) Life Cycle and Energy Cost Calculator.

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta kW = \left(\frac{\Delta kWh}{HOURS}\right) \times CF$$

Where:

ΔkWh = Annual energy savings (kWh)

$HOURS$ = Operating Equivalent hours = 365 x 12 = 4,380 hours[344]

CF = Coincidence Factor = 0.84[345]

2.5.3.5 Deemed Savings Estimates for Combination Ovens

Deemed savings values are listed below:

- Combination Oven, Electric, ENERGY STAR Deemed Savings kWh – 6,368
- Combination Oven, Electric, ENERGY STAR Deemed Peak Demand Savings kW – 1.22

2.5.3.6 Incremental Cost

The incremental cost is $2,000 for electric combination ovens[346].

2.5.3.7 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from Energy Star. If this measure is added to Energy Smart programs, the evaluation should include an assessment of actual usage schedules to replace the default Energy Star schedule values.

---

[344] ENERGY STAR Commercial Kitchen Equipment Savings Calculator – Convection Ovens assumes an operating time of 12 hours.

[345] KEMA report titled "Business Programs: Deemed Savings Manual V1.0," March 2010 conducted for State of Wisconsin Public Service Commission of Wisconsin lists Coincidence Factors by building type and identifies food service at 0.84.

[346]Incremental cost for combination oven is from the ENERGY STAR Commercial Food Service Calculator, which references the "Combi 2016 Prices Updated" document from: https://www.caetrm.com/media/reference-documents/Combi_2016_Prices_Updated.xlsx

2.5.4 FRYERS

2.5.4.1 Measure Description

This measure applies to ENERGY STAR or its equivalent electric commercial open-deep fat fryers in retrofit and new construction applications. Commercial fryers consist of a reservoir of cooking oil that allows food to be fully submerged without touching the bottom of the vessel. Electric fryers use a heating element immersed in the cooking oil.

High efficiency standard and large vat fryers offer shorter cook times and higher production rates through the use of advanced burner and heat exchanger design. Standby losses are reduced in more efficient models through the use of fry pot insulation.

2.5.4.2 Baseline & Efficiency Standard

Key parameters for defining fryer efficiency are Heavy Load Cooking Energy Efficiency and Idle Energy Rate. ENERGY STAR requirements apply to a standard fryer and a large vat fryer. A standard fryer measures 14 to 18 inches wide with a vat capacity from 25 to 60 pounds. A large vat fryer measures 18 inches to 24 inches wide with a vat capacity greater than 50 pounds. The ENERGY STAR criteria should be reviewed on an annual basis to reflect the latest requirements.

There are currently no federal minimum standards for Commercial Fryers, however, ASTM publishes Test Methods[347] that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

Table 2-99 ENERGY STAR Criteria[348] and FSTC Baseline for Open Deep-Vat Electric Fryers

Performance Parameters	**ENERGY STAR Electric Fryer Criteria**	
	Standard Fryers	**Large Vat Fryers**
Heavy-Load Cooking Energy Efficiency	> 83%	> 80%
Idle Energy Rate	< 800 W	<1,100 W

2.5.4.3 Estimated Useful Life

According to DEER 2014, commercial fryers are assigned an EUL of 12 years.[349]

2.5.4.4 Deemed Savings Values

Annual savings can be calculated by determining the energy consumed by a standard efficiency fryer as compared with an ENERGY STAR rated fryer.

[347] The industry standards for energy use and cooking performance of fryers are ASTM Standard Test Method for the Performance of Open Deep Fat Fryers (F1361) and ASTM Standard Test Method for the Performance of Large Vat Fryers (FF2144).

[348] ENERGY STAR Program Requirements for Commercial Fryers, Version 3.0 https://www.energystar.gov/sites/default/files/ENERGY%20STAR%20Commercial%20Fryers%20Version%203.0%20%28Rev.%20December%20-%202020%29%20Specification.pdf

[349] Database for Energy Efficient Resources, 2008, http://www.deeresources.com/deer0911planning/downloads/EUL_Summary_10-1-08.xls

$$\Delta kWh = kWhbase - kWheff$$

$$kWh(base\ or\ eff) = kWhcooking + kWhidle + kWhpreheat$$

$$kWhcooking = \left(LB \times \frac{Efood}{CookEff}\right) \times Days$$

$$kWhidle = IdleEnergy \times \left(DailyHrs - \frac{LB}{Capacity} - \frac{PreheatTime}{60}\right) \times Days$$

$$kWhpreheat = PreheatEnergy \times Days$$

Key parameters used to compute savings are defined in Table 2-100.

Table 2-100 Energy Consumption Related Parameters for Commercial Fryers[350]

Parameter	Description	Value	Source
Daily Hrs.	Daily Operating Hours	12 hours	FSTC
Preheat Time	Time to Preheat (Min)	15 Minutes	FSTC
E_{food}	ASTM defined Energy to Food	0.167 kWh/lb, 570 Btu/lb.	FSTC
Days	Number of Days of operation	365 Days	FSTC
CookEff	Cooking Energy Efficiency (%)	See Table 2-101	FSTC
IdleEnergy	Idle energy rate (kW), (Btu/h)		FSTC, ENERGY STAR
Capacity	Production capacity (lbs./hr)		FSTC
Preheat Energy	kWh/day, Btu/day		FSTC
LB	Food cooked per day (lb/day)		FSTC

General assumptions used for deriving deemed electric and gas savings are defined in the following tables. These values are taken from the ENERGY STAR *Commercial Kitchen Equipment Savings* Calculator as well as the Food Service Technology Center (FSTC) work papers and research.

350 Assumptions based on PG&E Commercial Fryers Work Paper developed by FSTC, June 13, 2012

Table 2-101 Baseline and Efficient Assumptions for Electric Standard and Large Vat Fryers

Parameter	Baseline Electric Fryers		Efficient Electric Fryers	
	Standard	Large Vat	Standard	Large Vat
Preheat Energy (kWh/lb)	2.3	2.5	1.7	2.1
Idle Energy Rate (kW)	1.05	1.35	0.80	1.10
Cooking Energy Efficiency (%)	75%	70%	83%	80%
Production Capacity (lbs./hour)	65	100	70	110
Lbs. of food cooked/day	150	150	150	150

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta kW = \left(\frac{\Delta kWh}{HOURS}\right) \times CF$$

Where:

ΔkWh = Annual energy savings (kWh)

$HOURS$ = Operating equivalent hours = 365 x 12 = 4,380

CF = Coincidence factor = 0.84[351]

Deemed savings using the assumptions above are tabulated below. These values are per installed unit based on the type of fryer.

Table 2-102 Deemed Savings per Fryer Vat

Measure Description	Deemed Savings per Fryer Vat	
	kWh	kW
Fryer, Electric, ENERGY STAR	2,208	0.42
Fryer, Large Vat, Electric, ENERGY STAR	2,659	0.51

2.5.4.5 *Incremental Cost*

The incremental cost is $1,200[352].

2.5.4.6 *Future Studies*

At the time of authorship, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from FSTC. If this measure is added to Energy Smart programs, the evaluation should include an assessment of actual usage schedules to replace the default FSTC schedule values.

[351] Coincidence factors utilized in other jurisdictions for Commercial Fryers vary from 0.84 to 1.0. The KEMA report titled "Business Programs: Deemed Savings Parameter Development," November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

[352] Cost from ENERGY STAR which cites reference as "EPA research on available models using AutoQuotes, 2010" http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COG

2.5.5 STEAM COOKERS

2.5.5.1 Measure Description

This measure applies to ENERGY STAR or its equivalent electric steam cookers in retrofit and new construction applications. Commercial steam cookers, also known as "compartment steamers," vary in configuration and size based on the number of pans. High efficiency steam cookers offer shorter cook times, higher production rates and reduced heat loss due to better insulation and more efficient steam delivery system.

2.5.5.2 Baseline & Efficiency Standard

Key parameters for defining steam cookers efficiency are Heavy Load Cooking Energy Efficiency and Idle Energy Rate. ENERGY STAR requirements apply to steam cookers based on the pan capacity. These criteria should be reviewed on an annual basis to reflect the latest ENERGY STAR requirements.

There are currently no federal minimum standards for Commercial Steam Cookers, however, ASTM publishes Test Methods[353] that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

Table 2-103 ENERGY STAR Criteria for Electric Steam Cookers[354]

Pan Capacity	Cooking Efficiency	Idle Rate (watts)
3-pan	50%	400
4-pan	50%	530
5-pan	50%	670
6-pan and larger	50%	800

Table 2-104 ENERGY STAR Criteria for Gas Steam Cookers[355]

Pan Capacity	Cooking Efficiency	Idle Rate (Btu/h)
5-pan	38%	10,400
6-pan and larger	38%	12,500

2.5.5.3 Estimated Useful Life

According to DEER 2014 steam cookers are assigned an EUL of 12 years.

2.5.5.4 Deemed Savings Values

Energy savings for steam cookers is derived by determining the total energy consumed by standard steam cooker as compared with an ENERGY STAR rated steam cooker. Total energy for a steam cooker includes the energy used during cooking, the energy used when the equipment is idling, the energy spent when set in a constant steam mode and the energy required during pre-heat.

---

353 The industry standard for steam cookers energy use and cooking performance is ASTM Standard F1484-99, Test Method for the Performance of Steam Cookers/

354 ENERGY STAR Commercial Steam Cookers Version 1.2, effective August 1, 2003.

355 ENERGY STAR provides criteria for 3-pan, 4-pan but availability of products in this range is limited or unavailable.

$$\Delta Energy = Energybase, total - Energyeff, total$$

$$Energy(base, total\ or\ eff, total) = Energycooking + Energyidle + Energysteam + Energypreheat$$

Where:

$$Energycooking = LB\ food \times EfoodCook\ Eff \times Days$$

$$Energyidle = (1 - \%Steam) \times IdleEnergy \times (DailyHrs - \frac{LBfood}{Capacity} - \frac{PreheatTime}{60}) \times Days$$

$$Energysteam = (\%Steam) \times \frac{Capacity \times Efood}{Cook\ Eff} \times \left(DailyHrs - \frac{LBfood}{Capacity} - \frac{PreheatTime}{60}\right) \times Days$$

$$Energypreheat = PreheatEnergy \times Days$$

General assumptions used for deriving deemed electric savings are defined in the following tables. These values are taken from the ENERGY STAR *Commercial Kitchen Equipment Savings* Calculator as well as the Food Service Technology Center (FSTC) work papers and research.

Table 2-105 Energy Consumption Related Parameters for Commercial Steam Cookers

Parameter	Description	Value	Source/Approach
Daily Hrs.	Daily Operating Hours	12 hours	FSTC
Preheat Time	Steam Cooker Preheat Time (Min)	15 min	FSTC
E_{food}	ASTM defined Energy to Food	0.0308 kWh/lb, 105 Btu/lb	FSTC
Days	Number of days of operation	365 days	FSTC
CookEff	Cooking energy efficiency (%)	See Table 2-106	FSTC
IdleEnergy	Idle energy rate (kW), (Btu/h)		FSTC, ENERGY STAR

%Steam	Constant Steam energy use		FSTC
Capacity	Production capacity (lb/hr)		ENERGY STAR
Preheat Energy	kWh/day, Btu/day		ENERGY STAR
LB_{food}	Food cooked per day (lb/day)		ENERGY STAR

Table 2-106 Deemed Savings Assumptions for Electric Steam Cookers

Parameter	Baseline Model	Efficient Electric Model
Cooking Efficiency (%)	26%	50%
Preheat Energy (kWh)	1.5	1.5
Constant Steam Mode Time (%)	90%	10%
Lbs. of food Cooked/Day	100	100
Production Capacity (lbs./hr/pan)	23.33	16.67
Idle Energy Rate (kW/pan)	0.33	0.13

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta kW = \left(\frac{\Delta kWh}{HOURS}\right) \times CF$$

Where:

ΔkWh = Annual energy savings (kWh)

4380 = Operating Equivalent hours = 365 x 12 = 4380 hours

0.84[356] = Coincidence Factor (CF)

Deemed savings are per installed unit based on the number of pans per steam cooker.

Table 2-107 Deemed Savings for Steam Cookers

Number of Pans	kW	kWh
Steam Cooker, Electric, 3-pan - ENERGY STAR	5.4	28,214
Steam Cooker, Electric, 4-pan - ENERGY STAR	7.3	38,081
Steam Cooker, Electric, 5-pan - ENERGY STAR	9.2	47,948
Steam Cooker, Electric, 6-pan - ENERGY STAR	11.1	57,815

[356] Coincidence factors utilized in other jurisdictions for Commercial Steam Cookers vary from 0.84 to 1.0. The KEMA report titled "Business Programs: Deemed Savings Parameter Development," November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

2.5.5.5 Incremental Cost

The incremental cost is $2,490[357].

2.5.5.6 Future Studies

At the time of authorship, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from FSTC. If this measure is added to Energy Smart programs, the evaluation should include an assessment of actual usage schedules to replace the default FSTC schedule values.

[357] 32Source for efficient electric steamer incremental cost is $2,490 per 2009 PG&E Workpaper - PGECOFST104.1 - Commercial Steam Cooker - Electric and Gas as reference by KEMA in the ComEd C & I TRM.

2.5.6 PRE-RINSE SPRAY VALVES

2.5.6.1 Measure Description

This measure consists of installing low-flow pre-rinse spray valves which reduce hot water use and save energy associated with heating the water. The low-flow pre-rinse spray valves have the same cleaning effect as the existing standard spray valves even though they use less water.

Savings are shown assuming two possible delivery channels:

- Direct install retrofit of functioning equipment
- Downstream rebate measure, replacing failed equipment, new construction.

2.5.6.2 Baseline & Efficiency Standard

For direct install (DI) PRSVs, a the pre-2019 code of 1.60 GPM may be used. For downstream rebates or replace on burnout, the baseline is 1.28 GPM[358].

The maximum flow rate of program-qualifying low-flow pre-rinse spray valves is 1.07 GPM. To qualify for savings the facility must have electric domestic hot water equipment.

2.5.6.3 Estimated Useful Life

The EUL of a PRSV is 5 years.[359] DI PRSV may claim two years of RUL at the 1.60 baseline, while the last three years must use the 1.28 GPM baseline. This results in a weighted EUL of 3.19 years for DI PRSV, using the early replacement baseline.

2.5.6.4 Deemed Savings Values

Table 2-108 Deemed Savings – Direct Install

Facility Type	Days/Year	Minutes/Day	kWh	kW
Fast Food	365	45	980	0.134
Casual Dining	365	105	2,287	0.251
Institutional	365	210	4,574	0.376
Dormitory	274	210	3,434	0.501
K-12 School	200	105	1,253	0.313

Table 2-109 Deemed Savings – Rebate/ROB/NC

Facility Type	Days/Year	Minutes/Day	kWh	kW
Fast Food	365	45	388	0.053
Casual Dining	365	105	906	0.099
Institutional	365	210	1,813	0.149
Dormitory	274	210	1,361	0.199
K-12 School	200	105	497	0.124

[358] FEMP Performance Requirements for Federal Purchases of Pre-Rinse Spray Valves, Based on ASTM F2324-13: Standard Test Method for Pre-Rinse Spray Valves.

[359] FEMP Purchasing Specification for Energy-Efficiency Products, Pre-Rinse Spray Valves: http://www1.eere.energy.gov/femp/pdfs/pseep_spray_valves.pdf

Annual kWh electric and peak kW savings can be calculated using the following equations and Table 2-110 summarizes the needed variables:

$$\Delta kWh = \frac{\rho \times CP \times U \times (FB - FP) \times (TH - TSupply) \times \frac{1}{Et} \times \frac{Days}{Year}}{3412BTU/kWh}$$

$$\Delta kW = \frac{\rho \times CP \times U \times (FB - FP) \times (TH - TSupply) \times \frac{1}{Et} \times P}{3412BTU/kWh}$$

Table 2-110 Variables for the Deemed Savings Algorithm

Parameter	Description	Value
F_B	Direct Install Average baseline flow rate (GPM) Downstream Rebate Average baseline flow rate (GPM)	1.60 1.28
F_P	Average post measure flow rate of sprayer (GPM)	1.07
Days/Year	Annual Operating Days for the applications: See Table 2-111 for building type definitions:	
	1. Fast Food Restaurant	365[360]
	2. Casual Dining Restaurant	365
	3.Institutional	365
	4. Dormitory	274[361]
	5. K-12 School	200
T_{supply}	Average supply (cold) water temperature (°F)	74.8
T_H	Average mixed hot water (after spray valve) temperature (°F)	120[362]
U_B	Baseline water usage duration for the following applications:	
	1. Fast Food Restaurant (see Table 2-112)	45 min/day/unit[363]
	2. Casual Dining Restaurant (see Table 2-112)	105 min/day/unit
	3. Institutional (see Table 2-112)	210 min/day/unit

[360] Osman S &. Koomey, J. G. , . Lawrence Berkeley National Laboratory 1995. Technology Data Characterizing Water Heating in Commercial Buildings: Application to End-Use Forecasting. December.

[361]For dormitories with few occupants in the summer: 365 x (9/12) = 274.

[362] According to ASTM F2324 03 Cleanability Test the optimal operating conditions are at 120ºF.

[363] CEE Commercial Kitchens Initiative Program Guidance on Pre-Rinse Valves.

	4. Dormitory (see Table 2-112)	210 min/day/unit
	5. K-12 School (see Table 2-112)	105 min/day/unit[364]
ρ	Density of water 8.33 lbs./Gallon	8.33
C_P	Heat capacity of water, 1 BTU/lb·°F	1
E_t	Thermal efficiency of water heater	0.98 electric & 0.80 gas
P	Hourly peak demand as a fraction of daily water consumption for the following applications:	
	1. Fast food restaurant (Fast Food)	0.05[365]
	2. Casual Dining Restaurant (Sit Down Rest.)	0.04
	3. Institutional (Nursing Home)	0.03
	4. Dormitory (Sit Down Rest.)	0.04
	5. K-12 School (High School)	0.05

Table 2-111 Building Type Definitions

Building Type	Operating Days per Year	Representative PRSV Usage Examples
1. Fast food restaurant	365	Establishments engaged in providing food services where patrons order and pay before eating. These facilities typically use disposable serving ware. PRSV are used for rinsing cooking ware, utensils, trays, etc. Examples: Fast food restaurant, supermarket food preparation and food service area, drive-ins, grills, luncheonettes, sandwich, and snack shops.
2. Casual dining restaurant	365	Establishments primarily engaged in providing food services to customers who order and are served while seated (i.e. waiter/waitress service). These facilities typically use chinaware and use the PRSV to rinse dishes, cooking ware, utensils, trays, etc. Example: Full meal restaurant.
3. Institutional	365	Establishments located in institutional facilities (e.g. nursing homes, hospitals, prisons, military) where food is prepared in large volumes and patrons order food before eating, such as in dining halls and cafeterias. These facilities typically use disposable serving ware and serving trays. PRSVs are used for rinsing cooking ware, utensils, tray, etc. Examples: Nursing home, hospital, prison cafeteria, and military barrack mess hall.

[364] School mealtime duration is assumed to be half of that of institutions, assuming that institutions (e.g. prisons, university dining halls, hospitals, nursing homes) serve three meals per day at 70 minutes each, and schools serve breakfast to half of the students and lunch to all, yielding 105 minutes per day.

[365] ASHRAE Handbook 2011. HVAC Applications. Chapter 50 –Service Water Heating. American Society of Heating Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) 2011. ASHRAE, Inc., Atlanta, GA.

4. Dormitory	274	Establishments located in higher education facilities where food is prepared in large volumes and patrons order food before eating, such as in dining halls and cafeterias. These facilities typically use disposable serving ware and serving trays. PRSVs are used for rinsing cooking ware, utensils, trays, etc. Example: University dining halls.
5. K-12 school	200	Establishments located in K-12 schools where food is prepared in large volumes and patrons order food before eating, such as in dining halls and cafeterias. These facilities typically use disposable serving ware and serving trays. PRSVs are used for rinsing cooking ware, utensils, trays, etc. Example: K-12 school cafeterias

Table 2-112 Daily Operating Hours

Food Service Operation	Min (Min/Day)	Max (Min/Day)	Average (Min/Day)
Small Service (e.g., quick-service restaurants)	30	60	45
Medium Service (e.g., casual dining restaurants)	90	120	105
Large Service (e.g., institutional: cafeterias in universities, prisons, and nursing homes, etc.)	180	240	210

The following are example calculations for a fast food restaurant in New Orleans using the previous equations.

$$Direct\ Install\ \Delta kWh$$

$$= \frac{8.33\ BTU/Gal\ x\ 45\ minday\ x\ (1.60 - 1.07)GPM\ x\ (120 - 74.8°\text{F})x\ \left(\frac{1}{0.98}\right)\ x\,\frac{365\ days}{year}}{3412\ BTU/kWh}$$

$$= 980\ kWh$$

$$Direct\ Install\ \Delta kW = \frac{0.05\ x\ 8.33\ x\ 45\ minday\ x\ (1.60 - 1.07)GPM\ x\ (120 - 74.8°\text{F})\ x\ \left(\frac{1}{0.98}\right)}{3412\ BTU/kWh}$$

$$= 0.134\ kW$$

$ROB\ \Delta kWh$

$$= \frac{8.33\ BTU/Gal\ x\ 45\ minday\ x\ (1.28-1.07)GPM\ x\ (120-74.8°\text{F})x\ \left(\frac{1}{0.98}\right)\ x\frac{365\ days}{year}}{3412\ BTU/kWh}$$

$$= 388\ kWh$$

$$Direct\ Install\ \Delta kW = \frac{0.05\ x\ 8.33\ x\ 45\ minday\ x\ (1.28-1.07)GPM\ x\ (120-74.8°\text{F})\ x\ \left(\frac{1}{0.98}\right)}{3412\ BTU/kWh}$$

$$= 0..053\ kW$$

$$Lfetime\ \Delta kWh = 980\ kWh * 2\ years\ RUL + 388 * 3\ years = 3{,}124\ kWh$$

2.5.6.5 Incremental Cost

For direct install, program-actual costs should be used when available. If unknown, use a default value of \$92.90[366]. For downstream rebate, replace on burnout, or new construction use \$46.12.[367]

2.5.6.6 Future Studies

At the time of authorship, this measure was not implemented in Energy Smart programs. If this measure is incorporated into Energy Smart, the TPE recommends studying the following parameters: DHW setpoint; flow rate of installed PRSVs; and the flow rate of baseline PRSVs (to be collected by the program implementer and sent to the TPE for testing).

---

366 Average of costs recognized by Ameren Missouri (\$85.8) and KCPL (\$100).

367 CA DEER Workpaper SWFS013-01, authored by Southwest Gas (2010)

2.5.7 DEMAND CONTROL VENTILATION FOR KITCHENS

2.5.7.1 Measure Description

Commercial Demand Control Kitchen Ventilation (DCKV) systems are a technology implemented in a variety of commercial kitchen types in order to reduce energy use associated with ventilation fan energy use as well as the HVAC energy use associated with conditioning the requisite make up air (MAU). The systems incorporate sensors and variable speed controls to operate the ventilation equipment only when it is necessary.

2.5.7.2 Baseline and Efficiency Standards

The baseline for this measure is a commercial kitchen exhaust fan controlled with a simple on/off switch that operates at one fixed speed and can optionally include an MAU to resupply a portion of the ventilation air. The efficient case is a ventilation fan controlled by a DCKV system which modifies the fan speed depending on the requirements within the kitchen and cooking appliances.

2.5.7.3 Estimated Useful Life

According to DEER 2014 the EUL of this measure is 15 years[368].

2.5.7.4 Deemed Savings Values

Table 2-113 Rated Exhaust kW by Building Type, with or without Dedicated MAU

Building Type	Energy Savings ($kWh/kW_{exhaust}$)		Demand Savings ($kW/kW_{exhaust}$)		Heating Savings[369] ($kWh / kW_{exhaust}$)	Cooling Savings ($kWh / kW_{exhaust}$)
	MAU	No MAU	MAU	No MAU		
Supermarket	4,731	3,519	0.975	0.725	1,479	1,925
Restaurant[370]	5,492	4,085	0.975	0.725	1,717	2,235
Hotel	8,022	5,967	0.975	0.725	2,507	3,264
Campus	4,808	3,576	0.975	0.725	1,503	1,957
K-12 School, Inc Summer Sessions	3,205	2,384	0.975	0.725	1,002	1,304
K-12 School, No Summer Sessions	2,340	1,740	0.975	0.725	731	952

Note: If exhaust fan is only rated in horsepower, use the conversion 1 hp = 0.746 kW

[368] DEER 2014 for Variable Speed Drive controlled by CO2 sensor for HVAC-VSD-DCV

[369] Heating and cooling savings are assumed to be the same with or without an MAU. This is because any exhaust air will be replaced with outside air by the MAU or via increased infiltration proportional to exhaust airflow and thus will result in the same impact on heating and cooling equipment regardless of infiltration method. The savings calculation methodology was obtained from Work Paper SCE13CC008 (discussed below) and the AR TRM which also did not differentiate between MAU and non-MAU facilities.

[370] Source data (discussed below) included various restaurant types thus this value is applicable for all full service and fast-food kitchens.

Deemed demand and annual savings are based on average fan kW reductions, HVAC savings, and hours of use by kitchen type as calculated using Southern California Edison work paper SCE13CC008[371], and the AR TRM 8.1. Average fan energy savings (kW/kW) were calculated based on whether the kitchen had a dedicated MAU or not. The hours of use and annual days of operation were calculated from 72 surveyed sites with DCKV systems as well as 11 metered sites. For the School hours of use and days of operation, the AR TRM 8.1 was referenced.

Table 2-114 Annual Hours of Operation by Building Type

Building Type	Annual Operating Hours
Supermarket	4,864
Restaurant	5,652
Hotel	8,226
College / University	4,939
Institutional	6,789
K-12 School, Inc Summer Sessions	3,288
K-12 School, No Summer Sessions	2,400

Using the savings data from SCE13CC008 for 16 climate zones in CA, along with Heating Degree Day (HDD) and Cooling Degree Day (CDD) data for these climate zones[372], a linear regression was performed to calibrate heating and cooling load with New Orleans weather. The subsequent regression models had R-square values of 0.969 and 0.890 for heating and cooling energy load respectively thus indicating a high degree of confidence in calculated loads for New Orleans. The regressed values were then normalized to the average rated exhaust horsepower of 14.3 HP based on the 72 sites' data in SCE13CC008 and divided by the 17 hours per day and 365 days per year as input into the Outdoor Air Calculator by the work paper author. Thus, using these HVAC load values, the operation profiles calculated in the table above, and the average 25% reduction in exhaust fan airflow as calculated in SCE13CC008, the deemed HVAC savings values were calculated for each building type.

Table 2-115 Regressed Load Savings Calibrated for NOLA

Fan Type	Demand Savings ($kW/kW_{exhaust}$)	Heating Savings (kWh/kW/hr/day)	Cooling Savings (kWh/kW/hr/day)
MAU	0.975	0.305	0.397
No MAU	0.725	0.305	0.397

$$Savings_{kWh} = Demand\ Savings \times CAP \times AOH$$

[371] "Commercial Kitchen Exhaust Hoods Demand Controlled Ventilation." Work Paper SCE13CC008. Southern California Edison Company. 11 June, 2014 Accessed from: http://www.deeresources.net/workpapers

[372] "The Pacific Energy Center's Guide to: California Climate Zones and Bioclimatic Design." October 2006. Retrieved from: https://www.pge.com/includes/docs/pdfs/about/edusafety/training/pec/toolbox/arch/climate/california_climate_zones_01-16.pdf

$$Savings_{kW} = Demand\ Savings \times CAP$$

Where:

Demand Savings = Fan demand reduction per rated kW of exhaust fan, kW/$kW_{exhaust}$. See Table 2-115.

CAP = Rated capacity of exhaust fan, kW

AOH = Annual Operating Hour of operation, day(s). See Table 2-114.

$$kWh\ Savings_{Heating} = \frac{Heating\ Savings \times kW_{exhaust} \times AOH}{Eff_{heat}}$$

$$kWh\ Savings_{Cooling} = \frac{Cooling\ Savings \times kW_{exhaust} \times AOH}{Eff_{cool}}$$

Where:

Heat Reduction = Heating energy savings per rated exhaust kW, kWh/kW/hr/day. See Table 2-115.

Cool Reduction = Cooling energy savings per rated exhaust kW, kWh/kW/hr/day. See Table 2-115.

$kW_{exhaust}$ = Rated kW of the installed exhaust fan, kW

AOH = Annual Operating Hour of operation. See Table 2-114.

Eff_{heat} = Efficiency of heating system (%)

Eff_{cool} = Efficiency of cooling system (%)

2.5.7.5 Incremental Cost

The incremental cost is $2,383 per exhaust fan rated HP[373].

2.5.7.6 Future Studies

There are no future studies planned at this time for this measure at this time.

[373] "Commercial Kitchen Exhaust Hoods Demand Controlled Ventilation." Work Paper SCE13CC008. Southern California Edison Company. 11 June, 2014

2.5.8 ENERGY STAR HOT FOOD HOLDING CABINETS

2.5.8.1 Measure Description

Hot Food Holding Cabinets (HFHC) keep cooked foods hot, fresh, and out of temperature danger zones until customers are ready to order. Cabinets that meet the ENERGY STAR requirements often incorporate better insulation which reduces heat loss, offers better temperature uniformity within the cabinet from top to bottom and keeps the external cabinet cooler. In addition, many certified cabinets may include additional energy saving devices such as magnetic door gaskets, auto-door closures, or Dutch doors. Savings occur from reduced idle energy consumption. ENERGY STAR models are, on average, 70 percent more energy efficient than standard models.

2.5.8.2 Baseline and Efficiency Standard

To qualify for this measure the installed equipment must be an ENERGY STAR certified HFHC. Qualification is based upon idle energy consumption per given interior cabinet volumes, measured in cubic feet. Measuring cabinet interior volume: commercial hot food holding cabinet interior volume shall be calculated using straight-line segments following the gross interior dimensions of the appliance and using the equation below. Interior volume shall not account for racks, air plenums or other interior parts.

$$Interior\ Volume = Interior\ Height \times Interior\ Width\ \times Interior\ Depth$$

Table 2-116 Maximum Idle Energy Requirements for ENERGY STAR Qualification

Product Interior Volume (Cubic Feet)	Product Idle Energy Consumption Rate (Watts)
0 < Volume < 13	≤ 21.5 x Volume
13 ≤ Volume <28	≤ (2.0 x Volume) + 254.0
28 ≤ Volume	≤ (3.8 x Volume) + 203.5

The baseline equipment is an electric HFHC that's not ENERGY STAR certified and at end of its life. Baseline energy use is 40 watts per cubic foot[374].

2.5.8.3 Estimated Useful Life

According to ENERGY STAR[375] the EUL for HFHC is 12 years.

2.5.8.4 Deemed Savings Values

Custom calculation below; otherwise use deemed values depending on HFHC size.

[374] https://www.energystar.gov/sites/default/files/asset/document/commercial_kitchen_equipment_calculator_0.xlsx

[375] ENERGY STAR Commercial Kitchen Equipment Calculator: https://www.energystar.gov/sites/default/files/asset/document/commercial_kitchen_equipment_calculator_0.xlsx

Table 2-117 HFHC Deemed Savings

Cabinet Size	Savings (kWh)	Savings (kW)
Full Size (20 cubic feet) HFHC	2,772	0.204
¾ Size (12 cubic feet) HFHC	1,216	0.090
½ Size (8 cubic feet) HFHC	811	0.060

2.5.8.4.1 Energy Savings

$$kWh_{savings} = Baseline_{kWh} - Efficient_{kWh}$$

$$Baseline_{kWh} = \frac{Power_{\ Baseline} \times Hours_{\ Day} \times Days}{1000}$$

$$Efficient_{kWh} = \frac{Power_{\ ENERGY\ STAR} \times Hours_{\ Day} \times Days}{1000}$$

Where:

$Hours_{Day}$= Custom. If Unknown, use 15[376]

$Days$ = Custom. If Unknown, use 365.25

$Power_{Baseline}$ = Baseline power consumption = Cubic feet × 40W/ft^3

$Power_{ENERGY\ STAR}$ = Custom idle power consumption using ENERGY STAR idle power consumption (see Table 2-116).

2.5.8.4.2 Demand Reductions

Demand is calculated using the following equation:

$$kW_{savings} = \frac{kWh_{savings}}{AOH} \times CF$$

Where:

CF = Coincidence factor[377]

[376] Algorithms and assumptions derived from ENERGY STAR Commercial Kitchen Equipment Savings Calculator.

[377] Values taken from Minnesota Technical Reference Manual, 'Electric Oven and Range' measure and is based upon "Project on Restaurant Energy Performance-End-Use Monitoring and Analysis", Appendixes I and II, Claar, et. al., May 1985

Table 2-118 HFHC Peak Coincidence Factors

Location	CF
Fast Food Limited Menu	0.30
Fast Food Expanded Menu	0.40
Pizza	0.50
Full Service Limited Menu	0.50
Full Service Expanded Menu	0.40
Cafeteria	0.40

For example, if an $18ft^3$ HFHC is installed in a cafeteria the measure would save the following.

$$kWh = ((18*40)-((18*2.0)+254)) \times 15 \times 365.25/1000 = (720 - 290) \times 15 \times 365.25/1000 = 2{,}356\ kWh$$

$$kW = (2{,}356kWh/(15*365.25)) \times 0.40 = 0.43 \times 0.40 = 0.17\ kW$$

2.5.8.5 Incremental Cost

The incremental cost is $902[378].

2.5.8.6 Future Studies

There are no future studies planned for this measure at this time.

[378] Based on the difference between a similar ENERGY STAR and non-qualifying model, EPA research using AutoQuotes, July 2016

2.5.9 ENERGY STAR DISHWASHERS

2.5.9.1 Measure Description

This measure defines energy savings and peak reductions from ENERGY STAR commercial dishwashers in retrofit and new construction applications. Commercial dishwashers, also known as “ware washers,” fall into two categories of machine type: stationary rack machines (under counter, single tank/door type, glass washing, and pot, pan and utensil) and conveyor machines (rack and rack free/flight type, single and multiple tank). Key parameters used to characterize the efficient performance of commercial dishwashers are Idle Energy Rate and Water Consumption Rate. Energy savings from commercial dishwashers is primarily attributed to reducing the amount of water used which reduces the energy consumed to heat that water. This is accomplished via combinations of the following:

- Improved nozzle and rinse arm design
- Auxiliary pre-rinse section
- Heat recovery technology
- Sophisticated controls and sensors
- Effective curtain designs to minimize airflow
- Auto-mode capabilities, including low power mode during long periods of idle

Eligible Products: High temp (hot water sanitizing), low temp (chemical sanitizing) machines, and dual sanitizing machines.

Ineligible Products: Steam, gas, and other non-electric models; dishwashers intended for use in residential or laboratory applications.

2.5.9.2 Baseline & Efficiency Standard

Descriptions of commercial dishwasher configurations, as defined by ENERGY STAR, are as follows:

Stationary Rack Machines – A dishwashing machine in which a rack of dishes remains stationary within the machine while subjected to sequential wash and rinse sprays. This definition also applies to machines in which the rack revolves on an axis during the wash and rinse cycles.

- Under Counter – A stationary rack machine with an overall height of 38 inches or less, designed to be installed under food preparation workspaces. Under counter dishwashers can be either chemical or hot water sanitizing, with an internal or external booster heater for the latter.
- Stationary Single Tank Door – A stationary rack machine designed to accept a standard 20” x 20” dish rack, which requires the raising of a door to place the rack into the wash/rinse chamber. Closing of the door typically initiates the wash cycle. Single tank door type models can be either chemical or hot water sanitizing, with an internal or external booster heater for the latter.
- Pot, Pan, and Utensil – A stationary rack, door type machine designed to clean and sanitize pots, pans, and kitchen utensils.

Conveyor Machines – A dishwashing machine that employs a conveyor or similar mechanism to carry dishes through a series of wash and rinse sprays within the machine.

- Single Tank Conveyor – A conveyor machine that includes a tank for wash water followed by a sanitizing rinse (pumped or fresh water). This type of machine does not have a pumped rinse tank.

This type of machine may include a pre-washing section ahead of the washing section and an auxiliary rinse section, for purposes of reusing the sanitizing rinse water, between the power rinse and sanitizing rinse sections. Single tank conveyor dishwashers can be either chemical or hot water sanitizing, with an internal or external booster heater for the latter.

- Multiple Tank Conveyor – A conveyor type machine that includes one or more tanks for wash water and one or more tanks for pumped rinse water, followed by a sanitizing rinse. This type of machine may include a pre-washing section before the washing section and an auxiliary rinse section, for purposes of reusing the sanitizing rinse water, between the power rinse and sanitizing rinse sections. Multiple tank conveyor dishwashers can be either chemical or hot water sanitizing, with an internal or external booster heater for the latter.

Each of these machines are further classified by their rinse water washing strategies; high temperature, sanitized by heat with boost heating (~180^{o}) and low temperature, sanitized by chemicals (~120^{o}-140^{o}). While less common, dual-method sanitization machines are also available.

There are currently no federal minimum standards for Commercial Dishwashers, however, the ASTM and the National Sanitation Foundation (NSF) publishes Test Methods[379] that allow uniform procedures to be applied to each commercial dishwasher for a fair comparison of performance results. To meet the strict efficiency requirements developed by the U.S. Environmental Protection Agency's ENERGY STAR program, manufacturers use high quality components and employ innovative designs. All ENERGY STAR certified machines are certified to NSF 3 sanitation standards.

Table 2-119 ENERGY STAR[380] Requirements for Commercial Dishwashers[381]

Machine Type	High Temp Efficiency Requirements (~180°F)		Low Temp Efficiency Requirements (~120°F – 140°F)	
	Tank Heater Idle Energy Rate (kW)	Water Consumption	Tank Heater Idle Energy Rate (kW)	Water Consumption
Under Counter	≤ 0.30	≤ 0.86	≤ 0.25	≤ 1.19
Stationary Single Tank Door	≤ 0.55	≤ 0.89	≤ 0.30	≤ 1.18
Pot, Pan, and Utensil	< 0.90	< 0.58 GPSF	≤ 0.85	≤ 0.79
Single Tank Conveyor	≤ 1.20	≤ 0.70	≤ 1.00	≤ 0.54
Multiple Tank Conveyor	≤ 1.85	≤ 0.54	≤ 0.25	≤ 1.19

379 The industry standards for energy use is ASTM Standard F1920, Standard Test Method for Energy Performance of Rack Conveyor, Hot Water Sanitizing, Commercial Dishwashing Machines, ASTM Standard F1696, Standard Test Method for Energy Performance of Single-Rack Hot Water Sanitizing, Door-Type Commercial Dishwashing Machines and NSF/ANSI 3-2007 Standard, Commercial Warewashing Equipment.

380 ENERGY STAR Commercial Dishwashers Version 2.0 effective as of February 1, 2013. http://www.energystar.gov/index.cfm?c=comm_dishwashers.pr_crit_comm_dishwashers.

381 ENERGY STAR Commercial Dishwashers Version 2.0 includes 3 new dishwasher types: 1) Pot, Pan, and Utensil, 2) Single Tank Flight Type, and 3) Multiple Tank Flight Type. These new dishwasher types will be incorporated into the measure once they are incorporated into the ENERGY STAR Commercial Dishwasher Savings Calculator.

Where:

GPR = Gallons per Rack

GPSF = Gallons per Square Foot of Rack

GPH = Gallons per Hour

2.5.9.3 Estimated Useful Life[382]

The estimated useful life (EUL) of commercial dishwashers vary based on the machine type. Under Counters have an EUL of 10 years, Door-Types have an EUL of 15 years and Conveyor Types have an EUL of 20 years.

2.5.9.4 Deemed Savings Values[383]

Annual savings were calculated by determining the energy consumed for baseline commercial dishwashers compared against ENERGY STAR performance requirements. The annual energy consumption for commercial dishwashers was determined by the summation of the annual energy used for water heating, the booster heater and when the machine is in idle mode.

$$E_{total} = E_{DHW} + E_{boost} + E_{idle}$$

These are defined as follows for both gas and electric calculations:

$$E_{DHW} = \frac{\left(RPD \times GPR \times Days \times d \times c_p \times \Delta T_{DHW}\right)}{EF_{DHW} \times Conversion\ Factor}$$

$$E_{BOOST} = \frac{\left(RPD\ x\ GPR\ x\ Days\ x\ d\ x\ c_p\ x\ \Delta T_{BOOST}\right)}{EF_{BOOST}\ x\ Conversion\ Factor}$$

(*only* applicable in High Temperature Machines)

$$E_{idle} = kW_{\text{idle}} \times \left(HRS - \frac{(RPD \times MPR)}{60}\right) \times \text{Days}$$

Where:

RPD = Average number of racks washed per day, varies by machine

GPR = Average gallons per rack used by dishwasher, varies by machine

Days = Operating Day per Year = 365 days/yr.

d = Density of water, constant value 8.34 lb/gal

[382] EUL values from CEE Program Design Guidance-Commercial Dishwashers, updated 5/11/2009.

[383] Assumptions from the ENERGY STAR Commercial Dishwashers Savings Calculator (May 2013 update).

c_p = Specific heat of water, 1 Btu/lb-^{o}F

ΔT_{DHW} = Temperature rise at primary water heater, 70^{o}F (default)

ΔT_{BOOST} = Temperature rise at booster heater, 40^{o}F (default)

EF_{DHW}= Efficiency of building water heater, 98% for electric (default), 80% for gas

EF_{BOOST} = Efficiency of booster water heater, 98% for electric (default), 80% for gas

$Conversion\ Factor$ = 100,000 Btu/therm or 3,413 Btu/kWh.

kW_{idle} = Energy consumed while idle, varies by machine

HRS = Hours per day dishwasher operates, 18 hours (default)

MPR = Time to wash one rack of dishes, minutes per rack, varies by machines

60 = Minutes per hour

To determine electric savings for the different types of commercial dishwashers, Table 2-120 and

Table 2-121 list the assumptions made for the machine dependent parameters; Idle Power, Racks per Day, Minutes per Rack and Gallons per Rack. Table 2-120 lists the parameters for machines that employ Low Temperature cleaning and

Table 2-121 lists parameters for machines that employ High Temperature cleaning.

Table 2-120 Default Assumptions for Low Temperature, Electric and Gas Water Heaters

Performance	Under Counter		Single Tank Door		Single Tank Conveyor		Multi Tank Conveyor	
	Base	Change	Base	Change	Base	Change	Base	Change
Idle Power	0.5	0.5	0.6	0.6	1.6	1.5	2.0	2.0

Racks/Day	75	75	280	280	400	400	600	600
Min/Rack	2.0	2.0	1.5	1.5	0.3	0.3	0.3	0.3
Gal/Rack	1.73	1.19	2.1	1.18	1.31	0.79	1.04	0.54

Table 2-121 Default Assumptions for High Temperature, Electric and Gas Water Heaters[4]

Performance	**Under Counter**		**Single Tank Door**		**Single Tank Conveyor**		**Multi Tank Conveyor**		**Pot, Pan, and Utensil**	
	Base	**Change**	**Base**	**Change**	**Base**	**Change**	**Base**	**Change**	**Base**	**Change**
Idle Power	0.76	0.5	0.87	0.7	1.93	1.5	2.59	2.25	1.2	1.2
Racks/Day	75	75	280	280	400	400	600	600	280	280
Min/Rack	2.0	2.0	1.0	1.0	0.3	0.3	0.2	0.2	3.0	3.0
Gal/Rack	1.09	0.86	1.29	0.89	0.87	0.70	0.97	0.54	0.70	0.58

Peak Demand Savings can be derived by dividing the annual energy savings by the operating hours and multiplying by the Coincidence Factor.

$$\Delta kW = \left(\frac{\Delta kWh}{HRS}\right) \times CF$$

Where:

ΔkWh = Annual energy savings (kWh)

HRS = Operating hours = 365 x 18 = 6,570 hours (default)

CF = Coincidence Factor = 0.84 (default)[384]

[384] The KEMA report titled "Business Programs: Deemed Savings Parameter Development," November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

If specific equipment data is not available for use with the measure savings calculations described above, deemed electric and gas savings from ENERGY STAR commercial dishwashers can be seen in Table 2-122. Equipment savings are defined based on the following information:

- Dishwasher Type (Under Counter, Stationary Single Tank Door, Pots, Pans, and Utensils, Single Tank Conveyor, or Multiple Tank Conveyor)
- Water Temperature (Low Temperature or High Temperature)
- Building Water Heater Fuel (Electric or Gas)
- Booster Water Heater Fuel (Electric or Gas): Only applicable in High Temperature Units
- Default Assumptions from ENERGY STAR Commercial Dishwasher Savings Calculator

Table 2-122 Deemed Savings for Commercial Dishwashers

Water Temperature	Water Heater Fuel/Booster Heater Fuel	Measure Description	kWh	kW
High Temperature	Electric / Electric	Under Counter	4,305	0.6
		Stationary Single Tank Door	12,602	1.6
		Pots, Pans, and Utensils	3,364	0.4
		Single Tank Conveyor	10,971	1.4
		Multiple Tank Conveyor	29,764	3.8
	Gas / Electric	Under Counter	2,099	0.3
		Stationary Single Tank Door	4,905	0.6
		Pots, Pans, and Utensils	1,223	0.2
		Single Tank Conveyor	4,987	0.6
		Multiple Tank Conveyor	11,378	1.5
	Gas / Gas	Under Counter	2,604	0.2
		Stationary Single Tank Door	1558	0.1
		Pots, Pans, and Utensils	438	0.1
		Single Tank Conveyor	4,266	0.5
		Multiple Tank Conveyor	4,325	0.6
Low Temperature	Electric / No Booster	Under Counter	3,957	0.5
		Stationary Single Tank Door	17,369	2.2
		Pots, Pans, and Utensils	17,434	2.2
		Single Tank Conveyor	24,303	3.1
	Gas/ No Booster	Multiple Tank Conveyor	1,415	0.2
		Under Counter	4,383	0.6
		Stationary Single Tank Door	5,479	0.7
		Pots, Pans, and Utensils	3,957	0.5

2.5.9.5 Incremental Cost

The incremental capital cost for this measure is provided below:[385]

Table 2-123 Incremental Cost

Dishwasher Type		Incremental Cost
Low Temp	Under Counter	$234
	Stationary Single Tank Door	$662
	Single Tank Conveyor	$0
	Multi Tank Conveyor	$970
High Temp	Under Counter	$2,025
	Stationary Single Tank Door	$995
	Single Tank Conveyor	$2,050
	Multi Tank Conveyor	$970
	Pot, Pan, and Utensil	$1,710

2.5.9.6 Future Studies

This measure uses ENERGY STAR default inputs. Deemed savings should be updated to align with any applicable code updates.

[385] Measure cost from ENERGY STAR Commercial Kitchen Equipment Savings Calculator which cites reference as "EPA research on available models using AutoQuotes, 2012"

2.5.10 ENERGY STAR ICE MAKERS

2.5.10.1 Measure Description

This measure involves ENERGY STAR air-cooled commercial ice makers in retrofit and new construction applications. Eligible equipment types are batch type (also known as cube-type) and continuous type (also known as nugget or flakers). Batch-type ice makers harvest ice with alternating freezing and harvesting periods and can be used in a variety of applications but are generally used to generate ice for use in beverages. Both types of equipment qualify based on their configuration as ice-making heads (IMHs), remote condensing units (RCUs) and self-contained units (SCUs). Remote condensing units designed for connection to a remote condenser rack are also eligible.

2.5.10.2 Baseline and Efficiency Standards

The ENERGY STAR[386] criteria for ice makers define efficiency requirements for both energy and potable water use. The baseline standard for batch ice makers are federal minimum levels that went into effect January 28, 2018. The following four tables show the standards and requirements for equipment manufactured on or after January 28, 2018.

Table 2-124 Federal Minimum Standards for Air-Cooled Batch Ice Makers

Equipment Type	Ice Harvest Rate (H) (lbs. of ice / 24 hrs.)	Batch Ice Makers Consumption Rate (kWh/100 lbs. ice)
Ice Making Heads	< 300	10.0 – 0.01233H
	≥ 300 and < 800	7.05 – 0.0025H
	≥ 800 and < 1,500	5.55 – 0.00063H
	≥ 1,500	4.61
Remote Condensing Units (w/out remote compressor)	< 988	7.97 – 0.00342H
	≥ 988 and < 4,000	4.59
Remote Condensing Units (w/ remote compressor)	< 930	7.97 – 0.00342H
	≥ 934 and < 4,000	4.79
Self-Contained Units	< 110	14.79 – 0.0469H
	≥ 110 and < 200	12.42 – 0.02533H
	≥ 200 and < 4,000	7.35

[386] ENERGY STAR Commercial Ice Makers Version 3.0, effective on January 28, 2018.

Table 2-125 Federal Minimum Standards for Air-Cooled Continuous Ice Makers

Equipment Type	Ice Harvest Rate (H) (lbs. of ice / 24 hrs.)	Batch Ice Makers Consumption Rate (kWh/100 lbs. ice)
Ice Making Heads	<310	9.19– 0.00629H
	≥310 and <820	8.23-0.0032H
	≥4,000	5.61
Remote Condensing Units (w/out remote compressor)	<800	9.7– 0.0058H
	≥800 and <4,000	5.06
Remote Condensing Units (w/ remote compressor)	<800	9.9– 0.0058H
	≥800 and <4,000	5.26
Self-Contained Units	<200	14.22–0.03H
	≥200 and <700	9.47-0.00624H
	≥700 and <4,000	5.1

Table 2-126 ENERGY STAR Requirements for Air-Cooled Batch Ice Makers

Equipment Type	Ice Harvest Rate (H) (lbs. of ice / 24 hrs.)	Batch Ice Makers Consumption Rate (kWh/100 lbs. ice)	Potable Water Use (gal/100 lbs. ice)
Ice Making Heads	≤ 300	≤ 9.2– 0.01134H	≤ 20.0
	≥ 300 and ≤ 800	≤ 6.49-0.0023H	≤ 20.0
	≥ 800 and ≤ 1,500	≤ 5.11-0.00058H	≤ 20.0
	≥ 1,500 and ≤ 4,000	≤ 4.24	≤ 20.0
Remote Condensing Units (w/out remote compressor)	≤988	≤ 7.17– 0.00308H	≤ 20.0
	≥988 and ≤4,000	≤ 4.13	≤ 20.0
Remote Condensing Units (w/ remote compressor)	≤988	≤ 7.17– 0.00308H	≤ 20.0
	≥988 and ≤4,000	≤ 4.13	≤ 20.0
Self-Contained Units	≤110	≤ 12.57 – 0.0399H	≤ 25.0
	≥110 and ≤200	≤ 10.56-0.0215H	≤ 25.0
	≥200 and ≤4,000	≤ 6.25	≤ 25.0

Table 2-127 ENERGY STAR Requirements for Air-Cooled Continuous Ice Makers

Equipment Type	Ice Harvest Rate (H) (lbs. of ice / 24 hrs.)	Batch Ice Makers Consumption Rate (kWh/100 lbs. ice)	Potable Water Use (gal/100 lbs. ice)
Ice Making Heads	< 310	≤ 7.90– 0.005409H	≤ 15.0
	≥ 310 and < 820	≤ 7.08-0.002752H	≤ 15.0
	≥ 4,000	≤ 4.82	≤ 15.0
Remote Condensing Units (w/out remote compressor)	< 800	≤ 7.76– 0.00464H	≤ 15.0
	≥ 800 and < 4,000	≤ 4.05	≤ 15.0
Remote Condensing Units (w/ remote compressor)	< 800	≤ 7.76– 0.00464H	≤ 15.0
	≥ 800 and < 4,000	≤ 4.05	≤ 15.0
Self-Contained Units	< 200	≤ 12.37–0.0261H	≤ 15.0
	≥ 200 and < 700	≤ 8.24-0.005429H	≤ 15.0
	≥ 700 and < 4,000	≤ 4.44	≤ 15.0

2.5.10.3 Estimated Useful Life

According to DEER 2011 the commercial ice maker will have an EUL of 10 years.

2.5.10.4 Deemed Savings Values

Energy savings and demand reductions for commercial ice makers are based on the energy consumption from the harvesting of ice, either in batches or continuously. The following subsections outline deemed calculations for energy savings and demand reductions, respectively.

Annual electric savings are calculated by determining the energy consumed for baseline ice makers compared against the energy consumed by qualifying ENERGY STAR product using the harvest rate of the more efficient unit.

The following two equations show how energy savings and demand reductions can be calculated, respectively:

$$\Delta kWh = \frac{\left(kWh_{base,per\ 100\ lb} - kWh_{ee,per\ 100\ lb}\right)}{100} \times DC \times H \times 365$$

$$\Delta kW = \left(\frac{\Delta kWh}{HRS}\right) \times CF$$

Where:

$kWh_{base,per\ 100\ lb}$ = calculated on the harvest rate and type of ice machine from the Federal Minimum Energy Consumption Rate relationships in Table 2-124 and

Table 2-125

$kWh_{ee,per\ 100\ lb}$ = Qualifying energy efficient model consumption found in the AHRI directory of certified products by model information.

$100\ =\ \text{conversion factor to convert}\ kWh_{base,per\ 100\ lb}\ \text{and}\ kWh_{ee,per\ 100\ lb}$ into maximum kWh consumption per pound of ice

DC = Duty Cycle of the ice maker representing the percentage of time the ice machine is making ice = 0.75

H = Harvest Rate (lbs. of ice made per day)

365 = days per year

HRS = Annual operating hours = 365 * 24 = 8,760 hours/year

CF = 1.0

For example, the annual energy savings and demand reductions for a batch type IMH commercial ice maker with an ice harvest rate *(H)* of 550 lbs. of ice per day and a consumption rate of kWh/100 lbs. ice of 4.45 are calculated as:

$$\Delta kWh = \frac{\left((7.05 - 0.0025 \times 550\ ) - 4.45\right)}{100} \times 0.75 \times 550 \times 365 = 1{,}844\ kWh$$

$$\Delta kW = \left(\frac{1{,}844\ kWh}{8{,}760\ hr/yr}\right) \times 1.0 = 0.2105\ kW$$

2.5.10.5 *Incremental Cost*[387]

Incremental costs are presented in the table below.

Table 2-128 Incremental Costs

Ice Harvest Rate (H)	Incremental Cost
100-200 lb. ice maker	$296
201-300 lb. ice maker	$312
301-400 lb. ice maker	$559
401-500 lb. ice maker	$981
501-1000 lb. ice maker	$1,485
1001-1500 lb. ice maker	$1,821
<1500 lb. ice maker	$2,194

2.5.10.6 *Future Studies*

At the time of authorship, this measure was not implemented in Energy Smart programs. Thus, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units rebated in the program. Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

[387] These values are from electronic work papers prepared in support of San Diego Gas & Electric's "Application for Approval of Electric and Gas Energy Efficiency Programs and Budgets for Years 2009-2011", SDGE, March 2, 2009. https://www.sdge.com/node/709

2.6 Lighting

2.6.1 LIGHTING EFFICIENCY

2.6.1.1 Measure Description

This chapter provides energy and demand reduction calculations for the replacement of commercial lighting equipment with energy efficient lamps or fixtures. The operating hours and demand factors are based on primary research in the New Orleans market. This chapter now incorporates the 2007 Energy Independence & Security Act (EISA) Phase II standards (also known as the “EISA Backstop”).

This chapter applies to high performance and reduced wattage T8s, fluorescent delamping, high output LED fixtures, HID fixtures and some GSLs. It is applicable only to manually controlled (switches and dimmers) residential lighting, and not LED fixtures or connected, ‘smart’ or otherwise automatically controlled lighting.

2.6.1.1.1 Fixture-Level Deemed Savings

Due to the myriad of possible baseline lighting configurations, efficient configurations and facility parameters that contribute to a commercial lighting savings calculation, the TPE has opted to not include deemed savings per-fixture. Such a value would require too many assumptions and is likely to be too in accurate to provide a fixed estimate. If the needed data cannot be collected by program implementers, then the project in question is ineligible for savings. The data requested to calculate deemed savings is consistent with what program implementers have historically collected in implementing Energy Smart programs and align with industry best practices for deemed savings for commercial lighting.

2.6.1.2 Baseline & Efficiency Standard

The following sections explain the various codes, standards, and required processes to establish the applicability of the Lighting Efficiency savings calculation method.

2.6.1.2.1 State Commercial Energy Codes

Louisiana’s state commercial energy code recognizes ASHRAE 90.1-2007 for commercial structures. These standards specify the maximum lighting power densities (LPDs) by building type (building area method) and interior space type (space-by-space method). LPDs apply to all new construction and major renovation projects. The ASHRAE 90.1-2007 LPDs for various building types are outlined in Appendix F. Agricultural lighting for animals will utilize recognized industry standards unique to the requirements of that animal to determine the LPD for the building housing those animals.

2.6.1.2.2 Retrofit Baseline Summary

For all retrofit projects, the baseline is the current federal efficacy standard. If the replacement system is a T8, then it must meet Consortium for Energy Efficiency (CEE) specification requirements for High Performance and Reduced Wattage T8 systems. Other high-performance systems, including but not limited to T5 and LED systems, are allowed. T12s are no longer an eligible baseline technology.

2.6.1.2.3 Federal Efficacy Standards

The Energy Independence and Security Act (EISA) of 2007 mandates minimum efficacy standards for general service incandescent lamps, modified spectrum general service incandescent lamps, incandescent reflector lamps, fluorescent lamps, and metal halide lamps.

Effective January 1, 2010, EISA increased minimum ballast efficacy factors and established pulse-start metal halides (PSMHs) as the new industry standard baseline for the metal halide technology (< 500 W). New construction projects must use PSMHs in metal halide applications.

The Energy Policy Act (EPAct) of 2005 and EISA of 2007 are two energy legislative rulings enacted to establish energy reduction targets for the United States. On July 14, 2009, the Department of Energy published a final rule for energy conservation standards for general service fluorescent lamps (GSFLs). These standards are shown in Table 2-129. As a result of this rule, all GSFLs manufactured in the United States, or imported for sale into the United States on or after July 14, 2012 (three years from the ruling date) must meet new, more stringent efficacy standards (measured in lumens per watt, LPW).

