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Keith D. Wood
Director, Resource Planning

March 25, 2022

Via Electronic Delivery
Ms. Lora W. Johnson, CMC, LMMC
Clerk of Council
Council of the City of New Orleans
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: **In Re: 2021 Triennial Integrated Resource Plan of Entergy New Orleans, LLC**
Docket No. UD-20-02

Dear Ms. Johnson:

Entergy New Orleans, LLC ("ENO" or the "Company") respectfully submits the Public Version of its 2021 Integrated Resource Plan with Appendices attached thereto in the above referenced Docket. 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 requisite original and number of hard copies once the Council resumes normal operations, or as you or the Council otherwise directs. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

ENO's filing contains information considered by ENO to be proprietary and confidential. Public disclosure of certain of this information may expose ENO and its customers to an unreasonable risk of harm. Therefore, in light of the commercially sensitive nature of such information, these exhibits bear the designation "Highly Sensitive Protected Materials" or words of similar import. The confidential information and documents included with the Application may be reviewed by appropriate representatives of the Council and its Advisors pursuant to the provisions of the Official Protective Order adopted in Council Resolution R-07-432 relative to the disclosure of Highly Sensitive Protected Materials. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

Should you have any questions regarding the above, I may be reached at (504) 670-3633. Thank you for your assistance with this matter.

Sincerely,

Keith D. Wood

KDW/bkd
Enclosures
cc: Official Service List (Public Version *via email)*

CERTIFICATE OF SERVICE
DOCKET NO. UD-20-02

I hereby certify that I have served the required number of copies of the foregoing report upon all other known parties of this proceeding, by the following: electronic mail, facsimile, overnight mail, hand delivery, and/or United States Postal Service, postage prepaid.

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New Orleans, Louisiana, this 25th day of March 2022.

Keith D. Wood


Entergy New Orleans, LLC

2021 Integrated Resource Plan

March 25, 2022

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Table of Contents

Abbreviations and Definitions

AMI	Advanced Metering Infrastructure	**LCOE**	Levelized Cost of Electricity
ANO	Arkansas Nuclear One	**LCR**	Local Clearing Requirement
ATB	National Renewable Energy Laboratory Annual Technology Baseline	**LMP**	Locational Marginal Price
BESS	Battery Energy Storage System	**LMR**	Load Modifying Resource
BOT	Build-Own-Transfer	**LRZ**	Local Resource Zone
BP21	Business Plan 2021	**LSE**	Load Serving Entity
CCGT	Combined Cycle Gas Turbine	**MISO**	Midcontinent Independent System Operator
CDD	Cooling Degree Days	**MTEP**	MISO Transmission Expansion Plan
CEO	Chief Executive Officer	**MW, MWh**	Megawatt, Megawatt Hour
Council	Council of the City of New Orleans	**NERC**	North American Electric Reliability Corporation
CT	Simple Cycle Combustion Turbine	**NOx**	Oxides of Nitrogen
DER	Distributed Energy Resource	**NRC**	Nuclear Regulatory Commission
DLC	Direct Load Control	**NREL**	National Renewable Energy Laboratory
DR	Demand Response	**NTG**	Net-to-Gross
DSM	Demand-Side Management	**OEM**	Original Equipment Manufacturer
EE	Energy Efficiency	**POV**	Point of View
EGU	Electric Generating Unit	**PPA**	Power Purchase Agreement
EIA	Energy Information Administration	**PRA**	Planning Resource Auction
ELCC	Effective Load Carrying Capability	**PRMR**	Planning Reserve Margin Requirement
ENO	Entergy New Orleans, LLC	**PV**	Solar Photovoltaic
Entergy	Entergy Corporation	**REC**	Renewable Energy Certificate
EPA	Environmental Protection Agency	**RICE**	Reciprocating Internal Combustion Engine
FERC	Federal Energy Regulatory Commission	**RCPS**	Renewable and Clean Portfolio Standard
GDS	GDS, Inc.	**RTO**	Regional Transmission Organization
GPO	Green Power Option program	**SERC**	Southeastern Electric Reliability Council
Grand Gulf	Grand Gulf Nuclear Station	**SLR**	Subsequent License Renewal
Guidehouse	Guidehouse Consulting, Inc.	**SO2**	Sulfur Dioxide
GOM	Gulf of Mexico	**SWB**	Sewerage & Water Board of New Orleans
GW, GWh	Gigawatt, Gigawatt Hour	**TRSC**	Total Relevant Supply Cost
HDD	Heating Degree Days	**WB**	White Bluff Steam Electric Station
HVAC	Heating, Ventilation and Air Conditioning	**UCAP**	Unforced Generation Capacity
ICAP	Installed Generation Capacity	**Union 1**	Union Power Block 1
IRP	Integrated Resource Plan	**UPC**	Use Per Customer
kW, kWh	Kilowatt, Kilowatt Hour	**ZRCs**	Zonal Resource Credits