Table 2-129 Lighting Efficiency – Current Federal Efficiency Standards for GSFL

Lamp Type	Nominal Lamp Wattage	Minimum Color Rendering Index (CRI)	Minimum Average Lamp Efficacy (Lumens/ Watt/ LPW)
4-foot Medium Bi-Pin	> 35W ≤ 35 W	69 45	75.0 75.0
2-foot U-Shaped	> 35W ≤ 35W	69 45	68.0 64.0
8-foot Slimline	> 65W ≤ 65W	69 45	80.0 80.0
8-foot High Output	> 100W ≤ 100W	69 45	80.0 80.0

Facilities with 4-foot and 8-foot T12s or with 2-foot U-Shaped T12s are still eligible to participate in lighting retrofit projects, but an assumed electronic T8 baseline should be used in place of the existing T12 equipment. These T12 fixtures will remain in the standard wattage table with the label "T12 (T8 baseline)" and will include adjusted wattages assumptions consistent with a T8 fixture with an equivalent length and lamp count. T12 fixtures not specified above will remain an eligible baseline technology.

Table 2-130 Adjusted Baseline Wattages for T12 Equipment

T12 Length	Lamp Count	Revised Lamp Wattage	Revised System Wattage
48 inch- Std, HO, and VHO (4 feet)	1	32	31
	2	32	58
	3	32	85
	4	32	112
	6	32	170
	8	32	224
96 inch-Std (8 feet) 60/75W	1	59	69
	2	59	110
	3	59	179
	4	59	219
	6	59	330
	8	59	438*
96 inch-HO and VHO (8 feet) 95/110W	1	86	101
	2	86	160
	3	86	261
	4	86	319
	6	86	481

T12 Length	Lamp Count	Revised Lamp Wattage	Revised System Wattage
	8	86	638
2 ft. U-Tube	1	32	32
	2	32	60
	3	32	89

* 8 lamp fixture wattage approximated by doubling 4 lamp fixture wattage.
Key: HO = high output, VHO = very high output

2.6.1.2.4 Fixture Qualification Process – High Performance and Reduced Wattage T-8 Equipment

CEE develops and maintains energy specifications for High Performance and Reduced Wattage T8 equipment. CEE high performance and reduced wattage T8 specifications can be found at:

- http://www.cee1.org/com/com-lt/com-lt-specs.pdf (High Performance products)
- http://www.cee1.org/com/com-lt/lw-spec.pdf (Reduced Wattage products)

CEE compiles a list of approved lamps and ballasts for T8 systems that are eligible for incentives for retrofits which is available for download on CEE's website at http://library.cee1.org/content/commercial-lighting-qualifying-products-lists.

2.6.1.2.5 Fixture Qualification Process – LED and Pin-Based CFL Products:

LED and pin-based CFL products must be pre-qualified under one of the following options:

- Product is on the ENERGY STAR Qualified Product List or ENERGY STAR Qualified Light Fixtures Product List (http://www.energystar.gov)
- Product is on the Northeast Energy Efficiency Partnerships (NEEP) DesignLights Consortium™ (DLC) Qualified Products Listing (www.designlights.org)
- Exceptions to the ENERGY STAR and/or DLC requirements are allowed for unlisted lamps and fixtures that have already been submitted to either ENERGY STAR or DLC for approval. If the lamp or fixture does not achieve approval within the AR DSM program year, however, then the lamp or fixture must immediately be withdrawn from the program. If withdrawn, savings may be claimed up to the point of withdrawal from the program. For Agricultural uses where the fixture is designed for animal use, if an LED bulb does not meet ENERGY STAR and/or DLC requirements, the bulb can be utilized if a thorough review of the bulb is conducted and verified by the TPE.
- Screw-based CFLs are no longer qualified for Energy Smart programs (see next section).

2.6.1.2.6 General Service Lamps

The first of two advances of lighting standards from EISA 2007 Regulations were phased in from January 2012 to January 2014 and dictated higher efficiency for General Service Lamps (GSLs). The baseline equipment was originally assumed to be an incandescent or halogen lamp with adjusted baseline wattages compliant with EISA 2007 Regulations.

Phase II takes effect on July 25, 2022, stipulating that all GSLs sold in the United States (US) must achieve a minimum efficacy of 45 lumens/watt. The ruling also significantly expands the definition of GSLs, extending the covered lumen range, base types, and shapes, while reducing the types of bulbs exempted.

"General Service Lamp" means a lamp that it:

- Has an [American National Standards Institute] (ANSI) base;

- Is able to operate at a voltage of 12 volts or 24 volts, at or between 100 to 130 volts, at or between 220 to 240 volts, or at 277 volts for integrated lamps, or is able to operate at any voltage for non-integrated lamps;
- Has an initial lumen output of greater than or equal to 310 lumens (or 232 lumens for modified spectrum general service incandescent lamps) and less than or equal to 3,300 lumens;
- Is not a light fixture;
- Is not an LED downlight retrofit kit; and
- Is used in general lighting applications."

Previously exempt lamps that are now subject to regulations under the expanded GSL definition include:

- Reflectors: The following three reflector lamp types (which represent most reflectors) are no longer exempt from GSL standards:
  - (A) Lamps rated at 50 watts or less that are ER30, BR30, BR40, or ER40 lamps;
  - (B) Lamps rated at 65 watts that are BR30, BR40, or ER40 lamps; or
  - (C) R20 incandescent reflector lamps rated 45 watts or less;
- Lumen maximums: The lumen maximum subject to the EISA GSL definition has been increased from 2,600 to 3,300 lumens;
- Base types: All standard bulb bases are included (small screw base and candelabra); and
- Others lamp types: 3-way, decorative (including globes <5", flame shapes and candelabra shapes), T-lamps (≤40w OR ≥ 10"), vibration service, rough service, and shatter resistant bulb exemptions are also discontinued.

The 45 lumen/watt efficacy requirement inherently disallows incandescent and halogen lamps, but the EISA backstop does not directly specify a technological standard to satisfy the efficacy requirement. LEDs are well beyond 45 lumens/W (very often operating at greater than 60 lumens/watt), and alternative technologies all fall below the new EISA backstop, effectively meaning that general service lamps which operate at 45 lumens/watts for common lighting categories are not available for purchase[388].

This precludes savings from being claimed in new construction and most retrofit applications. Savings can still be realized through early replacement, where existing incandescent, halogen, CFL and other inefficient technologies can be directly identified. Custom projects which involve to early retirement of incandescent, halogen and CFL lamps may continue after June 30, 2023. However, all projects that occur after June 30, 2023, will require that the TPA "bag and tag" the old lamps, to be stored until a quarterly verification inspection is conducted by TPE staff. To claim savings, implementation staff must record as-found lamp types and wattages and use Table 2-131, Table 2-132, and Table 2-133 below to determine the baseline.

Table 2-131 Baseline Wattage by Lumen Output for Omni-Directional Lamps[389]

Minimum Lumens	Maximum Lumens	EISA Phase I W_{base}	EISA Phase II W_{base}
310	749	29	12
750	1,049	43	20
1,050	1,489	53	28
1,490	2,600	72	45

[388] Notable exceptions include some compact fluorescent bulbs (CFL).

[389] Wattages developed using the 45 LPW standard.

Table 2-132 Baseline Wattage by Lumen Output for Directional/Reflector Lamps[390]

Lamp Type	Incandescent Equivalent (Pre-EISA)	EISA Phase I W_{base}	EISA Phase II W_{base}
PAR20	50	35	23
PAR30	50	35	23
R20	50	45	29
PAR38	60	55	35
BR30	65	EXEMPT	38
BR40	65	EXEMPT	38
ER40	65	EXEMPT	38
BR40	75	65	42
BR30	75	65	42
PAR30	75	55	35
PAR38	75	55	35
R30	75	65	42
R40	75	65	42
PAR38	90	70	45
PAR38	120	70	45
R20	≤ 45	EXEMPT	23
BR30	≤ 50	EXEMPT	EXEMPT
BR40	≤ 50	EXEMPT	EXEMPT
ER30	≤ 50	EXEMPT	EXEMPT
ER40	≤ 50	EXEMPT	EXEMPT

Table 2-133 Baseline Wattage by Lumen Output for Exempt Lamps[391]

Minimum Lumens	Maximum Lumens	Incandescent Equivalent (W_{base})
310	749	40
750	1,049	60
1,050	1,489	75
1,490	2,600	100

2.6.1.2.7 Input Wattages

Input wattages for pre-retrofit and qualifying fixtures are included in the Standard Fixture Wattage Table (Appendix E). This is a relatively comprehensive list of both old and new lighting technologies that could be expected for inclusion in a project. If there are fixtures identified that are not included in this table, those fixtures should be submitted to the TPE for review and incorporation into subsequent TRM updates. Interim approval may be made for certain fixtures at the discretion of the TPE. However, there may be eligible products that are not on the list. If a product is not on the list, then manufacturer's data should be reviewed prior to accepting the product into a program. LED products should be approved by DLC or ENERGY STAR before being recognized as an eligible product.

2.6.1.3 Estimated Useful Life

The table below shows the EUL by lamp type.

[390] Based on manufacturer available reflector lighting products as available in August 2013; using 45 lumens/watt.

[391] Lumen bins and incandescent equivalent wattages from ENERGY STAR labeling requirements, Version 1.0 http://www.energystar.gov/products/specs/sites/products/files/ENERGY%20STAR%20Lamps%20V1.0%20Final%20Draft%20Specification.pdf EISA Standards from: United States Department of Energy. Impact of EISA 2007 on General Service Incandescent Lamps: FACT SHEET.

Table 2-134 Estimated Useful Life by Lamp Type

Lamp Type	EUL	Source[392]
High Intensity Discharge (HID)	16.0	Based upon 50,000 hour manufacturer rated life and weighted-average 3,205 annual operating hours from Navigant U.S. Lighting Study.
Integrated-Ballast Cold-Cathode Fluorescent Lamps (CCFL)	5.0	Based upon 25,000 hour manufacturer rated life and weighted-average 5,493 annual operating hours from Navigant U.S. Lighting Study.
Integrated-Ballast LED Lamps	9.0	Based on 30,000 hour manufacturer rated life and weighted-average 3,260 annual operating hours from Navigant U.S. Lighting Study.
Light Emitting Diode (LED)	15.0	Based upon 50,000 hour manufacturer rated life and weighted-average 3,260 annual operating hours from Navigant U.S. Lighting Study.
General Service Lamp LED	1.0	The EUL for LED replacement under the auspices of EISA Phase II is based on the remaining useful life of the baseline lamp. The EUL for incandescent and halogen lamps is less than one year in commercial applications. With a final sale date of June 30, 2023, this puts the “savings ending date” for savings with an incandescent or halogen baseline on June 30, 2025. If a CFL baseline is used, the EUL will assume a CFL with an 8,000-hour rated life, which results in an EUL of one year[393]. With a final sale date of June 30, 2023, this puts the “savings ending date” for savings with an incandescent or halogen baseline on June 30, 2028.
Linear Fluorescents (T5, T8)	16.0	Based upon 50,000 hour manufacturer rated life and weighted-average 3,211 annual operating hours from Navigant U.S. Lighting Study.
Modular CFL and CCFL	16.0	Based upon 60,000 hour manufacturer rated life and weighted-average 3,251 annual operating hours from Navigant U.S. Lighting Study.

2.6.1.4 Deemed Savings Values

2.6.1.4.1 New Construction

The following formulas are to calculate deemed savings for new construction.

$$kW_{savings} = \left(\left(SF \times \frac{LPD}{1000}\right) - \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right)\right) \times CF \times IEF_D$$

[392] Navigant Consulting, “U.S. Lighting Market Characterization, Volume I: National Lighting Inventory and Energy Consumption Estimate, Final Report.” U.S. DOE. September 2002.

[393] EUL based on 8,000 hours and 11.49 hours per day (an average of commercial space types), with a .526 “switching degradation factor” for CFL.

$$kWh_{savings} = \left(\left(SF \times \frac{LPD}{1000}\right) - \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right)\right) \times AOH \times IEF_E$$

Where:

SF = Total affected square footage of the new construction facility

LPD = Maximum allowable power density by building type (W/ft^2) (Volume 3, *Appendices*)

$N_{fixt(i),post}$ = Post-retrofit # of fixtures of type i

$W_{fixt(i),post}$ = Rated wattage of post-retrofit fixtures of type i (Volume 3, *Appendices*)

CF = Peak demand coincidence factor (Table 2-136)

AOH = Annual operating hours for specified building type (Table 2-136)

IEF_D = Interactive effects factor for demand reduction (Table 2-137)

IEF_E = Interactive effects factor for energy savings (Table 2-137)

2.6.1.4.2 Retrofit with No Existing Controls

The following formulas are to calculate deemed savings for retrofits without existing controls.

$$kW_{savings} = \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right) \times CF \times IEF_D$$

$$kWh_{savings} = \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right) \times AOH \times IEF_E$$

2.6.1.4.3 Retrofit with Existing Controls

For lighting systems with existing controls, no additional control savings should be claimed with the savings specified by the equations below.

$$kW_{savings} = \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right) \times IEF_D \times CF_{controls}$$

$$kWh_{savings} = \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right) \times IEF_E \times AOH \times PAF$$

Where:

$N_{fixt(i),pre}$ = Pre-retrofit number of fixtures of type i

$N_{fixt(i),post}$ = Post-retrofit number of fixtures of type i

$W_{fixt(i),pre}$ = Rated wattage of pre-retrofit fixtures of type i (Volume 3, *Appendices*)

$W_{fixt(i),post}$ = Rated wattage of post-retrofit fixtures of type i (Volume 3, *Appendices*)

CF = Peak demand coincidence factor (Table 2-136)

$CF_{controls}$ = Controls peak demand coincidence factor = 0.26[394]

AOH = Annual operating hours for specified building type (Table 2-136)

PAF = Power adjustment factor for specified control type (Table 2-136**Error! Reference source not found.**)

IEF_D = Interactive effects factor for demand reduction (Table 2-137)

IEF_E = Interactive effects factor for energy savings (Table 2-137)

2.6.1.4.4 Operating Hours & Coincidence Factors (CF)

If the annual operating hours and/or CF for the specified building are not known, use the deemed average annual hours of operation and/or peak demand CF from Table 2-136 summarizes the general transferability ratings for the lighting end-use. Due to the low variability of schedules and weather for both indoor and outdoor lighting, there is a high degree of data transferability across regions, and it is appropriate to assume very similar annual operating hours across different regions.[395] To the extent that utility system peak periods are similar, it is also appropriate to assume very similar peak CFs across different regions.

Table 2-135 Transferability of Data across Geographic Regions

Analysis Group	Schedule Variability	Weather Variability	Transferability Rating
Lighting – Exterior	Low	Low	High
Lighting – Interior	Low	Low	High

Operating hours are the number of hours that a particular equipment type is in use over the course of a year. For these recommendations, raw building lighting operating hour data were adjusted by Frontier Associates according to the percentage of wattage consumed by each space within a building. Subsequently, weighted average operating hours (AOH) were developed for a range of building types.

The CF for lighting is the ratio of the lighting kW demand during the utility's peak period (New Orleans does not have a specific peak period definition, and CF values are assumed to reflect peak loads of similar utilities) to the connected lighting kW (∑(Ni xWi/ 1000) as defined above. Other issues are automatically accounted for, such as diversity and load factor. A portion of the CF values were arrived at through secondary research. In the cases where acceptable values were not available through other sources, Frontier Associates calculated values comprised of CF and building operating hour data available for the types of building spaces that would likely be found within that building type.

Deemed annual operating hours from the Arkansas TRM (AR TRM) were used as a basis for New Orleans AOH. These hours were originally developed by Frontier Associates for the AR TRM. The TPE used these values in conjunction with on-site monitoring from facility types commonly found New Orleans commercial lighting program participant populations. Direct monitoring data was collected from 210 loggers placed in 59 New Orleans and other major Louisiana utility territories. A total of (14) facility types

[394] RLW Analytics, *"2005 Coincidence Factor Study,"* Connecticut Energy Conservation Management Board. January 4, 2007. Default value applicable to all building types. This coincidence factor is a combination of the savings factor and peak coincidence factor.

[395] KEMA. End-Use Load Data Update Project Final Report: Phase 1: Cataloguing Available End-Use and Efficiency Measure Load Data. 2009. Prepared for the Northwest Power and Conservation Council and Northeast Energy Efficiency Partnerships, November.

received updated hours, and (10) new generic space types common in New Orleans area-projects were created.

Table 2-136 Annual Operating Hours (AOH) and Coincidence Factors (CF)[396]

Facility or Space Type	AOH	CF
Leisure Dining: Bar Area	2,676*	0.81
Corridor/Hallway/Stairwell	5,233*	0.90
Education: College/University	3,577	0.69
Education: K-12	2,333*	0.47
Exterior	4,319*	0.00
Food Sales: 24-Hour Supermarket	6,900	0.95
Food Sales: Non-24-Hour Supermarket	4,706	0.95
Food Service: Fast Food	6,473*	0.81
Food Service: Sit-Down Restaurant	4,731*	0.81
Health Care: In-Patient	4,019*	0.78
Health Care: Nursing Home	4,271*	0.78
Health Care: Out-Patient	3,386	0.77
Convenience Store (non-24 hour)	4,245*	0.90
Lodging (Hotel/Motel/Dorm): Common Areas	4,127*	0.82
Lodging (Hotel/Motel/Dorm): Room	3,370*	0.25
Manufacturing	5,740	0.73
Multi-family Housing: Common Areas	5,703*	0.87
Non-Warehouse Storage (Generic)	4,207*	0.77
Office	5,159*	0.77
Office (attached to other facility)	4,728*	0.77
Parking Structure	7,884	1.00
Public Assembly	2,638	0.56
Public Order and Safety	3,472	0.75
Religious Gathering	3,174*	0.53
Restroom (Generic)	3,516*	0.90
Retail: Enclosed Mall	4,813	0.93
Retail: Freestanding	3,515*	0.90
Retail: Other	4,312*	0.90
Retail: Strip Mall	3,965	0.90
Service: Excluding Food	3,406	0.90

[396] Unless otherwise noted, deemed AOH and CF values are based on Frontier Associates on behalf of Electric Utility Marketing Managers of Texas (EUMMOT). "Petition to Revise Existing Measurement & Verification Guidelines for Lighting Measures for Energy Efficiency Programs: Docket No. 39146." Public Utility Commission of Texas. Approved June 6, 2011. http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch.asp

Warehouse: Non-Refrigerated	2,417*	0.77
Warehouse: Refrigerated	3,798	0.84

*Annual operating hours with an asterisk (*) were developed using primary data collected in the ENO territory.

2.6.1.4.5 Interactive Effects

Lighting in air conditioned and refrigerated spaces adds heat to the space, increasing the cooling requirement during the cooling season and decreasing the heating requirement during the heating season. The decrease in waste heat from lighting mitigates these effects, thus reducing electricity used for cooling and increasing electricity or gas used for heating.

Deemed interactive effects factors for both demand and energy savings are presented in Table 2-137. These factors represent the percentage increase or decrease in energy savings for the refrigeration system's electric load attributed to the heat dissipated by the more efficient lighting system. For example, a factor of 1.20 indicates a 20% savings. The methodology for applying these Interactive Effects Factors to calculate savings is discussed in 2.6.1.4 *Deemed Savings*.

A detailed description of the derivation of interactive effects is available in Volume 3, *Appendices*.

Table 2-137 Commercial Conditioned and Refrigerated Space Interactive Effects Factors

Building Type	Temperature Description	Heating Type	IEF_D	IEF_E
All building types (Except Outdoor & Parking Structure)	Air Conditioned Space Normal Temps. (> 41°F)	Gas	1.20	1.09
		Electric Resistance		0.87
		Heat Pump		1.02
		Heating Unknown [397]		0.98
	Refrigerated Space Med. Temps. (33-41°F)	All	1.25	1.25
	Refrigerated Space Low Temps. (-10-10°F)	All	1.30	1.30

2.6.1.5 Incremental Costs

Incremental costs by lighting category are as follows.

2.6.1.5.1 High Performance and Reduced Wattage T8s

Incremental costs are detailed in Table 2-138[398].

Table 2-138 T8 Linear Fluorescent Incremental Costs

Measure	Watts	Baseline	Incremental Cost
4-lamp HPT8 High-bay	128	200W Pulse Start MH	$75
4-lamp HPT8 High-bay	128	250W Pulse Start MH	$75
6-lamp HPT8 High-bay	192	320W Pulse Start MH	$75

[397] These values should be used for programs where heat type cannot be determined.

[398] Illinois TRM V10.0

Measure	Watts	Baseline	Incremental Cost
6-lamp HPT8 High-bay	192	400W Pulse Start MH	$75
8-lamp HPT8 High-bay	256	320W Pulse Start MH	$75
8-lamp HPT8 High-bay	256	400W Pulse Start MH	$75
1-lamp HPT8 – 32W	32	1-lamp standard F328- Electronic ballast	$15
1-lamp HPT8 – 28W	28	1-lamp standard F328- Electronic ballast	$15
1-lamp HPT8 – 25W	25	1-lamp standard F328- Electronic ballast	$15
2-lamp HPT8 – 32W	64	2-lamp standard F328- Electronic ballast	$18
2-lamp HPT8 – 28W	56	2-lamp standard F328- Electronic ballast	$18
2-lamp HPT8 – 25W	50	2-lamp standard F328- Electronic ballast	$18
3-lamp HPT8 – 32W	96	3-lamp standard F328- Electronic ballast	$20
3-lamp HPT8 – 28W	84	3-lamp standard F328- Electronic ballast	$20
3-lamp HPT8 – 25W	75	3-lamp standard F328- Electronic ballast	$20
4-lamp HPT8 – 32W	128	4-lamp standard F328- Electronic ballast	$23
4-lamp HPT8 – 28W	112	4-lamp standard F328- Electronic ballast	$23
4-lamp HPT8 – 25W	100	4-lamp standard F328- Electronic ballast	$23
2-lamp HPT8 Troffer	64	3-lamp standard F328- Electronic ballast	$100
RW T8-F28 Lamp	28	F32 T8 Standard lamp	$2
RW T8-F28 Extra Life Lamp	28	F32 T8 Standard lamp	$2
RW T8-F32/25W Lamp	25	F32 T8 Standard lamp	$2
RW T8-F32/25 xtra Life Lamp	285	F32 T8 Standard lamp	$2
RWT8 F17T8 Lamp - 2 ft.	16	F17 T8 Standard lamp – 2 ft.	$2
RWT8 F25T8 Lamp - 3 ft.	23	F25 T8 Standard lamp – 3 ft.	$2
RWT8 F30T8 Lamp - 6' Utube	30	F32 T8 Standard Utube	$2
RWT8 F29T8 Lamp - Utube	29	F32 T8 Standard Utube	$2
RWT8 F96T8 Lamp - 8 ft.	65	F96 T8 Standard lamp – 8 ft.	$2

2.6.1.5.2 T5 Linear Fluorescent Fixtures

Incremental costs are detailed in Table 2-139.

Table 2-139 T5 Linear Fluorescent Incremental Costs

EE Measure	Watts	Baseline	Incremental Cost
2-lamp T5 High-bay	180	200W Pulse Start MH	$100
3-lamp T5 High-bay	180	200W Pulse Start MH	$100
4-lamp T5 High-bay	240	320W Pulse Start MH	$100
6- lamp T5 High-bay	192	320W Pulse Start MH	$100
1-lamp T5 Troffer	32	3-lamp T8	$40
2-lamp T5 Troffer	64	3-lamp T8	$80
1-lamp T5 Industrial/Strip	32	3-lamp T8	$30
2- lamp T5 Industrial/Strip	64	3-lamp T8	$60
3- lamp T5 Industrial/Strip	96	3-lamp T8	$90
4- lamp T5 Industrial/Strip	187	3-lamp T8	$120
1-lamp T5 Indirect	32	3-lamp T8	$30
2-lamp T5 Indirect	64	3-lamp T8	$60

2.6.1.5.3 LED Lamps

Incremental costs are detailed in Table 2-140 and Table 2-141.

Table 2-140 GSL LED Incremental Costs

LED Measure Description	Incremental Cost
Omnidirectional	$1.45
Directional	$1.65
Decorative and Globe	$1.66

Table 2-141 Non-GSL LED Incremental Costs[399]

LED Category	LED Measure Description	Incremental Cost
LED Downlight Fixtures	LED Recessed, Surface, Pendant Downlights	$27
LED Interior Directional	LED Track Lighting	$59
	LED Wall-Wash Fixtures	$59
LED Display Case	LED Display Case Light Fixture	$11/ft.
	LED Undercabinet Shelf-Mounted Task Light Fixtures	$11/ft.
	LED Refrigerated/Freezer Case light	$11/ft.

[399] Watt, lumen, lamp life, and ballast factor assumptions for efficient measures are based upon Consortium for Energy Efficiency (CEE) Commercial Lighting Qualifying Product Lists alongside past Efficiency Vermont projects and PGE refrigerated case study. Watt, lumen, lamp life, and ballast factor assumptions for baseline fixtures are based upon manufacturer specification sheets. Baseline cost data comes from lighting suppliers, past Efficiency Vermont projects, and professional judgment. Efficient cost data comes from 2012 DOE “Energy Savings Potential of Solid-State Lighting in General Illumination Applications”, Table A.1. See "LED Lighting Systems TRM Reference Tables.xlsx" for more information and specific product links.

LED Category	LED Measure Description	Incremental Cost
LED Linear Replacement Lamps	LED 4' Linear Replacement Lamp	$13
	LED 2' Linear Replacement Lamp	$13
LED Troffers	LED 2x2 Recessed Light Fixture, 2,000-3,500 Lumens	$53
	LED 2x2 Recessed Light Fixture, 3,501-5,000 Lumens	$69
	LED 2x4 Recessed Light Fixture, 3,000-4,500 Lumens	$55
	LED 2x4 Recessed Light Fixture, 4,501-6,000 Lumens	$76
	LED 2x4 Recessed Light Fixture, 6,001-7,500 Lumens	$104
	LED 1x4 Recessed Light Fixture, 1,500-3,000 Lumens	$22
	LED 1x4 Recessed Light Fixture, 3,001-4,500 Lumens	$75
	LED 1x4 Recessed Light Fixture, 4,401-6,000 Lumens	$83
LED Linear Ambient Fixtures	LED Surface & Suspended Linear Fixture, <=3,000 Lumens	$10
	LED Surface & Suspended Linear Fixture, 3,001-4,500 Lumens	$52
	LED Surface & Suspended Linear Fixture, 4,501-6,000 Lumens	$78
	LED Surface & Suspended Linear Fixture, 6,001-7,500 Lumens	$131
	LED Surface & Suspended Linear Fixture, >7,500 Lumens	$173
LED Low Bay & High Bay Fixtures	LED Low-Bay Fixtures, <= 10,000 Lumens	$44
	LED High-Bay Fixtures, 10,001-15,000 Lumens	$137
	LED High-Bay Fixtures, 15,001-20,000 Lumens	$202
	ED High-Bay Fixtures, 20,001-30,000 lumens	$264
	LED High-Bay Fixtures, 30,001-40,000 lumens	$400
	LED High-Bay Fixtures 40,001-50,000 lumens	$425
	ED High-Bay Fixtures >50,000 lumens	$550
LED Agricultural Interior Fixtures	LED Ag Interior Fixtures, <= 2,000 Lumens	$18
	LED Ag Interior Fixtures, 2,001-4,000 Lumens	$48
	LED Ag Interior Fixtures, 4,001-6,000 Lumens	$57
	LED Ag Interior Fixtures, 6,001-8,000 Lumens	$88
	LED Ag Interior Fixtures, 8,001-12,000 Lumens	$168
	LED Ag Interior Fixtures, 12,001-16 ,000 Lumens	$151
	LED Ag Interior Fixtures, 16,001-20,000 Lumens	$205
	LED Ag Interior Fixtures, > ,000 Lumens	$356
LED Exterior Fixtures	LED Exterior Fixtures, <=5,000 Lumens	$80
	LED Exterior Fixtures, 5,001-10,000 Lumens	$248
	LED Exterior Fixtures, 10,001-15,000 Lumens	$556
	LED Exterior Fixtures, 15,001-30,000 lumens	$946
	LED Exterior Fixtures, 30,001-40,000 lumens	$700

LED Category	LED Measure Description	Incremental Cost
	LED Exterior Fixtures, 40,001-50,000 lumens	$850
	ED Exterior Fixtures, > 50,000 lumens	$1,100

2.6.1.6 Future Studies

This measure category constitutes over 90% of C&I savings historically in Energy Smart. As a result, this category should be a primary focus of EM&V research. The TPE recommends the following:

- Conduct metering studies for commercial facilities not captured in EM&V to-date.
- Conduct an incremental cost study reflect New Orleans prices, sales tax, and labor costs.
- Conduct focused metering for lighting that is not listed in Energy Start or CEE lists.
- Conduct a market assessment for advanced lighting controls; mature lighting programs have begun further incorporation of Wi-Fi-enabled control schemes where lighting is incorporated into the Energy Management System (EMS). The TPE recommends a market assessment for advanced lighting control adoption in New Orleans.
- Conduct preliminary research to assess whether certain lighting categories would be better-served with a midstream program approach.

2.7 Other Measures

2.7.1 WINDOW FILM

2.7.1.1 Measure Description

This measure consists of the addition of solar film to the outside of glazing on the east, west or south-facing windows of small commercial buildings less than 15,000 gross square feet (any direction except 45 degrees of true north). This measure is based on square footage of qualifying windows.

2.7.1.2 Baseline and Efficiency Standards

This measure is applicable to existing commercial buildings with clear single- or double-pane glazing with a solar heat gain factor (SHGC) greater than 0.66. Existing Low E windows, windows with existing solar films or solar screens are not eligible for this measure.

To qualify for deemed savings, window film should be applied to glass facing east, west or south. The SHGC of the proposed films must be less than 0.50.

The windows must not be shaded by existing awnings, exterior curtains or blinds or any other shading device. They must be installed in a space conditioned by refrigerated air conditioning (central, window or wall unit).

The windows must meet all applicable codes and standards, including:

- ASTM-408: Standard Method for Total Normal Emittance by inspection meter.
- ASTM E-308: Standard Recommended Practice for Spectro-Photometry and Description of Color in CIE1931 (this is an indicator of luminous reflection and visibility).
- ASTM-E903: Standard Methods of Test for Solar Absorbance, Reflectance and Transmittance using an integrated sphere.
- ASTM G-90: Standard Practice for Performing Accelerated Outdoor Weatherizing for Non-Metallic Materials Using Concentrated Natural Light.
- ASTM G26: Xenon arc weathering to accelerate natural aging.
- ASTM E-84: Flammability for commercial and residential structures.

2.7.1.3 Estimated Useful Life

The EUL of this measure is 10 years, according to DEER 2008.

2.7.1.4 Deemed Savings Values

Deemed savings values for annual energy (kWh) and peak demand (kW) are provided in the tables on the following pages. Energy savings are calculated with kWh / sq. ft; demand reductions are kW / 1000 sq. ft.

Table 2-142 Window Film Deemed Savings by Direction and Heating Type

Direction of Window Film	DX Coils with Furnace		Heat Pump		Electric Resistance	
	Energy Savings	**Peak Demand Savings**	**Energy Savings**	**Peak Demand Savings**	**Energy Savings**	**Peak Demand Savings**
East	10.24	2.54	3.08	2.59	5.04	2.59
West	12.32	5.29	6.13	5.43	7.76	5.43
South	17.08	5.66	1.68	5.80	5.81	5.80

Deemed savings are applicable to commercial buildings and were calculated using two representative buildings: a strip mall and a small office building. Estimated savings for the east, west, and south window surfaces were based on a small office building with equal window surfaces on all four sides and for strip malls having glazing on one side. The deemed savings values presented herein represent the average savings per square foot of glazing for windows in each weather zone facing east, west, and south.

2.7.1.5 Incremental Cost

The incremental cost is $2-2.50 per square foot[400].

2.7.1.6 Future Studies

There are currently no future studies planned for this measure at this time.

[400] https://www.energystar.gov/ia/new_homes/comments/Background2.pdf

2.7.2 COMPRESSED AIR LEAK REPAIR

2.7.2.1 Measure Description

This measure consists of identifying and repairing air leaks in compressed air systems. A compressed air system is used in a commercial or industrial system for pneumatic controls of processes that require compressed air such as air dryers and cleaners. The air compressor is programed to maintain a set air pressure in the system during operating hours and air leaks in the system cause the pressure to drop requiring the system to cycle on or operate at a higher load to maintain the pressure causing the system efficiency to decrease. Air leaks are generally located at hose connections, valves, filters, condensate traps, and end use equipment. The most common method to repair a leak in the compressed air system is by tightening connections, replacing worn-out equipment, replacing cracked gaskets, and isolating unused equipment. This measure can only be applied to a compressed air leak repair cost that includes leak detection and repair.

2.7.2.2 Baseline & Efficiency Standard

The savings values for compressed air leak repair are applicable for existing operational compressed air systems. New construction does not qualify for this measure since it is expected to have no air leaks in the system when newly constructed.

2.7.2.3 Estimated Useful Life

The EUL for this measure is 3 years[401].

2.7.2.4 Deemed Savings Values

Due to the large variability in potential energy savings, the TPE has opted to not include deemed savings per leak repair. Such a value would require too many assumptions and the calculated savings has a large range depending on the system pressure, operating hours, and most importantly the leakage rate.

Annual electric kWh and peak kW savings can be calculated using the following equations and Table 2-110 summarizes the needed variables.

$$\Delta kWh = CFM \times kW_{cfm} \times AOH$$

$$CFM = TCFM \times \left(Leak\%_{pre} - Leak\%_{post}\right)$$

$$\Delta kW = CFM \times kW_{cfm}$$

401 http://ilsagfiles.org/SAG_files/Evaluation_Documents/Draft%20Reports%20for%20Comment/ComEd_Drafts_EPY10/ComEd_EUL_CY2019_CompAir_Evaluation_Research_Plan_Draft_2019-06-07.pdf

Table 2-143 Variables for the Deemed Savings Algorithm

Parameter	Description	Value
CFM	Average leak flow rate, cubic feet per minute	Based on Table 2-144
kW_{cfm}	Average compressed air system, kW per CFM	0.107 default, Table 2-145
AOH	Annual hours of operation, hours per year	5702 default, Table 2-146
TCFM	Total system flow rate, cubic feet per minutes	Site measured
$Leak\%_{pre}$	Baseline system leakage percentage	25% default
$Leak\%_{post}$	Repaired system leakage percentage	10% default

Table 2-144 Estimated Leakage Rate[402]

Gauge Pressure Before Leak	Diameter of Orifice				
	1/64”	1/32”	1/16”	1/8”	1/4"
50	0.229	0.916	3.66	14.7	58.6
60	0.264	1.06	4.23	16.9	67.6
70	0.3	1.2	4.79	19.2	76.7
80	0.335	1.34	5.36	21.4	85.7
90	0.37	1.48	5.92	23.7	94.8
100	0.406	1.62	6.49	26	104
150	0.582	2.37	9.45	37.5	150
200	0.761	3.1	12.35	49	196
300	0.995	4.88	18.08	71.8	287

Table 2-145 Air Compressor Efficiency by Control Type[403]

Control Type	Compressor Efficiency	Weighted Average Percentage
Reciprocating - On/off control	0.184	0%
Reciprocating - Load/Unload	0.136	40%
Screw - Load/Unload	0.152	0%
Screw - Inlet Modulation	0.055	0%
Screw - Inlet Modulation w/	0.055	40%
Screw - Variable Displacement	0.153	20%
Screw - VSD	0.178	0%
Unknown / Weighted Average	0.107	

402 UE Systems Inc. Compressed Air Ultrasonic Leak Detection Guide

403 Illinois Technical Reference Manual Version 3.0 Section 4.7.1 VSD Air Compressor

Table 2-146 Annual Operating Hours[404]

Building Type	Hours/Days	EFLH	Average Weight
Single shift	8/5	1,976	16%
2-shift	16/5	3,952	23%
3-shift	24/5	5,928	25%
4-shift	24/7	8,320	36%
Unknown / Average		5,702.32	

2.7.2.5 Incremental Cost

Actual program costs should be used. Deemed costs may be applied once program-average cost estimates have been developed (minimum of 20 projects).

2.7.2.6 Future Studies

There are currently no future studies planned for this measure at this time.

[404] Illinois Technical Reference Manual Version 3.0 Section 4.7.1 VSD Air Compressor

2.7.3 COOL ROOFS

2.7.3.1 Measure Description

This measure consists of replacing at least 75 percent of the roof area with a cool roof. A cool roof is a material of low specific heat and high reflectivity. The primary action of structure heat rejection is the reflection of solar heat back into the atmosphere, but additional heat rejection is realized by the low specific heat of the material quickly radiating any accumulated heat within it out into the atmosphere. A cool roof is defined by ASHRAE 90.1 as a roof having a minimum solar reflectivity of 0.55 and a minimum thermal emittance of 0.75. ASHRAE 90.1-2007 provides an alternative approach allowing products with a minimum Solar Reflective Index (SRI) of 64. The Cool Roof Rating Council (www.coolroofs.org) maintains an SRI database.

2.7.3.2 Baseline & Efficiency Standard

The savings values for cool roof replacement repairs are applicable for all existing baseline roofs. The baseline efficiency is estimated with a solar reflectance of 0.23 and thermal emittance of 0.90.[405]

2.7.3.3 Estimated Useful Life

The effective useful life EUL for this measure is 15 years.[406]

2.7.3.4 Deemed Savings Values

Deemed savings values for annual electric energy use (kWh) and peak demand (kW) is provided in the following tables, arranged by HVAC configuration.

Table 2-147 DX Cooling with Gas Heating

Building Type		kWh/sq. ft.^{2}	kW/1000 ft.^{2}.
Education	Primary School	0.0838	0.0065
	Secondary School	0.0753	0.0047
	Community College	0.1320	0.0372
	University	0.1438	0.0398
Office	Large	0.2346	0.0622
	Small	0.0983	0.0294
Retail	3-Story Large	0.1605	0.0428
	Single-Story Large	0.2685	0.0756
	Small - Retail	0.1125	0.0293
Restaurant	Fast Food	0.1099	0.0299

[405] Average reflectance properties of roofing material as obtained from the publication *Laboratory Testing and Reflectance Properties of Roofing Material* by Florida Solar Energy Center and the predominant roof material used in west south central region for non-small commercial buildings as obtained from CBECS 2003, Table B4

[406] DEER 2014 EUL tables

Table 2-148 DX Cooling with Electric Resistance Heating

Building Type		**kWh/sq. ft.**[2]	**kW/1000 ft.**[2]
Education	Primary School	0.0544	0.0065
	Secondary School	0.0558	0.0047
	Community College	0.1164	0.0348
	University	0.1339	0.0398
Office	Large	0.2168	0.0622
	Small	0.0785	0.0295
Retail	3-Story Large	0.1488	0.0428
	Single-Story Large	0.2381	0.0750
	Small - Retail	0.0808	0.0295
Restaurant	Fast Food	0.0743	0.0298

Table 2-149 Heat Pump

Building Type		**kWh/sq. ft.**[2]	**kW/1000 ft.**[2]
Education	Primary School	0.0718	0.0065
	Secondary School	0.0684	0.0047
	Community College	0.1312	0.0372
	University	0.1431	0.0398
Office	Large	0.2346	0.0622
	Small	0.0785	0.0295
Retail	3-Story Large	0.1605	0.0428
	Single-Story Large	0.2566	0.0750
	Small - Retail	0.0978	0.0295
Restaurant	Fast Food	0.0963	0.0298

Table 2-150 Chiller Loop Cooling W/ HW Boiler Loop Heating

Building Type		**kWh/ ft.**[2]	**kW/1000 ft.**[2]
Education	Secondary School	0.1126	0.0111
	Community College	0.0890	0.0228
	University	0.1088	0.0331
Office	Large	0.1780	0.0637
Retail	3-Story Large	0.1059	0.0301

eQUEST was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since Cool Roof savings are sensitive to weather, available TMY3 weather data specific to New Orleans was used for the analysis. The prototype building characteristics used in the building model are outlined in Appendix A.

2.7.3.5 Incremental Cost

Actual measure cost should be used where available. If not available, the incremental cost of a installing a cool roof is $8.45 per square foot. [407]

2.7.3.6 Future Studies

There are currently no future studies planned for this measure at this time.

[407] 2005 Database for Energy-Efficiency Resources (DEER), version 2005.2.01, "Technology and Measure Cost Data", California Public Utilities Commission, October 26, 2005

2.7.4 AIR CURTAINS

2.7.4.1 Measure Description

This measure applies to buildings with exterior entryways that utilize overhead doors. All other air curtain applications, such as through sliding door entryways or conventional foot-traffic entryways, require custom analysis as air curtain designs must often accommodate other factors that may change their effectiveness.

The use of overhead doors within exterior entryways during the heating season leads to the exfiltration of warm air from the upper portion of the door opening and the infiltration of colder air from the lower portion of the door opening. This results in increase heating energy use to compensate for heat losses every time a door is opened. By reducing heat losses, air curtains can also enhance the physical comfort of employees or customers near the entryway as there will be reduced temperature fluctuations when the door is opened and closed. In addition, in some cases excess heating capacity may be installed in buildings to meet this larger heating load. The addition of air curtains to exterior entryways that currently utilize overhead doors will result in energy savings and enhanced personal comfort, and also possibly in reduced equipment sizing and corresponding costs.

The primary markets for this measure are commercial and industrial facilities with overhead doors in exterior entryways, including but not limited to the following building types: retail, manufacturing, and warehouse (non-refrigerated).

Limitations:

- For use in conditioned spaces with an overhead door in an exterior entryway. This measure does include other door types such doorways to commercial spaces such as retail.
- This measure should only be applied to spaces in which the overhead door separates a conditioned space and an unconditioned space.
- Installation must follow manufacturer recommendations to attain proper air velocity, discharge angle down to the floor level, and unit position.
- Certain heating systems may not be a good fit for air curtains, such as locations with undersized heating capacity. In these cases, the installation of an air curtain may not effectively reduce heating system cycling given the inappropriately sized heating capacity.
- Buildings with slightly positive to slightly negative (~5 Pa to -10 Pa). For all other scenarios, custom analysis is recommended.
- Measure assumes that wind speeds at near ground level are less than or equal to 12 mph for 90% of the heating or cooling season. For areas with more extreme weather, custom analysis is necessary.

2.7.4.2 Baseline and Efficiency Standards

No air curtain or other currently installed means to effectively reduce heat loss and air mixing during door openings, such as a vestibule or strip curtain.

Overhead air curtains designed for commercial and industrial applications that have been tested and certified in accordance with ANSI/AMCA 220 and installed following manufacturer guidelines. Measure is for standard models without added heating.

2.7.4.3 Estimated Useful Life

The EUL is assumed to be 15 years.[408]

2.7.4.4 Deemed Savings Values

Deemed savings values are found in the table below.

Table 2-151 Deemed Savings Values

Door Size	kWh/ft²	kW/ft²
Egress	293	0.046
8'w x 8'h	309	0.048
10'w x 10'h	344	0.053
10'w x 12'h	365	0.055
12'w x 14'h	392	0.059
16'w x 16'h	417	0.062

The following methodology is highly complex and requires significant data collection. It is hoped that simplifying steps can be made in future iterations based on metering and evaluation of installations. The data collected through implementing the measure in the way currently drafted will aid in simplifying efforts at a future date.

2.7.4.4.1 Energy Savings

$$kWh_{cooling} = \left[\frac{(Q_{tbc} - Q_{tac})}{EER} - (HP * 0.7457)\right] * t_{open} * CBP$$

$$kWh_{HP\ heating} = \left[\frac{(Q_{tbc} - Q_{tac})}{HSPF} - (HP * 0.7457)\right] * t_{open} * HBP$$

$$kWh_{Gas\ Heating} = -(HP * 0.7457) * t_{open} * HDD$$

Where:

Q_{tbc} = rate of total heat transfer through the open entryway, before air curtain (kBtu/hr)

Q_{tac} = rate of total heat transfer through the open entryway, after air curtain (kBtu/hr)

(see calculation in 'Heat Transfer Through Open Entryway with/without Air Curtain' sections below)

EER = energy efficiency ratio of the cooling equipment (kBtu/kWh)

HP = Input power for air curtain (hp)

[408] Navigant Consulting Inc, Measures and Assumptions for Demand Side Management (DSM) Planning: Appendix C: Substantiation Sheets, "Air Curtains – Single Door," Ontario Energy Board, (April 2009): C-137. 2014 Database for Energy-Efficient Resources, EUL/RUL (Effective/Remaining Useful Life) Values, February 4, 2014.

Table 2-152 Fan Horsepower

Door Size	Fan HP
8'w x 8'h	1
10'w x 10'h	1.5
10'w x 12'h	4
12'w x 14'h	6
16'w x 16'h	12

0.7457 = unit conversion factor, brake horsepower to electric power (kW/HP)

t_{open} = average hours per day the door is open (hr/day)

CB = Cooling Balance Point, total days in year above balance point temperature 65 °F (day) = 239

HSPF = Heating System Performance Factor of heat pump equipment

HB = Heating Balance Point, total days in year above balance point temperature 65 °F (day) = 126

(i) Heat Transfer Through Open Entryway without Air Curtain (Cooling Season)

$$Q_{tbc} = 4.5 * CFM_{tot} * \frac{h_{oc} - h_{ic}}{1{,}000\frac{Btu}{kBtu}}$$

Where:

4.5 = unit conversion factor with density of air: $60\frac{min}{hr} * 0.075\frac{lbm}{ft^3}, \left(\frac{lb*min}{ft*hr}\right)$

CFM_{tot} = Total air flow through entryway (cfm), see calculation below

h_{oc} = average enthalpy of outside air during the cooling season (Btu/lb). See table below.[409]

Table 2-153 Average Enthalpy of Outside Air

Location	67 °F	72 °F	77 °F
New Orleans	35.7	36.6	37.7

h_{ic} = average enthalpy of indoor air, cooling season (Btu/lb). See the below table to determine the approximate indoor air enthalpy associated with an indoor temperature setpoint in indoor relative humidity. An estimate 26.6 Btu/lb associated with the 72 °F and 50% indoor relative humidity case can be used as an approximation if no other data is available. For other indoor temperature setpoints and RH, enthalpies may be interpolated.

Table 2-154 Average Humidity

Humidity (%)	67 °F	72 °F	77 °F
60	25.5	28.5	31.8

[409] Enthalpy values were calculated based on TMY3 dry bulb temperatures.

50	23.9	26.6	29.5
40	22.3	24.7	27.3

The total airflow through the entryway, CFM_{tot}, includes both infiltration due to wind as well as thermal forces, as follows below.

$$CFM_{tot} = \sqrt{(CFM_w)^2 + (CFM_t^2)}$$

Where:

CFM_w = Infiltration due to the wind (cfm)

CFM_t = Infiltration due to thermal forces (cfm)

The infiltration due to the wind is calculated as follows:

$$CFM_w = (v_{wc} * C_{wc}) * C_v * A_d * \left(88 \frac{fpm}{mph}\right)$$

Where:

v_{wc} = average wind speed during the cooling season (mph) = 3.48[410]

C_{wc} = wind speed correction factor due to wind direction in cooling season, (%). Because wind direction is not constant, a wind speed correction factor is used to adjust for the amount of time during the cooling season prevailing winds can be expected to impact the entryway. =0.2395[411]

C_v = effectiveness of openings = 0.3, assumes diagonal wind[412]

A_d = area of the doorway (ft^2) = user defined

The infiltration due to thermal forces is calculated as follows:

$$CFM_t = A_d * C_{dc} * \left(60 \frac{sec}{min}\right) * \sqrt{2 * g * \frac{H}{2} * \frac{T_{oc} - T_{ic}}{459.7 + T_{oc}}}$$

Where:

C_{dc} = the discharge coefficient during the cooling season483

$$C_{dc} = 0.4 + 0.0025 * |T_{ic} - T_{oc}|$$

g = acceleration due to gravity = 32.2 ft/sec2

[410] Average wind speeds were calculated based on the TMY3 wind speed data.

[411] Mean of directional correction factors, Illinois TRM

[412] ASHRAE, “Airflow Around Buildings,” in 2013 ASHRAE Handbook – Fundamentals (2013): p 24.3

H = the height of the entryway (ft)

T_{ic} = Average indoor air temperature during cooling season = assumed HVAC setpoint of 72°F

T_{oc} = Average outdoor temp during cooling season (°F) = the average outdoor temperature is dependent on the CDD period and zone. See table below.[413]

Table 2-155 Average Outdoor Air During Cooling Season

	T_{OC}				
Climate Zone	62 °F	67 °F	72 °F	77 °F	82 °F
New Orleans	75.8	78.2	80.0	82.8	85.6

459.7 = conversion factor from °F to °R = calculation requires absolute temperature for values not calculated as a difference of temperatures.

(ii) Heat Transfer Through Open Entryway with Air Curtain (Cooling Season)

$$Q_{tac} = Q_{tbc} * (1 - E)$$

Where:

E = the effectiveness of the air curtain (%) = 0.60485

2.7.4.4.2 Demand Reductions

$$\Delta kW = (\Delta kWh_{cooling} / (CDD * 24)) * CF$$

Where:

CF = Coincidence Factor for Commercial cooling = 91.30[414]

2.7.4.5 Incremental Cost

The incremental capital cost for overhead air curtains for exterior entryways are as follows, with an added average installation cost approximately equal to the capital cost.[415]

Table 2-156 Incremental Cost by Door Size

Door Size	**Capital Cost**
8’w x 8’h	$3,600
10’w x 10’h	$4,500
10’w x 12’h	$5,400
12’w x 14’h	$8,000

[413] Average temperatures were calculated based on TMY3 wet bulb temperatures.

[414] IL TRM V5.0 Vol.2 Sec. 4.4.33 , Page 307

[415] IL TRM V5.0 Vol.2 Sec. 4.4.33 , Page 301

16'w x 16'h	$13,300

2.7.4.6 Future Studies

There are currently no future studies planned for this measure at this time.

2.7.5 PLUG LOAD OCCUPANCY SENSORS

2.7.5.1 Measure Description

Plug load occupancy sensors are devices that control low wattage devices (<150 watts) using an occupancy sensor. Common applications are computer monitors, desk lamps, printers, and other desktop equipment. Three wattage tiers were analyzed based on available products in the market: 25W, 50W, and 150W.

2.7.5.2 Baseline and Efficiency Standards

Baseline data found in the table below.

Table 2-157 Plug Load Without Occupancy Sensors – Baseline Data

Size (watts)	Annual Energy Consumption[416] (kWh/ unit)	Annual Operating Hours	Demand (kW/unit)
25	110	4,400	0.025
50	220	4,400	0.05
150	555	3,700	0.15

Table 2-158 contains the annual energy consumption and demand for plug load occupancy sensors.

Table 2-158 Plug Load Occupancy Sensors – Minimum Requirements

Size (watts)	Annual Energy Consumption[417] (kWh/ unit)	Annual Operating Hours	Demand (kW/ unit)
25	45	1,452	0.025
50	91	1,452	0.050
150	234	1,250	0.150

2.7.5.3 Estimated Useful Life

According to DEER 2014 the EUL is eight years.

2.7.5.4 Deemed Savings Values

Deemed measure costs and savings for various sized plug load occupancy sensors are provided in Table 2-159.

Table 2-159 Plug Load Occupancy Sensors – Deemed Savings Values

Measure	Demand Reduction (kW/ unit)	Annual Energy Savings (kWh/ unit)
25W sensor	0.000	65
50W sensor	0.000	129
150W sensor	0.000	321

[416] Arkansas TRM

[417] Arkansas TRM

Four resources contained information on plug load occupancy sensors. The energy savings and amount of equipment controlled per sensor varied widely. The values for energy and demand savings are given in Table 2-160.

Table 2-160 Review of Plug Load Occupancy Sensor Measure Information

Available Resource	Type	Size	Annual Energy Saving (kWh/unit)	Demand Savings (kW/unit)
PG&E 2003	Plug load occupancy sensor	150	300	0.124
Quantec 2005	Power strip occupancy sensor	N/A	27	0.012
DEER 2005	Plug load occupancy sensor	50	143	0.051
KEMA 2010	Plug load occupancy sensor	50	221	0.025
NPCC 2005	Cubicle occupancy sensor	25	55	0.025
PacifiCorp 2009	Unitary savings in comprehensive potential study		196	0.00

2.7.5.5 Incremental Cost

The incremental cost is $70.[418]

2.7.5.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. If this measure is added to Energy Smart programs, the evaluation should include a field assessment to inventory the plug loads actually controlled.

[418] Ohio TRM.

2.7.6 ADVANCED POWER STRIPS

2.7.6.1 Measure Description

This measure involves the installation of a multi-plug Advanced Power Strip (APS) that has the ability to automatically disconnect specific loads depending on the power draw of a specified or "master" load. A load sensor in the strip disconnects power from the control outlets when the master power draw is below a certain threshold. The energy savings calculated for this measure are derived by estimating the number of hours that devices in typical office workstations are in "off" or "standby" mode and the number of watts consumed by each device in each mode. When the master device (i.e. computer) is turned off, power supply is cut to other related equipment (i.e. monitors, printers, speakers, etc.), eliminating these loads.

Commercial deemed savings were developed based on reported plug load electricity consumption. The assumed mix of peripheral electronics, and related data, are presented in the following table.

Table 2-161 shows the assumed number of hours each device is typically in "off" mode. Given the assumption that the master device, a desktop computer, will only be in off mode during non-work hours, watts consumed by devices in standby-mode are not counted toward energy savings for a commercial APS. Workday and weekend day watts consumed in off mode are a function of hours multiplied by estimated watt consumption.

There are two deemed savings paths available: Savings can be estimated as follows: 1) per APS for an average complete system or 2) by individual peripheral device.

Table 2-161 Peripheral Watt Consumption Breakdown

Peripheral Device	Workday Daily Off Hours[419]	Weekend Daily Off Hours	Off Power (W)[420,421]	Workday (W-hr) [A]	Weekend (W-hr) [B]
Coffee Maker	16	24	1.14	18.24	27.36
Computer: Desktop	16	24	3.3	52.80	79.20
Computer: Laptop	16	24	4.4	70.40	105.60
Computer Monitor: CRT	16	24	1.5	24.00	36.00
Computer Monitor: LCD	16	24	1.1	17.60	26.40
Computer Speakers	16	24	2.3	36.80	55.20
Copier	16	24	1.5	24.00	36.00
External Hard Drive	16	24	3.0	48.00	72.00

[419] Commercial hours of operation based on typical 8-hour workday schedule.

[420] New York State Energy Research and Development Authority (NYSERDA), "Advanced Power Strip Research Report". August 2011.

[421] Standby Power Summary Table, Lawrence Berkeley National Laboratory. http://standby.lbl.gov/summary-table.html.

Fax Machine: Inkjet	16	24	5.3	84.80	127.20
Fax Machine: Laser	16	24	2.2	35.20	52.80
Media Player: Blu-Ray	16	24	0.1	1.60	2.40
Media Player: DVD	16	24	2.0	32.00	48.00
Media Player: DVD-R	16	24	3.0	48.00	72.00
Media Player: DVD/VCR	16	24	4.0	64.00	96.00
Media Player: VCR	16	24	3.0	48.00	72.00
Microwave	16	24	3.08	49.28	73.92
Modem: Cable	0	24	3.8	0.00	91.20
Modem: DSL	0	24	1.4	0.00	33.60
Multi-Function Printer: Inkjet	16	24	5.26	84.16	126.24
Multi-Function Printer: Laser	16	24	3.12	49.92	74.88
Phone with Voicemail	16	24	2.92	46.72	70.08
Printer: Inkjet	16	24	1.3	20.80	31.20
Printer: Laser	16	24	3.3	52.80	79.20
Router	16	24	1.7	27.20	40.80
Scanner	16	24	2.1	33.60	50.40
Television: CRT	16	24	1.6	25.60	38.40
Television: LCD	16	24	0.5	8.00	12.00
Television: Plasma	16	24	0.6	9.60	14.40
Television: Projection	16	24	7.0	112.00	168.00

2.7.6.2 Baseline and Efficiency Standards

The baseline case is the absence of an APS, where peripherals are plugged into a traditional surge protector or wall outlet. The baseline assumes a typical mix of office equipment, shown in Table 2-161.

2.7.6.3 Estimated Useful Life

The EUL is 10 years according to the New York State Energy Research and Development Authority (NYSERDA) Advanced Power Strip Research Report from August 2011.[422]

2.7.6.4 Deemed Savings Values

Energy savings for a 7-plug APS in use in a commercial setting are calculated using the following algorithm, where kWh saved are calculated and summed for all peripheral devices:

$$\Delta kWh = \frac{\sum(Workdays * A_i) + \sum\left((365 - Workdays) * B_i\right)}{1{,}000}$$

Where:

Workdays = Average number of workdays per year[423] = 240 days

A = Watt-hours/day consumed in the "off" mode per workday

B = Watt-hours/day consumed in the "off" mode per weekend day

1,000 = Constant to convert watts to kilowatts

No demand reductions are awarded for this measure due to the assumption that typical office equipment will be operating throughout the workday.

Energy savings from an APS in an office setting are estimated to be 71.4 kWh using the above equation and assuming six unique peripheral devices. Energy savings per peripheral device are also available in the following table.

Table 2-162 Advanced Power Strips – Deemed Savings Values

Peripheral Device	kWh Savings
Coffee Maker	7.8
Computer: Desktop	22.6
Computer: Laptop	30.1
Computer Monitor: CRT	10.3
Computer Monitor: LCD	7.5
Computer Speakers	15.7
Copier	10.3
External Hard Drive	20.5
Fax Machine: Inkjet	36.3
Fax Machine: Laser	15.0
Media Player: Blu-Ray	0.7
Media Player: DVD	13.7
Media Player: DVD-R	20.5

[422] New York State Energy Research and Development Authority (NYSERDA): Advanced Power Strip Research Report, p. 30. August 2011.

[423] Assuming 50 working weeks, deducting 2 weeks for federal holidays and another 2 weeks for vacation; 48 weeks x 5 days/week = 240 days

Media Player: DVD/VCR	27.4
Media Player: VCR	20.5
Microwave	21.1
Modem: Cable	11.4
Modem: DSL	4.2
Multi-Function Printer: Inkjet	36.0
Multi-Function Printer: Laser	21.3
Phone with Voicemail	20.0
Printer: Inkjet	8.9
Printer: Laser	22.6
Router	11.6
Scanner	14.4
Television: CRT	10.9
Television: LCD	3.4
Television: Plasma	4.1
Television: Projection	47.9
Average APS: Small Business Whole System[424]	61.2

2.7.6.5 *Incremental Cost*

The incremental cost is $16 for a 5-plug strip and $26 for a 7-plug strip[425].

2.7.6.6 *Future Studies*

At the time of authorship of the NO TR V6.0, this measure was not implemented in Energy Smart programs. If this measure is added to Energy Smart programs, the evaluation should include a field assessment to inventory the plug loads actually controlled.

[424] Assuming Computer Monitor: LCD, Computer Speakers, Modem: Average, Printer: Average, and Scanner. Computer not included because it is assumed to be the controlling load. This average value is meant to apply to a typical small business application and should not be applied in other applications. For other applications, calculate the savings for each individual equipment type. kWh savings = 7.5 + 15.7 + [(11.4 + 4.2) ÷ 2] + [(8.9 + 22.6) ÷ 2] + 14.4 = 61.2 kWh.

[425] Price survey performed in NYSERDA Measure Characterization for Advanced Power Strips, p4

2.7.7 COMPUTER POWER MANAGEMENT

2.7.7.1 Measure Description

Computer Power Management (CPM) is the automated control of the power, or "sleep" settings of network desktop and notebook computer equipment. CPM involves using built-in features or add-on software programs to switch off displays and enable computers to enter a low power setting called sleep mode during periods of non-use. This measure applies to both ENERGY STAR® and conventional computer equipment and assumes that the same computer equipment is being used before and after CPM settings are activated. The power draw of a computer is assumed to be roughly equivalent during active and idle periods, so for the purposes of calculating savings, we will combine the terms active and idle as "active/idle" throughout the document.

2.7.7.2 Baseline and Efficiency Standards

The baseline conditions are the estimated number of hours that the computer spends in idle and sleep mode before the power settings are actively managed. The efficient conditions are the estimated number of hours that the computer spends in active/idle and sleep mode after the power settings are actively managed. Operating hours may be estimated from metering, or the default hours provided in the calculation of deemed savings may be used.

2.7.7.3 Deemed Savings Values

Deemed demand and annual savings are based on the ENERGY STAR® Low Carbon IT Savings calculator. The coincidence factor, default equipment wattages in Table 2-163, and the active/idle and sleep hours are taken from assumptions in the ENERGY STAR® calculator with all equipment set to enter sleep mode after 15 minutes of inactivity.

$$kWh_{savings} = \frac{W_{active/idle}\left(hours_{active/idle_{pre}} - hours_{active/idle_{post}}\right) + W_{sleep}\left(hours_{sleep_{pre}} - hours_{sleep_{post}}\right)}{1,000}$$

$$kW_{savings} = \frac{(W_{active/idle} - W_{sleep}) * CF}{1,000}$$

Where:

$W_{active/idle}$ = total wattage of the equipment, including computer and monitor, in active/idle mode; see Table 2-163.

$Hours_{active\_idle\_pre}$ = annual number of hours the computer is in active/idle mode before computer management software is installed = 6,293

$Hours_{active\_idle\_post}$ = annual number of hours the computer is in active/idle mode after computer management software is installed = 1,173

W_{sleep}= total wattage of the equipment, including computer and monitor, in sleep mode; see Table 2-163

$Hours_{sleep\_pre}$= annual number of hours the computer is in sleep mode before computer management software is installed = 0

$Hours_{sleep\_post}$ = annual number of hours the computer is in sleep mode after computer management software is installed = 5,120

CF= Coincidence Factor[426] = 0.25

1,000 = W/kW conversion

Table 2-163 Computer Power Management - Equipment Wattages

Equipment	W_{sleep}	$W_{active/idle}$
Conventional LCD Monitor	1	32
Conventional Computer	3	69
Conventional Notebook (including display)	2	21

Table 2-164 Computer Power Management - Deemed Savings Values

Equipment	kWh savings	kW savings
Conventional LCD Monitor	158.72	0.008
Conventional Computer	337.92	0.017
Conventional Notebook (including display)	97.28	0.005

2.7.7.4 Estimated Useful Life

The EUL of this measure is based on the useful life of the computer equipment which is being controlled. Computer technology may continue to function long after technological advances have diminished the usefulness of the equipment. The EUL for Computer Power Management is 4 years.[427]

2.7.7.5 Incremental Cost

The incremental cost is $29 per computer, including labor.[428]

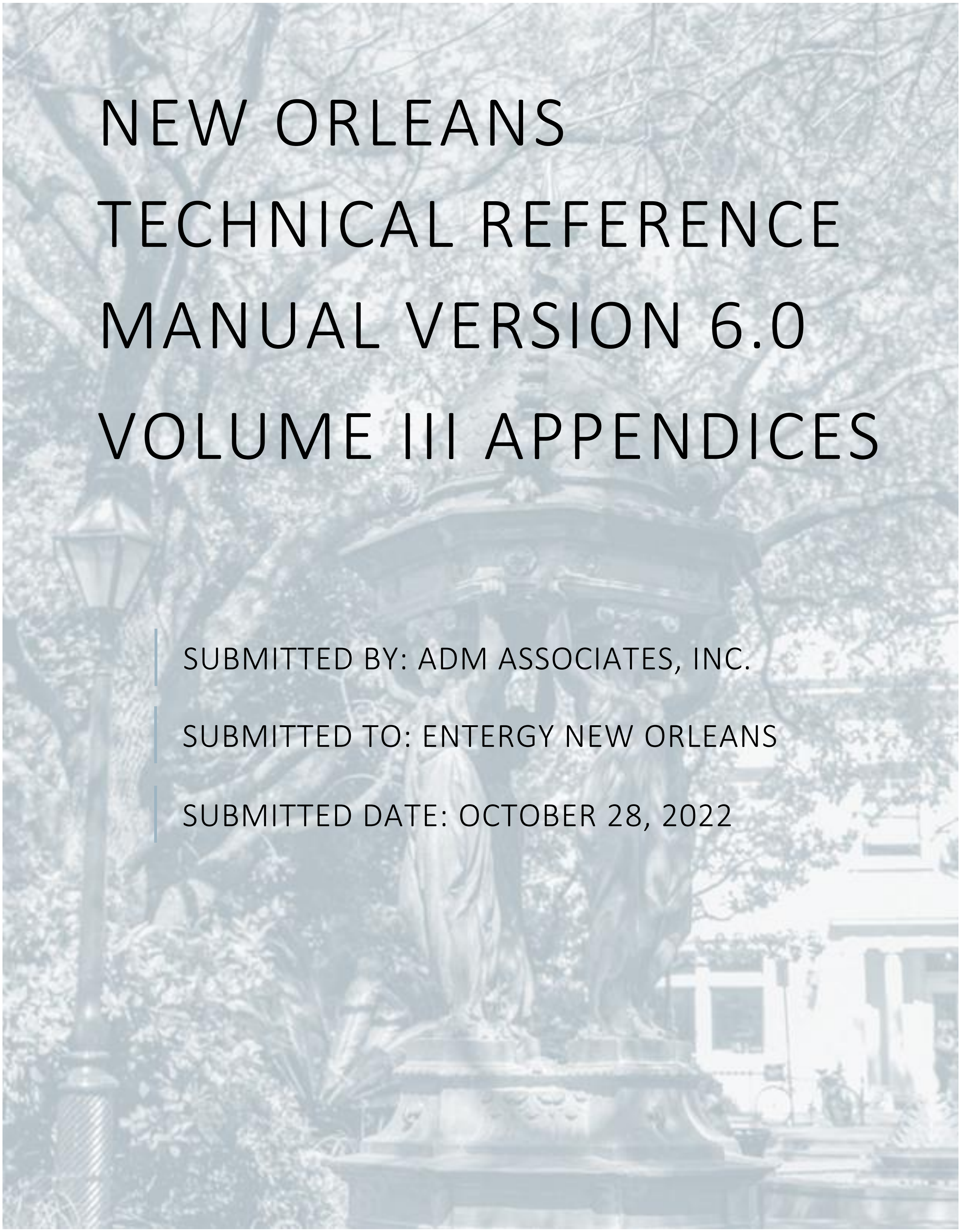
2.7.7.6 Future Studies

At the time of authorship of the NO TRM V6.0, this measure was not implemented in Energy Smart programs. If this measure is added to Energy Smart programs, the evaluation should include a field assessment to inventory the plug loads actually controlled.

[426] The coincidence factor is the percentage of time the computer is assumed to be not in use during the hours 3pm to 6pm from the ENERGY STAR® calculator modeling study.

[427] The Regional Technical Forum, Measure workbook for Commercial: Non-Res Network Computer Power Management. http://rtf.nwcouncil.org/measures/measure.asp?id=95. Accessed August 2013.

[428] Work Paper WPSCNROE0003 Revision 1, Power Management Software for Networked Computers. Southern California Edison



NEW ORLEANS TECHNICAL REFERENCE MANUAL VERSION 6.0 VOLUME III APPENDICES

SUBMITTED BY: ADM ASSOCIATES, INC.

SUBMITTED TO: ENTERGY NEW ORLEANS

SUBMITTED DATE: OCTOBER 28, 2022

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

ACRONYMS/ABBREVIATIONS

Table 1 Acronyms/Abbreviations

Acronym	Term
AC	Air Conditioner
AOH	Annual operating hours
APS	Advanced Power Strip
AR&R	Appliance Recycling & Replacement
BP	Behavioral Program
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CEE	Consortium for Energy Efficiency
CF	Coincidence factor
CFL	Compact fluorescent lamp (bulb)
CFM	Cubic feet per minute
CRE	Commercial Real Estate
DI	Direct install
DLC	Direct Load Control
DLC	Design Lights Consortium
EER	Energy efficiency ratio
EFLH	Equivalent full-load hours
EISA	Energy Independence and Security Act
EL	Efficiency loss
EM&V	Evaluation, Measurement, and Verification
ES	ENERGY STAR
EUL	Estimated Useful Life
GPM	Gallons per minute
HDD	Heating degree days
HID	High intensity discharge
HOU	Hours of Use
HP	Heat pump
HPwES	Home Performance with ENERGY STAR
HSPF	Heating seasonal performance factor
HVAC	Heating, Ventilation, and Air Conditioning
IEER	Integrated Energy Efficiency Ratio
IEF	Interactive Effects Factor
IPLV	Integrated part load value
IQW	Income Qualified Weatherization
ISR	In-Service Rate
kW	Kilowatt
kWh	Kilowatt hour

LCDR	Large Commercial Demand Response
LCIS	Large Commercial & Industrial Solutions
LCA	Lifecycle Cost Adjustment
LED	Light Emitting Diode
M&V	Measurement and Verification
MFS	Multifamily Solutions
MW	Megawatt
MWh	Megawatt hour
NC	New Construction
NTG	Net-to-Gross
PCT	Participant Cost Test
PFI	Publicly Funded Institutions
PY	Program Year
QA	Quality Assurance
QC	Quality Control
RCA	Refrigerant charge adjustment
RIM	Ratepayer Impact Measure
RLA	Retail Lighting and Appliances
ROB	Replace on Burnout
RR	Realization Rate
RUL	Remaining Useful Life
SCDR	Small Commercial Demand Response
SCIS	Small Commercial & Industrial Solutions
SEER	Seasonal Energy Efficiency Ratio
SK&E	School Kits and Education
TA	Trade Ally
TPI	Third-Party Implementer
TPE	Third-Party Evaluator
TRC	Total Resource Cost Test
TRM	Technical Reference Manual
UCT	Utility Cost Test
VFD	Variable Frequency Drive

SAVINGS TYPES

Table 2 Savings Types

Savings Types	Definition
Energy Savings (kWh)	The change in energy (kWh) consumption that results directly from program-related actions taken by participants in a program.
Demand Reductions (kW)	The time rate of energy flow. Demand usually refers to electric power measured in kW (equals kWh/h) but can also refer to natural gas, usually as Btu/hr., kBtu/hr., therms/day, etc.
Expected / *Ex ante* Gross	The change in energy consumption and/or peak demand that results directly from program-related actions taken by participants in a program, regardless of why they participated.
Verified / *Ex post* Gross	Latin for “from something done afterward” gross savings. The energy and peak demand reduction estimates reported by the evaluators after the gross impact evaluation and associated M&V efforts have been completed.
Net / *Ex post* Net	Verified / *ex post* gross savings multiplied by the net-to-gross (NTG) ratio. Changes in energy use that are attributable to a particular program. These changes may implicitly or explicitly include the effects of free-ridership, spillover, and induced market effects.
Annual Savings	Energy and demand reduction expressed on an annual basis, or the amount of energy and/or peak demand a measure or program can be expected to save over the course of a typical year. The TRM provides algorithms and assumptions to calculate annual savings and are based on the sum of the annual savings estimates of installed measures or behavior change.
Lifetime Savings	Energy savings expressed in terms of the total expected savings over the useful life of the measure. Typically calculated by multiplying the annual savings of a measure by its EUL. The TRC Test uses savings from the full lifetime of a measure to calculate the cost-effectiveness of programs.

1. APPENDICES

1.1 Appendix A Inputs

1.1.1 RESIDENTIAL

1.1.1.1 ENERGY STAR® Appliances

Unless otherwise noted, deemed savings values and inputs were derived form and found in the Energy Star calculators: https://www.energystar.gov/products/appliances

1.1.1.2 Domestic Hot Water

1.1.1.2.1 Ambient Water Main (Tin) and Ambient Air Temperature (T_{amb}) Calculations

Table 1-1 Ambient Water Main (Tin) and Outside Air Temperature (T_{amb}) Calculations

New Orleans	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Month	1	2	3	4	5	6	7	8	9	10	11	12	
Outside Air Temp (Tair)	49.9	55.6	64.1	69.4	75.1	80.7	81.6	82.3	77.7	68.2	65.6	54.5	68.7
Inlet Water Temp (Tin)	66.0	64.2	65.2	68.6	73.6	78.9	83.1	85.2	84.4	81.2	76.3	70.9	74.8
Offset (district water)	6.00												
Ratio	0.647												
Lag	34.8												

1.1.1.2.2 Estimated Hot Water Usage (By Tank Size)

The values in the table below are based off Table 136: Estimated Annual Hot Water Use (gal), Arkansas TRM 5.0, page 137.

Table 1-2 Estimated Annual Hot Water Use

Tanks Size (gal) of Replaced Water Heater	40	50	65	80
El Dorado Estimated Annual Hot Water Use (gal)	17,815	20,245	24,293	29,152

The TPE created a correction factor to compensate for the difference in the average water main temperatures between the two cities.

$$Correction\ Factor = \frac{El\ Dorado\ Average\ Water\ Main\ Temperature}{New\ Orleans\ Average\ Water\ Main\ Temperature} = \frac{70.1}{74.8} = .937166$$

The correction factor was applied to existing El Dorado hot water usage estimates.

Table 1-3 Tank Size of Replaced Water Heater

Tanks Size (gal) of Replaced Water Heater	40	50	65	80
New Orleans Estimated Annual Hot Water Use (gal)	16,696	18,973	22,767	27,320

Table 1-4 Estimated Average Ambient Temperatures by Water Heater Installation Location

Average ambient air temperature, New Orleans (TMY3)	68.78
Number of heating degree days, New Orleans (TMY3, base 65)	126
Number of cooling degree days, New Orleans (TMY3, base 65)	239
Ratio of conditioned/unconditioned	1.00549

Table 1-5 Heat Pump Water Heater Adjustment Factors

Types of Days	Count	% of year
Heating Days	126	35%
Cooling Days	239	65%

PA% for conditioned space: 2.784%

Table 1-6 COP Adjustment Factors

Heating Type	COP-Heating	COP-Cooling	Calculated F Adj	Calculated Adj	Estimated Adj
Gas	20	3	1.201	0.856	0.917
Heat Pump	2	3	1.046	0.983	1.201
Elec. Resistance	0.89	3	0.830	1.238	1.395

1.1.1.2.3 Water Heater Jackets

Estimated hot water usage (by tank size) Deemed water heating jacket savings are Table 143: Water Heater Jackets – Electric Heating Deemed Savings Values Arkansas TRM 5.0, page 144.

Table 1-7 Annual Average Daily Isolation

Daily Total Insolation (BTU/ft2/day) (AR TRM 5.0)	1,601
Average solar radiation El Dorado, AR (NREL)	1,407
Average solar radiation New Orleans, LA (NREL)	1,405
Correction factor	1.137
New Orleans Solar radiation x Correction Factor =	1,598

1.1.1.2.4 Weather Zone Localization Factor for SEF

- Average solar radiation New Orleans, LA (NREL): 4.33 kWh/m2/day = 1,405.254 BTU/ft2/day
- Average solar radiation El Dorado, AR (AR TRM 5.0): 1,601 BTU/ft2/day
- Latitude correction factor: 1.137

1.1.1.3 Envelope

1.1.1.3.1 Prototype Building Characteristics

Various building energy usage computer models have been used in development of deemed savings included in the TRM according to several factors:

- Building Type and Use. Prototype buildings support deemed savings development for measures to be implemented in the following building types: residential, converted residence (CR), commercial, and small commercial (SC).
- Model Vintage. Original prototypes date back to deemed savings developed in 2007/08 for use in the QuickStart programs. Prototype inputs have been updated for more recent models.
- Measure being modeled. Specific changes to a prototype are introduced to represent the specific measure being implemented in a given building.

In this Appendix, "top level" tables – those tables with the letter A followed only by a number in their table name (e.g., Table 1-8) provide the general characteristics of a given model prototype. "Supplemental tables" – (e.g.,Table 1-9 through Table 1-15) – provide the specific changes introduced to a given prototype for the modeling of specific measures.

The following table applies to the Attic Knee Wall Insulation, Ceiling Insulation, Wall Insulation, Floor Insulation, Roof Deck Insulation, Air Infiltration, Radiant Barriers, ENERGY STAR Windows, and Window Film measures. Table 1-8 BEopt™ – a residential building modeling platform developed by NREL – was used to estimate energy savings for these measures using the U.S. DOE EnergyPlus simulation engine.

Table 1-8 Residential Envelope Measures – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Site/Layout		
Conditioned Floor Area	1,764 ft.2	Average square footage of conditioned (heated) space between one story home and all SFD homes in 2009 RECS microdata for AR/LA/OK.1
Orientation	Square building with faces on each cardinal direction	LBNL Nationally Representative Housing Sample[2]

[1] 2009 RECS, Available at: http://www.eia.gov/consumption/residential/data/2009/

[2] Simulating a Nationally Representative Housing Sample Using EnergyPlus, Available at: http://www.osti.gov/scitech/servlets/purl/1012239

Number of Stories	Single story with unfinished attic	Preponderance of SFD homes in 2009 RECS microdata are single story
Building Envelope		
Foundation	Slab-on-ground, no edge insulation	Preponderance of SFD homes in 2009 RECS microdata (62%) have slab foundation Also a conservative assumption for base energy usage.
Slab Insulation	None – no perimeter, under-slab, or above-slab insulation	Not part of standard practice, also no requirement for slab insulation in residential code for relevant weather regions except the NW corner of state in IECC Climate Zone 4.
Ceiling Insulation	R-12	Table 25 of BA Home Simulation Protocols suggests R-9 is appropriate for homes closed rafter roofs built with 2 x 6 beams, R-15 for 2 x 10. Suspect 2 x 6 is more likely, but some share of homes will have had ceiling insulation replaced/added. Select R-12 based on the above information and engineering judgment.[3]
Wall Insulation	R-11	BAHSP, p. 35 – value for homes built 1980-1989
Air Leakage	0.9 ACH	Median ACH for older, low income housing.[4]
Window Area	15% of wall area	American Housing Survey 2007 and 2008 was used to inform the value for likely participants.

[3] Building America Home Simulation Protocols (BAHSP), Available at: http://www.nrel.gov/docs/fy11osti/49246.pdf

[4] Referenced information is from 2009 ASHRAE Fundamentals, Section 16.17 Residential Ventilation.

Window U-value (single pane)	1.12	2009 ASHRAE Fundamentals, Ch. 15 Table 4. Value for double-pane, metal frame, fixed, clear glass window.
Window U-value (double pane)	0.65	
Window SHGC	0.79	
Window SHGC	0.64	
HVAC		
Efficiency Rating, Air Conditioner	10 SEER	Federal Standard in effect from 1990-2006. Representative of low-efficiency program participant homes.
Efficiency Rating Space Heating (Gas Furnace)	78% AFUE	Annual Fuel Utilization Efficiency – base gas furnace efficiency
Efficiency Rating Space Heating (Electric Resistance Heat)	COP 1.0	Coefficient of Performance for central electric resistance heating systems
Efficiency Rating Space Heating (Heat Pump)	HSPF = 7.25	Average of Federal Standards: 1992 – 1/2006: 6.8 HSPF 1/2006 – 1/2015: 7.7 HSPF
Thermostat Settings	Heating: 71 F Cooling 76 F	BAHSP, p. 49
Duct Losses	20%	Lower tier of air leakage for typical homes as cited by ENERGY STAR5
Duct Insulation	R-4	
Domestic Hot Water		
Energy Factor, Electric Storage	0.9	BAHSP (p. 42) EWH with 50 gal tank, 3-inch insulation.
Energy Factor, Gas Storage	0.59	BAHSP (p. 42), midpoint between options 2 and 3
Lighting		
Share of Lighting by Type	Lamps are 66% incandescent, 21% CFL, 13% T-8 linear fluorescent	BAHSP (p. 16)

[5] ENERGY STAR, Duct Sealing: http://www.energystar.gov/?c=home_improvement.hm_improvement_ducts

Table 1-9 Insulation – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Ceiling Construction	2-foot-wide vaulted ceiling around the perimeter of the conditioned floor area	This modeling approach reduces simulation distortions introduced by a large, vaulted ceiling area, while still exposing the attic knee walls to the conditioned space.
Base Knee Wall Insulation	No existing insulation	Encountered insulation level drives eligibility for this measure
Improved Knee Wall Insulation	(1) Insulate to R-19, or (2) Insulate to R-30	Efficiency Measure

Table 1-10. Ceiling Insulation – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Base Ceiling Insulation	Five ranges of encountered ceiling insulation: R-0 to R-1 R-2 to R-4 R-5 to R-8 R-9 to R-14 R-15 to R-22	Insulation level as encountered by the EESP drives eligibility for this measure
Improved Ceiling Insulation	Insulate to R-38 & R-49	Efficiency measure – retrofit insulation level

Table 1-11. Wall Insulation – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Base Wall Insulation	R-0	Insulation level as encountered by the EESP drives eligibility for this measure
Improved Wall Insulation	R-13 & R-23	3.5” of fiberglass batt at R-3.7/in provides R-13 Full thickness of 4” cavity with open cell foam provides R-13 Full thickness of 4” cavity with open cell foam provides R-13

Table 1-12. Floor Insulation – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Foundation	Pier and beam with vented crawlspace	Floor Insulation not a relevant measure for homes with slab foundation

Base Floor Insulation	R-0	Insulation level as encountered by the EESP drives eligibility for this measure
Change Floor Insulation	R-19	This brings existing homes in compliance with IECC 2009.
Crawlspace Insulation	R-13	

Table 1-13. Air Infiltration – Prototype Home Characteristics		
Shell Characteristic	**Value**	**Source(s)**
Base Air Leakage	0.9 ACH	Median infiltration value of older low-income housing sample:
Change Air Leakage	.035 ACH	Minimum allowable air exchanges assuming a 1,764 ft2 and 3-bedroom prototype home: ASHRAE 62.2 P - 2010

Table 1-14. Radiant Barriers – Prototype Home Characteristics		
Shell Characteristic	**Value**	**Source(s)**
Ceiling Insulation Case 1	≤ R-19	Assumed existing insulation level
Ceiling Insulation Case 2	> R-19	Assumed existing insulation level
Base roof deck	No radiant barrier	Existing condition applicable for this measure
Change roof deck	Double-Sided, Foil: Installed radiant barrier meeting ENERGY STAR standards	Efficiency Measure

Table 1-15. Window Film – Prototype Home Characteristics		
Shell Characteristic	**Value**	**Source(s)**
Baseline Window Characteristics – double-pane model	0.81 U-value/0.64 SHGC	U-value assuming metal framed, double-pane clear glass windows 2009 ASHRAE Fundamentals, Ch.15 Tables 4 and 10
Baseline Window Characteristics – single-pane model	1.12 U-value/0.79 SHGC	
Change Case Window Characteristics – double-pane model	0.81 U-value/0.49 SHGC	Efficiency Measure – values based on 3M product performance and technical data
Change Case Window Characteristics – single-pane model	1.12 U-value/0.40 SHGC	

1.1.2 COMMERCIAL

1.1.2.1 Water Heating

Table 1-16 Ambient Water Main (Tin) and Outside Air Temperature (Tamb) Calculations

New Orleans	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Avg**
Month	1	2	3	4	5	6	7	8	9	10	11	12	
Outside Air Temp (T_{air})	49.9	55.6	64.1	69.4	75.1	80.7	81.6	82.3	77.7	68.2	65.6	54.5	68.7
Water Heater Inlet Water Temp (T_{in})	66.0	64.2	65.2	68.6	73.6	78.9	83.1	85.2	84.4	81.2	76.3	70.9	74.8
Offset (district water) =	6.00												
Ratio =	0.647												
Lag =	34.8												

Table 1-17 Duct Efficiency, Duct Insulation (SC), Cool Roofs & Window Awnings (SC) – Prototype Building Characteristics

Building Characteristics	**Building Type**		
	Small Office	**Stand-Alone Retail**	**Strip Mall**
General			
Ground Area (SQFT)	7,500	15,000	7,500
# of Stories	2	1	1
Floor Area (SQFT)	15,000	15,000	7,500
Roof			
Construction	Metal frame, > 24in oc	Metal frame, > 24in oc	Metal frame, > 24in oc
Ext. Finish	Roof, built up	Roof, built up	Roof, built up
Ext. Color	Med (abs = 0.6)	Med (abs = 0.6)	Med (abs = 0.6)

Ext. Insulation	Varied	Varied	Varied
Add ‘l Insulation	No batt or radiant barrier	No batt or radiant barrier	No batt or radiant barrier
Walls			
Construction	Matel frame, 2x6, 24in, oc	Matel frame, 2x6, 16in, oc	Matel frame, 2x4, 24in, oc
Ext. Finish	Wood/Plywood	CMU	Stucco/Gunite
Ext. Color	Med (abs = 0.6)	Med (abs = 0.6)	Med (abs = 0.6)
Ext. Insulation	3/4in fiber bd sheathing (R-2)	3/4in fiber bd sheathing (R-2)	3/4in fiber bd sheathing (R-2)
Add'l Insulation	R-19 Batt	R-11 Batt	R-11 Batt
Ceiling			
Construction	Acoustic Tile	Acoustic Tile	Acoustic Tile
Insulation	Varied	Varied	Varied
Windows			
Glass Category	Double Clr/Tint 1/4", 1/2" Air	Double Clr/Tint 1/4", 1/2" Air	Double Clr/Tint 1/4", 1/2" Air
Window Area	70% of Walls	70% of North Wall; All Others 0%	70% of North Wall; All Others 0%
Lighting			
Lighting Density (w/SQFT)	1.33	2.03	2.03
HVAC			
Cooling Source	DX Coils	DX Coils	DX Coils
System Type	Packaged Single Zone	Packaged Single Zone	Packaged Single Zone
Typ. Unit Size	11.25 to 20 tons	5.4 to 7.5 tons	< 5.4 tons
EER (Base)	8.50 EER	8.90 EER	9.70 EER
Heating Source	Furnace	Furnace	Furnace
Typ. Unit Size	>225 kBTUh	>225 kBTUh	>225 kBTUh
Efficiency (AFUE)	0.806	0.780	0.780
Fans			
Min. Design Flow (CFM/ft^2)	0.5	0.5	0.5
Cycle Fans at Night?	Cycle Fans (no OA at night)	Cycle Fans (no OA at night)	Cycle Fans (no OA at night)

DHW			
Fuel	Natural Gas	Natural Gas	Natural Gas
Type	Storage	Storage	Storage
Tank Insulation R-Value	12.00	12.00	12.00
Tank Capacity (Gal)	39	21	11

1.1.2.2 HVAC

The tables below provide the eQuest Equivalent Full Load Hours (EFLH) model results for various building types found in New Orleans. EFLH values developed in eQuest were then normalized with El Dorado, AR EFLH.

Table 1-18 eQuest Model EFLH Results

Building Type	**El Dorado**		**New Orleans**	
	$EFLH_c$	**$EFLH_h$**	**$EFLH_c$**	**$EFLH_h$**
Fast Food	2,111	411	3,013	178
Grocery	1,544	537	1,703	285
Health Clinic	1,317	510	1,451	325
Large Office	1,684	879	1,598	501
Lodging	5,833	588	7,647	372
Full Menu Restaurant	2,070	509	2,900	217
Retail	2,424	588	3,305	372
School	1,209	420	1,672	167
Small Office	1,564	115	2,098	37
University	1,755	771	1,799	602

Table 1-19 EFHL Normalized Multipliers

Building Type	**El Dorado**		**New Orleans**	
	$EFLH_c$	**$EFLH_h$**	**$EFLH_c$**	**$EFLH_h$**
Fast Food	1.00	1.00	1.43	0.43
Grocery	1.00	1.00	1.10	0.53
Health Clinic	1.00	1.00	1.10	0.64
Large Office	1.00	1.00	0.95	0.57
Lodging	1.00	1.00	1.31	0.63
Full Menu Restaurant	1.00	1.00	1.40	0.43
Retail	1.00	1.00	1.36	0.63
School	1.00	1.00	1.38	0.40
Small Office	1.00	1.00	1.34	0.33
University	1.00	1.00	1.02	0.78

1.1.2.3 Lighting Efficiency

The table below shows logger counts, standard deviations, and compare original AR TRM V6.0 hours with figures derived from direct monitoring.

Table 1-20 Commercial Lighting Updates

Facility or Space Type	Count of Loggers	ARM TRM 6 hours	New Orleans Recommended Value
Leisure Dining: Bar Area	12		2,676.0
Corridor/Hallway/Stairwell	39		5,537.3
Education: College/University		3,577.0	3,577.0
Education: K-12	9	2,777.0	2,333.5
Exterior		3,996.0	4,319.0
Food Sales: 24-Hour Supermarket		6,900.0	6,900.0
Food Sales: Non 24-Hour Supermarket	5	4,706.0	2,058.2
Food Service: Fast Food	11	6,188.0	6,473.4
Food Service: Sit-Down Restaurant	13	4,368.0	4,730.6
Health Care: In-Patient	3	5,730.0	4,019.4
Health Care: Nursing Home		4,271.0	4,271.0
Health Care: Out-Patient		3,386.0	3,386.0
Convenience Store (non-24 hour)	22		4,244.8
Lodging (Hotel/Motel/Dorm): Common Areas	22	6,630.0	4,126.9
Lodging (Hotel/Motel/Dorm): Room	13	3,055.0	3,369.9
Manufacturing		5,740.0	5,740.0
Multi-family Housing: Common Areas	24	4,772.0	5,703.4
Non-Warehouse Storage (Generic)	11		4,206.5
Office	27	3,737.0	5,158.5
Office (attached to other facility)	36		4,728.4
Parking Structure		7,884.0	7,884.0
Public Assembly		2,638.0	2,638.0
Public Order and Safety		3,472.0	3,472.0
Religious Gathering	8	1,824.0	3,174.3
Restroom (Generic)	11		3,515.6
Retail: Enclosed Mall		4,813.0	4,813.0
Retail: Freestanding	52	3,668.0	3,514.8
Retail: Other	4	4,527.0	4,311.8
Retail: Strip Mall		3,965.0	3,965.0
Service: Excluding Food		3,406.0	3,406.0
Warehouse: Non-Refrigerated	9	3,501.0	2,416.7
Warehouse: Offices	4		2,791.8
Warehouse: Refrigerated		3,798.0	3,798.0

1.1.2.3.1 Lighting Power Density

The table below presents LPD by building area type.

Table 1-21 ASHRAE 90.1-2007 Lighting Power Densities (LPD) – Building Area Method[6]

Building Area Type	LPD (W/ft^2)
Automotive Facility	0.9
Convention Center	1.2
Court House	1.2
Dining: Bar Lounge/Leisure	1.3
Dining: Fast Food	1.4
Dining: Family	1.6
Dormitory	1.0
Exercise Center	1.0
Gymnasium	1.1
Healthcare-Clinic	1.0
Hospital	1.2
Hotel	1.0
Library	1.3
Manufacturing Facility	1.3
Motel	1.0
Movie Theater	1.2
Multifamily	0.7
Museum	1.1
Office	1.0
Parking Garage	0.3
Penitentiary	1.0
Performing Arts Theater	1.6
Police/Fire Station	1.0
Post Office	1.1
Religious Building	1.3
Retail	1.5
School/University	1.2
Sports Arena	1.1
Town Hall	1.1
Transportation	1.0
Warehouse	0.8
Workshop	1.4

[6] ANSI/ASHRAE/IESNA Standard 90.1-2007, Table 9.5.1

Table 1-22 ASHRAE 90.1-2007 LPD – Space-by-Space Method by Space Types[7]

Common Space Types[8]		**LPD (W/ft²)**
Office- Enclosed		1.1
Office-Open Plan		1.1
Conference/Meeting/Multipurpose		1.3
Classroom/Lecture/Training		1.4
	For Penitentiary	1.3
Lobby		1.3
	For Hotel	1.1
	For Performing Arts Center	3.3
	For Motion Picture Theater	1.1
Audiences/Seating Area		0.9
	For Gymnasium	0.4
	For Exercise Center	0.3
	For Convention Center	0.7
	For Penitentiary	0.7
	For Religious Building	1.7
	For Sports Area	0.4
	For Performing Arts Theater	2.6
	For Motion Picture Theater	1.2
	For Transportation	0.5
Atrium- First Three Floors		0.6
Atrium- Additional Floors		0.2
Lounge/Reception		1.2
	For Hospital	0.8
Dining Area		0.9
	For Penitentiary	1.3
	For Hotel	1.3
	For Motel	1.2
	For Bar Lounge/Leisure Dining	1.4
	For Family Dining	2.1
Food Preparation		1.2
Laboratory		1.4
Restrooms		0.9
Dressing/Locker/Fitting Room		0.6
Corridor/Transition		0.5
	For Hospital	1.0
	For Manufacturing Facility	0.5
Stairs- Active		0.6
Active Storage		0.8
	For Hospital	0.9
Inactive Storage		0.3
	For Museum	0.8
Electrical/Mechanical		1.5

[7] ANSI/ASHRAE/IESNA Standard 90.1-2007, Table 9.6.1

[8] In cases where both a common space type and a building-specific space type are listed, the building-specific space type shall apply.

Workshop		1.9
Sales Area (for accent lighting)		1.7

Table 1-23 ASHRAE 90.1-2007 Lighting Power Densities (LPD) – Space-by-Space Method by Building-Specific Space Types[9]

Building-Specific Space Types[10]		**LPD (W/ft^2)**
Gymnasium/Exercise Center	Playing Area	1.4
	Exercise Area	0.9
Courthouse/Police Station/Penitentiary	Courtroom	1.9
	Confinement Cells	0.9
	Judges' Chambers	1.3
Fire Stations	Engine Room	0.8
	Sleeping Quarters	0.3
Post Office- Sorting Area		1.2
Convention Center- Exhibit Space		1.3
Library	Card File and Cataloging	1.1
	Stacks	1.7
	Reading Area	1.2
Hospital	Emergency	2.7
	Recovery	0.8
	Nurses' Station	1.0
	Exam/Treatment	1.5
	Pharmacy	1.2
	Patient Room	0.7
	Operating Room	2.2
	Nursery	0.6
	Medical Supply	1.4
	Physical Therapy	0.9
	Radiology	0.4
	Laundry-Washing	0.6
Automotive- Service/Repair		0.7
Manufacturing	Low Bay *<25ft floor to ceiling height)	1.2
	High Bay (>25ft floor to ceiling height)	1.7
	Detailed manufacturing	2.1
	Equipment Room	1.2
	Control Room	0.5
Hotel/Motel Guest Rooms		1.1
Dormitory- Living Quarters		1.1
Museum	General Exhibition	1

[9] ANSI/ASHRAE/IESNA Standard 90.1-2007, Table 9.6.1

[10] In cases where both a common space type and a building-specific space type are listed, the building-specific space type shall apply.

	Restoration	1.7
Bank/Office- Banking Activity Area		1.5
Religious Building	Worship Pulpit, Choir	2.4
	Fellowship Hall	0.9
Retail	Sales Area (for accent lighting)	1.7
	Mall Concourse	1.7
Sports Arena	Ring Sports Area	2.7
	Court Sports Area	2.3
	Indoor Playing Field Area	1.4
Warehouse	Fine Material Storage	1.4
	Medium/Bulky Material Storage	0.9
Parking Garage- Garage Area		0.2
Transportation	Airport- Concourse	0.6
	Air/Train/Bus- Baggage Area	1.0
	Terminal- Ticket Counter	1.5

Table 1-24 ASHRAE 90.1-2007 Lighting Power Densities (LPD) – Building Exteriors[11,12]

Tradable/ Non-tradable	**Exterior Space Type**		**LPD**
Tradable Surfaces	Uncovered Parking Areas- Parking lots and drives		0.15 Wft^2
	Building Grounds	Walkways <10ft wide	1.0 W/linear ft
		Walkways >10ftwide	0.02 W/ft^2
		Stairways	1 ft^2
	Building Entrances and Exits	Main entries	30 W/linear ft (of door width)
		Other doors	20 W/linear ft (of door width)
	Canopies and Overhangs- Canopies (free standing, attached & overhangs)		1.25 W/ft^2
	Outdoor Sales	Open areas (including vehicle sales lots)	0.5 W/ft^2
		Street frontage for vehicle sales lots (in addition to above)	20 W/linear ft.
Non-tradable Surfaces	Building Facades	For each illuminated wall or surface OR	0.2 W/ft^2
		For each illuminated wall or surface length	5.0 W/linear ft
	Automated Teller Machines and Night Depositories	Per location	270 W
		Per additional ATM per location	90 W

[11] ANSI/ASHRAE/IESNA Standard 90.1-2007, Table 9.4.5

[12] Exterior Building Lighting Power: The total exterior lighting power allowance for all exterior building applications is the sum of the individual lighting power densities permitted in Table 4 for these application plus an additional unrestricted allowance of 5% of that sum. The trade-offs are allowed only among exterior lighting applications listed in Table 4 "Tradable Surfaces" section.

	Entrances and Gatehouse Inspection Stations at Guarded Facilities- Uncovered areas (for covered areas use Canopies/Overhangs)	1.25 W/ft^2
	Loading Areas for Emergency Service Vehicles- Uncovered areas (for covered areas use Canopies/Overhangs)	0.5 W/ft^2
	Drive-up Windows at Fast Food Restaurants- per drive-through	400 W
	Parking near 24-hour Retail Entrances- Per main entry	800 W

1.1.2.3.2 Wattage Tables

The table below presents standard wattage.

Table 1-25 Wattage Tables

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
Integrated Ballast LEDs								
LED001-SCRW	LEDINT1W	Integrated Ballast LED, (1) 1W screw-in lamp/base, any bulb shape	1W LED - Int. Ballast	Electronic	N/A	N/A	1	1
LED002-SCRW	LEDINT2W	Integrated Ballast LED, (1) 2W screw-in lamp/base, any bulb shape	2W LED - Int. Ballast	Electronic	N/A	N/A	2	1
LED003-SCRW	LEDINT3W	Integrated Ballast LED, (1) 3W screw-in lamp/base, any bulb shape	3W LED - Int. Ballast	Electronic	N/A	N/A	3	1
LED004-SCRW	LEDINT4W	Integrated Ballast LED, (1) 4W screw-in lamp/base, any bulb shape	4W LED - Int. Ballast	Electronic	N/A	N/A	4	1
LED005-SCRW	LEDINT5W	Integrated Ballast LED, (1) 5W screw-in lamp/base, any bulb shape	5W LED - Int. Ballast	Electronic	N/A	N/A	5	1
LED006-SCRW	LEDINT6W	Integrated Ballast LED, (1) 6W screw-in lamp/base, any bulb shape	6W LED - Int. Ballast	Electronic	N/A	N/A	6	1
LED007-SCRW	LEDINT7W	Integrated Ballast LED, (1) 7W screw-in lamp/base, any bulb shape	7W LED - Int. Ballast	Electronic	N/A	N/A	7	1
LED008-SCRW	LEDINT8W	Integrated Ballast LED, (1) 8W screw-in lamp/base, any bulb shape	8W LED - Int. Ballast	Electronic	N/A	N/A	8	1
LED009-SCRW	LEDINT9W	Integrated Ballast LED, (1) 9W screw-in lamp/base, any bulb shape	9W LED - Int. Ballast	Electronic	N/A	N/A	9	1
LED010-SCRW	LEDINT10W	Integrated Ballast LED, (1) 10W screw-in lamp/base, any bulb shape	10W LED - Int. Ballast	Electronic	N/A	N/A	10	1
LED011-SCRW	LEDINT11W	Integrated Ballast LED, (1) 11W screw-in lamp/ base, any bulb shape	11W LED - Int. Ballast	Electronic	N/A	N/A	11	1
LED012-SCRW	LEDINT12W	Integrated Ballast LED, (1) 12W screw-in lamp/base, any bulb shape	12W LED - Int. Ballast	Electronic	N/A	N/A	12	1
LED013-SCRW	LEDINT13W	Integrated Ballast LED, (1) 13W screw-in lamp/base, any bulb shape	13W LED - Int. Ballast	Electronic	N/A	N/A	13	1
LED014-SCRW	LEDINT14W	Integrated Ballast LED, (1) 14W screw-in lamp/base, any bulb shape	14W LED - Int. Ballast	Electronic	N/A	N/A	14	1
LED015-SCRW	LEDINT15W	Integrated Ballast LED, (1) 15W screw-in lamp/base, any bulb shape	15W LED - Int. Ballast	Electronic	N/A	N/A	15	1
LED016-SCRW	LEDINT16W	Integrated Ballast LED, (1) 16W screw-in lamp/base, any bulb shape	16W LED - Int. Ballast	Electronic	N/A	N/A	16	1
LED017-SCRW	LEDINT17W	Integrated Ballast LED, (1) 17W screw-in lamp/base, any bulb shape	17W LED - Int. Ballast	Electronic	N/A	N/A	17	1
LED018-SCRW	LEDINT18W	Integrated Ballast LED, (1) 18W screw-in lamp/base, any bulb shape	18W LED - Int. Ballast	Electronic	N/A	N/A	18	1
LED019-SCRW	LEDINT19W	Integrated Ballast LED, (1) 19W screw-in lamp/base, any bulb shape	19W LED - Int. Ballast	Electronic	N/A	N/A	19	1
LED020-SCRW	LEDINT20W	Integrated Ballast LED, (1) 20W screw-in lamp/base, any bulb shape	20W LED - Int. Ballast	Electronic	N/A	N/A	20	1
LED021-SCRW	LEDINT21W	Integrated Ballast LED, (1) 21W screw-in lamp/base, any bulb shape	21W LED - Int. Ballast	Electronic	N/A	N/A	21	1
LED022-SCRW	LEDINT22W	Integrated Ballast LED, (1) 22W screw-in lamp/base, any bulb shape	22W LED - Int. Ballast	Electronic	N/A	N/A	22	1
LED023-SCRW	LEDINT23W	Integrated Ballast LED, (1) 23W screw-in lamp/base, any bulb shape	23W LED - Int. Ballast	Electronic	N/A	N/A	23	1