Chapter 1

Executive Summary

1.1. Continued Productive Collaboration

This 2021 Integrated Resource Plan ("IRP") report builds on the collaborative efforts and productive process that characterized the development of the 2018 IRP. Working under the current, updated IRP Rules adopted by the Council for the City of New Orleans ("Council"),[1] the parties have engaged in constructive discussions over the last 16 months about the inputs and analysis required to develop the 2021 IRP during a stakeholder process that included a series of four technical meetings.[2] The result is a report that meets the goal expressed in the preamble to the IRP Rules: "It is the Council's desire that a comprehensive IRP conducted in accordance with these IRP Rules provide ***a full picture*** of ***all reasonably available resource options*** in light of current and expected market conditions and technology trends, and generate an informed understanding of the ***economic, reliability, and risk evaluation*** of utility resource planning as well as associated ***social and environmental impacts*** [emphasis added]." Following is some additional context on these key elements:

- **A full picture** - This IRP provides a broad view of options for meeting customers' electrical needs across the 20-year planning period from 2022-41 in light of current and expected market conditions and technology trends. Starting with assumptions and inputs developed for ENO's Business Plan 2021 ("BP21"), analysis was performed on three different planning Scenarios that varied a number of key assumptions about future market conditions outside New Orleans and four different planning Strategies that assessed policy and planning objectives within the city. The parameters of these Scenarios and Strategies were discussed and agreed upon by the parties during the stakeholder process mentioned above. Important variables among the four Strategies included the assumed potential savings from, and costs of, Demand Side Management ("DSM") programs over the 20-year period and the assumed costs for renewable resources such as utility scale solar and onshore wind. DSM assumptions came from two DSM Potential Studies—one prepared by Guidehouse and the other prepared by GDS, Inc.—which presented generally consistent projections of future DSM achievable potential. The parties agreed on assignments of DSM input cases from one study or the other to each of the four Strategies for use in the analysis. Renewables cost inputs came from two sources--the Entergy Technology Assessment and the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB"). The parties agreed on the source of renewables cost inputs for each Scenario and Strategy. A discussion of the Scenarios and Strategies can be found in Chapter 4.
- **All reasonably available resource options** - As required by the IRP Rules, each Strategy was analyzed in the context of each Scenario to identify an optimized Portfolio of resources to serve customers' needs under that combination of assumptions. Given the combination of three Scenarios times four Strategies, this resulted in an initial set of 12 Optimized Portfolios. These Portfolios included different combinations of renewables, battery storage, and DSM programs depending on their particular assumptions. At the Stakeholders' request, a sensitivity case was produced based on the optimized portfolio from Scenario 3/Strategy 4 using lower renewables cost inputs provided by the Stakeholders. Additionally, in response to the eighth recommendation proposed by the Advisors for inclusion in the 2021 IRP[3] , two manual portfolios

1. See, Council Resolution No. R-17-429.
2. Technical Meeting #1 was held on December 9, 2020, Technical Meeting #2 on April 29, 2021, Technical Meeting #3 on August 12, 2021, and Technical Meeting #4 on January 20, 2022.
3. See, Resolution R-20-257, 2021 IRP Initiating Resolution, at 18.

were produced that assumed an alternative 2025 deactivation for Union Power Block 1 instead of the current 2033 assumed deactivation, one based on the Optimized Portfolio produced from Scenario 1/Strategy 1 and the other based on the optimized portfolio produced from Scenario 3/ Strategy 4. Finally, as a result of discussions at Technical Meeting #4, a third manual portfolio was developed to evaluate the possibility of near-term compliance with the Council's Renewable and Clean Portfolio Standard ("RCPS") through additional energy production rather than the purchase of unbundled Renewable Energy Certificates ("RECs"). This third manual portfolio kept the Union 1 deactivation in 2033 but advanced the addition of renewable resources to earlier years in the planning horizon. The parties reviewed all the portfolios and agreed on a representative subset of five Portfolios to carry through the remainder of the detailed total relevant supply cost analysis. A discussion of the downselected set of five Portfolios, the manual portfolios, and the sensitivity case can be found in Chapter 4.

- **Economic, reliability, and risk evaluation** - The analysis of total relevant supply cost, which represents the incremental fixed costs and total variable supply costs to serve customers' resource needs reliably under the assumptions of a particular Portfolio through the planning horizon, used cross-testing to identify a 20-year revenue requirement for each of the five downselected Portfolios in all three Scenarios. In order to work within schedule and resource constraints, the parties agreed to a framework under which additional stochastic analysis was conducted on four of the five Portfolios to evaluate their sensitivity to changes in two main input assumptions—natural gas price and CO_2 price. Information on the total relevant supply cost and risk analysis can be found in Chapter 4.
- **Social and environmental impacts** - The IRP Rules required the development of a scorecard to assist the Council in assessing the IRP based on several aspects of the Resource Portfolios, including social and environmental impacts, some of which are only able to be evaluated on a subjective basis. Starting from the Scorecard developed for the 2018 IRP, the parties affirmed the continued use of several metrics and agreed on updated metrics that focused on reliability and compliance with the Council's RCPS rules. More discussion can be found in Chapter 4.