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED024-SCRW	LEDINT24W	Integrated Ballast LED, (1) 24W screw-in lamp/base, any bulb shape	24W LED - Int. Ballast	Electronic	N/A	N/A	24	1
LED025-SCRW	LEDINT25W	Integrated Ballast LED, (1) 25W screw-in lamp/base, any bulb shape	25W LED - Int. Ballast	Electronic	N/A	N/A	25	1
LED026-SCRW	LEDINT26W	Integrated Ballast LED, (1) 26W screw-in lamp/base, any bulb shape	26W LED - Int. Ballast	Electronic	N/A	N/A	26	1
LED027-SCRW	LEDINT27W	Integrated Ballast LED, (1) 27W screw-in lamp/base, any bulb shape	27W LED - Int. Ballast	Electronic	N/A	N/A	27	1
LED028-SCRW	LEDINT28W	Integrated Ballast LED, (1) 28W screw-in lamp/base, any bulb shape	28W LED - Int. Ballast	Electronic	N/A	N/A	28	1
LED029-SCRW	LEDINT29W	Integrated Ballast LED, (1) 29W screw-in lamp/base, any bulb shape	29W LED - Int. Ballast	Electronic	N/A	N/A	29	1
LED030-SCRW	LEDINT30W	Integrated Ballast LED, (1) 30W screw-in lamp/base, any bulb shape	30W LED - Int. Ballast	Electronic	N/A	N/A	30	1
LED031-SCRW	LEDINT31W	Integrated Ballast LED, (1) 31W screw-in lamp/base, any bulb shape	31W LED - Int. Ballast	Electronic	N/A	N/A	31	1
LED032-SCRW	LEDINT32W	Integrated Ballast LED, (1) 32W screw-in lamp/base, any bulb shape	32W LED - Int. Ballast	Electronic	N/A	N/A	32	1
LED033-SCRW	LEDINT33W	Integrated Ballast LED, (1) 33W screw-in lamp/base, any bulb shape	33W LED - Int. Ballast	Electronic	N/A	N/A	33	1
LED034-SCRW	LEDINT34W	Integrated Ballast LED, (1) 34W screw-in lamp/base, any bulb shape	34W LED - Int. Ballast	Electronic	N/A	N/A	34	1
LED035-SCRW	LEDINT35W	Integrated Ballast LED, (1) 35W screw-in lamp/base, any bulb shape	35W LED - Int. Ballast	Electronic	N/A	N/A	35	1
LED036-SCRW	LEDINT36W	Integrated Ballast LED, (1) 36W screw-in lamp/base, any bulb shape	36W LED - Int. Ballast	Electronic	N/A	N/A	36	1
LED037-SCRW	LEDINT37W	Integrated Ballast LED, (1) 37W screw-in lamp/base, any bulb shape	37W LED - Int. Ballast	Electronic	N/A	N/A	37	1
LED038-SCRW	LEDINT38W	Integrated Ballast LED, (1) 38W screw-in lamp/base, any bulb shape	38W LED - Int. Ballast	Electronic	N/A	N/A	38	1
LED039-SCRW	LEDINT39W	Integrated Ballast LED, (1) 39W screw-in lamp/base, any bulb shape	39W LED - Int. Ballast	Electronic	N/A	N/A	39	1
LED040-SCRW	LEDINT40W	Integrated Ballast LED, (1) 40W screw-in lamp/base, any bulb shape	40W LED - Int. Ballast	Electronic	N/A	N/A	40	1
LED041-SCRW	LEDINT41W	Integrated Ballast LED, (1) 41W screw-in lamp/base, any bulb shape	41W LED - Int. Ballast	Electronic	N/A	N/A	41	1
LED042-SCRW	LEDINT42W	Integrated Ballast LED, (1) 42W screw-in lamp/base, any bulb shape	42W LED - Int. Ballast	Electronic	N/A	N/A	42	1
LED043-SCRW	LEDINT43W	Integrated Ballast LED, (1) 43W screw-in lamp/base, any bulb shape	43W LED - Int. Ballast	Electronic	N/A	N/A	43	1
LED044-SCRW	LEDINT44W	Integrated Ballast LED, (1) 44W screw-in lamp/base, any bulb shape	44W LED - Int. Ballast	Electronic	N/A	N/A	44	1
LED045-SCRW	LEDINT45W	Integrated Ballast LED, (1) 45W screw-in lamp/base, any bulb shape	45W LED - Int. Ballast	Electronic	N/A	N/A	45	1
LED046-SCRW	LEDINT46W	Integrated Ballast LED, (1) 46W screw-in lamp/base, any bulb shape	46W LED - Int. Ballast	Electronic	N/A	N/A	46	1
LED047-SCRW	LEDINT47W	Integrated Ballast LED, (1) 47W screw-in lamp/base, any bulb shape	47W LED - Int. Ballast	Electronic	N/A	N/A	47	1
LED048-SCRW	LEDINT48W	Integrated Ballast LED, (1) 48W screw-in lamp/base, any bulb shape	48W LED - Int. Ballast	Electronic	N/A	N/A	48	1
LED049-SCRW	LEDINT49W	Integrated Ballast LED, (1) 49W screw-in lamp/base, any bulb shape	49W LED - Int. Ballast	Electronic	N/A	N/A	49	1
LED050-SCRW	LEDINT50W	Integrated Ballast LED, (1) 50W screw-in lamp/base, any bulb shape	50W LED - Int. Ballast	Electronic	N/A	N/A	50	1
Non-Integrated Ballast LEDs								
LED001-FIXT	LED1W	Non-Integrated Ballast LED, 1W, any bulb shape, any application	1W LED - Non-Int. Ballast	Electronic	N/A	N/A	1	15
LED002-FIXT	LED2W	Non-Integrated Ballast LED, 2W, any bulb shape, any application	2W LED - Non-Int. Ballast	Electronic	N/A	N/A	2	15
LED003-FIXT	LED3W	Non-Integrated Ballast LED, 3W, any bulb shape, any application	3W LED - Non-Int. Ballast	Electronic	N/A	N/A	3	15
LED004-FIXT	LED4W	Non-Integrated Ballast LED, 4W, any bulb shape, any application	4W LED - Non-Int. Ballast	Electronic	N/A	N/A	4	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED005-FIXT	LED5W	Non-Integrated Ballast LED, 5W, any bulb shape, any application	5W LED - Non-Int. Ballast	Electronic	N/A	N/A	5	15
LED006-FIXT	LED6W	Non-Integrated Ballast LED, 6W, any bulb shape, any application	6W LED - Non-Int. Ballast	Electronic	N/A	N/A	6	15
LED007-FIXT	LED7W	Non-Integrated Ballast LED, 7W, any bulb shape, any application	7W LED - Non-Int. Ballast	Electronic	N/A	N/A	7	15
LED008-FIXT	LED8W	Non-Integrated Ballast LED, 8W, any bulb shape, any application	8W LED - Non-Int. Ballast	Electronic	N/A	N/A	8	15
LED009-FIXT	LED9W	Non-Integrated Ballast LED, 9W, any bulb shape, any application	9W LED - Non-Int. Ballast	Electronic	N/A	N/A	9	15
LED010-FIXT	LED10W	Non-Integrated Ballast LED, 10W, any bulb shape, any application	10W LED - Non-Int. Ballast	Electronic	N/A	N/A	10	15
LED011-FIXT	LED11W	Non-Integrated Ballast LED, 11W, any bulb shape, any application	11W LED - Non-Int. Ballast	Electronic	N/A	N/A	11	15
LED012-FIXT	LED12W	Non-Integrated Ballast LED, 12W, any bulb shape, any application	12W LED - Non-Int. Ballast	Electronic	N/A	N/A	12	15
LED013-FIXT	LED13W	Non-Integrated Ballast LED, 13W, any bulb shape, any application	13W LED - Non-Int. Ballast	Electronic	N/A	N/A	13	15
LED014-FIXT	LED14W	Non-Integrated Ballast LED, 14W, any bulb shape, any application	14W LED - Non-Int. Ballast	Electronic	N/A	N/A	14	15
LED015-FIXT	LED15W	Non-Integrated Ballast LED, 15W, any bulb shape, any application	15W LED - Non-Int. Ballast	Electronic	N/A	N/A	15	15
LED016-FIXT	LED16W	Non-Integrated Ballast LED, 16W, any bulb shape, any application	16W LED - Non-Int. Ballast	Electronic	N/A	N/A	16	15
LED017-FIXT	LED17W	Non-Integrated Ballast LED, 17W, any bulb shape, any application	17W LED - Non-Int. Ballast	Electronic	N/A	N/A	17	15
LED018-FIXT	LED18W	Non-Integrated Ballast LED, 18W, any bulb shape, any application	18W LED - Non-Int. Ballast	Electronic	N/A	N/A	18	15
LED019-FIXT	LED19W	Non-Integrated Ballast LED, 19W, any bulb shape, any application	19W LED - Non-Int. Ballast	Electronic	N/A	N/A	19	15
LED020-FIXT	LED20W	Non-Integrated Ballast LED, 20W, any bulb shape, any application	20W LED - Non-Int. Ballast	Electronic	N/A	N/A	20	15
LED021-FIXT	LED21W	Non-Integrated Ballast LED, 21W, any bulb shape, any application	21W LED - Non-Int. Ballast	Electronic	N/A	N/A	21	15
LED022-FIXT	LED22W	Non-Integrated Ballast LED, 22W, any bulb shape, any application	22W LED - Non-Int. Ballast	Electronic	N/A	N/A	22	15
LED023-FIXT	LED23W	Non-Integrated Ballast LED, 23W, any bulb shape, any application	23W LED - Non-Int. Ballast	Electronic	N/A	N/A	23	15
LED024-FIXT	LED24W	Non-Integrated Ballast LED, 24W, any bulb shape, any application	24W LED - Non-Int. Ballast	Electronic	N/A	N/A	24	15
LED025-FIXT	LED25W	Non-Integrated Ballast LED, 25W, any bulb shape, any application	25W LED - Non-Int. Ballast	Electronic	N/A	N/A	25	15
LED026-FIXT	LED26W	Non-Integrated Ballast LED, 26W, any bulb shape, any application	26W LED - Non-Int. Ballast	Electronic	N/A	N/A	26	15
LED027-FIXT	LED27W	Non-Integrated Ballast LED, 27W, any bulb shape, any application	27W LED - Non-Int. Ballast	Electronic	N/A	N/A	27	15
LED028-FIXT	LED28W	Non-Integrated Ballast LED, 28W, any bulb shape, any application	28W LED - Non-Int. Ballast	Electronic	N/A	N/A	28	15
LED029-FIXT	LED29W	Non-Integrated Ballast LED, 29W, any bulb shape, any application	29W LED - Non-Int. Ballast	Electronic	N/A	N/A	29	15
LED030-FIXT	LED30W	Non-Integrated Ballast LED, 30W, any bulb shape, any application	30W LED - Non-Int. Ballast	Electronic	N/A	N/A	30	15
LED031-FIXT	LED31W	Non-Integrated Ballast LED, 31W, any bulb shape, any application	31W LED - Non-Int. Ballast	Electronic	N/A	N/A	31	15
LED032-FIXT	LED32W	Non-Integrated Ballast LED, 32W, any bulb shape, any application	32W LED - Non-Int. Ballast	Electronic	N/A	N/A	32	15
LED033-FIXT	LED33W	Non-Integrated Ballast LED, 33W, any bulb shape, any application	33W LED - Non-Int. Ballast	Electronic	N/A	N/A	33	15
LED034-FIXT	LED34W	Non-Integrated Ballast LED, 34W, any bulb shape, any application	34W LED - Non-Int. Ballast	Electronic	N/A	N/A	34	15
LED035-FIXT	LED35W	Non-Integrated Ballast LED, 35W, any bulb shape, any application	35W LED - Non-Int. Ballast	Electronic	N/A	N/A	35	15
LED036-FIXT	LED36W	Non-Integrated Ballast LED, 36W, any bulb shape, any application	36W LED - Non-Int. Ballast	Electronic	N/A	N/A	36	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED037-FIXT	LED37W	Non-Integrated Ballast LED, 37W, any bulb shape, any application	37W LED - Non-Int. Ballast	Electronic	N/A	N/A	37	15
LED038-FIXT	LED38W	Non-Integrated Ballast LED, 38W, any bulb shape, any application	38W LED - Non-Int. Ballast	Electronic	N/A	N/A	38	15
LED039-FIXT	LED39W	Non-Integrated Ballast LED, 39W, any bulb shape, any application	39W LED - Non-Int. Ballast	Electronic	N/A	N/A	39	15
LED040-FIXT	LED40W	Non-Integrated Ballast LED, 40W, any bulb shape, any application	40W LED - Non-Int. Ballast	Electronic	N/A	N/A	40	15
LED041-FIXT	LED41W	Non-Integrated Ballast LED, 41W, any bulb shape, any application	41W LED - Non-Int. Ballast	Electronic	N/A	N/A	41	15
LED042-FIXT	LED42W	Non-Integrated Ballast LED, 42W, any bulb shape, any application	42W LED - Non-Int. Ballast	Electronic	N/A	N/A	42	15
LED043-FIXT	LED43W	Non-Integrated Ballast LED, 43W, any bulb shape, any application	43W LED - Non-Int. Ballast	Electronic	N/A	N/A	43	15
LED044-FIXT	LED44W	Non-Integrated Ballast LED, 44W, any bulb shape, any application	44W LED - Non-Int. Ballast	Electronic	N/A	N/A	44	15
LED045-FIXT	LED45W	Non-Integrated Ballast LED, 45W, any bulb shape, any application	45W LED - Non-Int. Ballast	Electronic	N/A	N/A	45	15
LED046-FIXT	LED46W	Non-Integrated Ballast LED, 46W, any bulb shape, any application	46W LED - Non-Int. Ballast	Electronic	N/A	N/A	46	15
LED047-FIXT	LED47W	Non-Integrated Ballast LED, 47W, any bulb shape, any application	47W LED - Non-Int. Ballast	Electronic	N/A	N/A	47	15
LED048-FIXT	LED48W	Non-Integrated Ballast LED, 48W, any bulb shape, any application	48W LED - Non-Int. Ballast	Electronic	N/A	N/A	48	15
LED049-FIXT	LED49W	Non-Integrated Ballast LED, 49W, any bulb shape, any application	49W LED - Non-Int. Ballast	Electronic	N/A	N/A	49	15
LED050-FIXT	LED50W	Non-Integrated Ballast LED, 50W, any bulb shape, any application	50W LED - Non-Int. Ballast	Electronic	N/A	N/A	50	15
LED051-FIXT	LED51W	Non-Integrated Ballast LED, 51W, any bulb shape, any application	51W LED - Non-Int. Ballast	Electronic	N/A	N/A	51	15
LED052-FIXT	LED52W	Non-Integrated Ballast LED, 52W, any bulb shape, any application	52W LED - Non-Int. Ballast	Electronic	N/A	N/A	52	15
LED053-FIXT	LED53W	Non-Integrated Ballast LED, 53W, any bulb shape, any application	53W LED - Non-Int. Ballast	Electronic	N/A	N/A	53	15
LED054-FIXT	LED54W	Non-Integrated Ballast LED, 54W, any bulb shape, any application	54W LED - Non-Int. Ballast	Electronic	N/A	N/A	54	15
LED055-FIXT	LED55W	Non-Integrated Ballast LED, 55W, any bulb shape, any application	55W LED - Non-Int. Ballast	Electronic	N/A	N/A	55	15
LED056-FIXT	LED56W	Non-Integrated Ballast LED, 56W, any bulb shape, any application	56W LED - Non-Int. Ballast	Electronic	N/A	N/A	56	15
LED057-FIXT	LED57W	Non-Integrated Ballast LED, 57W, any bulb shape, any application	57W LED - Non-Int. Ballast	Electronic	N/A	N/A	57	15
LED058-FIXT	LED58W	Non-Integrated Ballast LED, 58W, any bulb shape, any application	58W LED - Non-Int. Ballast	Electronic	N/A	N/A	58	15
LED059-FIXT	LED59W	Non-Integrated Ballast LED, 59W, any bulb shape, any application	59W LED - Non-Int. Ballast	Electronic	N/A	N/A	59	15
LED060-FIXT	LED60W	Non-Integrated Ballast LED, 60W, any bulb shape, any application	60W LED - Non-Int. Ballast	Electronic	N/A	N/A	60	15
LED061-FIXT	LED61W	Non-Integrated Ballast LED, 61W, any bulb shape, any application	61W LED - Non-Int. Ballast	Electronic	N/A	N/A	61	15
LED062-FIXT	LED62W	Non-Integrated Ballast LED, 62W, any bulb shape, any application	62W LED - Non-Int. Ballast	Electronic	N/A	N/A	62	15
LED063-FIXT	LED63W	Non-Integrated Ballast LED, 63W, any bulb shape, any application	63W LED - Non-Int. Ballast	Electronic	N/A	N/A	63	15
LED064-FIXT	LED64W	Non-Integrated Ballast LED, 64W, any bulb shape, any application	64W LED - Non-Int. Ballast	Electronic	N/A	N/A	64	15
LED065-FIXT	LED65W	Non-Integrated Ballast LED, 65W, any bulb shape, any application	65W LED - Non-Int. Ballast	Electronic	N/A	N/A	65	15
LED066-FIXT	LED66W	Non-Integrated Ballast LED, 66W, any bulb shape, any application	66W LED - Non-Int. Ballast	Electronic	N/A	N/A	66	15
LED067-FIXT	LED67W	Non-Integrated Ballast LED, 67W, any bulb shape, any application	67W LED - Non-Int. Ballast	Electronic	N/A	N/A	67	15
LED068-FIXT	LED68W	Non-Integrated Ballast LED, 68W, any bulb shape, any application	68W LED - Non-Int. Ballast	Electronic	N/A	N/A	68	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED069-FIXT	LED69W	Non-Integrated Ballast LED, 69W, any bulb shape, any application	69W LED - Non-Int. Ballast	Electronic	N/A	N/A	69	15
LED070-FIXT	LED70W	Non-Integrated Ballast LED, 70W, any bulb shape, any application	70W LED - Non-Int. Ballast	Electronic	N/A	N/A	70	15
LED071-FIXT	LED71W	Non-Integrated Ballast LED, 71W, any bulb shape, any application	71W LED - Non-Int. Ballast	Electronic	N/A	N/A	71	15
LED072-FIXT	LED72W	Non-Integrated Ballast LED, 72W, any bulb shape, any application	72W LED - Non-Int. Ballast	Electronic	N/A	N/A	72	15
LED073-FIXT	LED73W	Non-Integrated Ballast LED, 73W, any bulb shape, any application	73W LED - Non-Int. Ballast	Electronic	N/A	N/A	73	15
LED074-FIXT	LED74W	Non-Integrated Ballast LED, 74W, any bulb shape, any application	74W LED - Non-Int. Ballast	Electronic	N/A	N/A	74	15
LED075-FIXT	LED75W	Non-Integrated Ballast LED, 75W, any bulb shape, any application	75W LED - Non-Int. Ballast	Electronic	N/A	N/A	75	15
LED076-FIXT	LED76W	Non-Integrated Ballast LED, 76W, any bulb shape, any application	76W LED - Non-Int. Ballast	Electronic	N/A	N/A	76	15
LED077-FIXT	LED77W	Non-Integrated Ballast LED, 77W, any bulb shape, any application	77W LED - Non-Int. Ballast	Electronic	N/A	N/A	77	15
LED078-FIXT	LED78W	Non-Integrated Ballast LED, 78W, any bulb shape, any application	78W LED - Non-Int. Ballast	Electronic	N/A	N/A	78	15
LED079-FIXT	LED79W	Non-Integrated Ballast LED, 79W, any bulb shape, any application	79W LED - Non-Int. Ballast	Electronic	N/A	N/A	79	15
LED080-FIXT	LED80W	Non-Integrated Ballast LED, 80W, any bulb shape, any application	80W LED - Non-Int. Ballast	Electronic	N/A	N/A	80	15
LED081-FIXT	LED81W	Non-Integrated Ballast LED, 81W, any bulb shape, any application	81W LED - Non-Int. Ballast	Electronic	N/A	N/A	81	15
LED082-FIXT	LED82W	Non-Integrated Ballast LED, 82W, any bulb shape, any application	82W LED - Non-Int. Ballast	Electronic	N/A	N/A	82	15
LED083-FIXT	LED83W	Non-Integrated Ballast LED, 83W, any bulb shape, any application	83W LED - Non-Int. Ballast	Electronic	N/A	N/A	83	15
LED084-FIXT	LED84W	Non-Integrated Ballast LED, 84W, any bulb shape, any application	84W LED - Non-Int. Ballast	Electronic	N/A	N/A	84	15
LED085-FIXT	LED85W	Non-Integrated Ballast LED, 85W, any bulb shape, any application	85W LED - Non-Int. Ballast	Electronic	N/A	N/A	85	15
LED086-FIXT	LED86W	Non-Integrated Ballast LED, 86W, any bulb shape, any application	86W LED - Non-Int. Ballast	Electronic	N/A	N/A	86	15
LED087-FIXT	LED87W	Non-Integrated Ballast LED, 87W, any bulb shape, any application	87W LED - Non-Int. Ballast	Electronic	N/A	N/A	87	15
LED088-FIXT	LED88W	Non-Integrated Ballast LED, 88W, any bulb shape, any application	88W LED - Non-Int. Ballast	Electronic	N/A	N/A	88	15
LED089-FIXT	LED89W	Non-Integrated Ballast LED, 89W, any bulb shape, any application	89W LED - Non-Int. Ballast	Electronic	N/A	N/A	89	15
LED090-FIXT	LED90W	Non-Integrated Ballast LED, 90W, any bulb shape, any application	90W LED - Non-Int. Ballast	Electronic	N/A	N/A	90	15
LED091-FIXT	LED91W	Non-Integrated Ballast LED, 91W, any bulb shape, any application	91W LED - Non-Int. Ballast	Electronic	N/A	N/A	91	15
LED092-FIXT	LED92W	Non-Integrated Ballast LED, 92W, any bulb shape, any application	92W LED - Non-Int. Ballast	Electronic	N/A	N/A	92	15
LED093-FIXT	LED93W	Non-Integrated Ballast LED, 93W, any bulb shape, any application	93W LED - Non-Int. Ballast	Electronic	N/A	N/A	93	15
LED094-FIXT	LED94W	Non-Integrated Ballast LED, 94W, any bulb shape, any application	94W LED - Non-Int. Ballast	Electronic	N/A	N/A	94	15
LED095-FIXT	LED95W	Non-Integrated Ballast LED, 95W, any bulb shape, any application	95W LED - Non-Int. Ballast	Electronic	N/A	N/A	95	15
LED096-FIXT	LED96W	Non-Integrated Ballast LED, 96W, any bulb shape, any application	96W LED - Non-Int. Ballast	Electronic	N/A	N/A	96	15
LED097-FIXT	LED97W	Non-Integrated Ballast LED, 97W, any bulb shape, any application	97W LED - Non-Int. Ballast	Electronic	N/A	N/A	97	15
LED098-FIXT	LED98W	Non-Integrated Ballast LED, 98W, any bulb shape, any application	98W LED - Non-Int. Ballast	Electronic	N/A	N/A	98	15
LED099-FIXT	LED99W	Non-Integrated Ballast LED, 99W, any bulb shape, any application	99W LED - Non-Int. Ballast	Electronic	N/A	N/A	99	15
LED100-FIXT	LED100W	Non-Integrated Ballast LED, 100W, any bulb shape, any application	100W LED - Non-Int. Ballast	Electronic	N/A	N/A	100	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED101-FIXT	LED101 W	Non-Integrated Ballast LED, 101W, any bulb shape, any application	101W LED - Non-Int. Ballast	Electronic	N/A	N/A	101	15
LED102-FIXT	LED102 W	Non-Integrated Ballast LED, 102W, any bulb shape, any application	102W LED - Non-Int. Ballast	Electronic	N/A	N/A	102	15
LED103-FIXT	LED103 W	Non-Integrated Ballast LED, 103W, any bulb shape, any application	103W LED - Non-Int. Ballast	Electronic	N/A	N/A	103	15
LED104-FIXT	LED104 W	Non-Integrated Ballast LED, 104W, any bulb shape, any application	104W LED - Non-Int. Ballast	Electronic	N/A	N/A	104	15
LED105-FIXT	LED105 W	Non-Integrated Ballast LED, 105W, any bulb shape, any application	105W LED - Non-Int. Ballast	Electronic	N/A	N/A	105	15
LED106-FIXT	LED106 W	Non-Integrated Ballast LED, 106W, any bulb shape, any application	106W LED - Non-Int. Ballast	Electronic	N/A	N/A	106	15
LED107-FIXT	LED107 W	Non-Integrated Ballast LED, 107W, any bulb shape, any application	107W LED - Non-Int. Ballast	Electronic	N/A	N/A	107	15
LED108-FIXT	LED108 W	Non-Integrated Ballast LED, 108W, any bulb shape, any application	108W LED - Non-Int. Ballast	Electronic	N/A	N/A	108	15
LED109-FIXT	LED109 W	Non-Integrated Ballast LED, 109W, any bulb shape, any application	109W LED - Non-Int. Ballast	Electronic	N/A	N/A	109	15
LED110-FIXT	LED110 W	Non-Integrated Ballast LED, 110W, any bulb shape, any application	110W LED - Non-Int. Ballast	Electronic	N/A	N/A	110	15
LED111-FIXT	LED111 W	Non-Integrated Ballast LED, 111W, any bulb shape, any application	111W LED - Non-Int. Ballast	Electronic	N/A	N/A	111	15
LED112-FIXT	LED112 W	Non-Integrated Ballast LED, 112W, any bulb shape, any application	112W LED - Non-Int. Ballast	Electronic	N/A	N/A	112	15
LED113-FIXT	LED113 W	Non-Integrated Ballast LED, 113W, any bulb shape, any application	113W LED - Non-Int. Ballast	Electronic	N/A	N/A	113	15
LED114-FIXT	LED114 W	Non-Integrated Ballast LED, 114W, any bulb shape, any application	114W LED - Non-Int. Ballast	Electronic	N/A	N/A	114	15
LED115-FIXT	LED115 W	Non-Integrated Ballast LED, 115W, any bulb shape, any application	115W LED - Non-Int. Ballast	Electronic	N/A	N/A	115	15
LED116-FIXT	LED116 W	Non-Integrated Ballast LED, 116W, any bulb shape, any application	116W LED - Non-Int. Ballast	Electronic	N/A	N/A	116	15
LED117-FIXT	LED117 W	Non-Integrated Ballast LED, 117W, any bulb shape, any application	117W LED - Non-Int. Ballast	Electronic	N/A	N/A	117	15
LED118-FIXT	LED118 W	Non-Integrated Ballast LED, 118W, any bulb shape, any application	118W LED - Non-Int. Ballast	Electronic	N/A	N/A	118	15
LED119-FIXT	LED119 W	Non-Integrated Ballast LED, 119W, any bulb shape, any application	119W LED - Non-Int. Ballast	Electronic	N/A	N/A	119	15
LED120-FIXT	LED120 W	Non-Integrated Ballast LED, 120W, any bulb shape, any application	120W LED - Non-Int. Ballast	Electronic	N/A	N/A	120	15
LED121-FIXT	LED121 W	Non-Integrated Ballast LED, 121W, any bulb shape, any application	121W LED - Non-Int. Ballast	Electronic	N/A	N/A	121	15
LED122-FIXT	LED122 W	Non-Integrated Ballast LED, 122W, any bulb shape, any application	122W LED - Non-Int. Ballast	Electronic	N/A	N/A	122	15
LED123-FIXT	LED123 W	Non-Integrated Ballast LED, 123W, any bulb shape, any application	123W LED - Non-Int. Ballast	Electronic	N/A	N/A	123	15
LED124-FIXT	LED124 W	Non-Integrated Ballast LED, 124W, any bulb shape, any application	124W LED - Non-Int. Ballast	Electronic	N/A	N/A	124	15
LED125-FIXT	LED125 W	Non-Integrated Ballast LED, 125W, any bulb shape, any application	125W LED - Non-Int. Ballast	Electronic	N/A	N/A	125	15
LED126-FIXT	LED126 W	Non-Integrated Ballast LED, 126W, any bulb shape, any application	126W LED - Non-Int. Ballast	Electronic	N/A	N/A	126	15
LED127-FIXT	LED127 W	Non-Integrated Ballast LED, 127W, any bulb shape, any application	127W LED - Non-Int. Ballast	Electronic	N/A	N/A	127	15
LED128-FIXT	LED128 W	Non-Integrated Ballast LED, 128W, any bulb shape, any application	128W LED - Non-Int. Ballast	Electronic	N/A	N/A	128	15
LED129-FIXT	LED129 W	Non-Integrated Ballast LED, 129W, any bulb shape, any application	129W LED - Non-Int. Ballast	Electronic	N/A	N/A	129	15
LED130-FIXT	LED130 W	Non-Integrated Ballast LED, 130W, any bulb shape, any application	130W LED - Non-Int. Ballast	Electronic	N/A	N/A	130	15
LED131-FIXT	LED131 W	Non-Integrated Ballast LED, 131W, any bulb shape, any application	131W LED - Non-Int. Ballast	Electronic	N/A	N/A	131	15
LED132-FIXT	LED132 W	Non-Integrated Ballast LED, 132W, any bulb shape, any application	132W LED - Non-Int. Ballast	Electronic	N/A	N/A	132	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED133-FIXT	LED133W	Non-Integrated Ballast LED, 133W, any bulb shape, any application	133W LED - Non-Int. Ballast	Electronic	N/A	N/A	133	15
LED134-FIXT	LED134W	Non-Integrated Ballast LED, 134W, any bulb shape, any application	134W LED - Non-Int. Ballast	Electronic	N/A	N/A	134	15
LED135-FIXT	LED135W	Non-Integrated Ballast LED, 135W, any bulb shape, any application	135W LED - Non-Int. Ballast	Electronic	N/A	N/A	135	15
LED136-FIXT	LED136W	Non-Integrated Ballast LED, 136W, any bulb shape, any application	136W LED - Non-Int. Ballast	Electronic	N/A	N/A	136	15
LED137-FIXT	LED137W	Non-Integrated Ballast LED, 137W, any bulb shape, any application	137W LED - Non-Int. Ballast	Electronic	N/A	N/A	137	15
LED138-FIXT	LED138W	Non-Integrated Ballast LED, 138W, any bulb shape, any application	138W LED - Non-Int. Ballast	Electronic	N/A	N/A	138	15
LED139-FIXT	LED139W	Non-Integrated Ballast LED, 139W, any bulb shape, any application	139W LED - Non-Int. Ballast	Electronic	N/A	N/A	139	15
LED140-FIXT	LED140W	Non-Integrated Ballast LED, 140W, any bulb shape, any application	140W LED - Non-Int. Ballast	Electronic	N/A	N/A	140	15
LED141-FIXT	LED141W	Non-Integrated Ballast LED, 141W, any bulb shape, any application	141W LED - Non-Int. Ballast	Electronic	N/A	N/A	141	15
LED142-FIXT	LED142W	Non-Integrated Ballast LED, 142W, any bulb shape, any application	142W LED - Non-Int. Ballast	Electronic	N/A	N/A	142	15
LED143-FIXT	LED143W	Non-Integrated Ballast LED, 143W, any bulb shape, any application	143W LED - Non-Int. Ballast	Electronic	N/A	N/A	143	15
LED144-FIXT	LED144W	Non-Integrated Ballast LED, 144W, any bulb shape, any application	144W LED - Non-Int. Ballast	Electronic	N/A	N/A	144	15
LED145-FIXT	LED145W	Non-Integrated Ballast LED, 145W, any bulb shape, any application	145W LED - Non-Int. Ballast	Electronic	N/A	N/A	145	15
LED146-FIXT	LED146W	Non-Integrated Ballast LED, 146W, any bulb shape, any application	146W LED - Non-Int. Ballast	Electronic	N/A	N/A	146	15
LED147-FIXT	LED147W	Non-Integrated Ballast LED, 147W, any bulb shape, any application	147W LED - Non-Int. Ballast	Electronic	N/A	N/A	147	15
LED148-FIXT	LED148W	Non-Integrated Ballast LED, 148W, any bulb shape, any application	148W LED - Non-Int. Ballast	Electronic	N/A	N/A	148	15
LED149-FIXT	LED149W	Non-Integrated Ballast LED, 149W, any bulb shape, any application	149W LED - Non-Int. Ballast	Electronic	N/A	N/A	149	15
LED150-FIXT	LED150W	Non-Integrated Ballast LED, 150W, any bulb shape, any application	150W LED - Non-Int. Ballast	Electronic	N/A	N/A	150	15
LED151-FIXT	LED151W	Non-Integrated Ballast LED, 151W, any bulb shape, any application	151W LED - Non-Int. Ballast	Electronic	N/A	N/A	151	15
LED152-FIXT	LED152W	Non-Integrated Ballast LED, 152W, any bulb shape, any application	152W LED - Non-Int. Ballast	Electronic	N/A	N/A	152	15
LED153-FIXT	LED153W	Non-Integrated Ballast LED, 153W, any bulb shape, any application	153W LED - Non-Int. Ballast	Electronic	N/A	N/A	153	15
LED154-FIXT	LED154W	Non-Integrated Ballast LED, 154W, any bulb shape, any application	154W LED - Non-Int. Ballast	Electronic	N/A	N/A	154	15
LED155-FIXT	LED155W	Non-Integrated Ballast LED, 155W, any bulb shape, any application	155W LED - Non-Int. Ballast	Electronic	N/A	N/A	155	15
LED156-FIXT	LED156W	Non-Integrated Ballast LED, 156W, any bulb shape, any application	156W LED - Non-Int. Ballast	Electronic	N/A	N/A	156	15
LED157-FIXT	LED157W	Non-Integrated Ballast LED, 157W, any bulb shape, any application	157W LED - Non-Int. Ballast	Electronic	N/A	N/A	157	15
LED158-FIXT	LED158W	Non-Integrated Ballast LED, 158W, any bulb shape, any application	158W LED - Non-Int. Ballast	Electronic	N/A	N/A	158	15
LED159-FIXT	LED159W	Non-Integrated Ballast LED, 159W, any bulb shape, any application	159W LED - Non-Int. Ballast	Electronic	N/A	N/A	159	15
LED160-FIXT	LED160W	Non-Integrated Ballast LED, 160W, any bulb shape, any application	160W LED - Non-Int. Ballast	Electronic	N/A	N/A	160	15
LED161-FIXT	LED161W	Non-Integrated Ballast LED, 161W, any bulb shape, any application	161W LED - Non-Int. Ballast	Electronic	N/A	N/A	161	15
LED162-FIXT	LED162W	Non-Integrated Ballast LED, 162W, any bulb shape, any application	162W LED - Non-Int. Ballast	Electronic	N/A	N/A	162	15
LED163-FIXT	LED163W	Non-Integrated Ballast LED, 163W, any bulb shape, any application	163W LED - Non-Int. Ballast	Electronic	N/A	N/A	163	15
LED164-FIXT	LED164W	Non-Integrated Ballast LED, 164W, any bulb shape, any application	164W LED - Non-Int. Ballast	Electronic	N/A	N/A	164	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED165-FIXT	LED165 W	Non-Integrated Ballast LED, 165W, any bulb shape, any application	165W LED - Non-Int. Ballast	Electronic	N/A	N/A	165	15
LED166-FIXT	LED166 W	Non-Integrated Ballast LED, 166W, any bulb shape, any application	166W LED - Non-Int. Ballast	Electronic	N/A	N/A	166	15
LED167-FIXT	LED167 W	Non-Integrated Ballast LED, 167W, any bulb shape, any application	167W LED - Non-Int. Ballast	Electronic	N/A	N/A	167	15
LED168-FIXT	LED168 W	Non-Integrated Ballast LED, 168W, any bulb shape, any application	168W LED - Non-Int. Ballast	Electronic	N/A	N/A	168	15
LED169-FIXT	LED169 W	Non-Integrated Ballast LED, 169W, any bulb shape, any application	169W LED - Non-Int. Ballast	Electronic	N/A	N/A	169	15
LED170-FIXT	LED170 W	Non-Integrated Ballast LED, 170W, any bulb shape, any application	170W LED - Non-Int. Ballast	Electronic	N/A	N/A	170	15
LED171-FIXT	LED171 W	Non-Integrated Ballast LED, 171W, any bulb shape, any application	171W LED - Non-Int. Ballast	Electronic	N/A	N/A	171	15
LED172-FIXT	LED172 W	Non-Integrated Ballast LED, 172W, any bulb shape, any application	172W LED - Non-Int. Ballast	Electronic	N/A	N/A	172	15
LED173-FIXT	LED173 W	Non-Integrated Ballast LED, 173W, any bulb shape, any application	173W LED - Non-Int. Ballast	Electronic	N/A	N/A	173	15
LED174-FIXT	LED174 W	Non-Integrated Ballast LED, 174W, any bulb shape, any application	174W LED - Non-Int. Ballast	Electronic	N/A	N/A	174	15
LED175-FIXT	LED175 W	Non-Integrated Ballast LED, 175W, any bulb shape, any application	175W LED - Non-Int. Ballast	Electronic	N/A	N/A	175	15
LED176-FIXT	LED176 W	Non-Integrated Ballast LED, 176W, any bulb shape, any application	176W LED - Non-Int. Ballast	Electronic	N/A	N/A	176	15
LED177-FIXT	LED177 W	Non-Integrated Ballast LED, 177W, any bulb shape, any application	177W LED - Non-Int. Ballast	Electronic	N/A	N/A	177	15
LED178-FIXT	LED178 W	Non-Integrated Ballast LED, 178W, any bulb shape, any application	178W LED - Non-Int. Ballast	Electronic	N/A	N/A	178	15
LED179-FIXT	LED179 W	Non-Integrated Ballast LED, 179W, any bulb shape, any application	179W LED - Non-Int. Ballast	Electronic	N/A	N/A	179	15
LED180-FIXT	LED180 W	Non-Integrated Ballast LED, 180W, any bulb shape, any application	180W LED - Non-Int. Ballast	Electronic	N/A	N/A	180	15
LED181-FIXT	LED181 W	Non-Integrated Ballast LED, 181W, any bulb shape, any application	181W LED - Non-Int. Ballast	Electronic	N/A	N/A	181	15
LED182-FIXT	LED182 W	Non-Integrated Ballast LED, 182W, any bulb shape, any application	182W LED - Non-Int. Ballast	Electronic	N/A	N/A	182	15
LED183-FIXT	LED183 W	Non-Integrated Ballast LED, 183W, any bulb shape, any application	183W LED - Non-Int. Ballast	Electronic	N/A	N/A	183	15
LED184-FIXT	LED184 W	Non-Integrated Ballast LED, 184W, any bulb shape, any application	184W LED - Non-Int. Ballast	Electronic	N/A	N/A	184	15
LED185-FIXT	LED185 W	Non-Integrated Ballast LED, 185W, any bulb shape, any application	185W LED - Non-Int. Ballast	Electronic	N/A	N/A	185	15
LED186-FIXT	LED186 W	Non-Integrated Ballast LED, 186W, any bulb shape, any application	186W LED - Non-Int. Ballast	Electronic	N/A	N/A	186	15
LED187-FIXT	LED187 W	Non-Integrated Ballast LED, 187W, any bulb shape, any application	187W LED - Non-Int. Ballast	Electronic	N/A	N/A	187	15
LED188-FIXT	LED188 W	Non-Integrated Ballast LED, 188W, any bulb shape, any application	188W LED - Non-Int. Ballast	Electronic	N/A	N/A	188	15
LED189-FIXT	LED189 W	Non-Integrated Ballast LED, 189W, any bulb shape, any application	189W LED - Non-Int. Ballast	Electronic	N/A	N/A	189	15
LED190-FIXT	LED190 W	Non-Integrated Ballast LED, 190W, any bulb shape, any application	190W LED - Non-Int. Ballast	Electronic	N/A	N/A	190	15
LED191-FIXT	LED191 W	Non-Integrated Ballast LED, 191W, any bulb shape, any application	191W LED - Non-Int. Ballast	Electronic	N/A	N/A	191	15
LED192-FIXT	LED192 W	Non-Integrated Ballast LED, 192W, any bulb shape, any application	192W LED - Non-Int. Ballast	Electronic	N/A	N/A	192	15
LED193-FIXT	LED193 W	Non-Integrated Ballast LED, 193W, any bulb shape, any application	193W LED - Non-Int. Ballast	Electronic	N/A	N/A	193	15
LED194-FIXT	LED194 W	Non-Integrated Ballast LED, 194W, any bulb shape, any application	194W LED - Non-Int. Ballast	Electronic	N/A	N/A	194	15
LED195-FIXT	LED195 W	Non-Integrated Ballast LED, 195W, any bulb shape, any application	195W LED - Non-Int. Ballast	Electronic	N/A	N/A	195	15
LED196-FIXT	LED196 W	Non-Integrated Ballast LED, 196W, any bulb shape, any application	196W LED - Non-Int. Ballast	Electronic	N/A	N/A	196	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED197-FIXT	LED197W	Non-Integrated Ballast LED, 197W, any bulb shape, any application	197W LED - Non-Int. Ballast	Electronic	N/A	N/A	197	15
LED198-FIXT	LED198W	Non-Integrated Ballast LED, 198W, any bulb shape, any application	198W LED - Non-Int. Ballast	Electronic	N/A	N/A	198	15
LED199-FIXT	LED199W	Non-Integrated Ballast LED, 199W, any bulb shape, any application	199W LED - Non-Int. Ballast	Electronic	N/A	N/A	199	15
LED200-FIXT	LED200W	Non-Integrated Ballast LED, 200W, any bulb shape, any application	200W LED - Non-Int. Ballast	Electronic	N/A	N/A	200	15
LED201-FIXT	LED201W	Non-Integrated Ballast LED, 201W, any bulb shape, any application	201W LED - Non-Int. Ballast	Electronic	N/A	N/A	201	15
LED202-FIXT	LED202W	Non-Integrated Ballast LED, 202W, any bulb shape, any application	202W LED - Non-Int. Ballast	Electronic	N/A	N/A	202	15
LED203-FIXT	LED203W	Non-Integrated Ballast LED, 203W, any bulb shape, any application	203W LED - Non-Int. Ballast	Electronic	N/A	N/A	203	15
LED204-FIXT	LED204W	Non-Integrated Ballast LED, 204W, any bulb shape, any application	204W LED - Non-Int. Ballast	Electronic	N/A	N/A	204	15
LED205-FIXT	LED205W	Non-Integrated Ballast LED, 205W, any bulb shape, any application	205W LED - Non-Int. Ballast	Electronic	N/A	N/A	205	15
LED206-FIXT	LED206W	Non-Integrated Ballast LED, 206W, any bulb shape, any application	206W LED - Non-Int. Ballast	Electronic	N/A	N/A	206	15
LED207-FIXT	LED207W	Non-Integrated Ballast LED, 207W, any bulb shape, any application	207W LED - Non-Int. Ballast	Electronic	N/A	N/A	207	15
LED208-FIXT	LED208W	Non-Integrated Ballast LED, 208W, any bulb shape, any application	208W LED - Non-Int. Ballast	Electronic	N/A	N/A	208	15
LED209-FIXT	LED209W	Non-Integrated Ballast LED, 209W, any bulb shape, any application	209W LED - Non-Int. Ballast	Electronic	N/A	N/A	209	15
LED210-FIXT	LED210W	Non-Integrated Ballast LED, 210W, any bulb shape, any application	210W LED - Non-Int. Ballast	Electronic	N/A	N/A	210	15
LED211-FIXT	LED211W	Non-Integrated Ballast LED, 211W, any bulb shape, any application	211W LED - Non-Int. Ballast	Electronic	N/A	N/A	211	15
LED212-FIXT	LED212W	Non-Integrated Ballast LED, 212W, any bulb shape, any application	212W LED - Non-Int. Ballast	Electronic	N/A	N/A	212	15
LED213-FIXT	LED213W	Non-Integrated Ballast LED, 213W, any bulb shape, any application	213W LED - Non-Int. Ballast	Electronic	N/A	N/A	213	15
LED214-FIXT	LED214W	Non-Integrated Ballast LED, 214W, any bulb shape, any application	214W LED - Non-Int. Ballast	Electronic	N/A	N/A	214	15
LED215-FIXT	LED215W	Non-Integrated Ballast LED, 215W, any bulb shape, any application	215W LED - Non-Int. Ballast	Electronic	N/A	N/A	215	15
LED216-FIXT	LED216W	Non-Integrated Ballast LED, 216W, any bulb shape, any application	216W LED - Non-Int. Ballast	Electronic	N/A	N/A	216	15
LED217-FIXT	LED217W	Non-Integrated Ballast LED, 217W, any bulb shape, any application	217W LED - Non-Int. Ballast	Electronic	N/A	N/A	217	15
LED218-FIXT	LED218W	Non-Integrated Ballast LED, 218W, any bulb shape, any application	218W LED - Non-Int. Ballast	Electronic	N/A	N/A	218	15
LED219-FIXT	LED219W	Non-Integrated Ballast LED, 219W, any bulb shape, any application	219W LED - Non-Int. Ballast	Electronic	N/A	N/A	219	15
LED220-FIXT	LED220W	Non-Integrated Ballast LED, 220W, any bulb shape, any application	220W LED - Non-Int. Ballast	Electronic	N/A	N/A	220	15
LED221-FIXT	LED221W	Non-Integrated Ballast LED, 221W, any bulb shape, any application	221W LED - Non-Int. Ballast	Electronic	N/A	N/A	221	15
LED222-FIXT	LED222W	Non-Integrated Ballast LED, 222W, any bulb shape, any application	222W LED - Non-Int. Ballast	Electronic	N/A	N/A	222	15
LED223-FIXT	LED223W	Non-Integrated Ballast LED, 223W, any bulb shape, any application	223W LED - Non-Int. Ballast	Electronic	N/A	N/A	223	15
LED224-FIXT	LED224W	Non-Integrated Ballast LED, 224W, any bulb shape, any application	224W LED - Non-Int. Ballast	Electronic	N/A	N/A	224	15
LED225-FIXT	LED225W	Non-Integrated Ballast LED, 225W, any bulb shape, any application	225W LED - Non-Int. Ballast	Electronic	N/A	N/A	225	15
LED226-FIXT	LED226W	Non-Integrated Ballast LED, 226W, any bulb shape, any application	226W LED - Non-Int. Ballast	Electronic	N/A	N/A	226	15
LED227-FIXT	LED227W	Non-Integrated Ballast LED, 227W, any bulb shape, any application	227W LED - Non-Int. Ballast	Electronic	N/A	N/A	227	15
LED228-FIXT	LED228W	Non-Integrated Ballast LED, 228W, any bulb shape, any application	228W LED - Non-Int. Ballast	Electronic	N/A	N/A	228	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED229-FIXT	LED229 W	Non-Integrated Ballast LED, 229W, any bulb shape, any application	229W LED - Non-Int. Ballast	Electronic	N/A	N/A	229	15
LED230-FIXT	LED230 W	Non-Integrated Ballast LED, 230W, any bulb shape, any application	230W LED - Non-Int. Ballast	Electronic	N/A	N/A	230	15
LED231-FIXT	LED231 W	Non-Integrated Ballast LED, 231W, any bulb shape, any application	231W LED - Non-Int. Ballast	Electronic	N/A	N/A	231	15
LED232-FIXT	LED232 W	Non-Integrated Ballast LED, 232W, any bulb shape, any application	232W LED - Non-Int. Ballast	Electronic	N/A	N/A	232	15
LED233-FIXT	LED233 W	Non-Integrated Ballast LED, 233W, any bulb shape, any application	233W LED - Non-Int. Ballast	Electronic	N/A	N/A	233	15
LED234-FIXT	LED234 W	Non-Integrated Ballast LED, 234W, any bulb shape, any application	234W LED - Non-Int. Ballast	Electronic	N/A	N/A	234	15
LED235-FIXT	LED235 W	Non-Integrated Ballast LED, 235W, any bulb shape, any application	235W LED - Non-Int. Ballast	Electronic	N/A	N/A	235	15
LED236-FIXT	LED236 W	Non-Integrated Ballast LED, 236W, any bulb shape, any application	236W LED - Non-Int. Ballast	Electronic	N/A	N/A	236	15
LED237-FIXT	LED237 W	Non-Integrated Ballast LED, 237W, any bulb shape, any application	237W LED - Non-Int. Ballast	Electronic	N/A	N/A	237	15
LED238-FIXT	LED238 W	Non-Integrated Ballast LED, 238W, any bulb shape, any application	238W LED - Non-Int. Ballast	Electronic	N/A	N/A	238	15
LED239-FIXT	LED239 W	Non-Integrated Ballast LED, 239W, any bulb shape, any application	239W LED - Non-Int. Ballast	Electronic	N/A	N/A	239	15
LED240-FIXT	LED240 W	Non-Integrated Ballast LED, 240W, any bulb shape, any application	240W LED - Non-Int. Ballast	Electronic	N/A	N/A	240	15
LED241-FIXT	LED241 W	Non-Integrated Ballast LED, 241W, any bulb shape, any application	241W LED - Non-Int. Ballast	Electronic	N/A	N/A	241	15
LED242-FIXT	LED242 W	Non-Integrated Ballast LED, 242W, any bulb shape, any application	242W LED - Non-Int. Ballast	Electronic	N/A	N/A	242	15
LED243-FIXT	LED243 W	Non-Integrated Ballast LED, 243W, any bulb shape, any application	243W LED - Non-Int. Ballast	Electronic	N/A	N/A	243	15
LED244-FIXT	LED244 W	Non-Integrated Ballast LED, 244W, any bulb shape, any application	244W LED - Non-Int. Ballast	Electronic	N/A	N/A	244	15
LED245-FIXT	LED245 W	Non-Integrated Ballast LED, 245W, any bulb shape, any application	245W LED - Non-Int. Ballast	Electronic	N/A	N/A	245	15
LED246-FIXT	LED246 W	Non-Integrated Ballast LED, 246W, any bulb shape, any application	246W LED - Non-Int. Ballast	Electronic	N/A	N/A	246	15
LED247-FIXT	LED247 W	Non-Integrated Ballast LED, 247W, any bulb shape, any application	247W LED - Non-Int. Ballast	Electronic	N/A	N/A	247	15
LED248-FIXT	LED248 W	Non-Integrated Ballast LED, 248W, any bulb shape, any application	248W LED - Non-Int. Ballast	Electronic	N/A	N/A	248	15
LED249-FIXT	LED249 W	Non-Integrated Ballast LED, 249W, any bulb shape, any application	249W LED - Non-Int. Ballast	Electronic	N/A	N/A	249	15
LED250-FIXT	LED250 W	Non-Integrated Ballast LED, 250W, any bulb shape, any application	250W LED - Non-Int. Ballast	Electronic	N/A	N/A	250	15
LED251-FIXT	LED251 W	Non-Integrated Ballast LED, 251W, any bulb shape, any application	251W LED - Non-Int. Ballast	Electronic	N/A	N/A	251	15
LED252-FIXT	LED252 W	Non-Integrated Ballast LED, 252W, any bulb shape, any application	252W LED - Non-Int. Ballast	Electronic	N/A	N/A	252	15
LED253-FIXT	LED253 W	Non-Integrated Ballast LED, 253W, any bulb shape, any application	253W LED - Non-Int. Ballast	Electronic	N/A	N/A	253	15
LED254-FIXT	LED254 W	Non-Integrated Ballast LED, 254W, any bulb shape, any application	254W LED - Non-Int. Ballast	Electronic	N/A	N/A	254	15
LED255-FIXT	LED255 W	Non-Integrated Ballast LED, 255W, any bulb shape, any application	255W LED - Non-Int. Ballast	Electronic	N/A	N/A	255	15
LED256-FIXT	LED256 W	Non-Integrated Ballast LED, 256W, any bulb shape, any application	256W LED - Non-Int. Ballast	Electronic	N/A	N/A	256	15
LED257-FIXT	LED257 W	Non-Integrated Ballast LED, 257W, any bulb shape, any application	257W LED - Non-Int. Ballast	Electronic	N/A	N/A	257	15
LED258-FIXT	LED258 W	Non-Integrated Ballast LED, 258W, any bulb shape, any application	258W LED - Non-Int. Ballast	Electronic	N/A	N/A	258	15
LED259-FIXT	LED259 W	Non-Integrated Ballast LED, 259W, any bulb shape, any application	259W LED - Non-Int. Ballast	Electronic	N/A	N/A	259	15
LED260-FIXT	LED260 W	Non-Integrated Ballast LED, 260W, any bulb shape, any application	260W LED - Non-Int. Ballast	Electronic	N/A	N/A	260	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED261-FIXT	LED261W	Non-Integrated Ballast LED, 261W, any bulb shape, any application	261W LED - Non-Int. Ballast	Electronic	N/A	N/A	261	15
LED262-FIXT	LED262W	Non-Integrated Ballast LED, 262W, any bulb shape, any application	262W LED - Non-Int. Ballast	Electronic	N/A	N/A	262	15
LED263-FIXT	LED263W	Non-Integrated Ballast LED, 263W, any bulb shape, any application	263W LED - Non-Int. Ballast	Electronic	N/A	N/A	263	15
LED264-FIXT	LED264W	Non-Integrated Ballast LED, 264W, any bulb shape, any application	264W LED - Non-Int. Ballast	Electronic	N/A	N/A	264	15
LED265-FIXT	LED265W	Non-Integrated Ballast LED, 265W, any bulb shape, any application	265W LED - Non-Int. Ballast	Electronic	N/A	N/A	265	15
LED266-FIXT	LED266W	Non-Integrated Ballast LED, 266W, any bulb shape, any application	266W LED - Non-Int. Ballast	Electronic	N/A	N/A	266	15
LED267-FIXT	LED267W	Non-Integrated Ballast LED, 267W, any bulb shape, any application	267W LED - Non-Int. Ballast	Electronic	N/A	N/A	267	15
LED268-FIXT	LED268W	Non-Integrated Ballast LED, 268W, any bulb shape, any application	268W LED - Non-Int. Ballast	Electronic	N/A	N/A	268	15
LED269-FIXT	LED269W	Non-Integrated Ballast LED, 269W, any bulb shape, any application	269W LED - Non-Int. Ballast	Electronic	N/A	N/A	269	15
LED270-FIXT	LED270W	Non-Integrated Ballast LED, 270W, any bulb shape, any application	270W LED - Non-Int. Ballast	Electronic	N/A	N/A	270	15
LED271-FIXT	LED271W	Non-Integrated Ballast LED, 271W, any bulb shape, any application	271W LED - Non-Int. Ballast	Electronic	N/A	N/A	271	15
LED272-FIXT	LED272W	Non-Integrated Ballast LED, 272W, any bulb shape, any application	272W LED - Non-Int. Ballast	Electronic	N/A	N/A	272	15
LED273-FIXT	LED273W	Non-Integrated Ballast LED, 273W, any bulb shape, any application	273W LED - Non-Int. Ballast	Electronic	N/A	N/A	273	15
LED274-FIXT	LED274W	Non-Integrated Ballast LED, 274W, any bulb shape, any application	274W LED - Non-Int. Ballast	Electronic	N/A	N/A	274	15
LED275-FIXT	LED275W	Non-Integrated Ballast LED, 275W, any bulb shape, any application	275W LED - Non-Int. Ballast	Electronic	N/A	N/A	275	15
LED276-FIXT	LED276W	Non-Integrated Ballast LED, 276W, any bulb shape, any application	276W LED - Non-Int. Ballast	Electronic	N/A	N/A	276	15
LED277-FIXT	LED277W	Non-Integrated Ballast LED, 277W, any bulb shape, any application	277W LED - Non-Int. Ballast	Electronic	N/A	N/A	277	15
LED278-FIXT	LED278W	Non-Integrated Ballast LED, 278W, any bulb shape, any application	278W LED - Non-Int. Ballast	Electronic	N/A	N/A	278	15
LED279-FIXT	LED279W	Non-Integrated Ballast LED, 279W, any bulb shape, any application	279W LED - Non-Int. Ballast	Electronic	N/A	N/A	279	15
LED280-FIXT	LED280W	Non-Integrated Ballast LED, 280W, any bulb shape, any application	280W LED - Non-Int. Ballast	Electronic	N/A	N/A	280	15
LED281-FIXT	LED281W	Non-Integrated Ballast LED, 281W, any bulb shape, any application	281W LED - Non-Int. Ballast	Electronic	N/A	N/A	281	15
LED282-FIXT	LED282W	Non-Integrated Ballast LED, 282W, any bulb shape, any application	282W LED - Non-Int. Ballast	Electronic	N/A	N/A	282	15
LED283-FIXT	LED283W	Non-Integrated Ballast LED, 283W, any bulb shape, any application	283W LED - Non-Int. Ballast	Electronic	N/A	N/A	283	15
LED284-FIXT	LED284W	Non-Integrated Ballast LED, 284W, any bulb shape, any application	284W LED - Non-Int. Ballast	Electronic	N/A	N/A	284	15
LED285-FIXT	LED285W	Non-Integrated Ballast LED, 285W, any bulb shape, any application	285W LED - Non-Int. Ballast	Electronic	N/A	N/A	285	15
LED286-FIXT	LED286W	Non-Integrated Ballast LED, 286W, any bulb shape, any application	286W LED - Non-Int. Ballast	Electronic	N/A	N/A	286	15
LED287-FIXT	LED287W	Non-Integrated Ballast LED, 287W, any bulb shape, any application	287W LED - Non-Int. Ballast	Electronic	N/A	N/A	287	15
LED288-FIXT	LED288W	Non-Integrated Ballast LED, 288W, any bulb shape, any application	288W LED - Non-Int. Ballast	Electronic	N/A	N/A	288	15
LED289-FIXT	LED289W	Non-Integrated Ballast LED, 289W, any bulb shape, any application	289W LED - Non-Int. Ballast	Electronic	N/A	N/A	289	15
LED290-FIXT	LED290W	Non-Integrated Ballast LED, 290W, any bulb shape, any application	290W LED - Non-Int. Ballast	Electronic	N/A	N/A	290	15
LED291-FIXT	LED291W	Non-Integrated Ballast LED, 291W, any bulb shape, any application	291W LED - Non-Int. Ballast	Electronic	N/A	N/A	291	15
LED292-FIXT	LED292W	Non-Integrated Ballast LED, 292W, any bulb shape, any application	292W LED - Non-Int. Ballast	Electronic	N/A	N/A	292	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED293-FIXT	LED293 W	Non-Integrated Ballast LED, 293W, any bulb shape, any application	293W LED - Non-Int. Ballast	Electronic	N/A	N/A	293	15
LED294-FIXT	LED294 W	Non-Integrated Ballast LED, 294W, any bulb shape, any application	294W LED - Non-Int. Ballast	Electronic	N/A	N/A	294	15
LED295-FIXT	LED295 W	Non-Integrated Ballast LED, 295W, any bulb shape, any application	295W LED - Non-Int. Ballast	Electronic	N/A	N/A	295	15
LED296-FIXT	LED296 W	Non-Integrated Ballast LED, 296W, any bulb shape, any application	296W LED - Non-Int. Ballast	Electronic	N/A	N/A	296	15
LED297-FIXT	LED297 W	Non-Integrated Ballast LED, 297W, any bulb shape, any application	297W LED - Non-Int. Ballast	Electronic	N/A	N/A	297	15
LED298-FIXT	LED298 W	Non-Integrated Ballast LED, 298W, any bulb shape, any application	298W LED - Non-Int. Ballast	Electronic	N/A	N/A	298	15
LED299-FIXT	LED299 W	Non-Integrated Ballast LED, 299W, any bulb shape, any application	299W LED - Non-Int. Ballast	Electronic	N/A	N/A	299	15
LED300-FIXT	LED300 W	Non-Integrated Ballast LED, 300W, any bulb shape, any application	300W LED - Non-Int. Ballast	Electronic	N/A	N/A	300	15
LED301-FIXT	LED301 W	Non-Integrated Ballast LED, 301W, any bulb shape, any application	301W LED - Non-Int. Ballast	Electronic	N/A	N/A	301	15
LED302-FIXT	LED302 W	Non-Integrated Ballast LED, 302W, any bulb shape, any application	302W LED - Non-Int. Ballast	Electronic	N/A	N/A	302	15
LED303-FIXT	LED303 W	Non-Integrated Ballast LED, 303W, any bulb shape, any application	303W LED - Non-Int. Ballast	Electronic	N/A	N/A	303	15
LED304-FIXT	LED304 W	Non-Integrated Ballast LED, 304W, any bulb shape, any application	304W LED - Non-Int. Ballast	Electronic	N/A	N/A	304	15
LED305-FIXT	LED305 W	Non-Integrated Ballast LED, 305W, any bulb shape, any application	305W LED - Non-Int. Ballast	Electronic	N/A	N/A	305	15
LED306-FIXT	LED306 W	Non-Integrated Ballast LED, 306W, any bulb shape, any application	306W LED - Non-Int. Ballast	Electronic	N/A	N/A	306	15
LED307-FIXT	LED307 W	Non-Integrated Ballast LED, 307W, any bulb shape, any application	307W LED - Non-Int. Ballast	Electronic	N/A	N/A	307	15
LED308-FIXT	LED308 W	Non-Integrated Ballast LED, 308W, any bulb shape, any application	308W LED - Non-Int. Ballast	Electronic	N/A	N/A	308	15
LED309-FIXT	LED309 W	Non-Integrated Ballast LED, 309W, any bulb shape, any application	309W LED - Non-Int. Ballast	Electronic	N/A	N/A	309	15
LED310-FIXT	LED310 W	Non-Integrated Ballast LED, 310W, any bulb shape, any application	310W LED - Non-Int. Ballast	Electronic	N/A	N/A	310	15
LED311-FIXT	LED311 W	Non-Integrated Ballast LED, 311W, any bulb shape, any application	311W LED - Non-Int. Ballast	Electronic	N/A	N/A	311	15
LED312-FIXT	LED312 W	Non-Integrated Ballast LED, 312W, any bulb shape, any application	312W LED - Non-Int. Ballast	Electronic	N/A	N/A	312	15
LED313-FIXT	LED313 W	Non-Integrated Ballast LED, 313W, any bulb shape, any application	313W LED - Non-Int. Ballast	Electronic	N/A	N/A	313	15
LED314-FIXT	LED314 W	Non-Integrated Ballast LED, 314W, any bulb shape, any application	314W LED - Non-Int. Ballast	Electronic	N/A	N/A	314	15
LED315-FIXT	LED315 W	Non-Integrated Ballast LED, 315W, any bulb shape, any application	315W LED - Non-Int. Ballast	Electronic	N/A	N/A	315	15
LED316-FIXT	LED316 W	Non-Integrated Ballast LED, 316W, any bulb shape, any application	316W LED - Non-Int. Ballast	Electronic	N/A	N/A	316	15
LED317-FIXT	LED317 W	Non-Integrated Ballast LED, 317W, any bulb shape, any application	317W LED - Non-Int. Ballast	Electronic	N/A	N/A	317	15
LED318-FIXT	LED318 W	Non-Integrated Ballast LED, 318W, any bulb shape, any application	318W LED - Non-Int. Ballast	Electronic	N/A	N/A	318	15
LED319-FIXT	LED319 W	Non-Integrated Ballast LED, 319W, any bulb shape, any application	319W LED - Non-Int. Ballast	Electronic	N/A	N/A	319	15
LED320-FIXT	LED320 W	Non-Integrated Ballast LED, 320W, any bulb shape, any application	320W LED - Non-Int. Ballast	Electronic	N/A	N/A	320	15
LED321-FIXT	LED321 W	Non-Integrated Ballast LED, 321W, any bulb shape, any application	321W LED - Non-Int. Ballast	Electronic	N/A	N/A	321	15
LED322-FIXT	LED322 W	Non-Integrated Ballast LED, 322W, any bulb shape, any application	322W LED - Non-Int. Ballast	Electronic	N/A	N/A	322	15
LED323-FIXT	LED323 W	Non-Integrated Ballast LED, 323W, any bulb shape, any application	323W LED - Non-Int. Ballast	Electronic	N/A	N/A	323	15
LED324-FIXT	LED324 W	Non-Integrated Ballast LED, 324W, any bulb shape, any application	324W LED - Non-Int. Ballast	Electronic	N/A	N/A	324	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED325-FIXT	LED325 W	Non-Integrated Ballast LED, 325W, any bulb shape, any application	325W LED - Non-Int. Ballast	Electronic	N/A	N/A	325	15
LED326-FIXT	LED326 W	Non-Integrated Ballast LED, 326W, any bulb shape, any application	326W LED - Non-Int. Ballast	Electronic	N/A	N/A	326	15
LED327-FIXT	LED327 W	Non-Integrated Ballast LED, 327W, any bulb shape, any application	327W LED - Non-Int. Ballast	Electronic	N/A	N/A	327	15
LED328-FIXT	LED328 W	Non-Integrated Ballast LED, 328W, any bulb shape, any application	328W LED - Non-Int. Ballast	Electronic	N/A	N/A	328	15
LED329-FIXT	LED329 W	Non-Integrated Ballast LED, 329W, any bulb shape, any application	329W LED - Non-Int. Ballast	Electronic	N/A	N/A	329	15
LED330-FIXT	LED330 W	Non-Integrated Ballast LED, 330W, any bulb shape, any application	330W LED - Non-Int. Ballast	Electronic	N/A	N/A	330	15
LED331-FIXT	LED331 W	Non-Integrated Ballast LED, 331W, any bulb shape, any application	331W LED - Non-Int. Ballast	Electronic	N/A	N/A	331	15
LED332-FIXT	LED332 W	Non-Integrated Ballast LED, 332W, any bulb shape, any application	332W LED - Non-Int. Ballast	Electronic	N/A	N/A	332	15
LED333-FIXT	LED333 W	Non-Integrated Ballast LED, 333W, any bulb shape, any application	333W LED - Non-Int. Ballast	Electronic	N/A	N/A	333	15
LED334-FIXT	LED334 W	Non-Integrated Ballast LED, 334W, any bulb shape, any application	334W LED - Non-Int. Ballast	Electronic	N/A	N/A	334	15
LED335-FIXT	LED335 W	Non-Integrated Ballast LED, 335W, any bulb shape, any application	335W LED - Non-Int. Ballast	Electronic	N/A	N/A	335	15
LED336-FIXT	LED336 W	Non-Integrated Ballast LED, 336W, any bulb shape, any application	336W LED - Non-Int. Ballast	Electronic	N/A	N/A	336	15
LED337-FIXT	LED337 W	Non-Integrated Ballast LED, 337W, any bulb shape, any application	337W LED - Non-Int. Ballast	Electronic	N/A	N/A	337	15
LED338-FIXT	LED338 W	Non-Integrated Ballast LED, 338W, any bulb shape, any application	338W LED - Non-Int. Ballast	Electronic	N/A	N/A	338	15
LED339-FIXT	LED339 W	Non-Integrated Ballast LED, 339W, any bulb shape, any application	339W LED - Non-Int. Ballast	Electronic	N/A	N/A	339	15
LED340-FIXT	LED340 W	Non-Integrated Ballast LED, 340W, any bulb shape, any application	340W LED - Non-Int. Ballast	Electronic	N/A	N/A	340	15
LED341-FIXT	LED341 W	Non-Integrated Ballast LED, 341W, any bulb shape, any application	341W LED - Non-Int. Ballast	Electronic	N/A	N/A	341	15
LED342-FIXT	LED342 W	Non-Integrated Ballast LED, 342W, any bulb shape, any application	342W LED - Non-Int. Ballast	Electronic	N/A	N/A	342	15
LED343-FIXT	LED343 W	Non-Integrated Ballast LED, 343W, any bulb shape, any application	343W LED - Non-Int. Ballast	Electronic	N/A	N/A	343	15
LED344-FIXT	LED344 W	Non-Integrated Ballast LED, 344W, any bulb shape, any application	344W LED - Non-Int. Ballast	Electronic	N/A	N/A	344	15
LED345-FIXT	LED345 W	Non-Integrated Ballast LED, 345W, any bulb shape, any application	345W LED - Non-Int. Ballast	Electronic	N/A	N/A	345	15
LED346-FIXT	LED346 W	Non-Integrated Ballast LED, 346W, any bulb shape, any application	346W LED - Non-Int. Ballast	Electronic	N/A	N/A	346	15
LED347-FIXT	LED347 W	Non-Integrated Ballast LED, 347W, any bulb shape, any application	347W LED - Non-Int. Ballast	Electronic	N/A	N/A	347	15
LED348-FIXT	LED348 W	Non-Integrated Ballast LED, 348W, any bulb shape, any application	348W LED - Non-Int. Ballast	Electronic	N/A	N/A	348	15
LED349-FIXT	LED349 W	Non-Integrated Ballast LED, 349W, any bulb shape, any application	349W LED - Non-Int. Ballast	Electronic	N/A	N/A	349	15
LED350-FIXT	LED350 W	Non-Integrated Ballast LED, 350W, any bulb shape, any application	350W LED - Non-Int. Ballast	Electronic	N/A	N/A	350	15
LED351-FIXT	LED351 W	Non-Integrated Ballast LED, 351W, any bulb shape, any application	351W LED - Non-Int. Ballast	Electronic	N/A	N/A	351	15
LED352-FIXT	LED352 W	Non-Integrated Ballast LED, 352W, any bulb shape, any application	352W LED - Non-Int. Ballast	Electronic	N/A	N/A	352	15
LED353-FIXT	LED353 W	Non-Integrated Ballast LED, 353W, any bulb shape, any application	353W LED - Non-Int. Ballast	Electronic	N/A	N/A	353	15
LED354-FIXT	LED354 W	Non-Integrated Ballast LED, 354W, any bulb shape, any application	354W LED - Non-Int. Ballast	Electronic	N/A	N/A	354	15
LED355-FIXT	LED355 W	Non-Integrated Ballast LED, 355W, any bulb shape, any application	355W LED - Non-Int. Ballast	Electronic	N/A	N/A	355	15
LED356-FIXT	LED356 W	Non-Integrated Ballast LED, 356W, any bulb shape, any application	356W LED - Non-Int. Ballast	Electronic	N/A	N/A	356	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED357-FIXT	LED357 W	Non-Integrated Ballast LED, 357W, any bulb shape, any application	357W LED - Non-Int. Ballast	Electronic	N/A	N/A	357	15
LED358-FIXT	LED358 W	Non-Integrated Ballast LED, 358W, any bulb shape, any application	358W LED - Non-Int. Ballast	Electronic	N/A	N/A	358	15
LED359-FIXT	LED359 W	Non-Integrated Ballast LED, 359W, any bulb shape, any application	359W LED - Non-Int. Ballast	Electronic	N/A	N/A	359	15
LED360-FIXT	LED360 W	Non-Integrated Ballast LED, 360W, any bulb shape, any application	360W LED - Non-Int. Ballast	Electronic	N/A	N/A	360	15
LED361-FIXT	LED361 W	Non-Integrated Ballast LED, 361W, any bulb shape, any application	361W LED - Non-Int. Ballast	Electronic	N/A	N/A	361	15
LED362-FIXT	LED362 W	Non-Integrated Ballast LED, 362W, any bulb shape, any application	362W LED - Non-Int. Ballast	Electronic	N/A	N/A	362	15
LED363-FIXT	LED363 W	Non-Integrated Ballast LED, 363W, any bulb shape, any application	363W LED - Non-Int. Ballast	Electronic	N/A	N/A	363	15
LED364-FIXT	LED364 W	Non-Integrated Ballast LED, 364W, any bulb shape, any application	364W LED - Non-Int. Ballast	Electronic	N/A	N/A	364	15
LED365-FIXT	LED365 W	Non-Integrated Ballast LED, 365W, any bulb shape, any application	365W LED - Non-Int. Ballast	Electronic	N/A	N/A	365	15
LED366-FIXT	LED366 W	Non-Integrated Ballast LED, 366W, any bulb shape, any application	366W LED - Non-Int. Ballast	Electronic	N/A	N/A	366	15
LED367-FIXT	LED367 W	Non-Integrated Ballast LED, 367W, any bulb shape, any application	367W LED - Non-Int. Ballast	Electronic	N/A	N/A	367	15
LED368-FIXT	LED368 W	Non-Integrated Ballast LED, 368W, any bulb shape, any application	368W LED - Non-Int. Ballast	Electronic	N/A	N/A	368	15
LED369-FIXT	LED369 W	Non-Integrated Ballast LED, 369W, any bulb shape, any application	369W LED - Non-Int. Ballast	Electronic	N/A	N/A	369	15
LED370-FIXT	LED370 W	Non-Integrated Ballast LED, 370W, any bulb shape, any application	370W LED - Non-Int. Ballast	Electronic	N/A	N/A	370	15
LED371-FIXT	LED371 W	Non-Integrated Ballast LED, 371W, any bulb shape, any application	371W LED - Non-Int. Ballast	Electronic	N/A	N/A	371	15
LED372-FIXT	LED372 W	Non-Integrated Ballast LED, 372W, any bulb shape, any application	372W LED - Non-Int. Ballast	Electronic	N/A	N/A	372	15
LED373-FIXT	LED373 W	Non-Integrated Ballast LED, 373W, any bulb shape, any application	373W LED - Non-Int. Ballast	Electronic	N/A	N/A	373	15
LED374-FIXT	LED374 W	Non-Integrated Ballast LED, 374W, any bulb shape, any application	374W LED - Non-Int. Ballast	Electronic	N/A	N/A	374	15
LED375-FIXT	LED375 W	Non-Integrated Ballast LED, 375W, any bulb shape, any application	375W LED - Non-Int. Ballast	Electronic	N/A	N/A	375	15
LED376-FIXT	LED376 W	Non-Integrated Ballast LED, 376W, any bulb shape, any application	376W LED - Non-Int. Ballast	Electronic	N/A	N/A	376	15
LED377-FIXT	LED377 W	Non-Integrated Ballast LED, 377W, any bulb shape, any application	377W LED - Non-Int. Ballast	Electronic	N/A	N/A	377	15
LED378-FIXT	LED378 W	Non-Integrated Ballast LED, 378W, any bulb shape, any application	378W LED - Non-Int. Ballast	Electronic	N/A	N/A	378	15
LED379-FIXT	LED379 W	Non-Integrated Ballast LED, 379W, any bulb shape, any application	379W LED - Non-Int. Ballast	Electronic	N/A	N/A	379	15
LED380-FIXT	LED380 W	Non-Integrated Ballast LED, 380W, any bulb shape, any application	380W LED - Non-Int. Ballast	Electronic	N/A	N/A	380	15
LED381-FIXT	LED381 W	Non-Integrated Ballast LED, 381W, any bulb shape, any application	381W LED - Non-Int. Ballast	Electronic	N/A	N/A	381	15
LED382-FIXT	LED382 W	Non-Integrated Ballast LED, 382W, any bulb shape, any application	382W LED - Non-Int. Ballast	Electronic	N/A	N/A	382	15
LED383-FIXT	LED383 W	Non-Integrated Ballast LED, 383W, any bulb shape, any application	383W LED - Non-Int. Ballast	Electronic	N/A	N/A	383	15
LED384-FIXT	LED384 W	Non-Integrated Ballast LED, 384W, any bulb shape, any application	384W LED - Non-Int. Ballast	Electronic	N/A	N/A	384	15
LED385-FIXT	LED385 W	Non-Integrated Ballast LED, 385W, any bulb shape, any application	385W LED - Non-Int. Ballast	Electronic	N/A	N/A	385	15
LED386-FIXT	LED386 W	Non-Integrated Ballast LED, 386W, any bulb shape, any application	386W LED - Non-Int. Ballast	Electronic	N/A	N/A	386	15
LED387-FIXT	LED387 W	Non-Integrated Ballast LED, 387W, any bulb shape, any application	387W LED - Non-Int. Ballast	Electronic	N/A	N/A	387	15
LED388-FIXT	LED388 W	Non-Integrated Ballast LED, 388W, any bulb shape, any application	388W LED - Non-Int. Ballast	Electronic	N/A	N/A	388	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED389-FIXT	LED389 W	Non-Integrated Ballast LED, 389W, any bulb shape, any application	389W LED - Non-Int. Ballast	Electronic	N/A	N/A	389	15
LED390-FIXT	LED390 W	Non-Integrated Ballast LED, 390W, any bulb shape, any application	390W LED - Non-Int. Ballast	Electronic	N/A	N/A	390	15
LED391-FIXT	LED391 W	Non-Integrated Ballast LED, 391W, any bulb shape, any application	391W LED - Non-Int. Ballast	Electronic	N/A	N/A	391	15
LED392-FIXT	LED392 W	Non-Integrated Ballast LED, 392W, any bulb shape, any application	392W LED - Non-Int. Ballast	Electronic	N/A	N/A	392	15
LED393-FIXT	LED393 W	Non-Integrated Ballast LED, 393W, any bulb shape, any application	393W LED - Non-Int. Ballast	Electronic	N/A	N/A	393	15
LED394-FIXT	LED394 W	Non-Integrated Ballast LED, 394W, any bulb shape, any application	394W LED - Non-Int. Ballast	Electronic	N/A	N/A	394	15
LED395-FIXT	LED395 W	Non-Integrated Ballast LED, 395W, any bulb shape, any application	395W LED - Non-Int. Ballast	Electronic	N/A	N/A	395	15
LED396-FIXT	LED396 W	Non-Integrated Ballast LED, 396W, any bulb shape, any application	396W LED - Non-Int. Ballast	Electronic	N/A	N/A	396	15
LED397-FIXT	LED397 W	Non-Integrated Ballast LED, 397W, any bulb shape, any application	397W LED - Non-Int. Ballast	Electronic	N/A	N/A	397	15
LED398-FIXT	LED398 W	Non-Integrated Ballast LED, 398W, any bulb shape, any application	398W LED - Non-Int. Ballast	Electronic	N/A	N/A	398	15
LED399-FIXT	LED399 W	Non-Integrated Ballast LED, 399W, any bulb shape, any application	399W LED - Non-Int. Ballast	Electronic	N/A	N/A	399	15
LED400-FIXT	LED400 W	Non-Integrated Ballast LED, 400W, any bulb shape, any application	400W LED - Non-Int. Ballast	Electronic	N/A	N/A	400	15
LED401-FIXT	LED401 W	Non-Integrated Ballast LED, 401W, any bulb shape, any application	401W LED - Non-Int. Ballast	Electronic	N/A	N/A	401	15
LED402-FIXT	LED402 W	Non-Integrated Ballast LED, 402W, any bulb shape, any application	402W LED - Non-Int. Ballast	Electronic	N/A	N/A	402	15
LED403-FIXT	LED403 W	Non-Integrated Ballast LED, 403W, any bulb shape, any application	403W LED - Non-Int. Ballast	Electronic	N/A	N/A	403	15
LED404-FIXT	LED404 W	Non-Integrated Ballast LED, 404W, any bulb shape, any application	404W LED - Non-Int. Ballast	Electronic	N/A	N/A	404	15
LED405-FIXT	LED405 W	Non-Integrated Ballast LED, 405W, any bulb shape, any application	405W LED - Non-Int. Ballast	Electronic	N/A	N/A	405	15
LED406-FIXT	LED406 W	Non-Integrated Ballast LED, 406W, any bulb shape, any application	406W LED - Non-Int. Ballast	Electronic	N/A	N/A	406	15
LED407-FIXT	LED407 W	Non-Integrated Ballast LED, 407W, any bulb shape, any application	407W LED - Non-Int. Ballast	Electronic	N/A	N/A	407	15
LED408-FIXT	LED408 W	Non-Integrated Ballast LED, 408W, any bulb shape, any application	408W LED - Non-Int. Ballast	Electronic	N/A	N/A	408	15
LED409-FIXT	LED409 W	Non-Integrated Ballast LED, 409W, any bulb shape, any application	409W LED - Non-Int. Ballast	Electronic	N/A	N/A	409	15
LED410-FIXT	LED410 W	Non-Integrated Ballast LED, 410W, any bulb shape, any application	410W LED - Non-Int. Ballast	Electronic	N/A	N/A	410	15
LED411-FIXT	LED411 W	Non-Integrated Ballast LED, 411W, any bulb shape, any application	411W LED - Non-Int. Ballast	Electronic	N/A	N/A	411	15
LED412-FIXT	LED412 W	Non-Integrated Ballast LED, 412W, any bulb shape, any application	412W LED - Non-Int. Ballast	Electronic	N/A	N/A	412	15
LED413-FIXT	LED413 W	Non-Integrated Ballast LED, 413W, any bulb shape, any application	413W LED - Non-Int. Ballast	Electronic	N/A	N/A	413	15
LED414-FIXT	LED414 W	Non-Integrated Ballast LED, 414W, any bulb shape, any application	414W LED - Non-Int. Ballast	Electronic	N/A	N/A	414	15
LED415-FIXT	LED415 W	Non-Integrated Ballast LED, 415W, any bulb shape, any application	415W LED - Non-Int. Ballast	Electronic	N/A	N/A	415	15
LED416-FIXT	LED416 W	Non-Integrated Ballast LED, 416W, any bulb shape, any application	416W LED - Non-Int. Ballast	Electronic	N/A	N/A	416	15
LED417-FIXT	LED417 W	Non-Integrated Ballast LED, 417W, any bulb shape, any application	417W LED - Non-Int. Ballast	Electronic	N/A	N/A	417	15
LED418-FIXT	LED418 W	Non-Integrated Ballast LED, 418W, any bulb shape, any application	418W LED - Non-Int. Ballast	Electronic	N/A	N/A	418	15
LED419-FIXT	LED419 W	Non-Integrated Ballast LED, 419W, any bulb shape, any application	419W LED - Non-Int. Ballast	Electronic	N/A	N/A	419	15
LED420-FIXT	LED420 W	Non-Integrated Ballast LED, 420W, any bulb shape, any application	420W LED - Non-Int. Ballast	Electronic	N/A	N/A	420	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED421-FIXT	LED421W	Non-Integrated Ballast LED, 421W, any bulb shape, any application	421W LED - Non-Int. Ballast	Electronic	N/A	N/A	421	15
LED422-FIXT	LED422W	Non-Integrated Ballast LED, 422W, any bulb shape, any application	422W LED - Non-Int. Ballast	Electronic	N/A	N/A	422	15
LED423-FIXT	LED423W	Non-Integrated Ballast LED, 423W, any bulb shape, any application	423W LED - Non-Int. Ballast	Electronic	N/A	N/A	423	15
LED424-FIXT	LED424W	Non-Integrated Ballast LED, 424W, any bulb shape, any application	424W LED - Non-Int. Ballast	Electronic	N/A	N/A	424	15
LED425-FIXT	LED425W	Non-Integrated Ballast LED, 425W, any bulb shape, any application	425W LED - Non-Int. Ballast	Electronic	N/A	N/A	425	15
LED426-FIXT	LED426W	Non-Integrated Ballast LED, 426W, any bulb shape, any application	426W LED - Non-Int. Ballast	Electronic	N/A	N/A	426	15
LED427-FIXT	LED427W	Non-Integrated Ballast LED, 427W, any bulb shape, any application	427W LED - Non-Int. Ballast	Electronic	N/A	N/A	427	15
LED428-FIXT	LED428W	Non-Integrated Ballast LED, 428W, any bulb shape, any application	428W LED - Non-Int. Ballast	Electronic	N/A	N/A	428	15
LED429-FIXT	LED429W	Non-Integrated Ballast LED, 429W, any bulb shape, any application	429W LED - Non-Int. Ballast	Electronic	N/A	N/A	429	15
LED430-FIXT	LED430W	Non-Integrated Ballast LED, 430W, any bulb shape, any application	430W LED - Non-Int. Ballast	Electronic	N/A	N/A	430	15
LED431-FIXT	LED431W	Non-Integrated Ballast LED, 431W, any bulb shape, any application	431W LED - Non-Int. Ballast	Electronic	N/A	N/A	431	15
LED432-FIXT	LED432W	Non-Integrated Ballast LED, 432W, any bulb shape, any application	432W LED - Non-Int. Ballast	Electronic	N/A	N/A	432	15
LED433-FIXT	LED433W	Non-Integrated Ballast LED, 433W, any bulb shape, any application	433W LED - Non-Int. Ballast	Electronic	N/A	N/A	433	15
LED434-FIXT	LED434W	Non-Integrated Ballast LED, 434W, any bulb shape, any application	434W LED - Non-Int. Ballast	Electronic	N/A	N/A	434	15
LED435-FIXT	LED435W	Non-Integrated Ballast LED, 435W, any bulb shape, any application	435W LED - Non-Int. Ballast	Electronic	N/A	N/A	435	15
LED436-FIXT	LED436W	Non-Integrated Ballast LED, 436W, any bulb shape, any application	436W LED - Non-Int. Ballast	Electronic	N/A	N/A	436	15
LED437-FIXT	LED437W	Non-Integrated Ballast LED, 437W, any bulb shape, any application	437W LED - Non-Int. Ballast	Electronic	N/A	N/A	437	15
LED438-FIXT	LED438W	Non-Integrated Ballast LED, 438W, any bulb shape, any application	438W LED - Non-Int. Ballast	Electronic	N/A	N/A	438	15
LED439-FIXT	LED439W	Non-Integrated Ballast LED, 439W, any bulb shape, any application	439W LED - Non-Int. Ballast	Electronic	N/A	N/A	439	15
LED440-FIXT	LED440W	Non-Integrated Ballast LED, 440W, any bulb shape, any application	440W LED - Non-Int. Ballast	Electronic	N/A	N/A	440	15
LED441-FIXT	LED441W	Non-Integrated Ballast LED, 441W, any bulb shape, any application	441W LED - Non-Int. Ballast	Electronic	N/A	N/A	441	15
LED442-FIXT	LED442W	Non-Integrated Ballast LED, 442W, any bulb shape, any application	442W LED - Non-Int. Ballast	Electronic	N/A	N/A	442	15
LED443-FIXT	LED443W	Non-Integrated Ballast LED, 443W, any bulb shape, any application	443W LED - Non-Int. Ballast	Electronic	N/A	N/A	443	15
LED444-FIXT	LED444W	Non-Integrated Ballast LED, 444W, any bulb shape, any application	444W LED - Non-Int. Ballast	Electronic	N/A	N/A	444	15
LED445-FIXT	LED445W	Non-Integrated Ballast LED, 445W, any bulb shape, any application	445W LED - Non-Int. Ballast	Electronic	N/A	N/A	445	15
LED446-FIXT	LED446W	Non-Integrated Ballast LED, 446W, any bulb shape, any application	446W LED - Non-Int. Ballast	Electronic	N/A	N/A	446	15
LED447-FIXT	LED447W	Non-Integrated Ballast LED, 447W, any bulb shape, any application	447W LED - Non-Int. Ballast	Electronic	N/A	N/A	447	15
LED448-FIXT	LED448W	Non-Integrated Ballast LED, 448W, any bulb shape, any application	448W LED - Non-Int. Ballast	Electronic	N/A	N/A	448	15
LED449-FIXT	LED449W	Non-Integrated Ballast LED, 449W, any bulb shape, any application	449W LED - Non-Int. Ballast	Electronic	N/A	N/A	449	15
LED450-FIXT	LED450W	Non-Integrated Ballast LED, 450W, any bulb shape, any application	450W LED - Non-Int. Ballast	Electronic	N/A	N/A	450	15
LED451-FIXT	LED451W	Non-Integrated Ballast LED, 451W, any bulb shape, any application	451W LED - Non-Int. Ballast	Electronic	N/A	N/A	451	15
LED452-FIXT	LED452W	Non-Integrated Ballast LED, 452W, any bulb shape, any application	452W LED - Non-Int. Ballast	Electronic	N/A	N/A	452	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED453-FIXT	LED453W	Non-Integrated Ballast LED, 453W, any bulb shape, any application	453W LED - Non-Int. Ballast	Electronic	N/A	N/A	453	15
LED454-FIXT	LED454W	Non-Integrated Ballast LED, 454W, any bulb shape, any application	454W LED - Non-Int. Ballast	Electronic	N/A	N/A	454	15
LED455-FIXT	LED455W	Non-Integrated Ballast LED, 455W, any bulb shape, any application	455W LED - Non-Int. Ballast	Electronic	N/A	N/A	455	15
LED456-FIXT	LED456W	Non-Integrated Ballast LED, 456W, any bulb shape, any application	456W LED - Non-Int. Ballast	Electronic	N/A	N/A	456	15
LED457-FIXT	LED457W	Non-Integrated Ballast LED, 457W, any bulb shape, any application	457W LED - Non-Int. Ballast	Electronic	N/A	N/A	457	15
LED458-FIXT	LED458W	Non-Integrated Ballast LED, 458W, any bulb shape, any application	458W LED - Non-Int. Ballast	Electronic	N/A	N/A	458	15
LED459-FIXT	LED459W	Non-Integrated Ballast LED, 459W, any bulb shape, any application	459W LED - Non-Int. Ballast	Electronic	N/A	N/A	459	15
LED460-FIXT	LED460W	Non-Integrated Ballast LED, 460W, any bulb shape, any application	460W LED - Non-Int. Ballast	Electronic	N/A	N/A	460	15
LED461-FIXT	LED461W	Non-Integrated Ballast LED, 461W, any bulb shape, any application	461W LED - Non-Int. Ballast	Electronic	N/A	N/A	461	15
LED462-FIXT	LED462W	Non-Integrated Ballast LED, 462W, any bulb shape, any application	462W LED - Non-Int. Ballast	Electronic	N/A	N/A	462	15
LED463-FIXT	LED463W	Non-Integrated Ballast LED, 463W, any bulb shape, any application	463W LED - Non-Int. Ballast	Electronic	N/A	N/A	463	15
LED464-FIXT	LED464W	Non-Integrated Ballast LED, 464W, any bulb shape, any application	464W LED - Non-Int. Ballast	Electronic	N/A	N/A	464	15
LED465-FIXT	LED465W	Non-Integrated Ballast LED, 465W, any bulb shape, any application	465W LED - Non-Int. Ballast	Electronic	N/A	N/A	465	15
LED466-FIXT	LED466W	Non-Integrated Ballast LED, 466W, any bulb shape, any application	466W LED - Non-Int. Ballast	Electronic	N/A	N/A	466	15
LED467-FIXT	LED467W	Non-Integrated Ballast LED, 467W, any bulb shape, any application	467W LED - Non-Int. Ballast	Electronic	N/A	N/A	467	15
LED468-FIXT	LED468W	Non-Integrated Ballast LED, 468W, any bulb shape, any application	468W LED - Non-Int. Ballast	Electronic	N/A	N/A	468	15
LED469-FIXT	LED469W	Non-Integrated Ballast LED, 469W, any bulb shape, any application	469W LED - Non-Int. Ballast	Electronic	N/A	N/A	469	15
LED470-FIXT	LED470W	Non-Integrated Ballast LED, 470W, any bulb shape, any application	470W LED - Non-Int. Ballast	Electronic	N/A	N/A	470	15
LED471-FIXT	LED471W	Non-Integrated Ballast LED, 471W, any bulb shape, any application	471W LED - Non-Int. Ballast	Electronic	N/A	N/A	471	15
LED472-FIXT	LED472W	Non-Integrated Ballast LED, 472W, any bulb shape, any application	472W LED - Non-Int. Ballast	Electronic	N/A	N/A	472	15
LED473-FIXT	LED473W	Non-Integrated Ballast LED, 473W, any bulb shape, any application	473W LED - Non-Int. Ballast	Electronic	N/A	N/A	473	15
LED474-FIXT	LED474W	Non-Integrated Ballast LED, 474W, any bulb shape, any application	474W LED - Non-Int. Ballast	Electronic	N/A	N/A	474	15
LED475-FIXT	LED475W	Non-Integrated Ballast LED, 475W, any bulb shape, any application	475W LED - Non-Int. Ballast	Electronic	N/A	N/A	475	15
LED476-FIXT	LED476W	Non-Integrated Ballast LED, 476W, any bulb shape, any application	476W LED - Non-Int. Ballast	Electronic	N/A	N/A	476	15
LED477-FIXT	LED477W	Non-Integrated Ballast LED, 477W, any bulb shape, any application	477W LED - Non-Int. Ballast	Electronic	N/A	N/A	477	15
LED478-FIXT	LED478W	Non-Integrated Ballast LED, 478W, any bulb shape, any application	478W LED - Non-Int. Ballast	Electronic	N/A	N/A	478	15
LED479-FIXT	LED479W	Non-Integrated Ballast LED, 479W, any bulb shape, any application	479W LED - Non-Int. Ballast	Electronic	N/A	N/A	479	15
LED480-FIXT	LED480W	Non-Integrated Ballast LED, 480W, any bulb shape, any application	480W LED - Non-Int. Ballast	Electronic	N/A	N/A	480	15
LED481-FIXT	LED481W	Non-Integrated Ballast LED, 481W, any bulb shape, any application	481W LED - Non-Int. Ballast	Electronic	N/A	N/A	481	15
LED482-FIXT	LED482W	Non-Integrated Ballast LED, 482W, any bulb shape, any application	482W LED - Non-Int. Ballast	Electronic	N/A	N/A	482	15
LED483-FIXT	LED483W	Non-Integrated Ballast LED, 483W, any bulb shape, any application	483W LED - Non-Int. Ballast	Electronic	N/A	N/A	483	15
LED484-FIXT	LED484W	Non-Integrated Ballast LED, 484W, any bulb shape, any application	484W LED - Non-Int. Ballast	Electronic	N/A	N/A	484	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
LED485-FIXT	LED485W	Non-Integrated Ballast LED, 485W, any bulb shape, any application	485W LED - Non-Int. Ballast	Electronic	N/A	N/A	485	15
LED486-FIXT	LED486W	Non-Integrated Ballast LED, 486W, any bulb shape, any application	486W LED - Non-Int. Ballast	Electronic	N/A	N/A	486	15
LED487-FIXT	LED487W	Non-Integrated Ballast LED, 487W, any bulb shape, any application	487W LED - Non-Int. Ballast	Electronic	N/A	N/A	487	15
LED488-FIXT	LED488W	Non-Integrated Ballast LED, 488W, any bulb shape, any application	488W LED - Non-Int. Ballast	Electronic	N/A	N/A	488	15
LED489-FIXT	LED489W	Non-Integrated Ballast LED, 489W, any bulb shape, any application	489W LED - Non-Int. Ballast	Electronic	N/A	N/A	489	15
LED490-FIXT	LED490W	Non-Integrated Ballast LED, 490W, any bulb shape, any application	490W LED - Non-Int. Ballast	Electronic	N/A	N/A	490	15
LED491-FIXT	LED491W	Non-Integrated Ballast LED, 491W, any bulb shape, any application	491W LED - Non-Int. Ballast	Electronic	N/A	N/A	491	15
LED492-FIXT	LED492W	Non-Integrated Ballast LED, 492W, any bulb shape, any application	492W LED - Non-Int. Ballast	Electronic	N/A	N/A	492	15
LED493-FIXT	LED493W	Non-Integrated Ballast LED, 493W, any bulb shape, any application	493W LED - Non-Int. Ballast	Electronic	N/A	N/A	493	15
LED494-FIXT	LED494W	Non-Integrated Ballast LED, 494W, any bulb shape, any application	494W LED - Non-Int. Ballast	Electronic	N/A	N/A	494	15
LED495-FIXT	LED495W	Non-Integrated Ballast LED, 495W, any bulb shape, any application	495W LED - Non-Int. Ballast	Electronic	N/A	N/A	495	15
LED496-FIXT	LED496W	Non-Integrated Ballast LED, 496W, any bulb shape, any application	496W LED - Non-Int. Ballast	Electronic	N/A	N/A	496	15
LED497-FIXT	LED497W	Non-Integrated Ballast LED, 497W, any bulb shape, any application	497W LED - Non-Int. Ballast	Electronic	N/A	N/A	497	15
LED498-FIXT	LED498W	Non-Integrated Ballast LED, 498W, any bulb shape, any application	498W LED - Non-Int. Ballast	Electronic	N/A	N/A	498	15
LED499-FIXT	LED499W	Non-Integrated Ballast LED, 499W, any bulb shape, any application	499W LED - Non-Int. Ballast	Electronic	N/A	N/A	499	15
LED500-FIXT	LED500W	Non-Integrated Ballast LED, 500W, any bulb shape, any application	500W LED - Non-Int. Ballast	Electronic	N/A	N/A	500	15
LED505-FIXT	LED505W	Non-Integrated Ballast LED, 505W, any bulb shape, any application	505W LED - Non-Int. Ballast	Electronic	N/A	N/A	505	15
LED510-FIXT	LED510W	Non-Integrated Ballast LED, 510W, any bulb shape, any application	510W LED - Non-Int. Ballast	Electronic	N/A	N/A	510	15
LED515-FIXT	LED515W	Non-Integrated Ballast LED, 515W, any bulb shape, any application	515W LED - Non-Int. Ballast	Electronic	N/A	N/A	515	15
LED520-FIXT	LED520W	Non-Integrated Ballast LED, 520W, any bulb shape, any application	520W LED - Non-Int. Ballast	Electronic	N/A	N/A	520	15
LED525-FIXT	LED525W	Non-Integrated Ballast LED, 525W, any bulb shape, any application	525W LED - Non-Int. Ballast	Electronic	N/A	N/A	525	15
LED530-FIXT	LED530W	Non-Integrated Ballast LED, 530W, any bulb shape, any application	530W LED - Non-Int. Ballast	Electronic	N/A	N/A	530	15
LED535-FIXT	LED535W	Non-Integrated Ballast LED, 535W, any bulb shape, any application	535W LED - Non-Int. Ballast	Electronic	N/A	N/A	535	15
LED540-FIXT	LED540W	Non-Integrated Ballast LED, 540W, any bulb shape, any application	540W LED - Non-Int. Ballast	Electronic	N/A	N/A	540	15
LED545-FIXT	LED545W	Non-Integrated Ballast LED, 545W, any bulb shape, any application	545W LED - Non-Int. Ballast	Electronic	N/A	N/A	545	15
LED550-FIXT	LED550W	Non-Integrated Ballast LED, 550W, any bulb shape, any application	550W LED - Non-Int. Ballast	Electronic	N/A	N/A	550	15
Compact Fluorescent Fixtures								
CF2/1-SCRW	CF2W	Compact Fluorescent, (1) 2W screw-in lamp/base w/ permanent disk installed, any bulb shape	2W CFL	Mag. or Elec.	1	2	2	N/A
CF3/1-SCRW	CF3W	Compact Fluorescent, (1) 3W screw-in lamp/base w/ permanent disk installed, any bulb shape	3W CFL	Mag. or Elec.	1	3	3	N/A
CF4/1-SCRW	CF4W	Compact Fluorescent, (1) 4W screw-in lamp/base w/ permanent disk installed, any bulb shape	4W CFL	Mag. or Elec.	1	4	4	N/A

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
CF5/1-SCRW	CF5W	Compact Fluorescent, (1) 5W screw-in lamp/base w/ permanent disk installed, any bulb shape	5W CFL	Mag. or Elec.	1	5	5	N/A
CF6/1-SCRW	CF6W	Compact Fluorescent, (1) 6W screw-in lamp/base w/ permanent disk installed, any bulb shape	6W CFL	Mag. or Elec.	1	6	6	N/A
CF7/1-SCRW	CF7W	Compact Fluorescent, (1) 7W screw-in lamp/base w/ permanent disk installed, any bulb shape	7W CFL	Mag. or Elec.	1	7	7	N/A
CF8/1-SCRW	CF8W	Compact Fluorescent, (1) 8W screw-in lamp/base w/ permanent disk installed, any bulb shape	8W CFL	Mag. or Elec.	1	8	8	N/A
CF9/1-SCRW	CF9W	Compact Fluorescent, (1) 9W screw-in lamp/base w/ permanent disk installed, any bulb shape	9W CFL	Mag. or Elec.	1	9	9	N/A
CF10/1-SCRW	CF10W	Compact Fluorescent, (1) 10W screw-in lamp/base w/ permanent disk installed, any bulb shape	10W CFL	Mag. or Elec.	1	10	10	N/A
CF11/1-SCRW	CF11W	Compact Fluorescent, (1) 11W screw-in lamp/base w/ permanent disk installed, any bulb shape	11W CFL	Mag. or Elec.	1	11	11	N/A
CF12/1-SCRW	CF12W	Compact Fluorescent, (1) 12W screw-in lamp/base w/ permanent disk installed, any bulb shape	12W CFL	Mag. or Elec.	1	12	12	N/A
CF13/1-SCRW	CF13W	Compact Fluorescent, (1) 13W screw-in lamp/base w/ permanent disk installed, any bulb shape	13W CFL	Mag. or Elec.	1	13	13	N/A
CF14/1-SCRW	CF14W	Compact Fluorescent, (1) 14W screw-in lamp/base w/ permanent disk installed, any bulb shape	14W CFL	Mag. or Elec.	1	14	14	N/A
CF15/1-SCRW	CF15W	Compact Fluorescent, (1) 15W screw-in lamp/base w/ permanent disk installed, any bulb shape	15W CFL	Mag. or Elec.	1	15	15	N/A
CF16/1-SCRW	CF16W	Compact Fluorescent, (1) 16W screw-in lamp/base w/ permanent disk installed, any bulb shape	16W CFL	Mag. or Elec.	1	16	16	N/A
CF17/1-SCRW	CF17W	Compact Fluorescent, (1) 17W screw-in lamp/base w/ permanent disk installed, any bulb shape	17W CFL	Mag. or Elec.	1	17	17	N/A
CF18/1-SCRW	CF18W	Compact Fluorescent, (1) 18W screw-in lamp/base w/ permanent disk installed, any bulb shape	18W CFL	Mag. or Elec.	1	18	18	N/A
CF19/1-SCRW	CF19W	Compact Fluorescent, (1) 19W screw-in lamp/base w/ permanent disk installed, any bulb shape	19W CFL	Mag. or Elec.	1	19	19	N/A
CF20/1-SCRW	CF20W	Compact Fluorescent, (1) 20W screw-in lamp/base w/ permanent disk installed, any bulb shape	20W CFL	Mag. or Elec.	1	20	20	N/A
CF21/1-SCRW	CF21W	Compact Fluorescent, (1) 21W screw-in lamp/base w/ permanent disk installed, any bulb shape	21W CFL	Mag. or Elec.	1	21	21	N/A
CF22/1-SCRW	CF22W	Compact Fluorescent, (1) 22W screw-in lamp/base w/ permanent disk installed, any bulb shape	22W CFL	Mag. or Elec.	1	22	22	N/A
CF23/1-SCRW	CF23W	Compact Fluorescent, (1) 23W screw-in lamp/base w/ permanent disk installed, any bulb shape	23W CFL	Mag. or Elec.	1	23	23	N/A
CF24/1-SCRW	CF24W	Compact Fluorescent, (1) 24W screw-in lamp/base w/ permanent disk installed, any bulb shape	24W CFL	Mag. or Elec.	1	24	24	N/A
CF25/1-SCRW	CF25W	Compact Fluorescent, (1) 25W screw-in lamp/base w/ permanent disk installed, any bulb shape	25W CFL	Mag. or Elec.	1	25	25	N/A

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
CF26/1-SCRW	CF26W	Compact Fluorescent, (1) 26W screw-in lamp/base w/ permanent disk installed, any bulb shape	26W CFL	Mag. or Elec.	1	26	26	N/A
CF27/1-SCRW	CF27W	Compact Fluorescent, (1) 27W screw-in lamp/base w/ permanent disk installed, any bulb shape	27W CFL	Mag. or Elec.	1	27	27	N/A
CF28/1-SCRW	CF28W	Compact Fluorescent, (1) 28W screw-in lamp/base w/ permanent disk installed, any bulb shape	28W CFL	Mag. or Elec.	1	28	28	N/A
CF29/1-SCRW	CF29W	Compact Fluorescent, (1) 29W screw-in lamp/base w/ permanent disk installed, any bulb shape	29W CFL	Mag. or Elec.	1	29	29	N/A
CF30/1-SCRW	CF30W	Compact Fluorescent, (1) 30W screw-in lamp/base w/ permanent disk installed, any bulb shape	30W CFL	Mag. or Elec.	1	30	30	N/A
CF31/1-SCRW	CF31W	Compact Fluorescent, (1) 31W screw-in lamp/base w/ permanent disk installed, any bulb shape	31W CFL	Mag. or Elec.	1	31	31	N/A
CF32/1-SCRW	CF32W	Compact Fluorescent, (1) 32W screw-in lamp/base w/ permanent disk installed, any bulb shape	32W CFL	Mag. or Elec.	1	32	32	N/A
CF33/1-SCRW	CF33W	Compact Fluorescent, (1) 33W screw-in lamp/base w/ permanent disk installed, any bulb shape	33W CFL	Mag. or Elec.	1	33	33	N/A
CF34/1-SCRW	CF34W	Compact Fluorescent, (1) 34W screw-in lamp/base w/ permanent disk installed, any bulb shape	34W CFL	Mag. or Elec.	1	34	34	N/A
CF35/1-SCRW	CF35W	Compact Fluorescent, (1) 35W screw-in lamp/base w/ permanent disk installed, any bulb shape	35W CFL	Mag. or Elec.	1	35	35	N/A
CF36/1-SCRW	CF36W	Compact Fluorescent, (1) 36W screw-in lamp/base w/ permanent disk installed, any bulb shape	36W CFL	Mag. or Elec.	1	36	36	N/A
CF37/1-SCRW	CF37W	Compact Fluorescent, (1) 37W screw-in lamp/base w/ permanent disk installed, any bulb shape	37W CFL	Mag. or Elec.	1	37	37	N/A
CF38/1-SCRW	CF38W	Compact Fluorescent, (1) 38W screw-in lamp/base w/ permanent disk installed, any bulb shape	38W CFL	Mag. or Elec.	1	38	38	N/A
CF39/1-SCRW	CF39W	Compact Fluorescent, (1) 39W screw-in lamp/base w/ permanent disk installed, any bulb shape	39W CFL	Mag. or Elec.	1	39	39	N/A
CF40/1-SCRW	CF40W	Compact Fluorescent, (1) 40W screw-in lamp/base w/ permanent disk installed, any bulb shape	40W CFL	Mag. or Elec.	1	40	40	N/A
CF41/1-SCRW	CF41W	Compact Fluorescent, (1) 41W screw-in lamp/base w/ permanent disk installed, any bulb shape	41W CFL	Mag. or Elec.	1	41	41	N/A
CF42/1-SCRW	CF42W	Compact Fluorescent, (1) 42W screw-in lamp/base w/ permanent disk installed, any bulb shape	42W CFL	Mag. or Elec.	1	42	42	N/A
CF43/1-SCRW	CF43W	Compact Fluorescent, (1) 43W screw-in lamp/base w/ permanent disk installed, any bulb shape	43W CFL	Mag. or Elec.	1	43	43	N/A
CF44/1-SCRW	CF44W	Compact Fluorescent, (1) 44W screw-in lamp/base w/permanent disk installed, any bulb shape	44W CFL	Mag. or Elec.	1	44	44	N/A
CF45/1-SCRW	CF45W	Compact Fluorescent, (1) 45W screw-in lamp/base w/permanent disk installed, any bulb shape	45W CFL	Mag. or Elec.	1	45	45	N/A
CF46/1-SCRW	CF46W	Compact Fluorescent, (1) 46W screw-in lamp/base w/permanent disk installed, any bulb shape	46W CFL	Mag. or Elec.	1	46	46	N/A

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
CF47/1-SCRW	CF47W	Compact Fluorescent, (1) 47W screw-in lamp/base w/permanent disk installed, any bulb shape	47W CFL	Mag. or Elec.	1	47	47	N/A
CF48/1-SCRW	CF48W	Compact Fluorescent, (1) 48W screw-in lamp/base w/permanent disk installed, any bulb shape	48W CFL	Mag. or Elec.	1	48	48	N/A
CF49/1-SCRW	CF49W	Compact Fluorescent, (1) 49W screw-in lamp/base w/permanent disk installed, any bulb shape	49W CFL	Mag. or Elec.	1	49	49	N/A
CF50/1-SCRW	CF50W	Compact Fluorescent, (1) 50W screw-in lamp/base w/permanent disk installed, any bulb shape	50W CFL	Mag. or Elec.	1	50	50	N/A
CF51/1-SCRW	CF51W	Compact Fluorescent, (1) 51W screw-in lamp/base w/permanent disk installed, any bulb shape	51W CFL	Mag. or Elec.	1	51	51	N/A
CF52/1-SCRW	CF52W	Compact Fluorescent, (1) 52W screw-in lamp/base w/permanent disk installed, any bulb shape	52W CFL	Mag. or Elec.	1	52	52	N/A
CF53/1-SCRW	CF53W	Compact Fluorescent, (1) 53W screw-in lamp/base w/permanent disk installed, any bulb shape	53W CFL	Mag. or Elec.	1	53	53	N/A
CF54/1-SCRW	CF54W	Compact Fluorescent, (1) 54W screw-in lamp/base w/permanent disk installed, any bulb shape	54W CFL	Mag. or Elec.	1	54	54	N/A
CF55/1-SCRW	CF55W	Compact Fluorescent, (1) 55W screw-in lamp/base w/permanent disk installed, any bulb shape	55W CFL	Mag. or Elec.	1	55	55	N/A
CF56/1-SCRW	CF56W	Compact Fluorescent, (1) 56W screw-in lamp/base w/permanent disk installed, any bulb shape	56W CFL	Mag. or Elec.	1	56	56	N/A
CF57/1-SCRW	CF57W	Compact Fluorescent, (1) 57W screw-in lamp/base w/permanent disk installed, any bulb shape	57W CFL	Mag. or Elec.	1	57	57	N/A
CF58/1-SCRW	CF58W	Compact Fluorescent, (1) 58W screw-in lamp/base w/permanent disk installed, any bulb shape	58W CFL	Mag. or Elec.	1	58	58	N/A
CF59/1-SCRW	CF59W	Compact Fluorescent, (1) 59W screw-in lamp/base w/permanent disk installed, any bulb shape	59W CFL	Mag. or Elec.	1	59	59	N/A
CF60/1-SCRW	CF60W	Compact Fluorescent, (1) 60W screw-in lamp/base w/permanent disk installed, any bulb shape	60W CFL	Mag. or Elec.	1	60	60	N/A
CF61/1-SCRW	CF61W	Compact Fluorescent, (1) 61W screw-in lamp/base w/permanent disk installed, any bulb shape	61W CFL	Mag. or Elec.	1	61	61	N/A
CF62/1-SCRW	CF62W	Compact Fluorescent, (1) 62W screw-in lamp/base w/permanent disk installed, any bulb shape	62W CFL	Mag. or Elec.	1	62	62	N/A
CF63/1-SCRW	CF63W	Compact Fluorescent, (1) 63W screw-in lamp/base w/permanent disk installed, any bulb shape	63W CFL	Mag. or Elec.	1	63	63	N/A
CF64/1-SCRW	CF64W	Compact Fluorescent, (1) 64W screw-in lamp/base w/permanent disk installed, any bulb shape	64W CFL	Mag. or Elec.	1	64	64	N/A
CF65/1-SCRW	CF65W	Compact Fluorescent, (1) 65W screw-in lamp/base w/permanent disk installed, any bulb shape	65W CFL	Mag. or Elec.	1	65	65	N/A
CF66/1-SCRW	CF66W	Compact Fluorescent, (1) 66W screw-in lamp/base w/permanent disk installed, any bulb shape	66W CFL	Mag. or Elec.	1	66	66	N/A
CF67/1-SCRW	CF67W	Compact Fluorescent, (1) 67W screw-in lamp/base w/permanent disk installed, any bulb shape	67W CFL	Mag. or Elec.	1	67	67	N/A

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
CF68/1-SCRW	CF68W	Compact Fluorescent, (1) 68W screw-in lamp/base w/permanent disk installed, any bulb shape	68W CFL	Mag. or Elec.	1	68	68	N/A
CF69/1-SCRW	CF69W	Compact Fluorescent, (1) 69W screw-in lamp/base w/permanent disk installed, any bulb shape	69W CFL	Mag. or Elec.	1	69	69	N/A
CF70/1-SCRW	CF70W	Compact Fluorescent, (1) 70W screw-in lamp/base w/permanent disk installed, any bulb shape	70W CFL	Mag. or Elec.	1	70	70	N/A
CF71/1-SCRW	CF71W	Compact Fluorescent, (1) 71W screw-in lamp/base w/permanent disk installed, any bulb shape	71W CFL	Mag. or Elec.	1	71	71	N/A
CF72/1-SCRW	CF72W	Compact Fluorescent, (1) 72W screw-in lamp/base w/permanent disk installed, any bulb shape	72W CFL	Mag. or Elec.	1	72	72	N/A
CF73/1-SCRW	CF73W	Compact Fluorescent, (1) 73W screw-in lamp/base w/permanent disk installed, any bulb shape	73W CFL	Mag. or Elec.	1	73	73	N/A
CF74/1-SCRW	CF74W	Compact Fluorescent, (1) 74W screw-in lamp/base w/permanent disk installed, any bulb shape	74W CFL	Mag. or Elec.	1	74	74	N/A
CF75/1-SCRW	CF75W	Compact Fluorescent, (1) 75W screw-in lamp/base w/permanent disk installed, any bulb shape	75W CFL	Mag. or Elec.	1	75	75	N/A
CF80/1-SCRW	CF80W	Compact Fluorescent, (1) 80W screw-in lamp/base w/permanent disk installed, any bulb shape	80W CFL	Mag. or Elec.	1	80	80	N/A
CF85/1-SCRW	CF85W	Compact Fluorescent, (1) 85W screw-in lamp/base w/permanent disk installed, any bulb shape	85W CFL	Mag. or Elec.	1	85	85	N/A
CF100/1-SCRW	CF100W	Compact Fluorescent, (1) 100W screw-in lamp/base w/ permanent disk installed, any bulb shape	100W CFL	Mag. or Elec.	1	100	100	N/A
CF125/1-SCRW	CF125W	Compact Fluorescent, (1) 125W screw-in lamp/base w/ permanent disk installed, any bulb shape	125W CFL	Mag. or Elec.	1	125	125	N/A
CF150/1-SCRW	CF150W	Compact Fluorescent, (1) 150W screw-in lamp/base w/ permanent disk installed, any bulb shape	150W CFL	Mag. or Elec.	1	150	150	N/A
CF200/1-SCRW	CF200W	Compact Fluorescent, (1) 200W screw-in lamp/base w/ permanent disk installed, any bulb shape	200W CFL	Mag. or Elec.	1	200	200	N/A
CFC2/1-SCRW	CFC2W	Compact Fluorescent, Cold Cathode, (1) 2W screw-in lamp/base w/ permanent locking device, any bulb shape	2W Cold Cathode	Electronic	1	2	2	N/A
CFC2/2-SCRW	CFC2W	Compact Fluorescent, Cold Cathode, (2) 2W screw-in lamp/base w/ permanent locking device, any bulb shape	4W Cold Cathode	Electronic	2	2	4	N/A
CFC3/1-SCRW	CFC3W	Compact Fluorescent, Cold Cathode, (1) 3W screw-in lamp/base w/ permanent locking device, any bulb shape	3W Cold Cathode	Electronic	1	3	3	N/A
CFC3/2-SCRW	CFC3W	Compact Fluorescent, Cold Cathode, (2) 3W screw-in lamp/base w/ permanent locking device, any bulb shape	6W Cold Cathode	Electronic	2	3	6	N/A
CFC4/1-SCRW	CFC4W	Compact Fluorescent, Cold Cathode, (1) 4W screw-in lamp/base w/ permanent locking device, any bulb shape	4W Cold Cathode	Electronic	1	4	4	N/A
CFC4/2-SCRW	CFC4W	Compact Fluorescent, Cold Cathode, (2) 4W screw-in lamp/base w/ permanent locking device, any bulb shape	8W Cold Cathode	Electronic	2	4	8	N/A
CFC5/1-SCRW	CFC5W	Compact Fluorescent, Cold Cathode, (1) 5W screw-in lamp/base w/ permanent locking device, any bulb shape	5W Cold Cathode	Electronic	1	5	5	N/A

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
CFC5/2-SCRW	CFC5W	Compact Fluorescent, Cold Cathode, (2) 5W screw-in lamp/base w/ permanent locking device, any bulb shape	10W Cold Cathode	Electronic	2	5	10	N/A
CFC8/1-SCRW	CFC8W	Compact Fluorescent, Cold Cathode, (1) 8W screw-in lamp/base w/ permanent locking device, any bulb shape	8W Cold Cathode	Electronic	1	8	8	N/A
CFC8/2-SCRW	CFC8W	Compact Fluorescent, Cold Cathode, (2) 8W screw-in lamp/base w/ permanent locking device, any bulb shape	16W Cold Cathode	Electronic	2	8	16	N/A
CFC13/1-SCRW	CFC13W	Compact Fluorescent, Cold Cathode, (1) 13W screw-in lamp/base w/ permanent locking device, any bulb shape	13W Cold Cathode	Electronic	1	13	13	N/A
CFC18/1-SCRW	CFC18W	Compact Fluorescent, Cold Cathode, (1) 18W screw-in lamp/base w/ permanent locking device, any bulb shape	18W Cold Cathode	Electronic	1	18	18	N/A
CFD10/1	CFD10W	Compact Fluorescent, 2D, (1) 10W lamp	1-Lamp 10W CFL 2D	Mag-STD	1	10	16	N/A
CFD10/1-L	CFD10W	Compact Fluorescent, 2D, (1) 10W lamp	1-Lamp 10W CFL 2D	Electronic	1	10	14	N/A
CFD16/1	CFD16W	Compact Fluorescent, 2D, (1) 16W lamp	1-Lamp 16W CFL 2D	Mag-STD	1	16	26	N/A
CFD16/1-L	CFD16W	Compact Fluorescent, 2D, (1) 16W lamp	1-Lamp 16W CFL 2D	Electronic	1	16	18	N/A
CFD21/1	CFD21W	Compact Fluorescent, 2D, (1) 21W lamp	1-Lamp 21W CFL 2D	Mag-STD	1	21	26	N/A
CFD21/1-L	CFD21W	Compact Fluorescent, 2D, (1) 21W lamp	1-Lamp 21W CFL 2D	Electronic	1	21	22	N/A
CFD28/1	CFD28W	Compact Fluorescent, 2D, (1) 28W lamp	1-Lamp 28W CFL 2D	Mag-STD	1	28	35	N/A
CFD28/1-L	CFD28W	Compact Fluorescent, 2D, (1) 28W lamp	1-Lamp 28W CFL 2D	Electronic	1	28	29	N/A
CFD38/1	CFD38W	Compact Fluorescent, 2D, (1) 38W lamp	1-Lamp 38W CFL 2D	Mag-STD	1	38	46	N/A
CFD38/1-L	CFD38W	Compact Fluorescent, 2D, (1) 38W lamp	1-Lamp 38W CFL 2D	Electronic	1	38	32	N/A
CFG13/1-L	CFG13W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 13W lamp	1-Lamp 13W CFL Multi	Electronic	1	13	13	N/A
CFG18/1-L	CFG18W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 18W lamp	1-Lamp 18W CFL Multi	Electronic	1	18	18	N/A
CFG23/1-L	CFG23W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 23W lamp	1-Lamp 23W CFL Multi	Electronic	1	23	23	N/A
CFG26/1-L	CFG26W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 26W lamp	1-Lamp 26W CFL Multi	Electronic	1	26	26	N/A
CFG32/1-L	CFG32W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 32W lamp	1-Lamp 32W CFL Multi	Electronic	1	32	32	N/A
CFG42/1-L	CFG42W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 42W lamp	1-Lamp 42W CFL Multi	Electronic	1	42	42	N/A
CFM13/1-L	CFM13 W	Compact Fluorescent, Multi, 4-pin, (1) 13W lamp	1-Lamp 13W CFL Multi 4-Pin	Electronic	1	13	16	N/A
CFM13/2-L	CFM13 W	Compact Fluorescent, Multi, 4-pin, (2) 13W lamps	2-Lamp 13W CFL Multi 4-Pin	Electronic	2	13	30	N/A
CFM15/1-L	CFM15 W	Compact Fluorescent, Multi, 4-pin, (1) 15W lamp	1-Lamp 15W CFL Multi 4-Pin	Electronic	1	15	18	N/A
CFM18/1-L	CFM18 W	Compact Fluorescent, Multi, 4-pin, (1) 18W lamp	1-Lamp 18W CFL Multi 4-Pin	Electronic	1	18	20	N/A
CFM18/2-L	CFM18 W	Compact Fluorescent, Multi, 4-pin, (2) 18W lamps	2-Lamp 18W CFL Multi 4-Pin	Electronic	2	18	40	N/A
CFM21/1-L	CFM21 W	Compact Fluorescent, Multi, 4-pin, (1) 21W lamp	1-Lamp 21W CFL Multi 4-Pin	Electronic	1	21	23	N/A
CFM26/1-L	CFM26 W	Compact Fluorescent, Multi, 4-pin, (1) 26W lamp	1-Lamp 26W CFL Multi 4-Pin	Electronic	1	26	29	N/A

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
CFM26/2-L	CFM26W	Compact Fluorescent, Multi, 4-pin, (2) 26W lamps	2-Lamp 26W CFL Multi 4-Pin	Electronic	2	26	51	N/A
CFM28/1-L	CFM28W	Compact Fluorescent, Multi, 4-pin, (1) 28W lamp	1-Lamp 28W CFL Multi 4-Pin	Electronic	1	28	31	N/A
CFM32/1-L	CFM32W	Compact Fluorescent, Multi, 4-pin, (1) 32W lamp	1-Lamp 32W CFL Multi 4-Pin	Electronic	1	32	35	N/A
CFM42/1-L	CFM42W	Compact Fluorescent, Multi, 4-pin, (1) 42W lamp	1-Lamp 42W CFL Multi 4-Pin	Electronic	1	42	46	N/A
CFM42/2-L	CFM42W	Compact Fluorescent, Multi, 4-pin, (2) 42W lamps	2-Lamp 42W CFL Multi 4-Pin	Electronic	2	42	93	N/A
CFM42/8-L	CFM42W	Compact Fluorescent, Multi, 4-pin, (8) 42W lamps, (4) 2-lamp ballasts	8-Lamp 42W CFL Multi 4-Pin	Electronic	8	42	372	N/A
CFM57/1-L	CFM57W	Compact Fluorescent, Multi, 4-pin, (1) 57W lamp	1-Lamp 57W CFL Multi 4-Pin	Electronic	1	57	59	N/A
CFM60/1-L	CFM60W	Compact Fluorescent, Multi, 4-pin, (1) 60W lamp	1-Lamp 60W CFL Multi 4-Pin	Electronic	1	60	70	N/A
CFM70/1-L	CFM70W	Compact Fluorescent, Multi, 4-pin, (1) 70W lamp	1-Lamp 70W CFL Multi 4-Pin	Electronic	1	70	73	N/A
CFM85/1-L	CFM85W	Compact Fluorescent, Multi, 4-pin, (1) 85W lamp	1-Lamp 85W CFL Multi 4-Pin	Electronic	1	85	96	N/A
CFM120/1-L	CFM120W	Compact Fluorescent, Multi, 4-pin, (1) 120W lamp	1-Lamp 120W CFL Multi 4-Pin	Electronic	1	120	135	N/A
CFQ9/1	CFQ9W	Compact Fluorescent, Quad, (1) 9W lamp	1-Lamp 9W CFL Quad	Mag-STD	1	9	14	N/A
CFQ9/2	CFQ9W	Compact Fluorescent, Quad, (2) 9W lamps	2-Lamp 9W CFL Quad	Mag-STD	2	9	23	N/A
CFQ10/1	CFQ10W	Compact Fluorescent, quad, (1) 10W lamp	1-Lamp 10W CFL Quad	Mag-STD	1	10	15	N/A
CFQ13/1	CFQ13W	Compact Fluorescent, quad, (1) 13W lamp	1-Lamp 13W CFL Quad	Mag-STD	1	13	17	N/A
CFQ13/1-L	CFQ13W	Compact Fluorescent, quad, (1) 13W lamp, BF=1.05	1-Lamp 13W CFL Quad	Electronic	1	13	15	N/A
CFQ13/2	CFQ13W	Compact Fluorescent, quad, (2) 13W lamps	2-Lamp 13W CFL Quad	Mag-STD	2	13	31	N/A
CFQ13/2-L	CFQ13W	Compact Fluorescent, quad, (2) 13W lamps, BF=1.0	2-Lamp 13W CFL Quad	Electronic	2	13	28	N/A
CFQ13/3	CFQ13W	Compact Fluorescent, quad, (3) 13W lamps	3-Lamp 13W CFL Quad	Mag-STD	3	13	48	N/A
CFQ15/1	CFQ15W	Compact Fluorescent, quad, (1) 15W lamp	1-Lamp 15W CFL Quad	Mag-STD	1	15	20	N/A
CFQ17/1	CFQ17W	Compact Fluorescent, quad, (1) 17W lamp	1-Lamp 17W CFL Quad	Mag-STD	1	17	24	N/A
CFQ17/2	CFQ17W	Compact Fluorescent, quad, (2) 17W lamps	2-Lamp 17W CFL Quad	Mag-STD	2	17	48	N/A
CFQ18/1	CFQ18W	Compact Fluorescent, quad, (1) 18W lamp	1-Lamp 18W CFL Quad	Mag-STD	1	18	26	N/A
CFQ18/1-L	CFQ18W	Compact Fluorescent, quad, (1) 18W lamp, BF=1.0	1-Lamp 18W CFL Quad	Electronic	1	18	20	N/A
CFQ18/2	CFQ18W	Compact Fluorescent, quad, (2) 18W lamps	2-Lamp 18W CFL Quad	Mag-STD	2	18	45	N/A
CFQ18/2-L	CFQ18W	Compact Fluorescent, quad, (2) 18W lamp, BF=1.0	2-Lamp 18W CFL Quad	Electronic	2	18	38	N/A
CFQ18/4	CFQ18W	Compact Fluorescent, quad, (4) 18W lamps	4-Lamp 18W CFL Quad	Mag-STD	2	18	90	N/A
CFQ20/1	CFQ20W	Compact Fluorescent, quad, (1) 20W lamp	1-Lamp 20W CFL Quad	Mag-STD	1	20	23	N/A
CFQ20/2	CFQ20W	Compact Fluorescent, quad, (2) 20W lamps	2-Lamp 20W CFL Quad	Mag-STD	2	20	46	N/A
CFQ22/1	CFQ22W	Compact Fluorescent, Quad, (1) 22W lamp	1-Lamp 22W CFL Quad	Mag-STD	1	22	24	N/A
CFQ22/2	CFQ22W	Compact Fluorescent, Quad, (2) 22W lamps	2-Lamp 22W CFL Quad	Mag-STD	2	22	48	N/A
CFQ22/3	CFQ22W	Compact Fluorescent, Quad, (3) 22W lamps	3-Lamp 22W CFL Quad	Mag-STD	3	22	72	N/A

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
CFQ23/1	CFQ23W	Compact Fluorescent, Quad, (1) 23W lamp	1-Lamp 23W CFL Quad	Mag-STD	1	23	27	N/A
CFQ25/1	CFQ25W	Compact Fluorescent, Quad, (1) 25W lamp	1-Lamp 25W CFL Quad	Mag-STD	1	25	33	N/A
CFQ25/2	CFQ25W	Compact Fluorescent, Quad, (2) 25W lamps	2-Lamp 25W CFL Quad	Mag-STD	2	25	66	N/A
CFQ26/1	CFQ26W	Compact Fluorescent, quad, (1) 26W lamp	1-Lamp 26W CFL Quad	Mag-STD	1	26	33	N/A
CFQ26/1-L	CFQ26W	Compact Fluorescent, quad, (1) 26W lamp, BF=0.95	1-Lamp 26W CFL Quad	Electronic	1	26	27	N/A
CFQ26/2	CFQ26W	Compact Fluorescent, quad, (2) 26W lamps	2-Lamp 26W CFL Quad	Mag-STD	2	26	66	N/A
CFQ26/2-L	CFQ26W	Compact Fluorescent, quad, (2) 26W lamps, BF=0.95	2-Lamp 26W CFL Quad	Electronic	2	26	50	N/A
CFQ26/3	CFQ26W	Compact Fluorescent, quad, (3) 26W lamps	3-Lamp 26W CFL Quad	Mag-STD	3	26	99	N/A
CFQ26/6-L	CFQ26W	Compact Fluorescent, quad, (6) 26W lamps, BF=0.95	6-Lamp 26W CFL Quad	Electronic	6	26	150	N/A
CFQ28/1	CFQ28W	Compact Fluorescent, quad, (1) 28W lamp	1-Lamp 28W CFL Quad	Mag-STD	1	28	33	N/A
CFQ28/1-L	CFQ28W	Compact Fluorescent, quad, (1) 28W lamp	1-Lamp 28W CFL Quad	Electronic	1	28	31	N/A
CFQ28/2-L	CFQ28W	Compact Fluorescent, quad, (2) 28W lamps	2-Lamp 28W CFL Quad	Electronic	2	28	60	N/A
CFT5/1	CFT5W	Compact Fluorescent, twin, (1) 5W lamp	1-Lamp 5W CFL Twin	Mag-STD	1	5	9	N/A
CFT5/2	CFT5W	Compact Fluorescent, long twin, (2) 5W lamps	2-Lamp 5W CFL Twin	Mag-STD	2	5	18	N/A
CFT7/1	CFT7W	Compact Fluorescent, twin, (1) 7W lamp	1-Lamp 7W CFL Twin	Mag-STD	1	7	10	N/A
CFT7/2	CFT7W	Compact Fluorescent, twin, (2) 7W lamps	2-Lamp 7W CFL Twin	Mag-STD	2	7	21	N/A
CFT9/1	CFT9W	Compact Fluorescent, twin, (1) 9W lamp	1-Lamp 9W CFL Twin	Mag-STD	1	9	12	N/A
CFT9/2	CFT9W	Compact Fluorescent, twin, (2) 9W lamps	2-Lamp 9W CFL Twin	Mag-STD	2	9	23	N/A
CFT9/3	CFT9W	Compact Fluorescent, twin, (3) 9 W lamps	3-Lamp 9W CFL Twin	Mag-STD	3	9	34	N/A
CFT13/1	CFT13W	Compact Fluorescent, twin, (1) 13W lamp	1-Lamp 13W CFL Twin	Mag-STD	1	13	17	N/A
CFT13/1-L	CFT13W	Compact Fluorescent, twin, (1) 13W lamp	1-Lamp 13W CFL Twin	Electronic	1	13	15	N/A
CFT13/2	CFT13W	Compact Fluorescent, twin, (2) 13W lamps	2-Lamp 13W CFL Twin	Mag-STD	2	13	31	N/A
CFT13/2-L	CFT13W	Compact Fluorescent, twin, (2) 13W lamps	2-Lamp 13W CFL Twin	Electronic	2	13	28	N/A
CFT13/3	CFT13W	Compact Fluorescent, twin, (3) 13 W lamps	3-Lamp 13W CFL Twin	Mag-STD	3	13	48	N/A
CFT18/1	CFT18W	Compact Fluorescent, Long twin., (1) 18W lamp	1-Lamp 18W CFL Twin	Mag-STD	1	18	24	N/A
CFT18/1-L	CFT18W	Compact Fluorescent, twin, (1) 18W lamp	1-Lamp 18W CFL Twin	Electronic	1	18	20	N/A
CFT18/2	CFT18W	Compact Fluorescent, twin, (2) 18 W lamps	2-Lamp 18W CFL Twin	Mag-STD	2	18	38	N/A
CFT22/1	CFT22W	Compact Fluorescent, twin, (1) 22W lamp	1-Lamp 22W CFL Twin	Mag-STD	1	22	27	N/A
CFT22/2	CFT22W	Compact Fluorescent, twin, (2) 22W lamps	2-Lamp 22W CFL Twin	Mag-STD	2	22	54	N/A
CFT22/4	CFT22W	Compact Fluorescent, twin, (4) 22W lamps	4-Lamp 22W CFL Twin	Mag-STD	4	22	108	N/A
CFT24/1	CFT24W	Compact Fluorescent, long twin, (1) 24W lamp	1-Lamp 24W CFL Twin	Mag-STD	1	24	32	N/A
CFT26/1	CFT26W	Compact Fluorescent, twin, (1) 26W lamp	1-Lamp 26W CFL Twin	Mag-STD	1	26	32	N/A