1.2. Key Takeaways

- The various portfolios analyzed in the 2021 IRP indicate that once a capacity need arises for ENO, it can likely be met by a combination of renewable and storage resources rather than additional fossil generation. The timing of capacity needs, as well as the amounts and types of resources best suited to fill the needs, varied based on the Scenario and Strategy constraints imposed. This finding is important given the climate goals articulated in the RCPS, the Council's policy goal articulated in Resolution R-22-11 of pursuing 100% renewable energy for City of New Orleans and SWB operations by 2025, and Entergy's own corporate sustainability goals.
- The IRP analysis indicates that it is more beneficial for customers for ENO to operate Union 1 until 2033 instead of deactivating it early in 2025. Both manual portfolios that assumed a 2025 deactivation date (Manual Portfolios 1a and 4a) resulted in higher TRSCs across each of the Scenarios than the optimized portfolios that used the current 2033 assumption (Optimized Portfolios for Scenario 1/Strategy 1 and Scenario 1/Strategy 2). However, given the variability of timing in capacity needs across the portfolios and the climate policy goals mentioned above, these first two points underscore the importance of maintaining flexibility in ENO's resource planning and considering a broad range of options to continue serving customers with affordable, reliable, and sustainable electricity.

- The TRSCs for Manual Portfolio 3a are higher across each Scenario relative to the TRSCs for the other three portfolios that use Guidehouse DSM programs. The goal in creating Manual Portfolio 3a was to evaluate the viability of achieving near-term RCPS compliance by keeping Union 1's deactivation at 2033 while accelerating the addition of renewable resources as an alternative to relying on the purchase of unbundled RECs. This result suggests that, while there could be benefits to accelerating renewable resources under some circumstances, completely excluding the use of RECs from near-term RCPS compliance could result in added costs for customers depending on the cost of unbundled RECs.
- The IRP will serve as a near-term source to inform the implementation of Energy Smart DSM programs in the city over the next few years. The programs identified in the two 20 year potential studies will be valuable inputs to the Program Year 13-15 implementation plan that will be filed later in 2022 for review by the Council.
- This IRP will inform the Company's compliance efforts under the Council's RCPS adopted in Docket UD-19-01[4]. The Company is required under the RCPS rules to file its three year prospective Compliance Plan for 2023-2025 within 90 days after filing this IRP report[5]. The Scenario 1 total relevant supply cost for the optimized portfolio produced for Scenario 1/Strategy 2 (designated as the "But For RCPS" portfolio) will be used as the baseline for calculating incremental costs associated with the three-year RCPS compliance plan for 2023-2025 in accordance with Section 4.d.1 of the RCPS rules. ENO's generation portfolio already emits far less CO_2 than the national average for investor-owned utilities, with a 2021 CO_2 emission rate of 548 lbs/MWh. This IRP analysis will support our efforts to continue reducing our CO_2 emissions and comply with the Council's RCPS goals.
- Because the IRP rules do not require the identification of a preferred portfolio, the comparative value of this IRP report comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a guide for the future, not from focusing on the costs of one Portfolio versus another. Actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current market costs.

1.3. Action Plan

There are numerous ongoing and planned activities that are important to supporting Council goals and Company initiatives in the near term. Some of these include filing the Energy Smart PY 13-15 Implementation Plan and the RCPS Compliance Plan for 2023-25 discussed above. Additional efforts include supporting the continued deployment of electric vehicle ("EV") charging infrastructure throughout the city, pursuing implementation of a residential battery storage pilot, identification of additional renewable opportunities in the city, development of proposals to support the Council's desire for 100% renewable power for city and Sewerage & Water Board operations by 2025, addition of a large customer offering under the existing Green Power Option program, development of backup generation solutions to support residential customers, the City of New Orleans, and key commercial customers after storm events , and submission of the system resiliency and storm hardening plan contemplated under Docket UD-21-03. The Action Plan for pursuing these efforts is found in Chapter 5.

In conclusion, ENO greatly appreciates the continued, collaborative efforts of the Council, its Advisors, Intervenors, and the public that resulted in this 2021 IRP report. The IRP continues to be an instructive view of resource options under a range of possible future Scenarios that should be useful in ongoing discussions about meeting the electricity needs of ENO's customers and supporting the policy goals of the Council.

4. See, Council Resolution R-21-182.
5. Council Resolution R-21-182, section 4.e.

Chapter 2

Integrated Resource Planning Process

2.1. Planning Principles and Objectives

Under the Council's IRP Rules, the planning process seeks to identify Portfolios of supply and demand-side resources that focus on affordability, reliability, and environmental stewardship to meet customer power needs across a range of possible future Scenarios. This work is particularly relevant given the ongoing evolution of the electric utility and ENO's continued focus on meeting its customers' needs and expectations.

2.1.1. Planning Objectives

While the utility environment may be changing, ENO strives to achieve a balance between providing customers sustainably-sourced, reliable power, at the lowest reasonable supply cost, while considering risk. The ENO IRP was developed consistent with these objectives and in accordance with the following objectives articulated in Section 3 of the Council's IRP Rules:

1. Optimize the integration of supply-side resources and demand-side resources, while taking into account transmission and distribution, to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost given an acceptable level of risk;
2. Maintain the Utility's financial integrity;
3. Anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors;
4. Support the resiliency and sustainability of the Utility's systems in New Orleans;
5. Comply with local, state and federal regulatory requirements and known policies (including such policies identified in the Initiating Resolution) established by the Council;
6. Evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and distributed energy resources ("DERs"), among others;
7. Achieve a range of acceptable risk in the trade-off between cost and risk; and
8. Maintain transparency and engagement with stakeholders throughout the IRP process by conducting technical conferences and providing for stakeholder feedback regarding the Planning Scenarios, Planning Strategies, input parameters, and assumptions.

ENO is dedicated to engaging in resource planning that builds a strong, resilient future for our customers and the communities we serve. The fundamental goal for ENO's resource planning is to deliver sustainable resources that are centered on positive customer outcomes and which balance three key objectives: affordability, reliability, and environmental stewardship. This balance looks at both the near-term and long-term benefits and risks associated with each key objective. ENO recognizes the need for increased focus on environmental stewardship and its role as a key objective in the planning process is noted below.

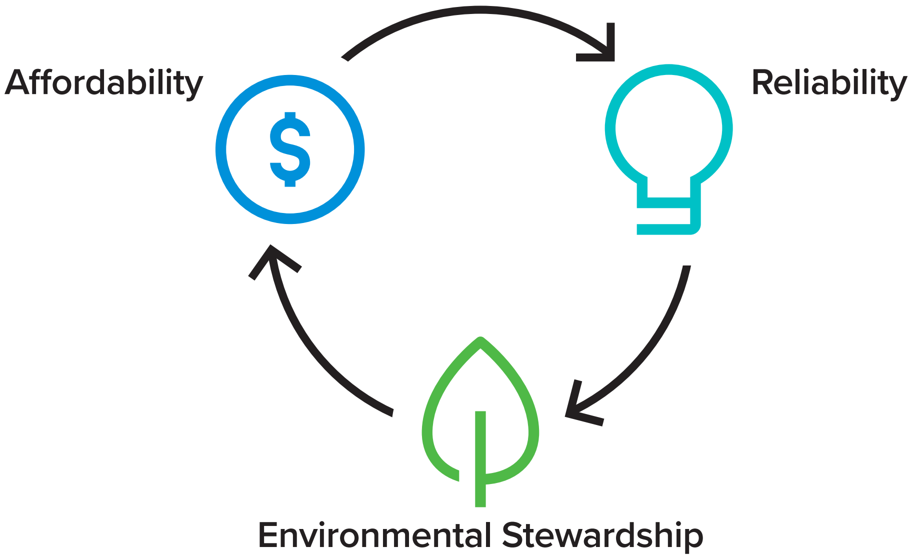


Figure 1: Key Planning Objectives

- Affordability as a planning objective means keeping customer costs reasonable, considering current and future cost impacts of infrastructure improvements made on behalf of our customers, and taking advantage of scale to provide cost synergies.
- Reliability as a planning objective means ensuring that the stability of the grid is maintained through adequate resources to meet capacity and energy needs along with adequate transmission and distribution systems to ensure that power is consistently delivered to customers.
- Environmental stewardship as a planning objective refers to the use and protection of the natural environment, ensuring compliance with existing and likely regulation, adaptability[6] of resources, and paths towards a lower-carbon economy.

We balance these three objectives through an iterative planning process. The planning process assesses need and designs, tests portfolios against future scenarios, and evaluates risks associated with each key objective. This process yields sustainable portfolios composed of lowest reasonable cost resources that provide direction with respect to future resource decisions.

Like much of what we do, our planning process focuses on positive customer outcomes. ENO strives to do more than just deliver electricity: we power life for this generation and the generations to come, just as we have for nearly a century. In doing so, we are focused on empowering customers to achieve their desired outcomes. Understanding our customers' needs and evolving desires is critical. Our relationship with our customers and investments in advanced metering and advanced analytics gives us insights into those needs and interests. We have observed increased customer interest in targeted customer offerings such as energy efficiency, resiliency as a service and other innovative products and services.

6. Adaptability refers to the ability of a resource to respond to changing circumstances. An example of an adaptable resource includes hydrogen capability for combined cycle or simple cycle combustion turbine resources, allowing those resources to be converted from natural gas to hydrogen when the market supports such a transition.

Our customers' needs and interests continue to change, as do the technologies available to meet those needs and the associated local and federal policies. Consistent review of technology options and cost and operational data, and further innovation on grid configuration opens new possibilities to meet customer need while realizing our planning objectives. Improvements in existing generating technology, new and innovative clean generating technologies, and increased data availability provide new tools for ENO to continue to meet customer needs reliably and affordably. As costs continue to decline on carbon-free technologies, ENO has the ability to deliver more utility-scale renewable energy to customers. Additionally, we continue to monitor and explore energy storage and technologies that utilize alternative fuels as possible resources. As options for smaller grid-connected devices like distributed generation and energy storage increase, both at a utility and customer level, different grid configurations such as local and regional microgrids could become more viable to meet customer needs.