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
CFT26/1-L	CFT26W	Compact Fluorescent, twin, (1) 26W lamp	1-Lamp 26W CFL Twin	Electronic	1	26	27	N/A
CFT26/2-L	CFT26W	Compact Fluorescent, twin, (2) 26W lamps	2-Lamp 26W CFL Twin	Electronic	2	26	51	N/A
CFT28/1	CFT28W	Compact Fluorescent, twin, (1) 28W lamp	1-Lamp 28W CFL Twin	Mag-STD	1	28	33	N/A
CFT28/2	CFT28W	Compact Fluorescent, twin, (2) 28W lamps	2-Lamp 28W CFL Twin	Mag-STD	2	28	66	N/A
CFT32/1-L	CFT32W	Compact Fluorescent, twin, (1) 32W lamp	1-Lamp 32W CFL Twin	Electronic	1	32	34	N/A
CFT32/2-L	CFT32W	Compact Fluorescent, twin, (2) 32W lamps	2-Lamp 32W CFL Twin	Electronic	2	32	62	N/A
CFT32/6-L	CFT32W	Compact Fluorescent, twin, (6) 32W lamps	6-Lamp 32W CFL Twin	Electronic	6	32	186	N/A
CFT36/1	CFT36W	Compact Fluorescent, long twin, (1) 36W lamp	1-Lamp 36W CFL Long Twin	Mag-STD	1	36	51	N/A
CFT40/1	CFT40W	Compact Fluorescent, long twin, (1) 40W lamp	1-Lamp 40W CFL Long Twin	Mag-STD	1	40	46	N/A
CFT40/1-L	CFT40W	Compact Fluorescent, long twin, (1) 40W lamp	1-Lamp 40W CFL Long Twin	Electronic	1	40	43	N/A
CFT40/2	CFT40W	Compact Fluorescent, long twin, (2) 40W lamps	2-Lamp 40W CFL Long Twin	Mag-STD	2	40	85	N/A
CFT40/2-L	CFT40W	Compact Fluorescent, long twin, (2) 40W lamps	2-Lamp 40W CFL Long Twin	Electronic	2	40	72	N/A
CFT40/3	CFT40W	Compact Fluorescent, long twin, (3) 40 W lamps	3-Lamp 40W CFL Long Twin	Mag-STD	3	40	133	N/A
CFT40/3-L	CFT40W	Compact Fluorescent, long twin, (3) 40W lamps	3-Lamp 40W CFL Long Twin	Electronic	3	40	105	N/A
CFT40/5-L	CFT40W	Compact Fluorescent, long twin, (5) 40W lamps	5-Lamp 40W CFL Long Twin	Electronic	5	40	177	N/A
CFT50/1-L	CFT50W	Compact Fluorescent, long twin, (1) 50W lamp	1-Lamp 50W CFL Long Twin	Electronic	1	50	54	N/A
CFT50/2-L	CFT50W	Compact Fluorescent, long twin, (2) 50W lamps	1-Lamp 50W CFL Long Twin	Electronic	1	50	108	N/A
CFT55/1-L	CFT55W	Compact Fluorescent, long twin, (1) 55W lamp	1-Lamp 55W CFL Long Twin	Electronic	1	55	58	N/A
CFT55/2-L	CFT55W	Compact Fluorescent, long twin, (2) 55W lamps	2-Lamp 55W CFL Long Twin	Electronic	2	55	108	N/A
CFT55/3-L	CFT55W	Compact Fluorescent, long twin, (3) 55W lamps	3-Lamp 55W CFL Long Twin	Electronic	3	55	168	N/A
CFT55/4-L	CFT55W	Compact Fluorescent, long twin, (4) 55W lamps	4-Lamp 55W CFL Long Twin	Electronic	4	55	220	N/A
CFT80/1-L	CFT80W	Compact Fluorescent, long twin, (1) 80W lamp	1-Lamp 80W CFL Long Twin	Electronic	1	80	90	N/A
EXIT Sign Fixtures								
ECF5/1	CFT5W	EXIT Compact Fluorescent, (1) 5W lamp	1-Lamp 5W CFL Exit	Mag-STD	1	5	9	16
ECF5/2	CFT5W	EXIT Compact Fluorescent, (2) 5W lamps	2-Lamp 5W CFL Exit	Mag-STD	2	5	20	16
ECF6/1	CFT6W	EXIT Compact Fluorescent, (1) 6W lamp	1-Lamp 6W CFL Exit	Mag-STD	1	6	13	16
ECF6/2	CFT6W	EXIT Compact Fluorescent, (2) 6W lamps, (2) ballasts	2-Lamp 6W CFL Exit	Mag-STD	2	6	26	16
ECF7/1	CFT7W	EXIT Compact Fluorescent, (1) 7W lamp	1-Lamp 7W CFL Exit	Mag-STD	1	7	10	16
ECF7/2	CFT7W	EXIT Compact Fluorescent, (2) 7W lamps	2-Lamp 7W CFL Exit	Mag-STD	2	7	21	16
ECF9/1	CFT9W	EXIT Compact Fluorescent, (1) 9W lamp	1-Lamp 9W CFL Exit	Mag-STD	1	9	12	16
ECF9/2	CFT9W	EXIT Compact Fluorescent, (2) 9W lamps	2-Lamp 9W CFL Exit	Mag-STD	2	9	20	16
EF2/2	F2T1	EXIT Sub-miniature T-1 Fluorescent, (2) lamps	2-Lamp 2W T-1 Exit	Electronic	2	2	5	16

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
EF6/1	F6T5	EXIT Miniature Bi-pin Fluorescent, (1) 6W lamp, (1) ballast	1-Lamp 6W Bi-Pin Fluorescent Exit	Mag-STD	1	6	9	16
EF6/2	F6T5	EXIT Miniature Bi-pin Fluorescent, (2) 6W lamps, (2) ballasts	2-Lamp 6W Bi-Pin Fluorescent Exit	Mag-STD	2	6	18	16
EF8/1	F8T5	EXIT T5 Fluorescent, (1) 8W lamp	1-Lamp 8W T-5 Exit	Mag-STD	1	8	12	16
EF8/2	F8T5	EXIT T5 Fluorescent, (2) 8W lamps	2-Lamp 8W T-5 Exit	Mag-STD	2	8	24	16
EI5/1	I5	EXIT Incandescent, (1) 5W lamp	1-Lamp 5W incandescent Exit		1	5	5	1.5
EI5/2	I5	EXIT Incandescent, (2) 5W lamps	2-Lamp 5W incandescent Exit		2	5	10	1.5
EI7.5/1	I7.5	EXIT Tungsten, (1) 7.5 W lamp	1-Lamp 7.5W Tungsten Exit		1	7.5	8	1.5
EI7.5/2	I7.5	EXIT Tungsten, (2) 7.5 W lamps	2-Lamp 7.5W Tungsten Exit		2	7.5	15	1.5
EI10/2	I10	EXIT Incandescent, (2) 10W lamps	2-Lamp 10W incandescent Exit		2	10	20	1.5
EI15/1	I15	EXIT Incandescent, (1) 15W lamp	1-Lamp 15W incandescent Exit		1	15	15	1.5
EI15/2	I15	EXIT Incandescent, (2) 15W lamps	2-Lamp 15W incandescent Exit		2	15	30	1.5
EI20/1	I20	EXIT Incandescent, (1) 20W lamp	1-Lamp 20W incandescent Exit		1	20	20	1.5
EI20/2	I20	EXIT Incandescent, (2) 20W lamps	2-Lamp 20W incandescent Exit		2	20	40	1.5
EI25/1	I25	EXIT Incandescent, (1) 25W lamp	1-Lamp 25W incandescent Exit		1	25	25	1.5
EI25/2	I25	EXIT Incandescent, (2) 25W lamps	2-Lamp 25W incandescent Exit		2	25	50	1.5
EI34/1	I34	EXIT Incandescent, (1) 34W lamp	1-Lamp 34W incandescent Exit		1	34	34	1.5
EI34/2	I34	EXIT Incandescent, (2) 34W lamps	2-Lamp 34W incandescent Exit		2	34	68	1.5
EI40/1	I40	EXIT Incandescent, (1) 40W lamp	1-Lamp 40W incandescent Exit		1	40	40	1.5
EI40/2	I40	EXIT Incandescent, (2) 40W lamps	2-Lamp 40W incandescent Exit		2	40	80	1.5
EI50/2	I50	EXIT Incandescent, (2) 50W lamps	2-Lamp 50W incandescent Exit		2	50	100	1.5
EI6/1	6S6	EXIT Incandescent, (1) 6 W lamp	1-Lamp 6W incandescent Exit		1	6	6	1.5
EI6/2	6S6	EXIT Incandescent, (2) 6 W lamps	2-Lamp 6W incandescent Exit		2	6	12	1.5
ELED2/1	LED2W	EXIT Light Emitting Diode, (1) 2W lamp, Single Sided	1-Lamp 2W LED Exit		1	2	2	15

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
ELED2/2	LED2W	EXIT Light Emitting Diode, (2) 2W lamps, Dual Sided	2-Lamp 2W LED Exit		2	2	4	15
ELED3	LED3W	EXIT Light Emitting Diode, (1) 3W lamp, Single Sided	1-Lamp 3W LED Exit		1	3	3	15
EP	P0W	EXIT Photoluminescent, 0W	Photoluminescent Exit Sign		0	0	0	15
T5 Linear Fluorescent Systems								
F22PS	F13T5	Fluorescent, (2) 21", Preheat T5 lamps, (1) Magnetic ballasts with integral starter, (BF=0.80)	2' 2-Lamp T5	Mag-STD	2	13	26	15.5
F24PS	F13T5	Fluorescent, (4) 21", Preheat T5 lamps, (2) Magnetic ballasts with integral starter (BF=0.80)	2' 4-Lamp T5	Mag-STD	4	13	53	15.5
F21GPL-H	F14T5	Fluorescent (1) 22" (563mm) T-5 lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 1-Lamp T5	PRS Elec.	1	14	18	15.5
F22GPL-H	F14T5	Fluorescent (2) 22" (563mm) T-5 lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 2-Lamp T5	PRS Elec.	2	14	33	15.5
F23GPL-H	F14T5	Fluorescent (3) 22" (563mm)T-5 lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 3-Lamp T5	PRS Elec.	3	14	50	15.5
F23GPL/2-H	F14T5	Fluorescent (3) 22" (563mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 3-Lamp T5	PRS Elec.	3	14	51	15.5
F24GPL/2-H	F14T5	Fluorescent (4) 22" (563mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 4-Lamp T5	PRS Elec.	4	14	66	15.5
F31GPL-H	F21T5	Fluorescent (1) 34" (863mm) T-5 lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	3' 1-Lamp T5	PRS Elec.	1	21	25	15.5
F32GPL-H	F21T5	Fluorescent (2) 34" (863mm) T-5 lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	3' 2-Lamp T5	PRS Elec.	2	21	48	15.5
F33GPL/2-H	F21T5	Fluorescent (3) 34" (863mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	3' 3-Lamp T5	PRS Elec.	3	21	73	15.5
F34GPL/2-H	F21T5	Fluorescent (4) 34" (863mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	3' 4-Lamp T5	PRS Elec.	4	21	96	15.5
F21GPHL-H	F24T5/HO	Fluorescent (1) 22" (563mm) T-5 HO lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 1-Lamp T5HO	PRS Elec.	1	24	27	15.5
F22GPHL-H	F24T5/HO	Fluorescent (2) 22" (563mm) T-5 HO lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 2-Lamp T5HO	PRS Elec.	2	24	52	15.5
F23GPHL/2-H	F24T5/HO	Fluorescent (3) 22" (563mm)T-5 HO lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 3-Lamp T5HO	PRS Elec.	3	24	79	15.5
F24GPHL/2-H	F24T5/HO	Fluorescent (4) 22" (563mm)T-5 HO lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 4-Lamp T5HO	PRS Elec.	4	24	104	15.5
F26GPHL/3-H	F24T5/HO	Fluorescent (4) 22" (563mm) T-5 HO lamps; (3) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 6-Lamp T5HO	PRS Elec.	6	24	156	15.5
F41GPL-H	F28T5	Fluorescent (1) 45.8" (1163mm) T-5 lamp; (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 1-Lamp T5	PRS Elec.	1	28	33	15.5
F41GPL/T2-H	F28T5	Fluorescent (1) 45.8" (1163mm) T-5 lamp; Tandem 2-lamp PRS Ballast,HLO (.95 < BF < 1.1)	4' 1-Lamp T5	PRS Elec.	1	28	32	15.5
F42GPL-H	F28T5	Fluorescent (2) 45.8" (1163mm) T-5 lamps; (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 2-Lamp T5	PRS Elec.	2	28	63	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F43GPL/2-H	F28T5	Fluorescent (3) 45.8" (1163mm)T-5 lamps; (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 3-Lamp T5	PRS Elec.	3	28	96	15.5
F44GPL/2-H	F28T5	Fluorescent (4) 45.8" (1163mm)T-5 lamps; (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 4-Lamp T5	PRS Elec.	4	28	126	15.5
F51GPL-H	F35T5	Fluorescent (1) 57.6" (1463mm) T-5 lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	5' 1-Lamp T5	PRS Elec.	1	35	40	15.5
F52GPL-H	F35T5	Fluorescent (2) 57.6" (1463mm) T-5 lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	5' 2-Lamp T5	PRS Elec.	2	35	78	15.5
F53GPL/2-H	F35T5	Fluorescent (3) 57.6" (1463mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	5' 3-Lamp T5	PRS Elec.	3	35	118	15.5
F54GPL/2-H	F35T5	Fluorescent (4) 57.6" (1463mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	5' 4-Lamp T5	PRS Elec.	4	35	156	15.5
F31GPHL-H	F39T5/HO	Fluorescent (1) 34" (863mm) T-5 HO lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	3' 1-Lamp T5	PRS Elec.	1	39	44	15.5
F32GPHL-H	F39T5/HO	Fluorescent (2) 34" (863mm) T-5 HO lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	3' 2-Lamp T5	PRS Elec.	2	39	86	15.5
F33GPHL/2-H	F39T5/HO	Fluorescent (3) 34" (863mm)T-5 HO lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	3' 3-Lamp T5	PRS Elec.	3	39	130	15.5
F34GPHL/2-H	F39T5/HO	Fluorescent (4) 34" (863mm)T-5 HO lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	3' 4-Lamp T5	PRS Elec.	4	39	172	15.5
F46GPRL/2-H	F45T5/HO-RW	Fluorescent, (6) 45.8" T-5 HO reduced-wattage lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 6-Lamp T5HO	PRS Elec.	6	54	332	15.5
F46GPRL/3-H	F45T5/HO-RW	Fluorescent, (6) 45.8" T-5 HO reduced-wattage lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 6-Lamp T5HO	PRS Elec.	6	54	330	15.5
F41GPHL-H	F54T5/HO	Fluorescent (1) 45.8" T-5 HO lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 1-Lamp T5HO	PRS Elec.	1	54	64	15.5
F41GPHL/T2-H	F54T5/HO	Fluorescent (1) 45.8" T-5 HO lamp, Tandem 2-lamp PRS Ballast, HLO (.95 < BF < 1.1)	4' 1-Lamp T5HO	PRS Elec.	1	54	59	15.5
F42GPHL-H	F54T5/HO	Fluorescent (2) 45.8" T-5 HO lamps, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 2-Lamp T5HO	PRS Elec.	2	54	117	15.5
F43GPHL-H	F54T5/HO	Fluorescent, (3) 45.8" T-5 HO lamps, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 3-Lamp T5HO	PRS Elec.	3	54	181	15.5
F43GPHL/2-H	F54T5/HO	Fluorescent (3) 45.8" T-5 HO lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 3-Lamp T5HO	PRS Elec.	3	54	181	15.5
F44GPHL-H	F54T5/HO	Fluorescent, (4) 45.8" T-5 HO lamps, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 4-Lamp T5HO	PRS Elec.	4	54	230	15.5
F44GPHL/2-H	F54T5/HO	Fluorescent (4) 45.8" T-5 HO lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 4-Lamp T5HO	PRS Elec.	4	54	234	15.5
F45GPHL/2-H	F54T5/HO	Fluorescent (5) 45.8" T-5 HO lamps, (2) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 5-Lamp T5HO	PRS Elec.	5	54	298	15.5
F45GPRL/2-H	F54T5/HO-RW	Fluorescent (5) 45.2" T-5 HO reduced-wattage lamp, (2) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 5-Lamp T5HO	PRS Elec.	5	47-51	276	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F46GPHL/2-H	F54T5/HO	Fluorescent, (6) 45.8" T-5 HO lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 6-Lamp T5HO	PRS Elec.	6	54	362	15.5
F46GPHL/3-H	F54T5/HO	Fluorescent, (6) 45.8" T-5 HO lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 6-Lamp T5HO	PRS Elec.	6	54	351	15.5
F48GPHL/2-H	F54T5/HO	Fluorescent, (8) 45.8" T-5 HO lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 8-Lamp T5HO	PRS Elec.	8	54	460	15.5
F48GPHL/4-H	F54T5/HO	Fluorescent, (8) 45.8" T-5 HO lamps, (4) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 8-Lamp T5HO	PRS Elec.	8	54	468	15.5
F410GPHL/3-H	F54T5/HO	Fluorescent, (10) 45.8" T-5 HO lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 10L T5HO	PRS Elec.	10	54	577	15.5
F410GPHL/5-H	F54T5/HO	Fluorescent, (10) 45.8" T-5 HO lamps, (5) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 10L T5HO	PRS Elec.	10	54	585	15.5
F412GPHL/3-H	F54T5/HO	Fluorescent, (12) 45.8" T-5 HO lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 12 T5HO	PRS Elec.	12	54	690	15.5
F412GPHL/6-H	F54T5/HO	Fluorescent, (12) 45.8" T-5 HO lamps, (6) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 12-Lamp T5HO	PRS Elec.	12	54	702	15.5
F41GPRL-H	F54T5/HO-RW	Fluorescent (1) 45.2" T-5 HO reduced-wattage lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 1-Lamp T5HO	PRS Elec.	1	47-51	61	15.5
F42GPRL-H	F54T5/HO-RW	Fluorescent (2) 45.2" T-5 HO reduced-wattage lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 2-Lamp T5HO	PRS Elec.	2	47-51	110	15.5
F43GPRL-H	F54T5/HO-RW	Fluorescent (3) 45.2" T-5 HO reduced-wattage lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 3-Lamp T5HO	PRS Elec.	3	47-51	166	15.5
F44GPRL-H	F54T5/HO-RW	Fluorescent (4) 45.2" T-5 HO reduced-wattage lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 4-Lamp T5HO	PRS Elec.	4	47-51	211	15.5
F48GPRL/2-H	F54T5/HO-RW	Fluorescent, (8) 45.8" T-5 HO reduced-wattage lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 8-Lamp T5HO	PRS Elec.	8	50	428	15.5
F48GPRL/4-H	F54T5/HO-RW	Fluorescent, (8) 45.8" T-5 HO reduced-wattage lamps, (4) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 8-Lamp T5HO	PRS Elec.	8	50	436	15.5
F410GPRL/3-H	F54T5/HO-RW	Fluorescent, (10) 45.8" T-5 HO reduced-wattage lamps, (3) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 10L T5HO	PRS Elec.	10	50	537	15.5
F410GPRL/5-H	F54T5/HO-RW	Fluorescent, (10) 45.8" T-5 HO reduced-wattage lamps, (5) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 10L T5HO	PRS Elec.	10	50	545	15.5
F412GPRL/3-H	F54T5/HO-RW	Fluorescent, (12) 45.8" T-5 HO reduced-wattage lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 12-Lamp T5HO	PRS Elec.	12	50	642	15.5
F412GPRL/6-H	F54T5/HO-RW	Fluorescent, (12) 45.8" T-5 HO reduced-wattage lamps, (6) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 12-Lamp T5HO	PRS Elec.	12	50	654	15.5
F51GPHL-H	F80T5/HO	Fluorescent (1) 57.6" (1463mm) T-5 HO lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	5' 1-Lamp T5HO	PRS Elec.	1	80	90	15.5
F52GPHL/2-H	F80T5/HO	Fluorescent (2) 57.6" (1463mm) T-5 HO lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	5' 2-Lamp T5HO	PRS Elec.	2	80	180	15.5
T8 Linear Fluorescent Systems								
F1.51LS	F15T8	Fluorescent, (1) 18" T-8 lamp	1.5' 1-Lamp T8	Mag-STD	1	15	19	15.5
F1.52LS	F15T8	Fluorescent, (2) 18" T-8 lamps	1.5' 2-Lamp T8	Mag-STD	2	15	36	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F21GLL	F17T8	Fluorescent (1) 24" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	PRS Elec.	1	17	18	15.5
F21ILL	F17T8	Fluorescent, (1) 24", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	18	15.5
F21ILL-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	17	15.5
F21ILL/T2	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	17	15.5
F21ILL/T2 -R	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	15	15.5
F21ILL/T3	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	16	15.5
F21ILL/T3 -R	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	14	15.5
F21ILL/T4	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	15	15.5
F21ILL/T4 -R	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	13	15.5
F21ILU	F17T8	Fluorescent, (1) 24", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	17	15.5
F21ILU-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	15	15.5
F21ILU-V	F17T8	Fluorescent, (1) 24", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	2' 1-Lamp T8 VHLO	Electronic	1	17	22	15.5
F21LL	F17T8	Fluorescent, (1) 24", T-8 lamp, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	16	15.5
F21LL-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Rapid Start Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	15	15.5
F21LL/T2	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 2-Lamp RS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	16	15.5
F21LL/T3	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 3-Lamp RS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	17	15.5
F21LL/T4	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 4-Lamp RS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	17	15.5
F21SL	F17T8	Fluorescent, (1) 24", T-8 lamp, Standard Ballast	2' 1-Lamp T8	Mag-STD	1	17	24	15.5
F22GLL	F17T8	Fluorescent (2) 24" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	PRS Elec.	2	17	31	15.5
F22ILL	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	33	15.5
F22ILL-R	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 2-Lamp T8 RLO	Electronic	2	17	30	15.5
F22ILL/T4	F17T8	Fluorescent, (2) 24", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	30	15.5
F22ILL/T4 -R	F17T8	Fluorescent, (2) 24", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF<.85)	2' 2-Lamp T8 RLO	Electronic	2	17	27	15.5
F22ILU	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	30	15.5
F22ILU-R	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 2-Lamp T8 RLO	Electronic	2	17	27	15.5
F22ILU-V	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	2' 2-Lamp T8 VHLO	Electronic	2	17	41	15.5
F22ILU/T4 -R	F17T8	Fluorescent, (2) 24", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	2' 2-Lamp T8 RLO	Electronic	2	17	26	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F22LL	F17T8	Fluorescent, (2) 24", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	31	15.5
F22LL-R	F17T8	Fluorescent, (2) 24", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	2' 2-Lamp T8 RLO	Electronic	2	17	28	15.5
F22LL/T4	F17T8	Fluorescent, (2) 24", T-8 lamps, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	34	15.5
F23GLL	F17T8	Fluorescent (3) 24" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	2' 3-Lamp T8	PRS Elec.	3	17	47	15.5
F23ILL	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 3-Lamp T8	Electronic	3	17	47	15.5
F23ILL-H	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	2' 3-Lamp T8 HLO	Electronic	3	17	51	15.5
F23ILL-R	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 3-Lamp T8 RLO	Electronic	3	17	41	15.5
F23ILU	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 3-Lamp T8	Electronic	3	17	45	15.5
F23ILU-R	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 3-Lamp T8 RLO	Electronic	3	17	40	15.5
F23ILU-V	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	2' 3-Lamp T8 VHLO	Electronic	3	17	59	15.5
F23LL	F17T8	Fluorescent, (3) 24", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	2' 3-Lamp T8	Electronic	3	17	52	15.5
F23LL-R	F17T8	Fluorescent, (3) 24", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	2' 3-Lamp T8 RLO	Electronic	3	17	41	15.5
F24GLL	F17T8	Fluorescent (4) 24" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	2' 4-Lamp T8	PRS Elec.	4	17	59	15.5
F24ILL	F17T8	Fluorescent, (4) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 4-Lamp T8	Electronic	4	17	59	15.5
F24ILL-R	F17T8	Fluorescent, (4) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 4-Lamp T8 RLO	Electronic	4	17	53	15.5
F24ILU	F17T8	Fluorescent, (4) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 4-Lamp T8	Electronic	4	17	57	15.5
F24ILU-R	F17T8	Fluorescent, (4) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 4-Lamp T8 RLO	Electronic	4	17	52	15.5
F24LL	F17T8	Fluorescent, (4) 24", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	2' 4-Lamp T8	Electronic	4	17	68	15.5
F24LL-R	F17T8	Fluorescent, (4) 24", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	2' 4-Lamp T8 RLO	Electronic	4	17	57	15.5
F31ILL	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	26	15.5
F31ILL-H	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	3' 1-Lamp T8 HLO	Electronic	1	25	28	15.5
F31ILL-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	22	15.5
F31ILL/T2	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	23	15.5
F31ILL/T2-H	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp IS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	3' 1-Lamp T8	Electronic	1	25	26	15.5
F31ILL/T2-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	21	15.5
F31ILL/T3	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	23	15.5
F31ILL/T3-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	20	15.5
F31ILL/T4	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	22	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F31ILL/T4-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	20	15.5
F31ILU	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	23	15.5
F31ILU-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	20	15.5
F31ILU/T2	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	22	15.5
F31ILU/T2-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	20	15.5
F31ILU/T3-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	19	15.5
F31ILU/T4-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	19	15.5
F31LL	F25T8	Fluorescent, (1) 36", T-8 lamp, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	24	15.5
F31LL-H	F25T8	Fluorescent, (1) 36", T-8 lamp, Rapid Start Ballast, HLO (0.95 < BF < 1.1)	3' 1-Lamp T8 HLO	Electronic	1	25	26	15.5
F31LL-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Rapid Start Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	23	15.5
F31LL/T2	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp RS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	23	15.5
F31LL/T3	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp RS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	24	15.5
F31LL/T4	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	22	15.5
F32ILL	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	46	15.5
F32ILL-H	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	3' 2-Lamp T8 HLO	Electronic	2	25	52	15.5
F32ILL-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	42	15.5
F32ILL/2-R	F25T8	Fluorescent, (2) 36", T-8 lamps, (2) Instant Start Ballasts, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	44	15.5
F32ILL/T4	F25T8	Fluorescent, (2) 36", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	44	15.5
F32ILL/T4-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	39	15.5
F32ILU	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	44	15.5
F32ILU-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	39	15.5
F32ILU/T4-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	39	15.5
F32LL	F25T8	Fluorescent, (2) 36", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	46	15.5
F32LL-H	F25T8	Fluorescent, (2) 36", T-8 lamps, Rapid Start Ballast, HLO (0.95 < BF < 1.1)	3' 2-Lamp T8 HLO	Electronic	2	25	50	15.5
F32LL-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	42	15.5
F32LL-V	F25T8	Fluorescent, (2) 36", T-8 lamps, Rapid Start Ballast, VHLO (BF > 1.1)	3' 2-Lamp T8 VHLO	Electronic	2	25	70	15.5
F32LL/T4	F25T8	Fluorescent, (2) 36", T-8 lamps, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	45	15.5
F33ILL	F25T8	Fluorescent, (3) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 3-Lamp T8	Electronic	3	25	68	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F33ILL-R	F25T8	Fluorescent, (3) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 3-Lamp T8 RLO	Electronic	3	25	61	15.5
F33ILU	F25T8	Fluorescent, (3) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 3-Lamp T8	Electronic	3	25	65	15.5
F33ILU-R	F25T8	Fluorescent, (3) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 3-Lamp T8 RLO	Electronic	3	25	58	15.5
F33LL	F25T8	Fluorescent, (3) 36", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	3' 3-Lamp T8	Electronic	3	25	72	15.5
F33LL-R	F25T8	Fluorescent, (3) 36", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	3' 3-Lamp T8 RLO	Electronic	3	25	62	15.5
F34ILL	F25T8	Fluorescent, (4) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 4-Lamp T8	Electronic	4	25	88	15.5
F34ILL-R	F25T8	Fluorescent, (4) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 4-Lamp T8 RLO	Electronic	4	25	78	15.5
F34ILL/2-R	F25T8	Fluorescent, (4) 36", T-8 lamps, (2) Instant Start Ballasts, RLO (BF< 0.85)	3' 4-Lamp T8 RLO	Electronic	4	25	84	15.5
F34ILU	F25T8	Fluorescent, (4) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 4-Lamp T8	Electronic	4	25	86	15.5
F34ILU-R	F25T8	Fluorescent, (4) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 4-Lamp T8 RLO	Electronic	4	25	77	15.5
F34LL	F25T8	Fluorescent, (4) 36", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	3' 4-Lamp T8	Electronic	4	25	89	15.5
F34LL-R	F25T8	Fluorescent, (4) 36", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	3' 4-Lamp T8 RLO	Electronic	4	25	84	15.5
F36ILL/2	F25T8	Fluorescent, (6) 36", T-8 lamps, (2) Instant Start Ballasts, NLO (0.85 < BF < 0.95)	3' 6-Lamp T8	Electronic	6	25	135	15.5
F36ILL/2-R	F25T8	Fluorescent, (6) 36", T-8 lamps, (2) Instant Start Ballasts, RLO (BF< 0.85)	3' 6-Lamp T8 RLO	Electronic	6	25	121	15.5
F42GRLL-V	F28T8	Fluorescent, (2) 48", T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 28W VLHO	PRS Elec.	2	28	66	15.5
F43GRLL-V	F28T8	Fluorescent, (3) 48", T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 28W VLHO	PRS Elec.	3	28	92	15.5
F41GLL	F32T8	Fluorescent (1) 48" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	PRS Elec.	1	32	30	15.5
F41GLL-R	F32T8	Fluorescent (1) 48" T-8 lamp, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	PRS Elec.	1	32	25	15.5
F41ILL	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	31	15.5
F41ILL-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	36	15.5
F41ILL-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	27	15.5
F41ILL/T2	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	29	15.5
F41ILL/T2-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	33	15.5
F41ILL/T2-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	26	15.5
F41ILL/T3	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	28	15.5
F41ILL/T3-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	31	15.5
F41ILL/T3-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	25	15.5
F41ILL/T4	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	28	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F41ILL/T4-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	25	15.5
F41ILU	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	28	15.5
F41ILU-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	35	15.5
F41ILU-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	25	15.5
F41ILU/T2	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	27	15.5
F41ILU/T2-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	24	15.5
F41ILU/T3	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	27	15.5
F41ILU/T3-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	24	15.5
F41ILU/T4	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	27	15.5
F41ILU/T4-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	24	15.5
F41LE	F32T8	Fluorescent, (1) 48", T-8 lamp	4' 1-Lamp T8	Mag-ES	1	32	35	15.5
F41LL	F32T8	Fluorescent, (1) 48", T-8 lamp, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	32	15.5
F41LL-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Rapid Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	39	15.5
F41LL-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Rapid Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	27	15.5
F41LL/T2	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	30	15.5
F41LL/T2-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp RS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	35	15.5
F41LL/T2-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp RS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	27	15.5
F41LL/T3	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	31	15.5
F41LL/T3-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp RS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	33	15.5
F41LL/T3-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp RS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	25	15.5
F41LL/T4	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	30	15.5
F41LL/T4-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp RS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	26	15.5
F42GLL	F32T8	Fluorescent (2) 48" T-8 lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	PRS Elec.	2	32	59	15.5
F42GLL-R	F32T8	Fluorescent (2) 48" T-8 lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 2-Lamp T8 RLO	PRS Elec.	2	32	47	15.5
F42GLL-V	F32T8	Fluorescent, (2) 48" T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 VHLO	PRS Elec.	2	32	74	15.5
F42ILL	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	58	15.5
F42ILL-H	F32T8	Fluorescent, (2) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 2-Lamp T8 HLO	Electronic	2	32	66	15.5
F42ILL-R	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	51	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F42ILL-V	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 VHLO	Electronic	2	32	77	15.5
F42ILL/2	F32T8	Fluorescent, (2) 48", T-8 lamps, (2) 1-lamp Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	62	15.5
F42ILL/2-R	F32T8	Fluorescent, (2) 48" T-8 lamps, (2) 1-lamp Instant Start Ballasts, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	54	15.5
F42ILL/T4	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	56	15.5
F42ILL/T4-R	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	49	15.5
F42ILU	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	54	15.5
F42ILU-H	F32T8	Fluorescent, (2) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 2-Lamp T8 HLO	Electronic	2	32	64	15.5
F42ILU-R	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	48	15.5
F42ILU-V	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start, VHLO (BF> 1.1)	4' 2-Lamp T8 VHLO	Electronic	2	32	73	15.5
F42ILU/T4	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	54	15.5
F42ILU/T4-R	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	48	15.5
F42LE	F32T8	Fluorescent, (2) 48", T-8 lamp	4' 2-Lamp T8	Mag-ES	2	32	71	15.5
F42LL	F32T8	Fluorescent, (2) 48", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	60	15.5
F42LL-H	F32T8	Fluorescent, (2) 48", T-8 lamp, Rapid Start Ballast, HLO (0.95 < BF < 1.1)	4' 2-Lamp T8 HLO	Electronic	2	32	70	15.5
F42LL-R	F32T8	Fluorescent, (2) 48", T-8 lamp, Rapid Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	54	15.5
F42LL-V	F32T8	Fluorescent, (2) 48", T-8 lamp, Rapid Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 HLO	Electronic	2	32	85	15.5
F42LL/2	F32T8	Fluorescent, (2) 48", T-8 lamps, (2) 1-lamp Rapid Start Ballasts, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	64	15.5
F42LL/T4	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	59	15.5
F42LL/T4-R	F32T8	Fluorescent, (2) 48", T-8 lamp, Tandem 4-lamp RS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	53	15.5
F43GLL	F32T8	Fluorescent (3) 48" T-8 lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	PRS Elec.	3	32	88	15.5
F43GLL-R	F32T8	Fluorescent (3) 48" T-8 lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	PRS Elec.	3	32	72	15.5
F43GLL-V	F32T8	Fluorescent, (3) 48" T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 VHLO	Electronic	3	32	108	15.5
F43ILL	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	85	15.5
F43ILL-H	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 HLO	Electronic	3	32	93	15.5
F43ILL-R	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	Electronic	3	32	76	15.5
F43ILL-V	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 VHLO	Electronic	3	32	112	15.5
F43ILL/2	F32T8	Fluorescent, (3) 48" T-8 lamps, (2) Instant Start Ballasts, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	89	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F43ILL/2-H	F32T8	Fluorescent (3) 48" T-8 lamps, (1) 2-lamp and (1) 3-lamp IS Ballast,1 lead capped, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 HLO	Electronic	3	32	102	15.5
F43ILL/2-R	F32T8	Fluorescent, (3) 48" T-8 lamps, (1) 1-lamp and (1) 2-lamp IS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	Electronic	3	32	78	15.5
F43ILU	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	81	15.5
F43ILU-H	F32T8	Fluorescent, (3) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 HLO	Electronic	3	32	92	15.5
F43ILU-R	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	Electronic	3	32	72	15.5
F43ILU-V	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 VHLO	Electronic	3	32	108	15.5
F43LE	F32T8	Fluorescent, (3) 48", T-8 lamp	4' 3-Lamp T8	Mag-ES	3	32	110	15.5
F43LL	F32T8	Fluorescent, (3) 48", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	93	15.5
F43LL-H	F32T8	Fluorescent, (3) 48", T-8 lamp, Rapid Start Ballast, HLO (.95 < BF < 1.1)	4' 3-Lamp T8 HLO	Electronic	3	32	98	15.5
F43LL-R	F32T8	Fluorescent, (3) 48", T-8 lamp, Rapid Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	Electronic	3	32	76	15.5
F43LL/2	F32T8	Fluorescent, (3) 48", T-8 lamps, (1) 1-lamp and (1) 2-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	92	15.5
F44GLL	F32T8	Fluorescent (4) 48" T-8 lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	PRS Elec.	4	32	115	15.5
F44GLL-R	F32T8	Fluorescent (4) 48" T-8 lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	PRS Elec.	4	32	92	15.5
F44GLL-V	F32T8	Fluorescent, (4) 48" T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 VHLO	PRS Elec.	4	32	144	15.5
F44ILL	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	112	15.5
F44ILL-R	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	Electronic	4	32	98	15.5
F44ILL-V	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 VHLO	Electronic	4	32	151	15.5
F44ILL/2	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 2-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	116	15.5
F44ILL/2-H	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 3-lamp IS Ballasts, 1 lead capped, HLO (.95 < BF < 1.1)	4' 4-Lamp T8 HLO	Electronic	4	32	132	15.5
F44ILL/2-R	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 2-lamp IS Ballasts, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	Electronic	4	32	102	15.5
F44ILL/2-V	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 2-lamp IS Ballasts, VHLO (BF > 1.1)	4' 4-Lamp T8 VHLO	Electronic	4	32	154	15.5
F44ILU	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	107	15.5
F44ILU-H	F32T8	Fluorescent, (4) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 4-Lamp T8 HLO	Electronic	4	32	121	15.5
F44ILU-R	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	Electronic	4	32	95	15.5
F44ILU-V	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 VHLO	Electronic	4	32	146	15.5
F44LE	F32T8	Fluorescent, (4) 48", T-8 lamps	4' 4-Lamp T8	Mag-ES	4	32	142	15.5
F44LL	F32T8	Fluorescent, (4) 48", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	118	15.5
F44LL-R	F32T8	Fluorescent, (4) 48", T-8 lamps, Rapid Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	Electronic	4	32	105	15.5
F44LL/2	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 2-lamp Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	120	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F45ILL/2	F32T8	Fluorescent, (5) 48", T-8 lamps, (1) 3-lamp and (1) 2-lamp IS ballast, NLO (0.85 < BF < 0.95)	4' 5-Lamp T8	Electronic	5	32	143	15.5
F45GLL/2-V	F32T8	Fluorescent, (5) 48", T-8 lamps, (1) 3-lamp and (1) 2-lamp Prog. Start Ballast, VHLO (BF > 1.1)	4' 5-Lamp T8 VHLO	Electronic	5	32	182	15.5
F46GLL/2	F32T8	Fluorescent (6) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8	PRS Elec.	6	32	175	15.5
F46GLL/2-R	F32T8	Fluorescent (6) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 RLO	PRS Elec.	6	32	142	15.5
F46GLL/2-V	F32T8	Fluorescent (6) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 VHLO	PRS Elec.	6	32	217	15.5
F46ILL/2	F32T8	Fluorescent, (6) 48", T-8 lamps, (2) IS Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8	Electronic	6	32	170	15.5
F46ILL/2-R	F32T8	Fluorescent, (6) 48", T-8 lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 RLO	Electronic	6	32	151	15.5
F46ILL/2-V	F32T8	Fluorescent (6) 48" T-8 lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 VHLO	Electronic	6	32	226	15.5
F46ILU/2	F32T8	Fluorescent (6) 48" T-8 lamps, (2) IS Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8	Electronic	6	32	162	15.5
F46ILU/2-R	F32T8	Fluorescent (6) 48" T-8 lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 RLO	Electronic	6	32	144	15.5
F46ILU/2-V	F32T8	Fluorescent (6) 48" T-8 lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 VHLO	Electronic	6	32	218	15.5
F465LL/2	F32T8	Fluorescent, (6) 48", T-8 lamps, (2) Rapid Start Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8	Electronic	6	32	182	15.5
F48GLL/2	F32T8	Fluorescent (8) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, NLO (0.85 < BF < 0.95)	4' 8-Lamp T8	PRS Elec.	8	32	230	15.5
F48GLL/2-R	F32T8	Fluorescent (8) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, RLO (BF < 0.85)	4' 8-Lamp T8 RLO	PRS Elec.	8	32	184	15.5
F48GLL/2-V	F32T8	Fluorescent (8) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, VHLO (BF > 1.1)	4' 8-Lamp T8 VHLO	PRS Elec.	8	32	288	15.5
F48ILL/2	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	4' 8-Lamp T8	Electronic	8	32	224	15.5
F48ILL/2-R	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, RLO (BF < 0.85)	4' 8-Lamp T8 RLO	Electronic	8	32	196	15.5
F48ILU/2	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	4' 8-Lamp T8	Electronic	8	32	214	15.5
F48ILU/2-R	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, RLO (BF < 0.85)	4' 8-Lamp T8 RLO	Electronic	8	32	190	15.5
F48ILU/2-V	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, VHLO (BF > 1.1)	4' 8-Lamp T8 VHLO	Electronic	8	32	292	15.5
F41GNLL	F32T8-25W	Fluorescent (1) 48" T-8 @ 25W lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 25W	PRS Elec.	1	25	24	15.5
F41GNLL-R	F32T8-25W	Fluorescent (1) 48" T-8 @ 25W lamp, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 25W RLO	PRS Elec.	1	25	21	15.5
F41INLL	F32T8-25W	Fluorescent, (1) 48", T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 25W	Electronic	1	25	24	15.5
F41INLU	F32T8-25W	Fluorescent, (1), T-8 @ 25W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 25W	Electronic	1	25	23	15.5
F41INLU-R	F32T8-25W	Fluorescent, (1), T-8 @ 25W lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 25W RLO	Electronic	1	25	21	15.5
F41INLU-V	F32T8-25W	Fluorescent, (1), T-8 @ 25W lamp, Instant Start Ballast, VHLO (BF > 1.1)	4' 1-Lamp T8 25W VHLO	Electronic	1	25	32	15.5
F41INLU/T3-R	F32T8-25W	Fluorescent, (1) 48", T-8 @ 25W lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 25W RLO	Electronic	1	25	19	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F41INLU/ T4-R	F32T8-25W	Fluorescent, (1) 48", T-8 @ 25W lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 25W RLO	Electronic	1	25	19	15.5
F42GNLL	F32T8-25W	Fluorescent (2) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 25W	PRS Elec.	2	25	44	15.5
F42GNLL-R	F32T8-25W	Fluorescent (2) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 25W RLO	PRS Elec.	2	25	38	15.5
F42INLL	F32T8-25W	Fluorescent, (2) 48", T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 25W	Electronic	2	25	46	15.5
F42INLL-V	F32T8-25W	Fluorescent, (2) 48" T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 25W VHLO	Electronic	2	25	65	15.5
F42INLU	F32T8-25W	Fluorescent, (2), T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 25W	Electronic	2	25	43	15.5
F42INLU-R	F32T8-25W	Fluorescent (2) 48" T8 @ 25W lamps, Instant Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 25W RLO	Electronic	2	25	38	15.5
F42INLU-V	F32T8-25W	Fluorescent, (2) 48", T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 25W VHLO	Electronic	2	25	60	15.5
F42INLU/ T4-R	F32T8-25W	Fluorescent, (2) 48", T-8 @ 25W lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 25W RLO	Electronic	2	25	38	15.5
F43GNLL	F32T8-25W	Fluorescent (3) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 25W	PRS Elec.	3	25	66	15.5
F43GNLL-R	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 25W RLO	PRS Elec.	3	25	56	15.5
F43INLL	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 25W	Electronic	3	25	66	15.5
F43INLL-V	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 25W VHLO	Electronic	3	25	95	15.5
F43INLU	F32T8-25W	Fluorescent, (3) 48" T-8 lamps @ 25W, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 25W	Electronic	3	25	64	15.5
F43INLU-R	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 25W RLO	Electronic	3	25	57	15.5
F43INLU-V	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 25W VHLO	Electronic	3	25	93	15.5
F44GNLL	F32T8-25W	Fluorescent (4) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 25W	PRS Elec.	4	25	85	15.5
F44GNLL-R	F32T8-25W	Fluorescent (4) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 25W RLO	PRS Elec.	4	25	73	15.5
F44INLL	F32T8-25W	Fluorescent, (4) 48", T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 25W	Electronic	4	25	86	15.5
F44INLU	F32T8-25W	Fluorescent, (4) 48", T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 25W	Electronic	4	25	85	15.5
F44INLU-R	F32T8-25W	Fluorescent, (4) 48" T-8 @ 25W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 25W RLO	Electronic	4	25	75	15.5
F44INLU-V	F32T8-25W	Fluorescent, (4) 48" T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 25W VHLO	Electronic	4	25	122	15.5
F46INLU/ 2-R	F32T8-25W	Fluorescent (6) 48" T-8 @ 25W lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 25W RLO	Electronic	6	25	114	15.5
F46INLU/ 2-V	F32T8-25W	Fluorescent (6) 48" T-8 @ 25W lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 25W VHLO	Electronic	6	25	184	15.5
F41GRLL	F32T8-28W	Fluorescent (1) 48" T-8 @ 28W lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 28W	PRS Elec.	1	28	26	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F41GRLL-R	F32T8-28W	Fluorescent (1) 48" T-8 @ 28W lamp, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 28W RLO	PRS Elec.	1	28	22	15.5
F41IRLL	F32T8-28W	Fluorescent, (1) 48" T-8 @ 28W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 28W	Electronic	1	28	27	15.5
F41IRLL-V	F32T8-28W	Fluorescent, (1) 48" T-8 @ 28W lamp, Instant Start Ballast, VHLO (BF > 1.1)	4' 1-Lamp T8 28W VHLO	Electronic	1	28	35	15.5
F41IRLU	F32T8-28W	Fluorescent, (1), T-8 @ 28W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 28W	Electronic	1	28	25	15.5
F41IRLU-R	F32T8-28W	Fluorescent, (1), T-8 @ 28W lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 28W RLO	Electronic	1	28	22	15.5
F41IRLU-V	F32T8-28W	Fluorescent, (1), T-8 @ 28W lamp, Instant Start Ballast, VHLO (BF > 1.1)	4' 1-Lamp T8 28W VHLO	Electronic	1	28	33	15.5
F41IRLU/T3-R	F32T8-28W	Fluorescent, (1) 48", T-8 @ 28W lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 28W RLO	Electronic	1	28	21	15.5
F41IRLU/T4-R	F32T8-28W	Fluorescent, (1) 48", T-8 @ 28W lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 28W RLO	Electronic	1	28	21	15.5
F42GRLL	F32T8-28W	Fluorescent (2) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 28W	PRS Elec.	2	28	49	15.5
F42GRLL-R	F32T8-28W	Fluorescent (2) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 28W RLO	PRS Elec.	2	28	40	15.5
F42IRLL	F32T8-28W	Fluorescent, (2) 48", T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 28W NLO	Electronic	2	28	52	15.5
F42IRLL-V	F32T8-28W	Fluorescent, (2) 48" T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 28W VHLO	Electronic	2	28	68	15.5
F42IRLU	F32T8-28W	Fluorescent, (2), T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 28W	Electronic	2	28	48	15.5
F42IRLU-R	F32T8-28W	Fluorescent, (2) 48", T-8 @ 28W lamps, Instant Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 28W RLO	Electronic	2	28	43	15.5
F42IRLU-V	F32T8-28W	Fluorescent, (2) 48", T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 28W VHLO	Electronic	2	28	65	15.5
F42IRLU/T4-R	F32T8-28W	Fluorescent, (2) 48", T-8 @ 28W lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 28W RLO	Electronic	2	28	42	15.5
F43GRLL	F32T8-28W	Fluorescent (3) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 28W	PRS Elec.	3	28	75	15.5
F43GRLL-R	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 28W RLO	PRS Elec.	3	28	62	15.5
F43IRLL	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 28W	Electronic	3	28	76	15.5
F43IRLL-H	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, HLO (.95 < BF < 1.1)	4' 3-Lamp T8 28W HLO	Electronic	3	28	82	15.5
F43IRLL-V	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 28W VHLO	Electronic	3	28	97	15.5
F43IRLU	F32T8-28W	Fluorescent, (3) 48" T-8 lamps @ 28W, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 28W	Electronic	3	28	72	15.5
F43IRLU-R	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 28W RLO	Electronic	3	28	63	15.5
F43IRLU-V	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 28W VHLO	Electronic	3	28	96	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F44GRLL	F32T8-28W	Fluorescent (4) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 28W	PRS Elec.	4	28	99	15.5
F44GRLL-R	F32T8-28W	Fluorescent (4) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 28W RLO	PRS Elec.	4	28	80	15.5
F44IRLL	F32T8-28W	Fluorescent, (4) 48", T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 28W	Electronic	4	28	99	15.5
F44IRLL-R	F32T8-28W	Fluorescent, (4) 48", T-8 @ 28W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 28W RLO	Electronic	4	28	85	15.5
F44IRLU	F32T8-28W	Fluorescent, (4) 48", T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 28W	Electronic	4	28	94	15.5
F44IRLU-R	F32T8-28W	Fluorescent, (4) 48" T-8 @ 28W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 28W RLO	Electronic	4	28	83	15.5
F44IRLU-V	F32T8-28W	Fluorescent, (4) 48" T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 28W VHLO	Electronic	4	28	131	15.5
F46IRLU/2-R	F32T8-28W	Fluorescent (6) 48" T-8 @ 28W lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 28W	Electronic	6	28	126	15.5
F46IRLU/2-V	F32T8-28W	Fluorescent (6) 48" T-8 @ 28W lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 28W VHLO	Electronic	6	28	194	15.5
F48IRLU/2-V	F32T8-28W	Fluorescent (8) 48" T-8 @ 28W lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 28W VHLO	Electronic	8	28	250	15.5
F41GELL	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	PRS Elec.	1	30	28	15.5
F41GELL-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 1-Lamp T8 30W RLO	PRS Elec.	1	30	24	15.5
F41IELL	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	29	15.5
F41IELL-H	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 30W HLO	Electronic	1	30	34	15.5
F41IELL-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, RLO (BF < 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	26	15.5
F41IELL/T2	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	28	15.5
F41IELL/T3	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	27	15.5
F41IELL/T4	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	27	15.5
F41IELU	F32T8-30W	Fluorescent, (1) 48", T-8 @ 30W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	27	15.5
F41IELU-H	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 30W HLO	Electronic	1	30	32	15.5
F41IELU-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	24	15.5
F41IELU/T2	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	26	15.5
F41IELU/T2-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	23	15.5
F41IELU/T3	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	26	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F41IELU/T3-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	23	15.5
F41IELU/T4	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	25	15.5
F41IELU/T4-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	22	15.5
F42GELL	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	PRS Elec.	2	30	56	15.5
F42GELL-R	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 2-Lamp T8 30W RLO	PRS Elec.	2	30	43	15.5
F42IELL	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	Electronic	2	30	55	15.5
F42IELL-H	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 2-Lamp T8 30W HLO	Electronic	2	30	62	15.5
F42IELL-R	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 30W RLO	Electronic	2	30	49	15.5
F42IELL/T4	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	Electronic	2	30	53	15.5
F42IELL/T4-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 30W RLO	Electronic	2	30	46	15.5
F42IELU	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	Electronic	2	30	52	15.5
F42IELU-R	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start, RLO (BF< 0.85)	4' 2-Lamp T8 30W RLO	Electronic	2	30	45	15.5
F42IELU-V	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start, VHLO (BF > 1.1)	4' 2-Lamp T8 30W HLO	Electronic	2	30	70	15.5
F42IELU/T4	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	Electronic	2	30	51	15.5
F42IELU/T4-R	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 30W RLO	Electronic	2	30	45	15.5
F43GELL	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 30W	PRS Elec.	3	30	83	15.5
F43GELL-R	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 30W RLO	PRS Elec.	3	30	67	15.5
F43IELL	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 30W	Electronic	3	30	81	15.5
F43IELL-H	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 30W HLO	Electronic	3	30	86	15.5
F43IELL-R	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 30W RLO	Electronic	3	30	71	15.5
F43IELL/2	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, (1) 1-lamp and (1) 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 30W	Electronic	3	30	84	15.5
F43IELL/2-H	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, (1) 2-lamp, (1) 3-lamp IS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 30W HLO	Electronic	3	30	96	15.5
F43IELL/2-R	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, (1) 1-lamp and (1) 2-lamp IS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 30W RLO	Electronic	3	30	75	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F43IELU	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 30W	Electronic	3	30	77	15.5
F43IELU-R	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 30W RLO	Electronic	3	30	68	15.5
F43IELU-V	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 30W VHLO	Electronic	3	30	104	15.5
F44GELL	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 30W	PRS Elec.	4	30	109	15.5
F44GELL-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 30W RLO	PRS Elec.	4	30	86	15.5
F44IELL	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 30W	Electronic	4	30	106	15.5
F44IELL-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 30W RLO	Electronic	4	30	92	15.5
F44IELL/2	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, (2) 2-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 30W	Electronic	4	30	110	15.5
F44IELL/2-H	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, (2) 3-lamp IS Ballasts, 1 lead capped, HLO (.95 < BF < 1.1)	4' 4-Lamp T8 30W HLO	Electronic	4	30	124	15.5
F44IELL/2-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, (2) 2-lamp IS Ballasts, RLO (BF< 0.85)	4' 4-Lamp T8 30W RLO	Electronic	4	30	98	15.5
F44IELU	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 30W	Electronic	4	30	101	15.5
F44IELU-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 30W RLO	Electronic	4	30	89	15.5
F46IELU/2	F32T8-30W	Fluorescent (6) 48" T-8 @ 30W lamps, (2) IS Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8 30W	Electronic	6	30	154	15.5
F46IELU/2-R	F32T8-30W	Fluorescent (6) 48" T-8 @ 30W lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 30W RLO	Electronic	6	30	135	15.5
F51ILL	F40T8	Fluorescent, (1) 60", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	5' 1-Lamp T8	Electronic	1	40	36	15.5
F51ILL-R	F40T8	Fluorescent, (1) 60", T-8 lamp, Instant Start Ballast, RLO (BF < 0.85)	5' 1-Lamp T8 RLO	Electronic	1	40	43	15.5
F51ILL/T2	F40T8	Fluorescent, (1) 60", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	5' 1-Lamp T8	Electronic	1	40	36	15.5
F51ILL/T3	F40T8	Fluorescent, (1) 60", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	5' 1-Lamp T8	Electronic	1	40	35	15.5
F51ILL/T4	F40T8	Fluorescent, (1) 60", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	5' 1-Lamp T8	Electronic	1	40	34	15.5
F52ILL	F40T8	Fluorescent, (2) 60", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	5' 2-Lamp T8	Electronic	2	40	72	15.5
F52ILL-H	F40T8	Fluorescent, (2) 60", T-8 lamps, Instant Start Ballast, HILO (.95 < BF < 1.1)	5' 2-Lamp T8 HLO	Electronic	2	40	80	15.5
F52ILL-R	F40T8	Fluorescent, (2) 60", T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	5' 2-Lamp T8 RLO	Electronic	2	40	73	15.5
F52ILL/T4	F40T8	Fluorescent, (2) 60", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	5' 2-Lamp T8	Electronic	2	40	67	15.5
F53ILL	F40T8	Fluorescent, (3) 60", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	5' 3-Lamp T8	Electronic	3	40	106	15.5
F53ILL-H	F40T8	Fluorescent, (3) 60", T-8 lamps, Instant Start Ballast, HILO (.95 < BF < 1.1)	5' 3-Lamp T8 HLO	Electronic	3	40	108	15.5
F54ILL	F40T8	Fluorescent, (4) 60", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	5' 4-Lamp T8	Electronic	4	40	134	15.5
F54ILL-H	F40T8	Fluorescent, (4) 60", T-8 lamps, Instant Start Ballast, HLO (.95 < BF < 1.1)	5' 4-Lamp T8 HLO	Electronic	4	40	126	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F41LHL	F48T8/HO	Fluorescent, (1) 48", T-8 HO lamps, (1) Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 44W HO	Electronic	1	44	59	15.5
F42LHL	F48T8/HO	Fluorescent, (2) 48", T-8 HO lamps, (1) Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 44W HO	Electronic	2	44	98	15.5
F43LHL	F48T8/HO	Fluorescent, (3) 48", T-8 HO lamps, (2) Instant Start Ballasts, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 44W HO	Electronic	3	44	141	15.5
F44LHL	F48T8/HO	Fluorescent, (4) 48", T-8 HO lamps, (2) Instant Start Ballasts, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 44W HO	Electronic	4	44	168	15.5
F81ILL	F96T8	Fluorescent, (1) 96", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 1-Lamp T8	Electronic	1	59	69	15.5
F81ILL-H	F96T8	Fluorescent, (1) 96", T-8 lamp, Instant Start Ballast, HILO (.95 < BF < 1.1)	8' 1-Lamp T8 HLO	Electronic	1	59	70	15.5
F81ILL-R	F96T8	Fluorescent, (1) 96", T-8 lamp, Instant Start Ballast, RLO (BF < 0.85)	8' 1-Lamp T8 RLO	Electronic	1	59	67	15.5
F81ILL-V	F96T8	Fluorescent, (1) 96", T-8 lamp, Instant Start Ballast, VHLO (BF > 1.1)	8' 1-Lamp T8 VHLO	Electronic	1	59	72	15.5
F81ILL/T2	F96T8	Fluorescent, (1) 96", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	8' 1-Lamp T8	Electronic	1	59	55	15.5
F81ILL/T2-R	F96T8	Fluorescent, (1) 96", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF < 0.85)	8' 1-Lamp T8 RLO	Electronic	1	59	50	15.5
F81ILU	F96T8	Fluorescent, (1) 96" T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 1-Lamp T8	Electronic	1	59	67	15.5
F82ILL	F96T8	Fluorescent, (2) 96", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 2-Lamp T8	Electronic	2	59	110	15.5
F82ILL-R	F96T8	Fluorescent, (2) 96", T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	8' 2-Lamp T8 RLO	Electronic	2	59	100	15.5
F82ILL-V	F96T8	Fluorescent, (2) 96", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	8' 2-Lamp T8 VHLO	Electronic	2	59	149	15.5
F82ILU	F96T8	Fluorescent, (2) 96" T-8 ES lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 2-Lamp T8	Electronic	2	59	107	15.5
F83ILL	F96T8	Fluorescent, (3) 96", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 3-Lamp T8	Electronic	3	59	179	15.5
F84ILL	F96T8	Fluorescent, (4) 96", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 4-Lamp T8	Electronic	4	59	219	15.5
F84ILL/2-V	F96T8	Fluorescent, (4) 96", T-8 lamps, (2) Instant Start Ballasts, VHLO (BF > 1.1)	8' 4-Lamp T8 VHLO	Electronic	4	59	298	15.5
F86ILL	F96T8	Fluorescent, (6) 96", T-8 lamps, (2) 3-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	8' 6-Lamp T8	Electronic	6	59	330	15.5
F81LHL/T2	F96T8/HO	Fluorescent, (1) 96", T-8 HO lamp, Tandem 2-lamp Ballast	8' 1-Lamp T8 86W HO	Electronic	1	86	80	15.5
F82LHL	F96T8/HO	Fluorescent, (2) 96", T-8 HO lamps	8' 2-Lamp T8 86W HO	Electronic	2	86	160	15.5
F84LHL	F96T8/HO	Fluorescent, (4) 96", T-8 HO lamps	8' 4-Lamp T8 86W HO	Electronic	4	86	320	15.5
F81IERU	F96T8-RW	Fluorescent, (1) 96" T-8 reduced-wattage lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 1-Lamp T8 54W	Electronic	1	54	61	15.5
F82IERU	F96T8-RW	Fluorescent, (2) 96" T-8 @ reduced-wattage lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 2-Lamp T8 54W	Electronic	2	54	93	15.5
T12 and Other Linear Fluorescent Systems								
F1.51SS	F15T12	Fluorescent, (1) 18" T12 lamp	1.5' 1-Lamp T12 15W	Mag-STD	1	15	19	8.5
F1.52SS	F15T12	Fluorescent, (2) 18", T12 lamps	1.5' 2-Lamp T12 15W	Mag-STD	2	15	36	8.5
F21SS	F20T12	Fluorescent, (1) 24", STD lamp	2' 1-Lamp T12 20W	Mag-STD	1	20	25	8.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F22SS	F20T12	Fluorescent, (2) 24", STD lamps	2' 2-Lamp T12 20W	Mag-STD	2	20	50	8.5
F23SS	F20T12	Fluorescent, (3) 24", STD lamps	2' 3-Lamp T12 20W	Mag-STD	3	20	71	8.5
F24SS	F20T12	Fluorescent, (4) 24", STD lamps	2' 4-Lamp T12 20W	Mag-STD	4	20	100	8.5
F26SS/2	F20T12	Fluorescent, (6) 24", STD lamps, (2) ballasts	2' 6-Lamp T12 20W	Mag-STD	6	20	146	8.5
F21HS	F24T12/HO	Fluorescent, (1) 24", HO lamp	2' 1-Lamp T12HO	Mag-STD	1	35	62	8.5
F22HS	F24T12/HO	Fluorescent, (2) 24", HO lamps	2' 2-Lamp T12HO	Mag-STD	2	35	90	8.5
F32EL/T4	F25T12	Fluorescent, (2) 36" ES lamps, Tandem 4-lamp ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T12ES	Electronic	2	25	50	15.5
F41IAL	F25T12	Fluorescent, (1) 48", F25T12 lamp, Instant Start Ballast	4' 1-Lamp T12 25W	Electronic	1	25	25	15.5
F41IAL/T2-R	F25T12	Fluorescent, (1) 48", F25T12 lamp, Tandem 2-Lamp IS ballast, RLO (BF < 0.85)	4' 1-Lamp T12 25W RLO	Electronic	1	25	19	15.5
F41IAL/T3-R	F25T12	Fluorescent, (1) 48", F25T12 lamp, Tandem 3-Lamp IS ballast, RLO (BF < 0.85)	4' 1-Lamp T12 25W RLO	Electronic	1	25	20	15.5
F41IAL/T4-R	F25T12	Fluorescent, (1) 48", F25T12 lamp, Tandem 4-Lamp IS ballast, RLO (BF < 0.85)	4' 1-Lamp T12 25W RLO	Electronic	1	25	20	15.5
F42IAL-R	F25T12	Fluorescent, (2) 48", F25T12 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 2-Lamp T12 25W RLO	Electronic	2	25	39	15.5
F42IAL/T4-R	F25T12	Fluorescent, (2) 48", F25T12 lamps, Tandem 4-lamp IS Ballast, RLO (BF < 0.85)	4' 2-Lamp T12 25W RLO	Electronic	2	25	40	15.5
F43IAL-R	F25T12	Fluorescent, (3) 48", F25T12 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T12 25W RLO	Electronic	3	25	60	15.5
F44IAL-R	F25T12	Fluorescent, (4) 48", F25T12 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T12 25W RLO	Electronic	4	25	80	15.5
F31SE/T2	F30T12	Fluorescent, (1) 36", STD lamp, Tandem 2-lamp ballast	3' 1-Lamp T12	Mag-ES	1	30	37	8.5
F31SL	F30T12	Fluorescent, (1) 36", STD lamp	3' 1-Lamp T12	Electronic	1	30	31	15.5
F31SS	F30T12	Fluorescent, (1) 36", STD lamp	3' 1-Lamp T12	Mag-STD	1	30	46	8.5
F31SS/T2	F30T12	Fluorescent, (1) 36", STD lamp, Tandem 2-lamp ballast	3' 1-Lamp T12	Mag-STD	1	30	41	8.5
F32SE	F30T12	Fluorescent, (2) 36", STD lamps	3' 2-Lamp T12	Mag-ES	2	30	74	8.5
F32SL	F30T12	Fluorescent, (2) 36", STD lamps	3' 2-Lamp T12	Electronic	2	30	58	15.5
F32SS	F30T12	Fluorescent, (2) 36", STD lamps	3' 2-Lamp T12	Mag-STD	2	30	75	8.5
F33SE	F30T12	Fluorescent, (3) 36", STD lamps, (1) STD ballast and (1) ES ballast	3' 3-Lamp T12	Mag-ES	3	30	120	8.5
F33SS	F30T12	Fluorescent, (3) 36", STD lamps	3' 3-Lamp T12	Mag-STD	3	30	127	8.5
F34SE	F30T12	Fluorescent, (4) 36", STD lamps	3' 4-Lamp T12	Mag-ES	4	30	148	8.5
F34SL	F30T12	Fluorescent, (4) 36", STD lamps	3' 4-Lamp T12	Electronic	4	30	116	15.5
F34SS	F30T12	Fluorescent, (4) 36", STD lamps	3' 4-Lamp T12	Mag-STD	4	30	150	8.5
F36SE	F30T12	Fluorescent, (6) 36", STD lamps	3' 6-Lamp T12ES	Mag-ES	6	30	213	8.5
F36SS	F30T12	Fluorescent, (6) 36", STD lamps	3' 6-Lamp T12	Mag-STD	6	30	225	8.5
F31EE/T2	F30T12/ES	Fluorescent, (1) 36", ES lamp, Tandem 2-lamp ballast	3' 1-Lamp T12ES	Mag-ES	1	25	33	8.5
F31EL	F30T12/ES	Fluorescent, (1) 36", ES lamp	3' 1-Lamp T12ES	Electronic	1	25	26	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F31ES	F30T12/ES	Fluorescent, (1) 36", ES lamp	3' 1-Lamp T12ES	Mag-STD	1	25	42	8.5
F31ES/T2	F30T12/ES	Fluorescent, (1) 36", ES lamp, Tandem 2-lamp ballast	3' 1-Lamp T12ES	Mag-STD	1	25	33	8.5
F32EE	F30T12/ES	Fluorescent, (2) 36", ES lamps	3' 1-Lamp T12ES	Mag-ES	2	25	66	8.5
F32EL	F30T12/ES	Fluorescent, (2) 36", ES lamps	3' 1-Lamp T12ES	Electronic	2	25	50	15.5
F32ES	F30T12/ES	Fluorescent, (2) 36", ES lamps	3' 1-Lamp T12ES	Mag-STD	2	25	73	8.5
F33ES	F30T12/ES	Fluorescent, (3) 36", ES lamps	3' 2-Lamp T12ES	Mag-STD	3	25	115	8.5
F34EE	F30T12/ES	Fluorescent, (4) 36", ES lamps	3' 4-Lamp T12ES	Mag-ES	4	25	132	8.5
F36EE	F30T12/ES	Fluorescent, (6) 36", ES lamps	3' 6-Lamp T12ES	Mag-ES	6	30	198	8.5
F36ES	F30T12/ES	Fluorescent, (6) 36", ES lamps	3' 6-Lamp T12ES	Mag-STD	6	30	219	8.5
F31SHS	F36T12/HO	Fluorescent, (1) 36", HO lamp	3' 1-Lamp T5HO	Mag-STD	1	50	70	8.5
F32SHS	F36T12/HO	Fluorescent, (2) 36", HO, lamps	3' 2-Lamp T12HO	Mag-STD	2	50	114	8.5
F41SIL	F40T12	Fluorescent, (1) 48", STD IS lamp, Electronic ballast	4' 1-Lamp T12	Electronic	1	39	46	15.5
F41SIL/T2	F40T12	Fluorescent, (1) 48", STD IS lamp, Tandem 2-lamp IS ballast	4' 1-Lamp T12	Electronic	1	39	37	15.5
F42SIL	F40T12	Fluorescent, (2) 48", STD IS lamps, Electronic ballast	4' 2-Lamp T12IS	Electronic	2	39	74	15.5
F43SIL	F40T12	Fluorescent, (3) 48", STD IS lamps, Electronic ballast	4' 3-Lamp T12IS	Electronic	3	39	120	15.5
F44SIL	F40T12	Fluorescent, (4) 48", STD IS lamps, Electronic ballast	4' 4-Lamp T12IS	Electronic	4	39	148	15.5
F46SL	F40T12	Fluorescent, (6) 48", STD lamps	4' 4-Lamp T12	Electronic	6	40	186	15.5
F41TS	F40T10	Fluorescent, (1) 48", T-10 lamp	4' 1-Lamp T10	Mag-STD	1	40	51	8.5
F41EE	F40T12/ES	Fluorescent, (1) 48", ES lamp	4' 1-Lamp T12ES	Mag-ES	1	34	43	8.5
F41EE/2	F40T12/ES	Fluorescent, (1) 48", ES lamp, 2 ballast	4' 1-Lamp T12ES	Mag-ES	1	34	43	8.5
F41EE/T2	F40T12/ES	Fluorescent, (1) 48", ES lamp, Tandem 2-lamp ballast	4' 1-Lamp T12ES	Mag-ES	1	34	36	8.5
F41EL	F40T12/ES	Fluorescent, (1) 48", T12 ES lamp, Electronic Ballast	4' 1-Lamp T12ES	Electronic	1	34	32	15.5
F42EE	F40T12/ES	Fluorescent, (2) 48", ES lamp	4' 2-Lamp T12ES	Mag-ES	2	34	72	8.5
F42EE/2	F40T12/ES	Fluorescent, (2) 48", ES lamps, (2) 1-lamp ballasts	4' 2-Lamp T12ES	Mag-ES	2	34	86	8.5
F42EE/D2	F40T12/ES	Fluorescent, (2) 48", ES lamps, 2 Ballasts (delamped)	4' 2-Lamp T12ES	Mag-ES	2	34	76	8.5
F42EL	F40T12/ES	Fluorescent, (2) 48", T12 ES lamps, Electronic Ballast	4' 2-Lamp T12ES	Electronic	2	34	60	15.5
F43EE	F40T12/ES	Fluorescent, (3) 48", ES lamps	4' 3-Lamp T12ES	Mag-ES	3	34	115	8.5
F43EE/T2	F40T12/ES	Fluorescent, (3) 48", ES lamps, Tandem 2-lamp ballasts	4' 3-Lamp T12ES	Mag-ES	3	34	108	8.5
F43EL	F40T12/ES	Fluorescent, (3) 48", T12 ES lamps, Electronic Ballast	4' 3-Lamp T12ES	Electronic	3	34	92	15.5
F44EE	F40T12/ES	Fluorescent, (4) 48", ES lamps	4' 3-Lamp T12ES	Mag-ES	4	34	144	8.5
F44EE/D3	F40T12/ES	Fluorescent, (4) 48", ES lamps, 3 Ballasts (delamped)	4' 4-Lamp T12ES	Mag-ES	4	34	148	8.5
F44EE/D4	F40T12/ES	Fluorescent, (4) 48", ES lamps, 4 Ballasts (delamped)	4' 3-Lamp T12ES	Mag-ES	4	34	152	8.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F44EL	F40T12/ ES	Fluorescent, (4) 48", T12 ES lamps, Electronic Ballast	4' 4-Lamp T12ES	Electronic	4	34	120	15.5
F46EE	F40T12/ ES	Fluorescent, (6) 48", ES lamps	4' 6-Lamp T12ES	Mag-ES	6	34	216	8.5
F46EL	F40T12/ ES	Fluorescent, (6) 48", ES lamps	4' 6-Lamp T12ES	Electronic	6	34	180	15.5
F48EE	F40T12/ ES	Fluorescent, (8) 48", ES lamps	4' 8-Lamp T12ES	Mag-ES	8	34	288	8.5
F42EHS	F42T12/ HO/ES	Fluorescent, (2) 42", HO lamps (3.5' lamp)	4' 2-Lamp T12HO	Mag-STD	2	55	135	8.5
F43EHS	F42T12/ HO/ES	Fluorescent, (3) 42", HO lamps (3.5' lamp)	4' 3-Lamp T12ES HO	Mag-STD	3	55	215	8.5
F41EIS	F48T12/ ES	Fluorescent, (1) 48" ES Instant Start lamp. Magnetic ballast	4' 1-Lamp T12ES	Mag-STD	1	40	51	8.5
F42EIS	F48T12/ ES	Fluorescent, (2) 48" ES Instant Start lamps. Magnetic ballast	4' 2-Lamp T12ES	Mag-STD	2	40	82	8.5
F43EIS	F48T12/ ES	Fluorescent, (3) 48" ES Instant Start lamps. Magnetic ballast	4' 3-Lamp T12ES	Mag-STD	3	40	133	8.5
F44EIS	F48T12/ ES	Fluorescent, (4) 48" ES Instant Start lamps. Magnetic ballast	4' 4-Lamp T12IS	Mag-STD	4	40	164	8.5
F41SHS	F48T12/ HO	Fluorescent, (1) 48", STD HO lamp	4' 1-Lamp T12HO	Mag-STD	1	60	85	8.5
F42SHS	F48T12/ HO	Fluorescent, (2) 48", STD HO lamps	4' 2-Lamp T12HO	Mag-STD	2	60	145	8.5
F43SHS	F48T12/ HO	Fluorescent, (3) 48", STD HO lamps	4' 3-Lamp T12HO	Mag-STD	3	60	230	8.5
F44SHS	F48T12/ HO	Fluorescent, (4) 48", STD HO lamps	4' 4-Lamp T12HO	Mag-STD	4	60	290	8.5
F41EHS	F48T12/ HO/ES	Fluorescent, (1) 48", ES HO lamp	4' 1-Lamp T12HO	Mag-STD	1	55	80	8.5
F44EHS	F48T12/ HO/ES	Fluorescent, (4) 48", ES HO lamps	4' 3-Lamp T12ES HO	Mag-STD	4	55	270	8.5
F41SVS	F48T12/ VHO	Fluorescent, (1) 48", STD VHO lamp	4' 1-Lamp T12VHO	Mag-STD	1	110	140	8.5
F42SVS	F48T12/ VHO	Fluorescent, (2) 48", STD VHO lamps	4' 2-Lamp T12VHO	Mag-STD	2	110	252	8.5
F43SVS	F48T12/ VHO	Fluorescent, (3) 48", STD VHO lamps	4' 3-Lamp T12VHO	Mag-STD	3	110	377	8.5
F44SVS	F48T12/ VHO	Fluorescent, (4) 48", STD VHO lamps	4' 4-Lamp T12VHO	Mag-STD	4	110	484	8.5
F44EVS	F48T12/ VHO/ES	Fluorescent, (4) 48", VHO ES lamps	4' 4-Lamp T12VHO	Mag-STD	4	100	420	8.5
F51SL	F60T12	Fluorescent, (1) 60", STD lamp	5' 1-Lamp T12	Electronic	1	50	44	15.5
F51SS	F60T12	Fluorescent, (1) 60", STD lamp	5' 1-Lamp T12	Mag-STD	1	50	63	8.5
F52SL	F60T12	Fluorescent, (2) 60", STD lamps	5' 2-Lamp T12	Electronic	2	50	88	15.5
F52SS	F60T12	Fluorescent, (2) 60", STD lamps	5' 2-Lamp T12	Mag-STD	2	50	128	8.5
F51SHE	F60T12/ HO	Fluorescent, (1) 60", STD HO lamp	5' 1-Lamp T12HO	Mag-ES	1	75	88	8.5
F51SHL	F60T12/ HO	Fluorescent, (1) 60", STD HO lamp	5' 1-Lamp T12HO	Electronic	1	75	69	15.5
F51SHS	F60T12/ HO	Fluorescent, (1) 60", STD HO lamp	5' 1-Lamp T12HO	Mag-STD	1	75	92	8.5
F52SHE	F60T12/ HO	Fluorescent, (2) 60", STD HO lamps	5' 2-Lamp T12HO	Mag-ES	2	75	176	8.5
F52SHL	F60T12/ HO	Fluorescent, (2) 60", STD HO lamps	5' 2-Lamp T12HO	Electronic	2	75	138	15.5
F52SHS	F60T12/ HO	Fluorescent, (2) 60", STD HO lamps	5' 2-Lamp T12HO	Mag-STD	2	75	168	8.5
F51SVS	F60T12/ VHO	Fluorescent, (1) 60", VHO ES lamp	5' 1-Lamp T12VHO	Mag-STD	1	135	165	8.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F52SVS	F60T12/ VHO	Fluorescent, (2) 60", VHO ES lamps	5' 2-Lamp T12VHO	Mag-STD	2	135	310	8.5
F61ISL	F72T12	Fluorescent, (1) 72", STD lamp, IS electronic ballast	6' 1-Lamp T12	Electronic	1	55	68	15.5
F61SS	F72T12	Fluorescent, (1) 72", STD lamp	6' 1-Lamp T12	Mag-STD	1	55	76	8.5
F62ISL	F72T12	Fluorescent, (2) 72", STD lamps, IS electronic ballast	6' 2-Lamp T12IS	Electronic	2	55	108	15.5
F62SE	F72T12	Fluorescent, (2) 72", STD lamps	6' 2-Lamp T12	Mag-ES	2	55	122	8.5
F62SL	F72T12	Fluorescent, (2) 72", STD lamps	6' 2-Lamp T12	Electronic	2	55	108	15.5
F62SS	F72T12	Fluorescent, (2) 72", STD lamps	6' 2-Lamp T12	Mag-STD	2	55	142	8.5
F63ISL	F72T12	Fluorescent, (3) 72", STD lamps, IS electronic ballast	6' 3-Lamp T12IS	Electronic	3	55	176	15.5
F63SS	F72T12	Fluorescent, (3) 72", STD lamps	6' 3-Lamp T12	Mag-STD	3	55	202	8.5
F64ISL	F72T12	Fluorescent, (4) 72", STD lamps, IS electronic ballast	6' 4-Lamp T12IS	Electronic	4	55	216	15.5
F64SE	F72T12	Fluorescent, (4) 72", STD lamps	6' 4-Lamp T12	Mag-ES	4	55	244	8.5
F64SS	F72T12	Fluorescent, (4) 72", STD lamps	6' 4-Lamp T12	Mag-STD	4	56	244	8.5
F61SHS	F72T12/ HO	Fluorescent, (1) 72", STD HO lamp	6' 1-Lamp T12HO	Mag-STD	1	85	106	8.5
F62SHE	F72T12/ HO	Fluorescent, (2) 72", STD HO lamps	6' 2-Lamp T12HO	Mag-ES	2	85	194	8.5
F62SHL	F72T12/ HO	Fluorescent, (2) 72", STD HO lamps	6' 2-Lamp T12HO	Electronic	2	85	167	15.5
F62SHS	F72T12/ HO	Fluorescent, (2) 72", STD HO lamps	6' 2-Lamp T12HO	Mag-STD	2	85	200	8.5
F64SHE	F72T12/ HO	Fluorescent, (4) 72", HO lamps	6' 4-Lamp T12HO	Mag-ES	4	85	388	8.5
F61SVS	F72T12/ VHO	Fluorescent, (1) 72", VHO lamp	6' 1-Lamp T12VHO	Mag-STD	1	160	180	8.5
F62SVS	F72T12/ VHO	Fluorescent, (2) 72", VHO lamps	6' 2-Lamp T12VHO	Mag-STD	2	160	330	8.5
F71HS	F84T12/ HO	Fluorescent, (1) 84", HO lamp	7' 1-Lamp T12HO	Mag-ES	1	100	104	8.5
F72HS	F84T12/ HO	Fluorescent, (2) 84", HO lamp	7' 2-Lamp T12HO	Mag-ES	2	100	198	8.5
F81SL	F96T12	Fluorescent, (1) 96", STD lamp	8' 1-Lamp T12	Electronic	1	75	69	15.5
F81SL/T2	F96T12	Fluorescent, (1) 96", STD lamp, Tandem 2-lamp ballast	8' 1-Lamp T12	Electronic	1	75	55	15.5
F82SL	F96T12	Fluorescent, (2) 96", STD lamps	8' 2-Lamp T12	Electronic	2	75	110	15.5
F83SL	F96T12	Fluorescent, (3) 96", STD lamps	8' 3-Lamp T12	Electronic	3	75	179	15.5
F84SL	F96T12	Fluorescent, (4) 96", STD lamps	8' 4-Lamp T12	Electronic	4	75	220	15.5
F81EE	F96T12/ ES	Fluorescent, (1) 96" ES lamp	8' 4-Lamp T12ES	Mag-ES	1	60	75	8.5
F81EE/T2	F96T12/ ES	Fluorescent, (1) 96", ES lamp, Tandem 2-lamp ballast	8' 1-Lamp T12ES	Mag-ES	1	60	62	8.5
F81EL	F96T12/ ES	Fluorescent, (1) 96", ES lamp	8' 1-Lamp T12ES	Electronic	1	60	69	15.5
F81EL/T2	F96T12/ ES	Fluorescent, (1) 96", ES lamp, Tandem 2-lamp ballast	8' 1-Lamp T12ES	Electronic	1	60	55	15.5
F82EE	F96T12/ ES	Fluorescent, (2) 96", ES lamps	8' 2-Lamp T12ES	Mag-ES	2	60	123	8.5
F82EL	F96T12/ ES	Fluorescent, (2) 96", ES lamps	8' 2-Lamp T12ES	Electronic	2	60	110	15.5
F83EE	F96T12/ ES	Fluorescent, (3) 96", ES lamps	8' 3-Lamp T12ES	Mag-ES	3	60	198	8.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F83EL	F96T12/ ES	Fluorescent, (3) 96", ES lamps	8' 3-Lamp T12ES	Electronic	3	60	179	15.5
F84EE	F96T12/ ES	Fluorescent, (4) 96", ES lamps	8' 4-Lamp T12ES	Mag-ES	4	60	246	8.5
F84EL	F96T12/ ES	Fluorescent, (4) 96", ES lamps	8' 4-Lamp T12ES	Electronic	4	60	220	15.5
F86EE	F96T12/ ES	Fluorescent, (6) 96", ES lamps	8' 6-Lamp T12ES	Mag-ES	6	60	369	8.5
F81SHS	F96T12/ HO	Fluorescent, (1) 96", STD HO lamp	8' 1-Lamp T12HO	Mag-STD	1	110	121	8.5
F82SHE	F96T12/ HO	Fluorescent, (2) 96", STD HO lamps	8' 2-Lamp T12HO	Mag-ES	2	110	207	8.5
F82SHL	F96T12/ HO	Fluorescent, (2) 96", STD HO lamps	8' 2-Lamp T12HO	Electronic	2	110	173	15.5
F82SHS	F96T12/ HO	Fluorescent, (2) 96", STD HO lamps	8' 2-Lamp T12HO	Mag-STD	2	110	207	8.5
F83SHE	F96T12/ HO	Fluorescent, (3) 96", STD HO lamps	8' 3-Lamp T12HO	Mag-ES	3	110	319	8.5
F83SHS	F96T12/ HO	Fluorescent, (3) 96", STD HO lamps	8' 3-Lamp T12HO	Mag-STD	3	110	319	8.5
F84SHE	F96T12/ HO	Fluorescent, (4) 96", STD HO lamps	8' 4-Lamp T12HO	Mag-ES	4	110	414	8.5
F84SHL	F96T12/ HO	Fluorescent, (4) 96", STD HO lamps	8' 4-Lamp T12HO	Electronic	4	110	346	15.5
F84SHS	F96T12/ HO	Fluorescent, (4) 96", STD HO lamps	8' 4-Lamp T12HO	Mag-STD	4	110	414	8.5
F88SHS	F96T12/ HO	Fluorescent, (8) 96", STD HO lamps	8' 8-Lamp T12HO	Mag-STD	8	110	828	8.5
F81EHL	F96T12/ HO/ES	Fluorescent, (1) 96", ES HO lamp	8' 1-Lamp T12ES HO	Electronic	1	95	80	15.5
F81EHS	F96T12/ HO/ES	Fluorescent, (1) 96", ES HO lamp	8' 1-Lamp T12ES HO	Mag-STD	1	95	113	8.5
F82EHE	F96T12/ HO/ES	Fluorescent, (2) 96", ES HO lamps	8' 2-Lamp T12ES HO	Mag-ES	2	95	207	8.5
F82EHL	F96T12/ HO/ES	Fluorescent, (2) 96", ES HO lamps	8' 2-Lamp T12ES HO	Electronic	2	95	173	15.5
F82EHS	F96T12/ HO/ES	Fluorescent, (2) 96", ES HO lamps	8' 2-Lamp T12ES HO	Mag-STD	2	95	207	8.5
F83EHE	F96T12/ HO/ES	Fluorescent, (3) 96", ES HO lamps, (1) 2-lamp ES Ballast and (1) 1-lamp STD Ballast	8' 3-Lamp T12ES HO	Mag-ES/STD	3	95	319	8.5
F83EHS	F96T12/ HO/ES	Fluorescent, (3) 96", ES HO lamps	8' 3-Lamp T12ES HO	Mag-STD	3	95	319	8.5
F84EHE	F96T12/ HO/ES	Fluorescent, (4) 96", ES HO lamps	8' 4-Lamp T12ES HO	Mag-ES	4	95	414	8.5
F84EHL	F96T12/ HO/ES	Fluorescent, (4) 96", ES HO lamps	8' 4-Lamp T12ES HO	Electronic	4	95	346	15.5
F84EHS	F96T12/ HO/ES	Fluorescent, (4) 96", ES HO lamps	8' 4-Lamp T12ES HO	Mag-STD	4	95	414	8.5
F86EHS	F96T12/ HO/ES	Fluorescent, (6) 96", ES HO lamps	8' 6-Lamp T12ES HO	Mag-STD	6	95	519	8.5
F88EHE	F96T12/ HO/ES	Fluorescent, (8) 96", ES HO lamps	8' 8-Lamp T12ES HO	Mag-ES	8	95	828	8.5
F81SVS	F96T12/ VHO	Fluorescent, (1) 96", STD VHO lamp	8' 1-Lamp T12VHO	Mag-STD	1	215	205	8.5
F82SVS	F96T12/ VHO	Fluorescent, (2) 96", STD VHO lamps	8' 2-Lamp T12VHO	Mag-STD	2	215	380	8.5
F83SVS	F96T12/ VHO	Fluorescent, (3) 96", STD VHO lamps	8' 3-Lamp T12VHO	Mag-STD	3	215	585	8.5
F84SVS	F96T12/ VHO	Fluorescent, (4) 96", STD VHO lamps	8' 4-Lamp T12VHO	Mag-STD	4	215	760	8.5
F81EVS	F96T12/ VHO/ES	Fluorescent, (1) 96", ES VHO lamp	8' 1-Lamp T12ES VHO	Mag-STD	1	185	205	8.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
F82EVS	F96T12/ VHO/ES	Fluorescent, (2) 96", ES VHO lamps	8' 2-Lamp T12ES VHO	Mag-STD	2	195	380	8.5
F83EVS	F96T12/ VHO/ES	Fluorescent, (3) 96", ES VHO lamps	8' 3-Lamp T12ES VHO	Mag-STD	3	185	585	8.5
F84EVS	F96T12/ VHO/ES	Fluorescent, (4) 96", ES VHO lamps	8' 4-Lamp T12ES VHO	Mag-STD	4	185	760	8.5
F81SGS	F96T17	Fluorescent, (1) 96", T17 Grooved lamp	8' 1-Lamp T12	Mag-STD	1	215	235	8.5
F40SE/D1	None	Fluorescent, (0) 48" lamps, Completely delamped fixture with (1) hot ballast		Mag-ES	1	0	4	8.5
F40SE/D2	None	Fluorescent, (0) 48" lamps, Completely delamped fixture with (2) hot ballast		Mag-ES	1	0	8	8.5
Circline Fluorescent Fixtures								
FC6/1	FC6T9	Fluorescent, (1) 6" circular lamp, RS ballast	6" 1-Lamp T9 Cir	Mag-STD	1	20	25	15.5
FC8/1	FC8T9	Fluorescent, (1) 8" circular lamp, RS ballast	8" 1-Lamp T9 Cir	Mag-STD	1	22	26	15.5
FC8/2	FC8T9	Fluorescent, (2) 8" circular lamps, RS ballast	8" 2-Lamp T9 Cir	Mag-STD	2	22	52	15.5
FC20	FC6T9	Fluorescent, Circline, (1) 20W lamp, preheat ballast	20W 1-Lamp T9 Cir	Mag-STD	1	20	20	15.5
FC22	FC8T9	Fluorescent, Circline, (1) 22W lamp, preheat ballast	22W 1-Lamp T9 Cir	Mag-STD	1	22	20	15.5
FC12/1	FC12T9	Fluorescent, (1) 12" circular lamp, RS ballast	12" 1-Lamp T9 Cir	Mag-STD	1	32	31	15.5
FC12/2	FC12T9	Fluorescent, (2) 12" circular lamps, RS ballast	12" 2-Lamp T9 Cir	Mag-STD	2	32	62	15.5
FC32	FC12T9	Fluorescent, Circline, (1) 32W lamp, preheat ballast	32W 1-Lamp T9 Cir	Mag-STD	1	32	40	15.5
FC16/1	FC16T9	Fluorescent, (1) 16" circular lamp	16" 1-Lamp T9 Cir	Mag-STD	1	40	35	15.5
FC40	FC16T9	Fluorescent, Circline, (1) 32W lamp, preheat ballast	40W 1-Lamp T9 Cir	Mag-STD	1	32	42	15.5
Fluorescent Electrodeless Induction Fixtures								
FEI40/1	CFT40W	Electrodeless Fluorescent System, (1) 40W lamp	1-Lamp 40W Induction	Electronic	1	40	44	15.5
FEI55/1	CFT55W	Electrodeless Fluorescent System, (1) 55W lamp	1-Lamp 55W Induction	Electronic	1	55	59	15.5
FEI60/1	CFT60W	Electrodeless Fluorescent System, (1) 60W lamp	1-Lamp 60W Induction	Electronic	1	60	64	15.5
FEI70/1	CFT70W	Electrodeless Fluorescent System, (1) 70W lamp	1-Lamp 70W Induction	Electronic	1	70	74	15.5
FEI80/1	CFT80W	Electrodeless Fluorescent System, (1) 80W lamp	1-Lamp 80W Induction	Electronic	1	80	84	15.5
FEI85/1	CFT85W	Electrodeless Fluorescent System, (1) 85W lamp	1-Lamp 85W Induction	Electronic	1	85	89	15.5
FEI100/1	CFT100 W	Electrodeless Fluorescent System, (1) 100W lamp	1-Lamp 100W Induction	Electronic	1	100	105	15.5
FEI125/1	CFT125 W	Electrodeless Fluorescent System, (1) 125W lamp	1-Lamp 125W Induction	Electronic	1	125	131	15.5
FEI150/1	CFT150 W	Electrodeless Fluorescent System, (1) 150W lamp	1-Lamp 150W Induction	Electronic	1	150	157	15.5
FEI165/1	CFT165 W	Electrodeless Fluorescent System, (1) 165W lamp	1-Lamp 165W Induction	Electronic	1	165	173	15.5
FEI200/1	CFT200 W	Electrodeless Fluorescent System, (1) 200W lamp	1-Lamp 200W Induction	Electronic	1	200	210	15.5
FEI250/1	CFT250 W	Electrodeless Fluorescent System, (1) 250W lamp	1-Lamp 250W Induction	Electronic	1	250	263	15.5
FEI300/1	CFT300 W	Electrodeless Fluorescent System, (1) 300W lamp	1-Lamp 300W Induction	Electronic	1	300	315	15.5
FEI400/1	CFT400 W	Electrodeless Fluorescent System, (1) 400W lamp	1-Lamp 400W Induction	Electronic	1	400	420	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
U-Tube Fluorescent Fixtures								
FU1ILL	FU31T8/6	Fluorescent, (1) U-Tube, T-8 lamp, Instant Start ballast	1-Lamp T8 U-Tube	Electronic	1	32	31	15.5
FU1LL	FU31T8/6	Fluorescent, (1) U-Tube, T-8 lamp	1-Lamp T8 U-Tube	Electronic	1	32	32	15.5
FU1LL-R	FU31T8/6	Fluorescent, (1) U-Tube, T-8 lamp, RLO (BF < 0.85)	1-Lamp T8 U-Tube	Electronic	1	31	27	15.5
FU2ILL	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start Ballast	1-Lamp T8 U-Tube	Electronic	2	32	59	15.5
FU2ILL-H	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start HLO Ballast	2-Lamp T8 HLO U-Tube	Electronic	2	32	65	15.5
FU2ILL-R	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start RLO Ballast	2-Lamp T8 RLO U-Tube	Electronic	2	32	52	15.5
FU2ILL/T4	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start Ballast, Tandem 4-lamp ballast	2-Lamp T8 U-Tube	Electronic	2	32	56	15.5
FU2ILL/T4-R	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start Ballast, RLO, Tandem 4-lamp ballast	2-Lamp T8 RLO U-Tube	Electronic	2	32	49	15.5
FU2LL	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps	2-Lamp T8 U-Tube	Electronic	2	32	60	15.5
FU2LL-R	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, RLO (BF < 0.85)	2-Lamp T8 RLO U-Tube	Electronic	2	31	54	15.5
FU2LL/T2	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Tandem 4-lamp ballast	2-Lamp T8 U-Tube	Electronic	2	32	59	15.5
FU3ILL	FU31T8/6	Fluorescent, (3) U-Tube, T-8 lamps, Instant Start Ballast	3-Lamp T8 U-Tube	Electronic	3	32	89	15.5
FU3ILL-R	FU31T8/6	Fluorescent, (3) U-Tube, T-8 lamps, Instant Start RLO Ballast	3-Lamp T8ES U-Tube	Electronic	3	32	78	15.5
FU1ILU	FU32T8/6	Fluorescent, (1) 6" spacing U-Tube, T-8 lamp, IS Ballast, NLO (0.85 < BF < 0.95)	1-Lamp T8 6" Spacing U-Tube	Electronic	1	32	29	15.5
FU1ILU-H	FU32T8/6	Fluorescent, (1) 6" spacing U-Tube, T-8 lamp, IS Ballast, HLO (.95 < BF < 1.1)	1-Lamp T8 6" Spacing U-Tube HLO	Electronic	1	32	34	15.5
FU2ILU	FU32T8/6	Fluorescent, (2) 6" spacing U-Tube, T-8 lamps, IS Ballast, NLO (0.85 < BF < 0.95)	2-Lamp T8 6" Spacing U-Tube	Electronic	2	32	55	15.5
FU2ILU-R	FU32T8/6	Fluorescent, (2) 6" spacing U-Tube, T-8 lamps, IS Ballast, RLO (BF < 0.85)	2-Lamp T8 6" Spacing U-Tube RLO	Electronic	2	32	48	15.5
FU2ILU-V	FU32T8/6	Fluorescent, (2) 6" spacing U-Tube, T-8 lamps, IS Ballast, VHLO (BF > 1.1)	2-Lamp T8 6" Spacing U-Tube VHLO	Electronic	2	32	73	15.5
FU3ILU	FU32T8/6	Fluorescent, (3) 6" spacing U-Tube, T-8 lamps, IS Ballast, NLO (0.85 < BF < 0.95)	3-Lamp T8 6" Spacing U-Tube	Electronic	3	32	81	15.5
FU3ILU-R	FU32T8/6	Fluorescent, (3) 6" spacing U-Tube, T-8 lamps, IS Ballast, RLO (BF < 0.85)	3-Lamp T8 6" Spacing U-Tube RLO	Electronic	3	32	73	15.5
FU1SE	FU40T12	Fluorescent, (1) U-Tube, STD lamp	1-Lamp T12 U-Tube	Mag-ES	1	40	43	15.5
FU1SS	FU40T12	Fluorescent, (1) U-Tube, ES Lamp	1-Lamp T12 U-Tube ES	Mag-STD	1	40	43	8.5
FU2SE	FU40T12	Fluorescent, (2) U-Tube, STD lamps	2-Lamp T12 U-Tube	Mag-ES	2	40	72	15.5
FU2SL	FU40T12	Fluorescent (2) 48" U-bent Standard lamps, Electronic ballast, NLO (0.85 < BF < 0.95)	2-Lamp T12 U-Tube	Electronic	2	40	63	15.5
FU2SS	FU40T12	Fluorescent, (1) U-Tube, STD lamp, STD Mag Ballast	2-Lamp T12 U-Tube	Mag-STD	2	40	72	8.5
FU3SE	FU40T12	Fluorescent, (3) U-Tube, STD lamps	3-Lamp T12 U-Tube	Mag-ES	3	40	115	15.5
FU1EE	FU40T12/ES	Fluorescent, (1) U-Tube, ES lamp	1-Lamp T12ES U-Tube	Mag-ES	1	35	43	15.5
FU1ES	FU40T12/ES	Fluorescent, (1) U-Tube, ES Lamp	1-Lamp T12ES U-Tube	Mag-STD	1	34	43	8.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
FU2EE	FU40T12 /ES	Fluorescent, (2) U-Tube, ES lamps	1-Lamp T12ES U-Tube	Mag-ES	2	35	72	15.5
FU2EL	FU40T12 /ES	Fluorescent (2) 48" U-bent ES lamps, Electronic ballast, NLO (0.85 < BF < 0.95)	1-Lamp T12ES U-Tube	Electronic	2	34	63	15.5
FU2ES	FU40T12 /ES	Fluorescent, (2) U-Tube, ES lamps	1-Lamp T12ES U-Tube	Mag-STD	1	35	72	8.5
FU3EE	FU40T12 /ES	Fluorescent, (3) U-Tube, ES lamps	3-Lamp T12ES U-Tube	Mag-ES	3	35	115	15.5
High Pressure Sodium Fixtures								
HPS35/1	HPS35	High Pressure Sodium, (1) 35W lamp	35W HPS		1	35	46	15.5
HPS50/1	HPS50	High Pressure Sodium, (1) 50W lamp	50W HPS		1	50	66	15.5
HPS70/1	HPS70	High Pressure Sodium, (1) 70W lamp	70W HPS		1	70	95	15.5
HPS100/1	HPS100	High Pressure Sodium, (1) 100W lamp	100W HPS		1	100	138	15.5
HPS150/1	HPS150	High Pressure Sodium, (1) 150W lamp	150W HPS		1	150	188	15.5
HPS200/1	HPS200	High Pressure Sodium, (1) 200W lamp	200W HPS		1	200	250	15.5
HPS250/1	HPS250	High Pressure Sodium, (1) 250W lamp	250W HPS		1	250	295	15.5
HPS310/1	HPS310	High Pressure Sodium, (1) 310W lamp	310W HPS		1	310	365	15.5
HPS360/1	HPS360	High Pressure Sodium, (1) 360W lamp	360W HPS		1	360	414	15.5
HPS400/1	HPS400	High Pressure Sodium, (1) 400W lamp	400W HPS		1	400	465	15.5
HPS1000/ 1	HPS1000	High Pressure Sodium, (1) 1000W lamp	1000W HPS		1	1000	1100	15.5
Metal Halide Fixtures - Standard, Pulse Start, or Ceramic								
MH20/1-L	MH20	Metal Halide, (1) 20W lamp	20W Metal Halide	Electronic	1	20	23	15.5
MH22/1-L	MH22	Metal Halide, (1) 22W lamp	22W Metal Halide	Electronic	1	22	26	15.5
MH32/1	MH32	Metal Halide, (1) 32W lamp, Magnetic ballast	32W Metal Halide	Magnetic	1	32	42	15.5
MH39/1	MH39	Metal Halide, (1) 39W lamp, Magnetic ballast	39W Metal Halide	Magnetic	1	39	51	15.5
MH39/1-L	MH39	Metal Halide, (1) 39W lamp	39W Metal Halide	Electronic	1	39	44	15.5
MH50/1	MH50	Metal Halide, (1) 50W lamp, Magnetic ballast	50W Metal Halide	Magnetic	1	50	64	15.5
MH50/1-L	MH50	Metal Halide, (1) 50W lamp	50W Metal Halide	Electronic	1	50	56	15.5
MH70/1	MH70	Metal Halide, (1) 70W lamp, Magnetic ballast	70W Metal Halide	Magnetic	1	70	91	15.5
MH70/1-L	MH70	Metal Halide, (1) 70W lamp	70W Metal Halide	Electronic	1	70	78	15.5
MH100/1	MH100	Metal Halide, (1) 100W lamp, Magnetic ballast	100W Metal Halide	Magnetic	1	100	124	15.5
MH100/1 -L	MH100	Metal Halide, (1) 100W lamp	100W Metal Halide	Electronic	1	100	108	15.5
MH125/1	MH125	Metal Halide, (1) 125W lamp, Magnetic ballast	125W Metal Halide	Magnetic	1	125	148	15.5
MH150/1	MH150	Metal Halide, (1) 150W lamp, Magnetic ballast	150W Metal Halide	Magnetic	1	150	183	15.5
MH150/1 -L	MH150	Metal Halide, (1) 150W lamp	150W Metal Halide	Electronic	1	150	163	15.5
MH175/1	MH175	Metal Halide, (1) 175W lamp, Magnetic ballast	175W Metal Halide	Magnetic	1	175	208	15.5
MH175/1 -L	MH175	Metal Halide, (1) 175W lamp	175W Metal Halide	Electronic	1	175	196	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
MH200/1	MH200	Metal Halide, (1) 200W lamp, Magnetic ballast	200W Metal Halide	Magnetic	1	200	228	15.5
MH200/1 -L	MH200	Metal Halide, (1) 200W lamp	200W Metal Halide	Electronic	1	200	219	15.5
MH250/1	MH250	Metal Halide, (1) 250W lamp, Magnetic ballast	250W Metal Halide	Magnetic	1	250	288	15.5
MH250/1 -L	MH250	Metal Halide, (1) 250W lamp	250W Metal Halide	Electronic	1	250	275	15.5
MH320/1	MH320	Metal Halide, (1) 320W lamp, Magnetic ballast	320W Metal Halide	Magnetic	1	320	362	15.5
MH320/1 -L	MH320	Metal Halide, (1) 320W lamp	320W Metal Halide	Electronic	1	320	343	15.5
MH350/1	MH350	Metal Halide, (1) 350W lamp, Magnetic ballast	350W Metal Halide	Magnetic	1	350	391	15.5
MH350/1 -L	MH350	Metal Halide, (1) 350W lamp	350W Metal Halide	Electronic	1	350	375	15.5
MH360/1	MH360	Metal Halide, (1) 360W lamp, Magnetic ballast	360W Metal Halide	Magnetic	1	360	418	15.5
MH400/1	MH400	Metal Halide, (1) 400W lamp, Magnetic ballast	400W Metal Halide	Magnetic	1	400	453	15.5
MH400/1 -L	MH400	Metal Halide, (1) 400W lamp	400W Metal Halide	Electronic	1	400	429	15.5
MH450/1	MH450	Metal Halide, (1) 450W lamp, Magnetic ballast	450W Metal Halide	Magnetic	1	450	499	15.5
MH450/1 -L	MH450	Metal Halide, (1) 450W lamp	450W Metal Halide	Electronic	1	450	486	15.5
MH575/1	MH575	Metal Halide, (1) 575W lamp, Magnetic ballast	575W Metal Halide	Magnetic	1	575	630	15.5
MH750/1	MH750	Metal Halide, (1) 750W lamp, Magnetic ballast	750W Metal Halide	Magnetic	1	750	812	15.5
MH775/1	MH775	Metal Halide, (1) 775W lamp, Magnetic ballast	775W Metal Halide	Magnetic	1	775	843	15.5
MH875/1	MH875	Metal Halide, (1) 875W lamp	875W Metal Halide	Magnetic	1	875	939	15.5
MH1000/ 1	MH1000	Metal Halide, (1) 1000W lamp, Magnetic ballast	1000W Metal Halide	Magnetic	1	1000	1078	15.5
MH1000/ 1-L	MH1000	Metal Halide, (1) 1000W lamp	1000W Metal Halide	Electronic	1	1000	1067	15.5
MH1500/ 1	MH1500	Metal Halide, (1) 1500W lamp, Magnetic ballast	1500W Metal Halide	Magnetic	1	1500	1605	15.5
MH1650/ 1	MH1650	Metal Halide, (1) 1650W lamp	1650W Metal Halide	Magnetic	1	1650	1765	15.5
MH2000/ 1	MH2000	Metal Halide, (1) 2000W lamp	2000W Metal Halide	Magnetic	1	2000	2140	15.5
Mercury Vapor Fixtures								
MV40/1	MV40	Mercury Vapor, (1) 40W lamp	40W Mercury Vapor		1	40	50	15.5
MV50/1	MV50	Mercury Vapor, (1) 50W lamp	50W Mercury Vapor		1	50	74	15.5
MV75/1	MV75	Mercury Vapor, (1) 75W lamp	75W Mercury Vapor		1	75	93	15.5
MV100/1	MV100	Mercury Vapor, (1) 100W lamp	100W Mercury Vapor		1	100	125	15.5
MV160/1	MV160-SB	Mercury Vapor, Self-Ballasted, (1) 160W self-ballasted lamp	160W Mercury Vapor		1	160	160	15.5
MV175/1	MV175	Mercury Vapor, (1) 175W lamp	175W Mercury Vapor		1	175	205	15.5
MV250/1	MV250	Mercury Vapor, (1) 250W lamp	250W Mercury Vapor		1	250	290	15.5
MV400/1	MV400	Mercury Vapor, (1) 400W lamp	400W Mercury Vapor		1	400	455	15.5
MV700/1	MV700	Mercury Vapor, (1) 700W lamp	700W Mercury Vapor		1	700	780	15.5