As shown in Figure 2, we can deliver sustainable, lowest reasonable cost resources across an ever-evolving landscape by utilizing planning guidelines that target positive customer outcomes when it comes time to select specific resources.

Figure 2: Planning Guidelines

2.2. Existing Resources

As shown in Figures 3 and 4 below, which show generating capacity for approved and planned resource additions, ENO has been successful in transforming its portfolio with reliable, efficient gas-fired generation, renewables generation, and load modifying resources to meet its supply needs.

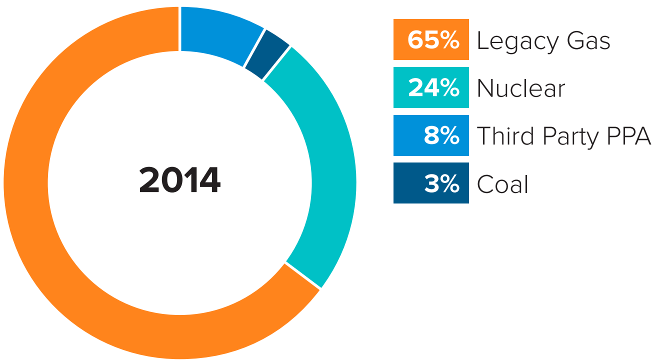


Figure 3 – ENO's 2014 Portfolio Makeup

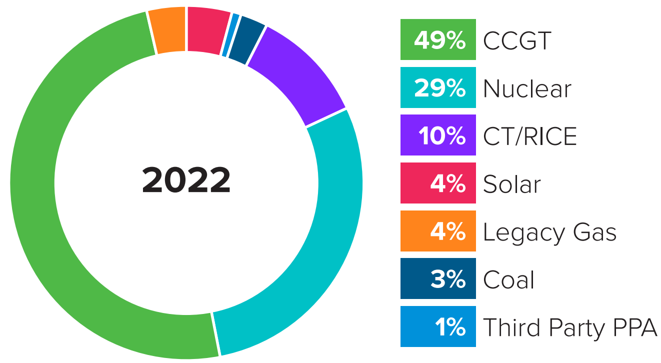


Figure 4 – ENO's 2022 Portfolio Makeup

ENO currently controls about 1.2 GW of generating capacity either through direct ownership or contracts with affiliate Entergy Operating Companies and other counterparties. Table 1 below shows ENO's supply resources by fuel type measured in unforced capacity (or UCAP)[7] with percentages of the overall Portfolio, considering existing units and planned additions.

Table 1: ENO's 2022 Resource Portfolio by Fuel Type

Fuel Type	MW UCAP	%
CCGT	597	48%
Nuclear	350	28%
CT / RICE	127	10%
Solar	47	4%
Legacy Gas	46	4%
Coal	31	3%
Load Modifying Resource	28	2%
Third Party PPA	11	1%
Total	**1,235.5**	**100%**

ENO's Portfolio by unit is shown in Table 2 below.

7. Unforced Capacity is a resource's Installed Capacity after applying its respective forced outage rate and/or capacity credit assumptions.

Table 2: ENO's 2022 Resource Portfolio by Unit

Plant	Unit	MW UCAP	Fuel Type	Typical Operating Role	Operation Date
Acadia	1	5.8	CCGT	Base Load/ Load Following	2002
ANO	1	22.5	Nuclear	Base Load	1974
ANO	2	23.3	Nuclear	Base Load	1980
Grand Gulf EAMP		23.8	Nuclear	Base Load	1985
Grand Gulf ELMP		2.5	Nuclear	Base Load	1985
Grand Gulf ENMP		162.9	Nuclear	Base Load	1985
Independence 1	1	7.0	Coal	Base Load/ Load Following	1983
Little Gypsy	2	7.0	Legacy Gas	Seasonal Load Following	1966
Little Gypsy	3	8.7	Legacy Gas	Seasonal Load Following	1969
N.O. Solar Station		9.9	Solar	Peaking/ Reserves	2020
Ninemile	4	11.9	Legacy Gas	Seasonal Load Following	1971
Ninemile	5	12.1	Legacy Gas	Seasonal Load Following	1973
Ninemile	6	114.9	CCGT	Base Load/ Load Following	2015
N.O. Power Station	1	125.9	CT / RICE	Peaking/ Reserves	2020
Perryville	1	1.9	CCGT	Base Load/ Load Following	2002
Perryville	2	0.7	CCGT	Peaking/ Reserves	2001
Riverbend 30		95.4	Nuclear	Base Load	1986
Union PB	1	473.2	CCGT	Base Load/ Load Following	2016
Waterford	2	5.8	Legacy Gas	Seasonal Load Following	1975
Waterford	3	20.7	Nuclear	Base Load	1985
Waterford	4	0.5	CT / RICE	Peaking/ Reserves	2009
White Bluff	1	10.7	Coal	Base Load/ Load Following	1980
White Bluff	2	12.5	Coal	Base Load/ Load Following	1981
Third Party PPA		11.2	N/A	N/A	-
Load Modifying Resources		27.7	N/A	Peaking/ Reserves	-
Iris Solar PPA		24.9	Solar	Renewable	2022
St. James Solar PPA		10.0	Solar	Renewable	2022
2022 ENO Solar		2.3	Solar	Renewable	2022
Total		**1,235.5**			

2.3. Future of Existing Resources

The IRP includes deactivation assumptions for existing generation in order to plan for and evaluate the best options for replacing that capacity over the planning horizon. Based on current planning assumptions, during the planning period, the total net reduction in ENO's generating capacity from the anticipated unit deactivations is expected to be approximately 600 MWs. Generally, current planning assumptions reflect generic deactivation assumptions for the generation fleet: 60 years for coal and legacy gas resources, and 30 years for combustion turbine ("CT") technology which includes both (CTs and combined cycle gas turbines ("CCGTs"). As resources age and assumed deactivation dates near, as equipment failures occur, or as operating performance diminishes, cross-functional teams are assembled to evaluate whether to keep a particular unit in service for an additional length of time at an acceptable level of cost and reliability. These deactivation assumptions do not constitute a definitive deactivation schedule but are based upon the best available information and are used as planning tools to help prompt cross-functional reviews and recommendations. It is not unusual for these assumptions to change over time, given the dynamic use and operating characteristics of generating resources. ENO's unit deactivation assumptions for the 2021 IRP are outlined below.

Union Power Block 1 - Deactivation currently assumed for Union 1 is 2033. This is a generic planning assumption only and does not reflect unit-specific analysis or decisions. As stated above, this resource will be reevaluated as it ages and operating conditions change. As shown in Table 2, above, Union 1 accounts for approximately 473 MW of capacity for ENO. The assumed deactivation date of Union 1 was accelerated to 2025 in manual portfolios developed under two of the Planning Strategies.

Affiliate PPAs – ENO receives allocations of several units that could deactivate during the planning period through affiliate life-of-unit Purchased Power Agreements ("PPAs"). These resource deactivations are assumed to total approximately 130 MW of capacity for ENO as shown in Table 2, above.

2.4. Planned Resources

ENO is anticipating the addition of two solar resources totaling 35 MW (70 MW nameplate) located in Washington Parish and St. James Parish in 2022. Contracted through PPAs, Iris Solar and St. James Solar will add emission-free renewable resources into its generation fleet, increase supply diversity, and address a capacity need identified in the certification filing that resulted in Council approval of ENO's entering into the PPAs.[8]

2.5. Customer Preferences and Long-term Planning

With advancements in technology and evolving priorities, both within and outside of the traditional utility framework, customer expectations continue to change. Today's customers are using energy more efficiently than ever before, due to both an increasing emphasis on social responsibility and sustainability and advances in EE standards. ENO recognizes that a well-designed electric system, with the proper mix of generating resources, is just as important to reducing customer costs and bills as are programs aimed at educating customers how to efficiently manage their usage.

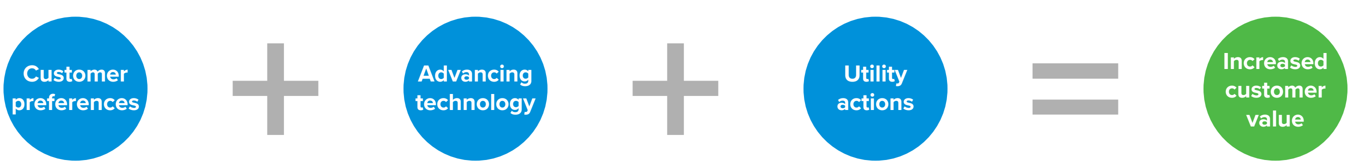


Figure 5: Changes and Opportunities Within the Utility Industry

8. See, Council Docket UD-18-06.

Customers are also seeking more options in the generation and delivery of energy and a better understanding of how they can manage their own energy use. ENO wants to actively engage its customers to obtain a better sense of their expectations and the ways in which ENO can bring offerings to the marketplace to meet those expectations. The IRP is one tool to help accomplish that goal. Increased understanding of customer needs will allow ENO to:

- Develop a comprehensive outlook on the future utility environment and more effectively anticipate and plan for the future energy needs of its customers and the city.
- Incorporate new, smart technologies and advanced analytics to better assess where expanding resource alternatives can be leveraged, and plan for improvements and enhancements to the electrical grid.
- Continue to seek cost-effective renewable resource additions to ENO's portfolio to support and expand offerings of renewable energy to interested customers.

Advancing Technology - Technological advancements provide the energy industry increased opportunities and alternative pathways to plan for and efficiently meet customers' energy needs and to partner with customers to accomplish those shared objectives. From improving the reliability and efficiency of energy production and delivery of that energy to customers, to more customer facing opportunities, like storage, conservation, and AMI-enabled options, these innovations can strengthen reliability and increase affordability for the homes, businesses, industries, and communities that ENO serves. The deployment of advanced meters and development of smart energy grids, for example, are enabling the entire utility industry to better understand the new and changing ways in which customers are using energy.