Fixture code	Lamp code	Description	Layman term	Ballast	Lamp	With Lamp	With Fixture	EUL
MV1000/1	MV1000	Mercury Vapor, (1) 1000W lamp	1000W Mercury Vapor		1	1000	1075	15.5

1.2 Appendix B Examples for Existing Baseline Methods for Settlement & Examples of Adjustments

1.2.1 EXAMPLES FOR EXISTING BASELINE METHODS FOR SETTLEMENT

Baselines facilitate the measurement of load reduction that occurs during a DR event. They represent an estimate of the load that would have existed in the absence of the program. In a settlement context, this measurement is required for programs that provide incentives based on measured load reductions. Not all DR programs require a baseline for settlement. Some programs depend on measure load as the basis for settlement (e.g., firm service level).

Baselines are also required for the ex post impact evaluation of a DR program. These baselines can be quite different from baselines for settlement. With the advantage of full season data and fewer limitations on computational complexity, impact evaluation baselines have traditionally taken advantage of day matching techniques across the whole season and regression approaches.

This section provides examples of baseline methods used for M&V for settlement in various wholesale markets. Most [or all] of the baseline examples below were tested in a PJM study comparing the accuracy of alternative baseline methods.[13] The methods tested were selected to provide a range of approaches for study. Findings from the PJM analysis and other baseline assessments are summarized in 1.3 *Appendix C Prior work in DR M&V Methods*. The section also addresses baselines for ex post impact evaluations as well.

The methods as described may vary from current methods in use. In a few cases, some simplification of the full method used in the market was made to facilitate the analysis. Also, markets refine their baseline methods over time as new issues arise with program operations. Nonetheless these provide a good illustration of approaches in use. In particular, the baseline methods selected for inclusion in the PJM report were selected to cover a range of:

- Estimation methods (averaging, matching, regression)
- Data timeframes (From same /Previous day to previous year)
- Data selection rules (e.g., proximity to event, similarity of load, similarity of weather, a subset of recent eligible days—highest x of y)
- Weather-sensitive and non-weather-sensitive loads
- Other complexities

Table 1-26 lists examples of customer baseline methodologies. Additional details on these methods are provided in the report on the PJM study.

[13] KEMA, Inc. PJM Empirical Analysis of Demand Response Baseline Methods. April 20, 2011 http://pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/pjm-analysis-of-dr- baseline-methods-full-report.ashx

Table 1-26 Examples of Customer Baseline Methodologies

#	CBL Protocol	Data Selection			Calculation Type
		Baseline Window	**Exclusion Rules--Final Selection of Days and Hours**	**Exclusion Rules--Excluded Days (Besides prev. event days)**	
1	PJM Economic CBL	45 most recent calendar days preceding event, extended up to 15 additional to replace excluded days	Weekday Events: High 4 of 5 most recent qualifying days.	Weekday Events: weekends, holidays, low-usage days.	Average
			Weekend/holiday Events: High 2 of 3 most recent qualifying like days.	Weekend/holiday Events: weekdays, low-usage days	
2	CAISO Standard CBL	Recent 10	10		Average
3	ERCOT middle 8 of 10[3]	Recent 10	8	Highest, lowest kWh consumption days	Average
4	Middle 4 of 6[4]	Recent 6	4	Highest, lowest kWh consumption days	Average
5	NYISO Standard CBL Standard CBL[5]	Weekdays: 10 recent weekdays starting 2 days before event day.	Weekdays: High 5 of 10	Low -usage days	Average
		Weekends: 3 recent like (Saturday or Sunday) weekend days. No exclusions for holidays or event days	Weekends: High 2 of 3		
6	ISONE Standard CBL[6]	Prior day baseline and current day meter data	0.9*baseline + 0.1*meter		Average
7	PJM emergency GLD comparable day (non- weather sensitive)[7]	Closest weekday (before or after event), excluding event days and holidays.	1 day	Weekends/ holidays	Matching
8	PJM emergency GLD comparable day (weather sensitive)[8]	Season	1 day -- SSE of THI	Weekends/ holidays	Matching
9	ERCOT matching day pair[9]	Previous Year	10 similar matching day pairs -- SSE of previous 24 hours' load	Day-pairs that include an event	Matching -- Average over 10 similar day-pairs

10	PJM emergency GLD same day10	Day of event	Hours pre- and post-event		Average
11	PJM emergency energy settlement11	Hour before			Flat
12	ERCOT regression CBL12	Previous year	365+		Regression
13	Alternative regression CBL13	Previous 20 like days	20		Regression

Notes associated with the table above are listed below.

1 PJM, “Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (http://pjm.com/~/media/documents/agreements/oa.ashx, retrieved 1/31/2011), section 3.3A.2, “Customer Baseline Load” (pp. 360-368).

2 Jenny Pedersen, California ISO, “Proxy Demand Resources Full Market Module,” (http://www.caiso.com/275d/275d778249a30.pdf, retrieved 1/31/2011), pp. 67-78.

3 ERCOT, “Emergency Interruptible Load Service Default Baseline Methodologies,” (no date), (http://www.ercot.com/content/services/programs/load/eils/keydocs/Default_Baseline_Methodologies_REVISED-FINAL.doc), retrieved 2/5/2011, p. 26. ERCOT applies a ratio adjustment when using this baseline; MMU, the party proposing inclusion of this CBL, requested it be evaluated with and without the Symmetric Additive Adjustment.

4 Personal communication, Pete Langbein (email 1/14/2011). The comments regarding adjustments in footnote 3 also apply here.

5 NYISO, “Manual 7:Emergency Demand Response Program Manual,” December 2010 (http://www.nyiso.com/public/webdocs/documents/manuals/operations/edrp_mnl.pdf, retrieved 11/26/2012), pp. 29-35. Page 35 also includes an example of a baseline method for Metering Generator Output.

6 Market Rule 1, Section III.8 http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf.

7 PJM, “Manual 19: Load Forecasting and Analysis,” Attachment A: Load Drop Estimate Guidelines (redline edited version), p. 24.

8 *Ibid*., pp. 24-25.

9 ERCOT, op. cit., p. 27.

10 PJM, op. cit., p. 25. 11 PJM, “RFP for PJM Empirical Analysis of Demand Response Baseline Methods,” October 29, 2010, p. 5.

11 ERCOT, op.cit., pp. 2-23. ". The ERCOT regression model consists of a daily energy equation and 24 hourly energy fraction equations. For detailed description, see ERCOT, "Emergency Interruptible Load Service Default Baseline Methodologies," (http://www.ercot.com/content/services/programs/load/eils/keydocs/Default_Baseline_Methodologies_REVISED-FINAL.doc), retrieved 2/5/2011, pp. 2-23. KEMA estimated the parameters of this model using one full year of hourly load and weather data for the year October 1, 2008 through September 30, 2009, then applied them to hourly data for October 1, 2009 through September 30, 2010 to produce the baseline forecasts. The forecasted baseline for a particular hour of any given date consists of the product of the predicted daily energy value for that date and the predicted hourly fraction for the relevant hour of the day.

12 KEMA, memorandum to Pete Langbein, Jim McAnany, Don Kujawski dated January 20, 2011, "Proposed additional regression CBL

1.2.1.1 Baseline Adjustments

The methods summarized in the table above are "provisional baseline" (PBL) methods; the result of this method may be adjusted to conditions of the current day. Example adjustment methods in use are indicated in Table 1-27. Most [or all] of these adjustment methods were tested in the PJM baseline study, in combination with the preliminary methods of the previous table.

The table provides a simplified description of the adjustment methods. Despite numerous details that distinguish particular adjustments in use from each other, they fall into longstanding categories of baseline adjustments. Because there are endless variations of adjustments, only adjustments that represented common adjustment approaches (e.g., adjusting the baseline line to the usage in a period before the event) were considered in the PJM analysis. The adjustments listed below span a range of possible adjustment algorithms.

Table 1-27 Examples of Baseline Adjustments[14]

#	Type	Basis	Name	Adjustment Rules	Adjustment Window and Other Notes
I	Additive	Load	Symmetric Additive[1]	PBL + [load(pre-event hours) - PBL(pre-event hours)]	First 3 of previous 4 hours
II			ISO-NE Asymmetric Additive (no longer in use)[2]	PBL + [load(pre-event hours) - PBL(pre-event hours)]	See description in document at footnote 2
III		Regression	PJM OA Alternative Weather Sensitive Adjustment (WSA)3	PBL + [reg(event period temp) - reg(PBL period temp)]	Piece-wise linear regression on temperature -- day types and hour load where load reductions are expected

[14] Goldberg, Miriam L, and G. Kennedy Agnew. Measurement and Verification for Demand Response (2013). Format modified for this document. "

IV	Ratio	Load	PJM OA Simple Adjustment4	PBL * [load(pre-event hours) / PBL(pre-event hours)]	First 2 of previous 3 hours --Only on days above 85 degrees, difference greater than 5%
V			NYISO Weather Sensitive Ajdustment5	PBL * [load(pre-event hours) / PBL(pre-event hours)]	First 2 of previous 4 hours -- limited between 80 and 120%
VI			CAISO6	PBL * [load(pre-event hours) / PBL(pre-event hours)]	First 3 of previous 4 hours -- limited between 80 and 120%
VII			ERCOT7	PBL * [load(pre-event hours) / reg(pre-event hours)]	First 2 of previous 3 hours
VIII		Regression	PJM OA Regression WSA8	PBL * [reg(event) / reg(PBL)]	Linear regression on THI, (8 AM to 8 PM), non- holiday, weekday hourly loads for season

* In this table, PBL stands for provisional baseline.

Notes associated with the table above are listed below.

1 PJM, “Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (http://pjm.com/~/media/documents/ agreements/oa.ashx, retrieved 1/31/2011), section 3.3A.3, p. 368.

2 Included for variety, but no longer current method. ISO New England Inc., Docket No. ER11-4336-000, Order No. 745 Compliance Filing (Part 1 of 2) (August 19, 2011), Exhibit C to Attachment 5 “Analysis and Assessment of Baseline Accuracy: Final Report,” KEMA

3 PJM, “RFP for PJM Empirical Analysis of Demand Response Baseline Methods,” October 29, 2010, Appendix A, Standard economic CBL with alternative weather sensitivity adjustment.

4 PJM Operating Agreement, op. cit., pp. 366-367.

5 NYISO, “Manual 7: Emergency Demand Response Program Manual,” December 2010 (http://www.nyiso.com/public/webdocs/documents/manuals/operations/edrp_mnl.pdf, retrieved 11/26/2012), pp. 29-35.

6 Jenny Pedersen, California ISO, “Proxy Demand Resources Full Market Module,” (http://www.caiso.com/275d/275d778249 a30.pdf, retrieved 1/31/2011), pp. 79-88.

7 ERCOT, “Emergency Interruptible Load Service Default Baseline Methodologies,” (no date), (http://www.ercot.com/content/ services/programs/load/eils/keydocs/Default_Baseline_Methodologies_REVISED-FINAL.doc), retrieved 2/5/2011, p. 28.

8 PJM Operating Agreement,pp.365-366.

The two basic kinds of pre-event period adjustments are difference (additive) and ratio (multiplicative) adjustments. Traditionally, these approaches compare observed load and baseline load for some pre-event period. An adjustment that makes the pre-event period baseline load equal to the pre-event period observed load is applied to the baseline throughout the event period. The additive approach measures the magnitude of the pre- event period load difference (positive or negative), and adds that to the baseline throughout the event period. The ratio approach applies the ratio that makes the pre-event period baseline load equal to the pre-event period observed load to the baseline throughout the event period.

The list of adjustments presented in the table above includes basic versions of the additive and multiplicative adjustments: Symmetric and Asymmetric Additive (I, II) and simple ratio adjustments (PJM OA Simple/NYISO Weather Sensitive/CAISO/ ERCOT - IV, V, VI and VII). There are differences among adjustment methods with respect to the hours used to produce these adjustments.