Increased Customer Value - By combining an understanding of what customers want with sound and comprehensive planning, ENO can deliver the type of service customers expect while continuing to address the planning objectives of affordability, reliability and sustainability.

2.6. Innovation

ENO strives to solve critical customer frictions for residential, commercial, and industrial customers by building new products and services. Every customer is an integral part of ENO's success. ENO collaborates with its customers, partners, and colleagues to build a more robust, sustainable power network for today and future generations.

For example, with the growing opportunity and challenges that will come with electrification of transportation in the coming years, ENO expects its customers to increasingly electrify as more vehicle models become available and their prices reach parity with, or become less expensive than, internal combustion engine alternatives. Specific to the commercial space, ENO also sees a growing number of organizations exploring electric vehicle alternatives in order to help them reach their internal sustainability goals. ENO's forecasting processes include assumptions around increased energy usage tied to electrification, which is discussed in greater detail in Chapter 3.

ENO looks to enable opportunities in this space and expects to remain customer centric with its approach. Accordingly, ENO will be exploring solutions in the future relating to fleet electrification, public charging, and workplace and residential charging. These will build on the foundation of the public charging pilot approved through the 2018 Rate Case which ENO expects will result in chargers being installed at 25 locations around the city. In parallel, ENO is committed to having the resources and infrastructure in place to support these initiatives.

2.7. MISO Resource Adequacy ("RA") & Planning Reserve Requirements

2.7.1. MISO RA Requirements

As a load serving entity ("LSE") within the Midcontinent Independent System Operator, Inc. ("MISO") since 2013, ENO is responsible for planning and maintaining a resource portfolio to reliably meet its customers' power needs. To this end, ENO must maintain proper types, locations, controls, and amounts of capacity in its portfolio. With respect to the amount of capacity, two considerations are relevant:

1. MISO Resource Adequacy Requirements
2. Long-Term Planning Reserve Margin Targets

Resource Adequacy is the process by which MISO obligates participating LSEs to procure sufficient short-term capacity, through the procurement of zonal resource credits ("ZRCs") equal to their Planning Reserve Margin Requirement ("PRMR"), in order to ensure regional reliability. ZRCs are provided by both supply-side generation and demand side alternatives. An LSE's PRMR is based on its forecasted peak load coincident with MISO's forecasted peak load, plus a planning reserve margin established by MISO annually for the MISO footprint.

Under MISO's Resource Adequacy process, the MISO-wide planning reserve margin is determined annually by November 1 prior to the upcoming planning year (which runs from June - May). Additionally, through MISO's annual Resource Adequacy process, MISO determines the amount of physical capacity needed within each particular region or Local Resource Zone ("LRZ") based on load requirements, capability of existing generation, and import capability of the LRZ. Those capacity requirements are referred to as the Local Clearing Requirement ("LCR") for the LRZ for the Planning Year. Through MISO's proposed changes to the methodology for setting each LRZ's LCR, MISO has sent signals emphasizing the need for in-zone resources to contribute to LRZ resource adequacy.

At present, the MISO Resource Adequacy process is a short-term construct. Requirements are set annually and apply only to the upcoming planning year. Similarly, the cost of ZRCs, as determined annually through the MISO Planning Resource Auction process, apply only to the upcoming year. Both the level of required ZRCs and the cost of those ZRCs are subject to change from year to year. In particular, the cost of ZRCs can change quickly as a result of variables such as changes in market participant bidding strategies, the availability of generation within MISO and a specific LRZ, or an LRZ's LCR. For example, if existing LRZ 9 (where ENO is located) generation is deactivated and replaced with generation outside of LRZ 9, there will be an increased risk of higher ZRC prices due to potentially insufficient in-zone generation to meet the LRZ 9 Local Clearing Requirement.

MISO market constructs, rules, and methodologies continue to evolve, including items that impact Resource Adequacy requirements and capacity accreditation. Currently, MISO is conducting a stakeholder process to design and implement a seasonal resource adequacy construct. ENO is participating in this process, and if needed, will adapt future resource planning efforts to align with changes implemented by MISO. Additionally, as capacity accreditation for renewable resources, such as solar, is updated by MISO and approved by the Federal Energy Regulatory Commission ("FERC"), ENO will align with these updates as needed.

As an LSE within MISO, ENO is responsible for planning and maintaining a resource portfolio to reliably meet its customers' power needs. Therefore, ENO plans beyond the immediate year requirements outlined by MISO's Resource Adequacy process. However, as discussed below, ENO's long-term reserve margin target will be informed by MISO's Resource Adequacy construct going forward.

2.7.2. Long-Term PRM Targets

Although the MISO Resource Adequacy process establishes minimum requirements that must be met in the short-term and are reviewed regularly as part of the resource planning process, it does not provide an appropriate basis for determining ENO's long-term resource needs. Moreover, relying on the short-term market for ZRCs to meet customers' long-term power needs could unnecessarily expose customers to cost and reliability risk. ENO employs a more stable approach for long-term planning to meet its long-term planning objectives. ENO's current planning reserve margin reflects a long-term point of view that is intended, in part, to provide a buffer, or margin, above peak load to maintain reliable service during unplanned events such as higher than expected peak loads and unplanned outages of units committed to supply energy into the MISO market.