There is the symmetric/asymmetric distinction among the additive adjustments. (The asymmetric additive adjustment is no longer used by the ISO-NE because of it produced a biased estimate of load reduction.) There are also some other restrictions - most prominently, NYISO's and CAISO's limitation bracketing the adjustment between 80 and 120 percent. Other than these relatively minor differences, the underlying adjustments are basic additive and ratio adjustments. Even the ERCOT adjustment, though applied to a baseline created using a regression approach, is a simple ratio adjustment based on the first 2 of the 3 previous hours.

The table also includes adjustments that use regression results to adjust a standard "x of y" type baseline (III and VIII). Both adjustments use regressions to establish a relationship between load and weather (either temperature or THI). They then compare estimated load as a function of temperature or THI during the baseline days and during the event period. The difference between those two estimates is used to adjust the baseline hour by hour.

1.2.2 BASELINE ADJUSTMENT EXAMPLES

The following section provides examples of calculated baselines without adjustment, with symmetrical multiplicative adjustment and a weather adjustment.

1.2.2.1 Calculated Baseline (without adjustment)

Example: Weekday Type: average for each hour from most recent 10 qualifying days.

The example (below) shows the demands for 24 days (the Event Day and the 23 most recent days) for a particular Hour. The Event occurred on a Monday, so the "weekday" type calculation is appropriate, requiring the 10 most recent qualifying days. The Wednesday twelve days prior (E-12) is excluded from this calculation, as it was also an Event Day. Days selected for the calculation are shown in blue highlight.

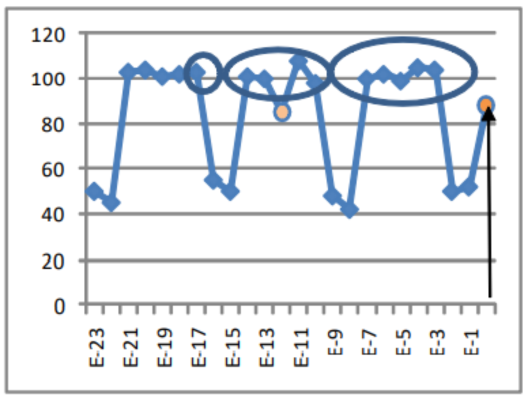
For the particular Hour shown in the example, the average of the 10 qualifying days is 102 MW, which becomes the Calculated Baseline for this Hour. Comparing this value to the metered load during this same Hour of the Event results in the load reduction: 102 – 88 = 14 MW.

A similar procedure would be followed for each Hour of the Event when MISO expects the load reduction to occur. The Event begins at the time when the Scheduling Instruction needs to be issued to fulfill the requisite load reduction; Calculated Baselines begin in hours after the Event has begun plus allowance for the specified notification time. For example, if the notification requirements were 2 hours and MISO required load reduction at 1400 hours, the Event begins at 1200 hours when the Scheduling Instruction needs to be issued to drop load by 1400 hours. . Calculated Baselines are calculated starting at 1400 hours.

BASELINE EXAMPLES: **CALCULATED BASELINE, NO ADJUSTMENT**

	DAY	LOAD [1]	Load Reduction
Saturday	E-23	50	
Sunday	E-22	45	
Monday	E-21	103	
Tuesday	E-20	104	
Wednesday	E-19	101	
Thursday	E-18	102	
Friday	E-17	103	
Saturday	E-16	55	
Sunday	E-15	50	
Monday	E-14	101	
Tuesday	E-13	100	
Wednesday	E-12	85	
Thursday	E-11	108	
Friday	E-10	98	
Saturday	E-9	48	
Sunday	E-8	42	
Monday	E-7	100	
Tuesday	E-6	102	
Wednesday	E-5	99	
Thursday	E-4	105	
Friday	E-3	104	
Saturday	E-2	50	
Sunday	E-1	52	
Monday	E	88	14

Demand reduction is equal to the difference between the Event Day and the Baseline. (Ignores other Event Days within history.)



Baseline Average: 102

(1) Load = Load during same hour from these days; one particular hour shown here.
E = Event Day
Note: Wednesday (E-12) also an Event day.

Figure 1-1 Calculated Baseline, No Adjustment[15]

[15] MISO (2021). BPM-026-r6. Demand Response Business Practices Manual

1.2.2.2 Calculated Baseline (with symmetrical multiplicative adjustment)

For the Symmetrical Multiplicative Adjustment, each Calculated Baseline hour during the Event, as determined using the “without adjustment” procedure described above, will be adjusted by a ratio. That ratio is determined by comparing a particular three-hour, load-weighted average value of the load on the Event Day with those same three hours from the Calculated Baseline (without adjustment). This ratio is limited to plus or minus 20% (i.e., the value of the ratio is limited to between 0.8 and 1.2). The “particular” three-hour period for which the ratio is calculated is the three-hour period beginning four hours prior to the Event, that is to say, the calculation skips the hour immediately prior to the start of the Event. The Event begins at the time when the Scheduling Instruction needs to be issued to fulfill the requisite load reduction, as described in the previous example. Once the ratio is determined, all the unadjusted Calculated Baseline hourly values during the Event are multiplied by the ratio. Then, these adjusted values are compared to the metered hourly values during the Event to determine the demand reduction.

In the example shown, values highlighted in blue are the three hours totaled to form the numerator of the ratio; values highlighted in green are the three hours totaled to form the denominator of the ratio. In this example, the assumption is the notification period required by the Market Participant is 30 minutes or less. As shown, this ratio is 1.186, which lies between 0.8 and 1.2 and so may be used to adjust each of the Calculated Baseline hourly values during the Event. If this ratio had been outside the 0.8 to 1.2 range, the nearest range limit (0.8 or 1.2) would be used to make the adjustments.

Each of the (unadjusted) Calculated Baseline hourly values is multiplied by the ratio to determine the adjusted Calculated Baseline values. These values are then compared to the actual hourly demands during the Event, the difference being the demand reduction.

BASELINE EXAMPLES **CALCULATED BASELINE, Symmetric Multiplicative Adjustment**

Demand reduction is equal to the difference between the Event Day and the adj. Baseline. (Ignores hour prior to Event.)

	HOUR ENDING	LOAD	Unadj. Baseline	Adj. Baseline	Load Reduced
	E-3	122	100		
	E-2	120	102		
	E-1	121	104		
Ignore →	E	122	103		
	E+1	90	103	122.2	**32.2**
Event	E+2	90	101	119.8	**29.8**
Hours	E+3	90	102	121.0	**31.0**
	E+4	90	104	123.4	**33.4**

Step1: Calculate Unadjusted Baseline for each hour.

See Calculated Baseline, No Adjustment for one example hour.

Step2: Calculate quantity-weighted ratio using 3 hours,

skipping immediately prior hour.

Sum Actual Load, 3 prior hours:	363
Sum Unadjusted Baseline, 3 prior hours:	306
Preliminary Ratio:	1.186

Step3: Use this result to adjust each baseline hour, up to ±20%.

Is Ratio between 0.8 and 1.2?	Yes
If "Yes", use Prelim. Ratio; if "No", use boundary (0.8 or 1.2) = FINAL RATIO:	**1.186**
Example for Hour Ending "E+1":	
Unadj. Baseline =	103
Ratio times Unadj. Baseline =	122.2

Step4: Calculate demand reduction: Adj.Baseline - Actual

Figure 1-2 Symmetric Multiplicative Adjustment[16]

[16] MISO (2021). BPM-026-r6. Demand Response Business Practices Manual

1.2.2.3 Calculated Baseline (with weather adjustment)

For the Weather Adjustment to the Calculated Baseline, each Calculated Baseline hour during the Event, as determined using the “without adjustment” procedure described previously, will be adjusted by an amount that reflects the impact of the difference between the temperatures during the Event and the average temperatures during the period used to calculate the baseline values. The weather adjustment consists of (1) determining the difference between the temperature during each Event Hour and the average for that same Hour during the period used to determine the unadjusted Calculated Baseline values, and (2) determining the impact on the Calculated Baseline of that temperature difference. Calculated Baselines begin in hours after the Event has begun plus allowance for the specified notification time.

The Market Participant will have previously submitted the results of regression analysis describing the relationship between temperature and load. These results are expressed as kW per degree and represent the number of kW increased (or decreased) for each 1° increase (or decrease) in temperature. The Market Participant may submit up to five (5) unique temperature set points in integer Fahrenheit degree format; for each set point, the Market Participant should provide a “factor”: the kW-per-degree impact of temperature variations up to this temperature. Therefore, temperatures below the first set point (lowest temperature) will be adjusted using the first “factor”; temperatures above the last set point (highest temperature) will not be adjusted. Please see the example provided (below) for a three-interval illustration.

For each Hour during the Event, the following procedures apply:

- Determine the unadjusted Calculated Baseline (kW),
- Determine the average temperature for that same hour from each day used in thecalculation of the unadjusted baseline,
- Compare the temperature for each Hour during the Event with the averagetemperature determined in Step 2,
- Determine from the regression results the change in the unadjusted CalculatedBaseline (kW) related to the temperature differential,
- Add this result (positive or negative) to the unadjusted Calculated Baseline todetermine the weather adjusted Calculated Baseline value (kW).

The difference between the weather adjusted Calculated Baseline and the load during that same Event Hour is the demand reduction.

BASELINE EXAMPLES: **CALCULATED BASELINE, Weather-Sensitive Adjustment**

	HOUR ENDING	LOAD	Day of Event TEMP	Baseline TEMP (1)	Baseline LOAD (1)	Adj. Baseline	Load Reduction
	E-2	1040					
	E-1	1080					
	E	1120					
Event Hours	E+1	920	88	81	950	**1106.0**	186.0
	E+2	900	89	82	980	**1139.0**	239.0
	E+3	890	91	84	1020	**1185.0**	295.0
	E+4	910	90	85	1010	**1130.0**	220.0
	E+5	900	85	85	1050	**1050.0**	150.0
	E+6	910	83	84	1060	**1039.0**	129.0

(1) Average of corresponding values during these same hours from Baseline days.

	Set Point	Factor
WSA1	85	21
WSA2	95	24
WSA3	150	18
WSA4		
WSA5		

Figure 1-3 Weather-Sensitive Adjustment[17]

- Step1: Calculate Baseline temperatures and loads each hour using "without adjustment" method.
- Step2: Use INPUTS provided through DR Tool (See Table inset) to adjust Baseline:
    - Read Set Points as "up to" temperature shown.
    - Increase (Decrease) Baseline load by "Factor" until Event Temp.reached.
- Step3: Determine Load Reduction from Adjusted Baseline and Load.
    - Example: Shown above, the temperature in Hour E+1 exceeds the Baseline temperature for that hour. Thus, the Baseline load needs to be adjusted to reflect this higher temperature.
    - As the temperature increases from 81 to 88, the load increases as shown in the box above. E.g., for any temperature "up to" 85, load changes by 21 kW per degree.

[17] MISO (2021). BPM-026-r6. Demand Response Business Practices Manual

For the entire increase from 81 → 88, LOAD increases by 21+21+21+21+24+24+24 = 156 kW

Therefore, the customer Baseline LOAD is increased from its Unadj. value of 950 by 156 to 1106.

1.2.2.4 Firm Service Level Baseline

For the Firm Service Level selection, performance assessment is based on whether the asset moved down to its Firm Service Level. Any potential credits and charges, however, are calculated based on a comparison to a Consumption Baseline.

1.2.3 NAESB PERFORMANCE EVALUATION METHODOLOGIES OF WHOLESALE DEMAND RESPONSE PROGRAMS

The North American Wholesale Electricity Demand Response Comparison, produced by the ISO-RTO Council, is an Excel workbook that aligns wholesale demand response programs and corresponding performance evaluation methodologies with the NAESB M&V Business Practice Standards for Wholesale Demand Response. The workbook content is protected, however the filters at the top of each column on the Products and Service Definitions tab and the Performance Evaluation Methods tab may be used to limit the display to specific Products and Services that meet the selected criteria within a column.

The workbook contains five tabs:

- Product and Service Definitions – descriptions that correspond to NAESB's Business Practice Standards for Measurement & Verification (M&V) of Wholesale Electricity Demand Response, with active links to supporting materials for each demand response Product or Service.
- Performance Evaluation Methods – descriptions about the performance evaluation methods associated with the Products and Services.
- Acronyms – a detailed list of acronyms used in the workbook and the ISO/RTO that uses the acronym.
- Definitions – a brief list of definitions.
- Timing Examples – scenarios that help describe the application of the Demand Response Event Timing diagram from the NAESB Business Practice Standards for Measurement and Verification (M&V) of Wholesale Electricity Demand Response.

The North American Wholesale Electricity Demand Response Comparison is available on the ISO-RTO Council website at: http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3003829518EBD%7D/IRC%20DR%20M&V%20Standards%20Implementation%20Comparison%20(2012-01-20).xls

1.3 Appendix C Prior work in DR M&V Methods

In this appendix, we review prior work relevant to M&V for DR, in 2 key areas:

- Method assessment studies for baselines used for settlement, and
- DR Evaluation protocols.

The DR evaluation protocols are described at a high level only. We also note efforts related to the IPMVP. The emphasis of this section is on baseline methods for market settlement, as this has been a key concern for market operations.

1.3.1 BASELINE METHODS ASSESSMENT STUDIES

1.3.1.1 California Energy Commission

The California Energy Commission (CEC) produced the report "Protocol Development for Demand Response Calculation – Findings and Recommendations" in February 2003.[18] The report was an early attempt to systematically explore the components of a baseline and compare baseline accuracy across the full range of possible baselines using actual data.

1.3.1.1.1 Test data

Interval load data were provided from several parts of the U.S., for both curtailed and uncurtailed accounts. A total of 646 accounts were used in the analysis. For some accounts, multiple years of data were used. The accounts used in the study were distributed across all regions of the country, the years 1998 through 2001, and curtailment/non-curtailment categories. All the regions had accounts with summer curtailment data. Only the Midwest, Northwest, and Southeast had non-summer curtailment data. Despite the fact that the report was produced for the CEC, only 4 of the 646 accounts were from California. Investigation of differences by region indicated that most differences across data sets provided appeared to be related to the types of accounts included rather than to regional variations. For this reason, results were provided separately by weather-sensitivity and degree of load variability in an account, as well as by season.

1.3.1.1.2 Methods tested

Methods tested were organized based on the three key characteristics of any baseline methodology:

- Data selection criteria –Short, rolling windows (5 to 10 prior eligible business days) to full prior seasons of data. The rolling windows can include further restrictions based on average load (e.g., five days with the highest average load out of most recent ten);
- Estimation methods –Simple averages to regression approaches using either hourly or daily temperature, degree days or temperature-humidity index (THI); and
- Adjustments – Additive and multiplicative approaches based on various pre-event hours as well as a THI-based adjustment not dependent on event day load.

The analysis tested 146 combinations of data selection criteria, estimation methods and adjustments, comparing median and 95th percentiles of relative error and Theils U statistic. Results were provided for all combinations of

[18] Protocol Development for Demand Response Calculation – Findings and Recommendations. California Energy Commission, February 2003. 400-02-017F.

the following characteristics: Summer/non-summer, curtailed/non-curtailed, weather sensitive/ non-weather sensitive, and high variability/non-high variability.

1.3.1.1.3 Key findings

The CEC report spelled out specific findings for each the three characteristics of a baseline methodology. The overarching conclusion was that no single approach offered a comprehensive solution across all kinds of account load characteristics and conditions.

The report states that "baseline calculation protocols should provide for alternatives based on customer load characteristics and operating practices." While it was recommended that customers have input into the baseline methodology based on their unique load characteristics, the program operator should have ultimate authority for the final decision.

More specific recommendations include:

- A rolling ten day window with an additive adjustment based on the two hours prior to event start provides the best, most practical default baseline.
- For weather-sensitive loads, limiting the rolling window to the five highest average load days is not as effective using a baseline adjustment. THI-based adjustment is the only adjustment that avoids the distortions of pre-cooling or gaming.
- Weather regression can be effective, but the increased data requirements, processing complexity and potential for changes at the site make these options less practical. Furthermore, simple averages with adjustments are nearly as good as weather regressions
- Highly variable loads are a challenge regardless of the baseline methodology employed.

1.3.1.2 ISO-NE

In 2010 and early 2011, ISO-NE evaluated the effect of continuous price responsive events on the accuracy of baselines. A separate analysis later in 2011 examined baseline inaccuracies in recent historical ISO-NE baselines to understand the role of load variability in the ongoing inaccuracies after the adoption of a symmetric baseline adjustment. Both analyses were performed on ISO-NE DR program populations.

1.3.1.2.1 Key findings, Frozen Baseline Analysis

The 2010/2011 analyses looked at bidding patterns in the Day Ahead Load Response Program and the effect on baseline accuracy.[19] Participants could offer load reduction at a low enough price that their bid would clear every day. Because cleared days are removed from subsequent baseline calculations, this bidding strategy resulted in the baseline remaining frozen at the same level as the first cleared day of the series. Natural, seasonal drift made the frozen baseline increasingly inaccurate as the number of cleared days increased.

Conclusions from the early 2011 report included:

- Asymmetric adjustments cause biased estimates of load reduction.

[19] ISO New England Inc., Docket No. ER11-4336-000, Order No. 745 Compliance Filing (Part 1 of 2) (August 19, 2011), Exhibit C to Attachment 5 "Analysis and Assessment of Baseline Accuracy: Final Report"

- Baseline accuracy and bias are directly impacted by the frequency with which demand resources clear in the energy market. Even with a symmetric adjustment, a long-term frozen baseline leads to baseline inaccuracies.
- It is possible to develop policies that improve baseline accuracy by limiting the number of days a customer can clear during a particular timeframe or requiring contemporary meter data be used in the baseline computation even if the resource clears.

1.3.1.2.2 Key findings Load Variability Analysis

The late 2011 variable load analysis explored a different question than the baseline comparison analyses. This analysis looked at the existing ISO-NE baseline and sought to categorize the sources of baseline inaccuracies across the program population.

Conclusions included:

- In absolute terms, most inaccuracy of baselines comes from a small fraction of highly variable resources.
- Systematic variation by day of week as well as across hours within a single day of the week (scheduling) accounts for much of the discrepancy for the population of highly variable resources.
- Additional research should include the testing of alternative baseline procedures on high variability load assets to determine if there are more accurate methods of evaluating these types of loads.
- If accurate alternative baseline methods that address the potential gaming issue cannot be created, then market rules constraining the participation of highly variable loads in demand response programs will have to be developed.

1.3.1.3 California Public Utilities Commission

The California Public Utilities Commission sponsored an analysis of the accuracy of baseline estimates for the California Investor Owned Utility (IOU) Aggregator DR programs.31[20] These programs include the statewide Capacity Bidding Program (CBP), which is operated by all three of the state's IOUs, PG&E's Aggregator Managed Portfolio (AMP) and Southern California Edison's Demand Response Resource Contracts (DRRC). The analysis tested a number of variations on the standard baseline used for the aggregator programs - a 10 of 10 day average with same day adjustment based on the first three hours of the previous four hours and capped at 20 percent. The analysis tested:

- Individual vs aggregate application of adjustments;
- Level of adjustment cap; and
- Aggregator choice of adjustment vs universal adjustment.

The different baseline variations were compared to ex post impact evaluation results based on regression methods and also tested on participant data using a simulated load reduction.

Findings included:

- Universal application of same-day adjustments almost always increases accuracy compared to aggregator choice.

---

[20] 2011 Statewide Evaluation of California Aggregator Demand Response Programs Volume II: Baseline Calculation Rules and Accuracy. Freeman, Sullivan & Co. June 1, 2012

- Calculating adjustments at the settlement portfolio level has a limited effect on bias but reduces the magnitude of same-day adjustments.
- The effect of increasing the adjustment cap varies by program and option. When it does change results, accuracy generally improves but only slightly.

1.3.1.4 PJM

In 2011, PJM sponsored an analysis of baseline options for PJM DR programs.[21] This analysis ranked baseline performance based on relative error and variability as well as expected administrative costs. Where baselines delivered similar levels of accuracy, preference was given to baselines with a lower expected cost to administer.

1.3.1.4.1 Test data

Data were provided by Electric Distribution Companies (EDC) within PJM. Almost all EDCs contributed hourly data. The available sample of DR customers represented 39 percent of the total number of DR customers across PJM territory and 54 percent of Peak Load Contribution (PLC), load of the customers at the time of PJM's system peak. Data were requested from 2008 through 2010.

1.3.1.4.2 Methods Tested

The evaluation tested a range of baselines designed to represent the range of baselines used by ISOs today. Those baselines included baselines:

- Used by PJM.
- Used by other ISOs and RTOs.
- Suggested by the Market Monitor.
- Suggested by evaluator.

The baselines represented a range of data selection criteria and estimation methods. Four of the baselines were based on the average load of a subset of a rolling window (eg. high 5 of 10). The similar rolling ISO-NE baseline was also included. In addition, there were two kinds of match-day baselines, two flat baselines and two regression-based baselines.

Four different adjustment types were applied to all of the baselines (where feasible and reasonable) including additive, ratio (multiplicative) and an additive, regression-based PJM weather sensitive (WS) adjustment. The additive and ratio adjustments were the same day load-based adjustments common across the industry. The PJM WS adjustment approach provides an adjustment based on event day weather rather than event day load. This approach avoids concerns related to same day load-based adjustments (eg., early shutdown, pre-cooling) but uses a regression-based characterization of weather sensitivity that requires additional data and computational complexity while only explicitly addressing weather as a source of variability.

1.3.1.4.3 Key Findings

- Baselines methods that use an average load over a subset of a rolling time period (10 of 10, high 5 of 10, high 4 of 5, middle 4 of 6, and ISO-NE) with a same day additive or multiplicative adjustment performed better than any unadjusted baselines or those adjusted with the PJM WS adjustment.

[21] http://pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/pjm-analysis-of-dr- baseline-methods-full-report.ashx

- These baselines all have similar results and performed well across all segments, time periods and weather conditions except in the case of variable load customers. Variable load customers should be segmented for purposes of applying a different performance evaluation methodology and/or market rule.
- The PJM weather sensitive adjustment applied to the PJM economic program high 4 of 5 baseline provided the best non- load-adjusted results. This approach has the additional cost and complexity of the regression based adjustment approach.
- PJM's existing high 4 of 5 baseline with additive adjustment was consistently among the most accurate baselines and required no additional administrative cost to implement. While other baseline methods demonstrated slightly better accuracy (e.g., 10 of 10, ISO-NE), PJM found that the incremental benefits could not justify the incremental costs, and no changes were made to the baseline method. Under a different scenario with a different existing baseline method and a different range of cost considerations, it is possible a different conclusion would be met.

1.3.1.5 ERCOT Demand Side Working Group

ERCOT sponsored an analysis of the settlement alternatives for baselines for weather sensitive loads with short curtailments.[22] The analysis compared 11 baseline calculation methods across four different levels of data aggregation. The baseline methods included:

- Adjusted Day-matching approaches with and without adjustment caps (10 of 10 and 3 of 10)
- Adjusted Weather-matched baseline without adjustment cap
- Regression-based baselines – four different specification types
- Randomly assigned comparison group (means and difference in difference)
- Pre-calculated load reduction estimate tables

Baselines were tested on Individual AC, Aggregate AC, Household-level and Feeder data. Findings include:

- Methods with randomly assigned control groups and large sample sizes perform the best.
- Day matching approaches were the least effective approach for weather sensitive loads.
- Pre-calculated load reduction tables can produce results that on average are correct if based on sound estimates based on estimates created using randomly assigned control groups and large sample sizes. May err for individual days, especially if they are cooler.
- Complex methods provide limited improvement.
- Finer interval data do not necessarily improve the accuracy of demand reduction measurement.

1.3.1.5.1 Peak Time Rebate

Peak Time Rebates (PTR) is an incentive-based peak pricing program design that is a relative newcomer to today's Demand Response product space. PTR rewards load response relative to a household-specific baseline but does not penalize non-response. PTR can be implemented as either an opt-in or default basis. Some believe that PTR as a default rate has the potential generate significant load response.

Recent empirical evidence provides mixed evidence regarding the potential of PTR programs and the best implementation approach. A presentation at the 2012 National Town Meeting on Demand Response by

[22] Empirical Data on Settlement of Weather Sensitive Loads. Freeman, Sullivan & Co. ERCOT Demand Side Working Group, September 20, 2012

Freeman, Sullivan and Co. considered data from six opt-in pilot studies.[23] A presentation at the Peak Load Management Alliance by Baltimore Gas and Electric and Brattle reported on the evaluation of their Smart Energy Pricing Pilot which included both PTR and CPP elements.[24]

1.3.1.5.2 Key Findings

- Load reduction percentages vary widely. FSC reports opt-in savings percentages of up to 17 percent but a single example of default savings in the single digits. BG&E, with an analysis design reflecting a default PTR rate, generated savings of between 17 and 20 percent over the ten hottest days of the summer. Supporting technologies increased the percentage savings.
- FSC focused on the inaccuracy of baseline and the potential implications for cost effectiveness.
    - The “no-risk” nature of PTR means that households showing show load reduction due to measurement error are compensated. In one simulation study, 60% of PTR program participants received payments resulting from measurement error in the baseline calculation, while delivering no demand reduction at all.
    - Measurement error will also lead to the non-payment of households that provided demand reductions, potentially leading to unhappy customers.
- BGE generated substantial savings under a default experiment and demonstrated near unanimous customer satisfaction.
- A default PTR rate may magnify the measurement problem
    - Compared to an opt-in rate, a smaller percentage of households on the default actively reduce load.
    - If load reduction is small, over-compensation is not balanced by under- compensation. This can reduce the cost-effectiveness.
- Baseline choice makes a difference. FSC found the 3 of 5 baseline was not effective for estimating load levels. The BG&E 3 of 14 baseline including Saturdays (for additional hot weather) was more effective.

1.3.1.6 Ontario Power Authority

In 2010 and 2011, the Ontario Power Authority (OPA) undertook an evaluation of the accuracy of current and alternative baselines used for the settlement of its large commercial and industrial Demand Response 3 (DR-3) Program.[25]

The evaluation focused on identifying a baseline methodology that:

- Is accurate for both small and large customers;
- Is fair across settlement accounts and customers;
- Avoids extreme errors that could negatively affect individual settlement payments; and
- Is accurate not only for the most common event window but across all event windows.

[23] “Peak Time Rebates: The Promise vs. The Reality”, National Town Meeting on Demand Response and Smart Grid, Dr. Stephen S. George. Freeman, Sullivan & Co. June 26-28, 2012.

[24] “BGE’s Smart Energy Pricing Pilot” Cheryl Hindes PLMA Panel, November 8, 2012

[25] Assessment of Settlement Baseline Methods for Ontario Power Authority's Commercial & Industrial Event Based Demand Response Programs. September 2010. Freeman, Sullivan and Co. The report is not public, but was made available to the authors. Contact the OPA Manager of Technical Services in the Conservation Area.

In addition, the analysis tested the accuracy of current and alternative baseline options for both individual customers vs. aggregation of settlement accounts and the application of in-day adjustments.

1.3.1.6.1 Methods Tested.

In total, 48 baseline methods were tested using data from 95 existing customers which included the following:

- Top 3, 7 and 9 out of the last 10 non-event days;
- Bottom 3 and 7 out of the last 10 non-event days;
- All 10 of the last 10 non-event days; and
- Top and Bottom 15 out of the last 20 non-event days.

Each baseline was also calculated using two types of same-day adjustment. These same- day (or in-day) adjustments were applied to the baseline day-selection methods. Both four- and six-hour adjustments were tested. All adjustments included a two-hour buffer between the event period and the period used to calculate the adjustment. To calculate these adjustments, the event-period baseline is multiplied by the ratio of the averages of actual and baseline loads during the four or six hours preceding a two-hour buffer immediately prior to the event window.

In addition, errors were calculated for a typical event window of 3 P.M. to 7 P.M., and were also averaged separately for customers above one MW of contracted load reduction and below one MW of contracted load reduction.

1.3.1.6.2 Key Findings

- Of 48 baselines initially analyzed, 6 produced average load impact errors within +/-2%. These 6 baselines included the Top 7, 9 and 10 of 10 Hourly baselines each with a 4-hour and 6-hour same-day adjustment. All were compared to the current method of Top 15 of 20 Hourly (with and without same-day adjustments) to highlight the improvements that can be realized with these alternate baseline methods.
- Baselines 10 of 10 and Top 9 of 10 Hourly each with a 6-hour adjustment exhibited the narrowest normalized error distributions and relatively few extreme values across settlement accounts. Both also perform well across different event window periods, though the 10 of 10 is the most robust over time
- The 10 of 10 baseline with a 6-hour adjustment was recommended due to the following reasons:
    - This method averages a very low overall load-impact error (-0.5%) during the most common event period;
    - Is accurate for customers both above and below one MW of contracted load reduction;
    - Produces the narrowest distribution of errors and generates few extreme error values whether error distributions are calculated at the customer level or at the settlement account level; and
    - Remains on average the most accurate baseline across all event windows starting as early as 12 P.M. and as late as 5 P.M.

The study also recommended that if a same-day adjustment is adopted, that the method be reassessed the following year to determine whether there is evidence that customers have reacted to the adjustment in ways that lead to inaccuracy.

1.3.1.7 Southern California Edison - Methods for Short-duration events

Between 2007 and 2011, Southern California Edison (SCE) investigated the feasibility of integrating short-duration dispatch events (fewer than 30 minutes) of its residential and commercial air conditioner cycling program into the California ISO market for non-spinning reserve ancillary services.[26] Such short term events offer a different set of advantages and challenges relative to events lasting several hours. The load impact evaluation and related analyses of dispatch events using end-use and feeder-level SCADA data demonstrated the value of short-term direct load control programs and also the technological barriers that need to be overcome for aggregations of small DR resources to meet ancillary service market requirements for electricity supply resources.

1.3.1.7.1 Key Findings

- Short duration events were found to have a minimal impact on customer comfort[27] and a reduced post-event snapback.
- Because there was no pre-event notification of dispatch to participating customers and snapback was minimal, baseline modeling approaches that utilized both pre- and post-event load information proved to be effective. For example, such load characteristics allow for auto-regressive model approaches as well as approaches that estimate counterfactual load looking both forward and backward in time.
- While ex ante forecast accuracy improved concurrently with calibration to realized ex post impact estimates, inherent variability in the measurable load impact of the aggregate resources remains a barrier to wholesale market integration. Telemetry of the aggregate resource through technological developments in AMI deployment present the most promising opportunity for this barrier to be overcome.

1.3.2 PROTOCOLS FOR DR PROGRAM EVALUATION

The California Public Utilities Commission and the Ontario Power Authority (OPA) developed protocols for the evaluation of demand response programs. California's protocol cites the California Energy Action Plan II as affirming the importance of DR as an energy resource and "emphasizes the need for DR resources that result in cost-effective savings and the creation of standardized measurement and evaluation mechanisms to ensure verifiable savings".[28] The OPA states their similar set of protocols were necessary "not only to assess progress toward meeting Provincial resource goals, but also to obtain information for improving program design and as input to resource planning."[29] These protocols are comprehensive and specifically design to facilitate the inclusion of DR as a resource.

This section summarizes the latter protocol which was effectively a refined version of the CPUC protocols. Stated objectives from the OPA Protocols include

---

[26]http://www3.sce.com/sscc/law/dis/dbattach10.nsf/0/8DAF6B099083E88B8825784700749DD7/$FILE/A.11- 03-003+DR+2012-14+-+SCE-1+Volume+5+-+Appendix.pdf

[27] http://certs.lbl.gov/pdf/lbnl-3550e.pdf

[28] ATTACHMENT A: Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance. California Public Utilities Commission Energy Division, April 2008. P. 11.

[29] Protocols for Estimating Load Impacts Associated with Demand Response Resources in Ontario. Ontario Power Authority, December 31, 2009. P.2

- Establish minimum requirements to support resource planning, cost-effectiveness analysis and program design and improvement;
- Focus on the outputs that should be provided, rather than on how to obtain them;
- Develop a common set of outputs to enable “apples-to-apples” comparison of load impacts across DR resource options, event conditions, and time;
- Be applicable to a wide range of DR resource options, to accommodate a changing landscape of policies, programs, and program delivery agents;
- Ensure that the documentation of methods and results allow knowledgeable reviewers to judge the quality of the work and the validity of the impact estimates provided; and
- Encourage recommendations for improvements to the evaluated DR resources and future load impact evaluations.

1.3.2.1 Ex Post Impact Methods

The DR protocols provide for standardized approaches for aggregate impact estimation methods that feed into ex post estimates of load reduction. Impact evaluation methods discussed include:

- Regression – Considered the leading method. Regression is only method that is equally suitable for producing both ex post and ex ante results. Though the intent of the protocols is not to dictate methods, the regression approach alone receives a full section discussing the methodology.
- Day-matching – A more traditional approach to DR evaluation that received more attention in the CPUC DR Protocols. Day-matching approaches offer a simple, intuitive approach to generating estimates of load reduction. The method does not provide a solid basis for ex ante estimates.
- Others, including sub-metering, duty cycle analysis, and operational experiment. These additional approaches refer to alternative forms of data acquisition, specialized regression techniques and experimental evaluation designs, respectively. Each of these will feed into one of the aforementioned methods, with regression being most likely approach.

1.3.2.2 Considerations for Ex Ante Estimates

Ex ante load impact estimates are designed to support program and resource planning.

Resource planning seeks to identify the optimal combination of resources that will balance supply and demand at least cost under a specified set of conditions. Program planning involves comparing the cost-effectiveness of different potential resource options, also under a specified set of conditions[30]

The protocol develops a long list of issues for consideration in the development of ex ante load reduction estimates. This list attempts to target the following:

- When DR will be called upon (day types, time periods, event window and extreme conditions),
- Who will participate and where will they be geographically (program enrollment and location specific), and
- How confident are the estimates of load reduction (uncertainty).

[30] Ibid. p. 13.

Other issues cited relate to more general program outcomes (e.g., free riders/structural benefiters, distributional impacts, persistence, and long-term impacts) or more specialized types of programs (customer price elasticity). The protocols introduced the concept of the 1-in-2 and 1-in-10 weather conditions. These facilitated the projection of ex post results onto potential future weather scenarios based on historical weather by simulating typical (1-in-2) and extreme (1-in-10) weather conditions.

1.3.2.3 Reporting

Five of the eight protocols in the OPA Protocols specifically refer to reporting. As stated in the objectives, a key goal of the protocols was to facilitate comparison across programs. Consistent report protocols make these kinds of comparison possible. The protocols address reporting in the following ways.

- Common Reporting Format (#3) – The OPA Protocol format is simplified compared to the original CPUC format but retains the full day of load estimates, with and with load reduction, estimated load reduction and hourly temperature.
- Hourly Results Across the Full Day (#2)
- Day Types and Event Conditions (#4) The protocols provide a list of the day types for which results should be provided separately for ex post, ex ante and validation results. Different kinds of resources require different subsets of these options.
- Statistical Reporting and Validation (#6) The protocols establish a set of regression results and statistics that provide sufficient information on the modeling effort to independently judge the success of the effort.
- Reporting and Documentation (#8) This protocol reiterates the importance of consistent reporting of all of the elements listed above along with a full description of all the methods used.

1.4 Appendix D Information Sources and References

1.4.1 PRIMARY SOURCES USED TO PREPARE PROTOCOLS 1-4

Preparation of these protocols draws from leading industry references used to guide EM&V activities for energy efficiency and demand response offerings throughout the United States. Materials that were used as primary sources to prepare these protocols include the following.

- Technical Reference Manuals for Arkansas and Texas.
    - Protocols for net-to-gross analysis and for process evaluation were based on materials from the Arkansas TRM
    - Texas TRM provided materials pertaining to TRM updating.
- Steven R. Schiller, Greg Leventis, Tom Eckman, and Sean Murphy. 2017. Guidance on Establishing and Maintaining Technical Reference Manuals for Energy Efficiency Measures. Prepared by Lawrence Berkeley National Laboratory for the State and Local Energy Efficiency Action Network.
- Reports on evaluation frameworks that were used included the following:
    - California Public Utilities Commission. 2004 (June). California Evaluation Framework.
    - California Public Utilities Commission. 2006 (April). California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals [a.k.a. TPE's Protocols].
    - DOE Office of Energy Efficiency and Renewable Energy (EERE). 2006 (February). EERE Guide for Managing General Program Evaluation Studies. (Referenced as EERE 2006.)
    - DOE/EPA. 2007 (November) National Action Plan for Energy Efficiency (NAPEE) Action Plan and Resource Guides for Process, Impact Evaluations and Understanding Cost-Effectiveness of Energy Efficiency Programs. (Referenced as NAPEE 2007).
    - Northeast Energy Efficiency Partnerships. 2010 (May). Regional EM&V Methods and Savings Assumptions Guidelines. (Referenced as NEEP EM&V Protocols).
    - NMR Group et al. 2018 (May). Evaluation Framework for Pennsylvania Act 129 Phase III Energy Efficiency and Conservation Programs, Final Version. Prepared for Pennsylvania Public Utilities Commission.
    - Steven R. Schiller and Tom Eckman. 2017 (June). Evaluation Measurement and Verification (EM&V) Frameworks—Guidance for Energy Efficiency Portfolios Funded by Utility Customers. Prepared by Lawrence Berkeley National Laboratory for the State and Local Energy Efficiency Action Network.
- Chapters from Uniform Methods Project, administered for DOE by National Renewable Energy Laboratory
    - Stewart, J.; Todd, A. (2017). Chapter 17: Residential Behavior Protocol, The Uniform Methods Project: Methods for Determining Energy-Efficiency Savings for Specific Measures
    - Violette, Daniel M.; Rathbun, Pamela. (2017). Chapter 21: Estimating Net Savings – Common Practices: Methods for Determining Energy-Efficiency Savings for Specific Measures.

1.4.2 PRIMARY SOURCES USED TO PREPARE NEW CONSTRUCTION PROTOCOLS

ASHRAE. (2002). Guideline 14-2002, Measurement of Energy and Demand Savings. American Society of Heating, Refrigerating and Air-Conditioning.

ASHRAE. (2007). Standard 90.1-2007, Energy Standard for Buildings Except Low-Rise Residential. American Society of Heating, Refrigerating and Air-Conditioning.

CADMAC. (1998). Appendix J - Quality Assurance Guidelines For Statistical, Engineering, and Self-Report Methods for Estimating DSM Program Impacts. California DSM Measurement Advisory Council.

CPUC. (2004). The California Evaluation Framework. California Public Utilities Commission and the Project Advisory Board.

Crawley, D. B., Griffith, B. T., Hand, J. W., & Kummert, M. (2005). Contrasting The Capabilities of Building Energy Performance Simulation Programs.

IPMVP. (2006). Volume III, Part I: Concepts and Practices for Determining Energy Savings in New Construction. International Performance Measurement and Verification Protocol.

1.4.3 PRIMARY SOURCES USED TO PREPARE RETROCOMISSIONING PROTOCOLS

1.4.3.1 Bibliography

ASHRAE. (2002). *Guideline 14-2002: Measurement of Energy and Demand Savings.* American Society of Heating, Refrigerating and Air-Conditioning.

BPA. (2011b). *Regression for M&V: Reference Guide.* Bonneville Power Administration.

California Commissioning Collaborative. (2006). *California Commissioning Guide: Existing Buildings.*

California Public Utilities Commission. (2006). *California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals.*

Dethman, L., Kunkle, R., and Degens, P. (2007). *Chasing O&M Savings: Process Lessons from Two Pilot Programs in the Northwest.* Prepared for the International Energy Program Evaluation Conference.

Natural Resources Canada. (2009). *Recommissioning (RCx) Tools Assessment Report.*

Northeast Energy Efficiency Partnerships. (2010). *Regional EM&V Methods and Savings Assumptions Guidelines.*

RLW Analytics, Inc. (2008). *2004–2005 Los Angeles County—Internal Services Department/Southern California Edison/Southern California Gas Company Energy Efficiency Partnership Impact Evaluation Study.* Prepared for California Public Utilities Commission.

U.S. Department of Energy Federal Energy Management Program. (2008). *M&V Guidelines: Measurement and Verification for Federal Energy Projects—Version 3.0.*

U.S. Environmental Protection Agency. (2008). *ENERGY STAR Building Upgrade Manual.*

1.4.3.2 References

BPA. (2011a). Existing Building Commissioning: An M&V Protocol Application Guide. Bonneville Power Administration.

EVO. (2012). International Performance Measurement and Verification Protocol—Concepts and Options for Determining Energy and Water Savings, Volume 1. Efficiency Valuation Organization.

Itron Inc. (2008). San Diego Gas and Electric 2005–2005 Retrocommissioning Program Final Report. Prepared for Portland Energy Conservation Inc.

Luskay, L., Haasl, T., Irvine, L., and Frey, D. (2002). Retrocommissioning Case Study— Applying Building Selection Criteria for Maximum Results. Prepared for the International Conference for Enhanced Building Operations.

PECI. (2009). A Study on Energy Savings and Measure Cost Effectiveness of Existing Building Commissioning. Prepared for Lawrence Berkeley National Laboratory. Portland Energy Conservation Inc.

PECI. (2010). Building Optimization Analysis Tool—Final Project Report to PG&E. Prepared for Pacific Gas and Electric. Portland Energy Conservation Inc.

Seventhwave. (2018). Gunasingh,, S., Zhou, J., & Hackel, S. Persistence of Savings from Retro-Commissioning Measures. Prepared for ComEd. https://slipstreaminc.org/sites/default/files/documents/publications/retrocommissioning-persistence-studyfinal-reportoct-2018.pdf

Thorne, J., and Nadel, S. (2003). Retrocommissioning: Program Strategies to Capture Energy Savings in Existing Buildings. Prepared for American Council for an Energy-Efficient Economy.

Tso, B., Hall, N., Lai, P., and Pulliam, R. (2007). How Much Does Retrocommissioning Really Save? Results from Three Commissioning Program Evaluations in California. Prepared for the International Energy Program Evaluation Conference.

Table 1-28 EUL Model

			PY →	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
EUL	Measure	Slope YR1	Slope YR+	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
3.76	Air Dist.	0.155	0.153	1.00	0.85	0.69	0.54	0.38	0.23	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.17	Plant Opt.	0.155	0.040	1.00	0.87	0.69	0.65	0.61	0.57	0.53	0.49	0.45	0.41	0.37	0.33	0.29	0.25	0.21	0.17	0.13	0.09	0.05	0.01	0.00
5.39	Ventilation	0.050	0.137	1.00	0.96	0.90	0.76	0.63	0.49	0.35	0.22	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20.65	Scheduling	0.120	0.007	1.00	0.89	0.76	0.75	0.75	0.74	0.73	0.73	0.72	0.71	0.71	0.70	0.69	0.69	0.68	0.67	0.67	0.66	0.65	0.65	0.64
28.68	Filters	0.270	-0.180	1.00	0.76	0.46	0.64	0.82	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
6.13	General	0.025	0.123	1.00	0.98	0.95	0.83	0.70	0.58	0.46	0.33	0.21	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 1-29 EUL Model Results

Measure	Persistence (1-3)	Persistence (4-7)	Persistence (8+)	EUL Uncapped	EUL Capped (yr 7)
Air distribution	2.54	1.23	0.00	3.76	3.76
Plant optimization	2.56	2.36	3.25	8.17	4.92
Ventilation	2.86	2.23	0.30	5.39	5.09
Scheduling	2.65	2.97	15.03	20.65	5.62
Filters	2.22	3.46	23.00	28.68	5.68
General	2.93	2.57	0.63	6.13	5.50

1.4.4 PRIMARY SOURCES USED TO PREPARE BEHAVIORAL PROTOCOLS

SEE Action. 2012. *Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations*. State and Local Energy Efficiency Action Network. Prepared by A. Todd, E. Stuart, S. Schiller, and C. Goldman, Lawrence Berkeley National Laboratory. https://www4.eere.energy.gov/seeaction/system/files/documents/emv_behaviorbased_eeprogram s.pdf.

Stewart, James and Annika Todd. 2020. *Chapter 17: Residential Behavior Evaluation Protocol, The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures: September 2011 – August 2020*. Golden, CO: National Renewable Energy Laboratory. NREL/SR-7A40-77435. https://www.nrel.gov/docs/fy21osti/77435.pdf.

1.4.4.1 References

ADM Associates, Inc. 2018. Evaluation of 2016-2017 Home Energy Reports Program. Report Submitted to Pacific Power.

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/washington/Home_Energy_Reports_2016-2017.pdf.

Allcott, H. 2011. "Social Norms and Energy Conservation." *Journal of Public Economics*, 95(2), pp. 1082-1095.

Allcott, H., and T. Rodgers. 2014. "The Short-Run and Long-Run Effects of Behavioral Interventions: Experimental Evidence from Energy Conservation." *American Economic Review* 104 (10), pp. 3003-3037.

Allcott, H. 2015. "Site Selection Bias in Program Evaluation." *The Quarterly Journal of Economics* 130 (3), pp. 1117-1165.

Baylis, P., P. Cappers, L. Jin, A. Spurlock, A. Todd. 2016. "Go for the Silver? Evidence from field studies quantifying the difference in evaluation results between "gold standard" randomized controlled trial methods versus quasi-experimental methods." ACEEE Summer Study on Energy Efficiency in Buildings 2016.

Bertrand, M., E. Duflo, S. Mullainathan. 2004. "How Much Should We Trust Difference-inDifferences Estimates?" Quarterly Journal of Economics 119 (1), 249–275.

Brandon, A., P. J. Ferraro, J. A. List, R. D. Metcalfe, M. K. Price, F. Rundhammer. 2017. “Do the Effects of Social Nudges Persist? Theory and Evidence from 38 Natural Field Experiments.” National Bureau of Economic Research working paper 23277. http://www.nber.org/papers/w23277.

Brandon, A., J. A. List, R. D. Metcalfe, M. K. Price, and F. Rundhammer. 2019. “Testing for Crowd Out in Social Nudges: Evidence from a Natural Field Experiment in the Market for Electricity.” Proceedings of the National Academy of Sciences 116 (12), 5293-5298.

Bruhn, M., and D. McKenzie. 2009. “In Pursuit of Balance: Randomization in Practice in Development Field Experiments.” American Economic Journal: Applied Economics 1(4): 200- 232.

Burlig, F., L. Preonas, M. Woerman. 2017. “Panel Data and Experimental Design.” Energy Institute at Haas working paper. https://ei.haas.berkeley.edu/research/papers/WP277.pdf.

Cadmus. 2018. Residential Customer Behavioral Savings Pilot Evaluation. Prepared by Cadmus for the Vermont Public Service Department. https://publicservice.vermont.gov/sites/dps/files/documents/VT%20PSD%20RCBS%20Y3%20Evaluation%20Report%20FINAL.pdf.

Cappers, P., A. Todd, M. Perry, B. Neenan, R. Boisvert, R. 2013. Quantifying the Impacts of Time-based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines. Lawrence Berkeley National Laboratory, Berkeley, CA and the 52 Electric Power Research Institute, Palo Alto, CA. LBNL-6301E. https://emp.lbl.gov/sites/default/files/lbnl-6301e.pdf. Consortium for Energy Efficiency Database. 2018. https://library.cee1.org/content/2018- behavior-program-summary-public-version.

Costa, D. L., M. E. Kahn. 2010. Energy Conservation “Nudges” and Environmentalist Ideology: Evidence from a Randomized Residential Electricity Field Experiment. NBER Working Paper 15939. http://www.nber.org/papers/w15939.

Davis, M. 2011. Behavior and Energy Savings: Evidence from a Series of Experimental Interventions. Environmental Defense Fund Report.

DNV GL. 2016. Puget Sound Energy: 2015 Home Energy Reports Impact Evaluation. http://www.oracle.com/us/industries/utilities/home-energy-reports-err-2015-3697558.pdf

DNV GL. 2018. Puget Sound Energy: 2017 Home Energy Reports Impact Evaluation-Final Report. https://conduitnw.org/Pages/File.aspx?rid=4415

Electric Power Research Institute. 2010. Guidelines for Designing Effective Energy Information Feedback Pilots: Research Protocols. Electric Power Research Institute: Palo Alto, CA. 1020855.

Fowlie, M. 2010. U.S. Department of Energy Smart Grid Investment Grant Technical Advisory Group Guidance Document #7, Topic: Design and Implementation of Program Evaluations that Utilize Randomized Experimental Approaches. November 8, 2010.

Fowlie M., Michael Greenstone, and Catherine Wolfram. 2018. “Do Energy Efficiency Investments Deliver? Evidence from the Weatherization Assistance Program.” The Quarterly Journal of Economics 133 (3), 1597-1644.

Frison, L., and S. J. Pocock. 1992. “Repeated measures in clinical trials: Analysis using mean summary statistics and its implications for design.” Statistics in Medicine 11.13 (1992): pp. 1685-704.

Greene, W. 2011. Econometric Analysis. New Jersey: Prentice Hall.

Harding, M., and A. Hsiaw. 2012. Goal Setting and Energy Efficiency. Stanford University working paper.

Hoffman, Ian, Steven R. Schiller, et al. 2015. Energy Savings Lifetimes and Persistence: Practices, Issues, and Data. Lawrence Berkeley National Laboratory Technical Brief. https://emp.lbl.gov/sites/default/files/savings-lifetime-persistence-brief.pdf

Ignelzi, P., J. Peters, L. Dethman, K. Randazzo, L. Lutzenhiser. 2013. Paving the Way for a Richer Mix of Residential Behavior Programs. Prepared for Enernoc Utility Solutions. CALMAC Study SCE0334.01.

Illinois Statewide Technical Reference Manual. 2018. 2019 Illinois Statewide Technical Reference Manual for Energy Efficiency Version 7.0, Volume 4: Cross-Cutting Measures and 53 Attachments. https://www.icc.illinois.gov/downloads/public/ILTRM_Effective_010119_v7.0_Vol_4_X-Cutting_Measures_and_Attach_092818_Final.pdf

Integral Analytics. 2011. Sacramento Municipal Utility District Home Energy Report Program Impact and Persistence Evaluation Report, Years 2008-2011. Prepared by May Wu, Integral Analytics.

Jenkins, Cheryl et al. 2017. Accounting for Behavioral Persistence-A Protocol and a Call for Discussion. Presented at the 2017 International Energy Program Evaluation Conference. https://www.iepec.org/?attachment_id=13250.

Khawaja, M. S. and J. Stewart. 2014. Long-Run Savings and Cost Effectiveness of Home Energy Report Programs. Cadmus Research Report. http://www.cadmusgroup.com/wpcontent/uploads/2014/11/Cadmus_Home_Energy_Reports_Winter2014.pdf.

List, J. A. 2011. “Why Economists Should Conduct Field Experiments and 14 Tips for Pulling One Off.” Journal of Economic Perspectives (25), pp. 3–16.

List, J. A., S. Sadoff, S., and M. Wagner. 2010. So You Want to Run an Experiment, Now What? Some Simple Rules of Thumb for Optimal Experimental Design. National Bureau of Economic Research Paper 15701.

Mazur-Strommen, S., and K. Farley. 2013. ACEEE Field Guide to Utility-Run Behavior Programs. American Council for an Energy Efficient Economy, Report Number B132.

Minnesota Department of Commerce, Division of Energy Resources. 2015. Energy Efficiency Behavioral Programs: Literature Review, Benchmarking Analysis, and Evaluation Guidelines. Prepared by Illume Advising with subcontractors Indica Consulting and Dr. Edward Vine. http://mn.gov/commerce-stat/pdfs/card-report-energy-efficiency-behavorial-prog.pdf.

National Renewable Energy Laboratory. 2017. Strategic Energy Management Protocol: The Uniform Methods Project. Prepared by James Stewart. https://www.nrel.gov/docs/fy17osti/68316.pdf.

Navigant Consulting. 2016. ComEd Home Energy Report Program Decay Rate and Persistence Study – Year Two. Prepared for Commonwealth Edison Company by C. Olig and E. Young.

Navigant Consulting. 2017. ComEd Home Energy Report Program Decay Rate and Persistence Study – Year Three. Prepared for Commonwealth Edison Company by W. Sierzchula and D. Dinsmoor.

NMR Group. 2017. 1606 Eversource Behavior Persistence Evaluation. Submitted to Energy Efficiency Board Evaluation Administrator. https://www.energizect.com/sites/default/files/R1606_Eversource%20Behavior%20Persistence%20Evaluation_FINAL_10.15.17.pdf.

Pennsylvania Act 129 Phase IV TRM. 2019. http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/technical_reference_manual.aspx

Pennsylvania Statewide Evaluation Team. 2018. Residential Behavioral Program Persistence Study. Prepared by A. Ciccone and J. Smith. http://www.puc.state.pa.us/Electric/pdf/Act129/SWE_Res_Behavioral_ProgramPersistence_Study_Addendum2018.pdf.

Pacific Gas & Electric. 2013. Evaluation of Pacific Gas and Electric Company's Home Energy Report Initiative for the 2010-2012 Program. Prepared by Freeman, Sullivan & Co. http://www.oracle.com/us/industries/utilities/evaluation-pacific-gas-company-3631944.pdf.

Rosenberg, M., G. Kennedy Agnew, K. Gaffney. 2013. "Causality, Sustainability, and Scalability – What We Still Do and Do Not Know about the Impacts of Comparative Feedback Programs." Paper prepared for 2013 International Energy Program Evaluation Conference, Chicago.

Seelig, M. J. 2013. Business Energy Reports. Presentation at BECC 2013. http://beccconference.org/wp-content/uploads/2013/12/BECC_PGE_BER_11-19-13_seelig-.pdf.

Shadish, W. R., T. D. Cook, D. T. Campbell. 2002. Experimental and Quasi-experimental Designs for Generalized Causal Inference. Belmont, CA: Wadsworth Cengage Learning.

Skumatz, L. 2016. "Persistence of Behavioral Programs: New Information and Implications for Program Optimization." The Electricity Journal 29 (5): pp. 27-32.

Sacramento Municipal Utility District. 2013. SmartPricing Options Interim Evaluation. Prepared for the U.S. Department of Energy and Lawrence Berkeley National Laboratory by Sacramento Municipal Utility District and Freeman, Sullivan, & Co.

Stewart, J. 2013a. Peak-Coincident Demand Savings from Behavior-Based Programs: Evidence from PPL Electric's Behavior and Education Program. UC Berkeley: Behavior, Energy and Climate Change Conference. http://escholarship.org/uc/item/3cc9b30t.

Stewart, J. 2013b. Energy Savings from Business Energy Feedback. Presentation at BECC 2013. http://beccconference.org/wp-content/uploads/2015/10/presentation_stewart.pdf.

Todd, A. 2014. Insights from Smart Meters: The Potential for Peak-Hour Savings from Behavior-Based Programs. Lawrence Berkeley National Laboratory. LBNL Paper LBNL6598E. http://escholarship.org/uc/item/2nv5q42n.

1.4.5 PRIMARY SOURCES USED TO PREPARE DEMAND RESPONSE PROTOCOLS

Goldberg, Miriam L, and G. Kennedy Agnew. Measurement and Verification for Demand Response. 2013

Measurement and Verification for Demand Response was produced by Miriam L. Goldberg (Measurement and Verification Working Group chair) and Kennedy Agnew of DNV KEMA Energy and Sustainability, for the Lawrence Berkeley National Laboratory, who is managing this work under a contract to the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability under Contract No. DE-AC02-05CH11231 https://www.ferc.gov/sites/default/files/2020-04/napdr-mv.pdf

Midcontinent Independent System Operator (MISO). 2021. BPM-026-r6. Demand Response Business Practices Manual. https://cdn.misoenergy.org/BPM%20026%20-%20Demand%20Response49596.zip

1.4.5.1 Links to referenced Business Practice Manuals and related MISO resources:

- BPM-001 Market Registration https://cdn.misoenergy.org//BPM%20001%20-%20Market%20Registration49545.zip

- BPM-002 Energy and Operating Reserve Markets https://cdn.misoenergy.org//BPM%20002%20-%20Energy%20and%20Operating%20Reserve%20Markets49546.zip
- BPM-005 Market Settlements https://cdn.misoenergy.org/BPM%20005%20Market%20Settlements49550.zip
- BPM-007 Physical Scheduling https://cdn.misoenergy.org/BPM%20007%20-%20Physical%20Scheduling49551.zip
- BPM-009 Market Monitoring and Mitigation https://cdn.misoenergy.org//BPM%20009%20-%20Market%20Monitoring%20and%20Mitigation49600.zip
- BPM-010 Network and Commercial Model https://cdn.misoenergy.org//BPM%20010%20-%20Network%20and%20Commercial%20Model49557.zip
- BPM-011 Resource Adequacy https://cdn.misoenergy.org//BPM%20011%20-%20Resource%20Adequacy110405.zip
- BPM-020 Transmission Planning https://cdn.misoenergy.org//BPM%20020%20-%20Transmission%20Planning113822.zip
- MISO Tariff https://docs.misoenergy.org/legalcontent/TariffAsFiledVersion.pdf
- Module C: Energy and Operating Reserve Markets https://docs.misoenergy.org/legalcontent/Module_A_-_Common_Tariff_Provisions.pdf
- Module D: Market Monitoring and Mitigation Measures https://docs.misoenergy.org/legalcontent/Module_D_-_Market_Monitoring_and_Mitigation_Measures.pdf
- Module E-1: Resource Adequacy https://docs.misoenergy.org/legalcontent/Module_E-1_-_Resource_Adequacy.pdf
- Schedule 29-A: ELMP for Energy and Operating Reserve Market https://docs.misoenergy.org/legalcontent/Schedule_29-A_-_ELMP_for_Energy_and_Operating_Reserve_Market.pdf
- Schedule 30: Emergency Demand Response Initiative https://docs.misoenergy.org/legalcontent/Schedule_30_-_Emergency_Demand_Response_Initiative.pdf
- Attachment L: Credit Policy https://docs.misoenergy.org/legalcontent/Attachment_L_-_Credit_Policy.pdf
- Attachment TT: Measurement and Verification (M&V) Criteria https://docs.misoenergy.org/legalcontent/Attachment_TT_-_Measurement_and_Verification_%28M_and_V%29_Criteria.pdf
- Demand Response Tool User Guide (version 3, 5/20/2010) https://cdn.misoenergy.org/Demand%20Response%20Tool%20User%20Guide177286.pdf
- Demand Side Resource Interface (DSRI) On-line User Guide https://cdn.misoenergy.org/Demand%20Side%20Resource%20Interface%20(DSRI)%20-%20Frequently%20Asked%20Questions575012.pdf