ENO's long term planning construct is informed by a recently-performed Loss of Load Expectation analysis which draws upon ENO's experience participating in MISO. The result of that analysis was a decision to change from the prior 12% reserve margin based on installed capacity ratings and forecasted non-coincident peak to a 12.69% reserve margin based on unforced capacity ratings and forecasted peak coincident to MISO. The changes in the planning reserve margin are intended to maintain the 1-day-in-10-year level of reliability over the long-term planning horizon while taking into account long-term uncertainty related to load forecast, weather impacts, and available supply.

ENO's current long-term planning construct is an annual construct and uses ENO's summer peak load coincident with MISO. In the event that MISO moves from its current annual Planning Resource Auction ("PRA") construct to a seasonal construct, ENO will evaluate what changes, if any, are needed to the long-term planning construct.

2.8. Resource Needs

A number of factors are considered and evaluated in order to understand and determine ENO's resource needs:

Long-Term Capacity Requirements - ENO is projected to need new generating capacity over the course of the 20-year IRP period in order to reliably serve customers. Taking deactivation assumptions and load growth into account, the long-term deficit is expected to exceed 600 MW by 2033. This need may grow to over 700 MW by the end of the planning horizon. Figure 6 below shows ENO's portfolio of existing resources, including both generating units and demand-side capacity, and planned resources, as described above, compared to ENO's peak load-plus-reserve-margin target. An assumption for the effect of future energy savings due to continued and expanded EE programs is included in the peak load forecast. The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life.

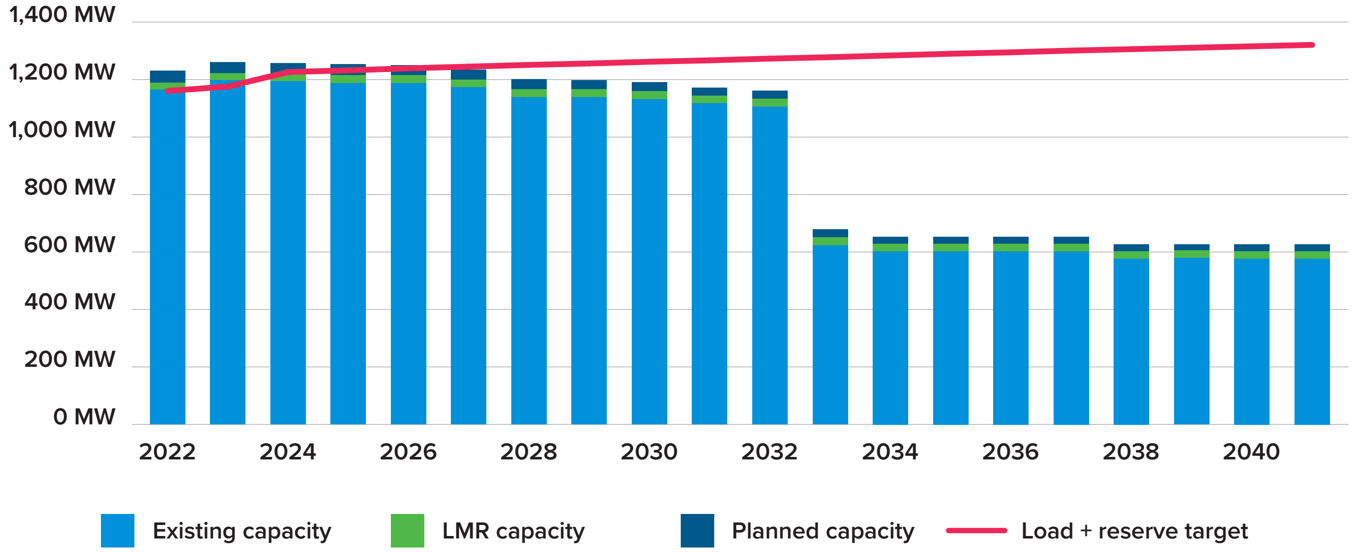


Figure 6: ENO Capacity Position

Energy Requirements - In addition to addressing long-term capacity requirements, ENO regularly assesses how the current generating fleet is expected to align with its long-term energy requirements. ENO is expected to remain a net seller in MISO's energy markets for the next decade. Without the addition of supply resources, beginning in 2033, ENO is expected to fall short of effectively meeting its long-term energy requirements without relying on the MISO market. However, the amount of energy produced by owned generation is subject to change based on fuel prices, market conditions, and unit operations.

Through the technology assessment and the IRP analytics, ENO evaluates energy-producing resources like renewable energy and dispatchable natural gas resources to meet both capacity and energy requirements over the long-term planning horizon. As resources deactivate and capacity requirements increase, ENO will look to balance energy producing and peaking generation to meet customer requirements effectively and efficiently.

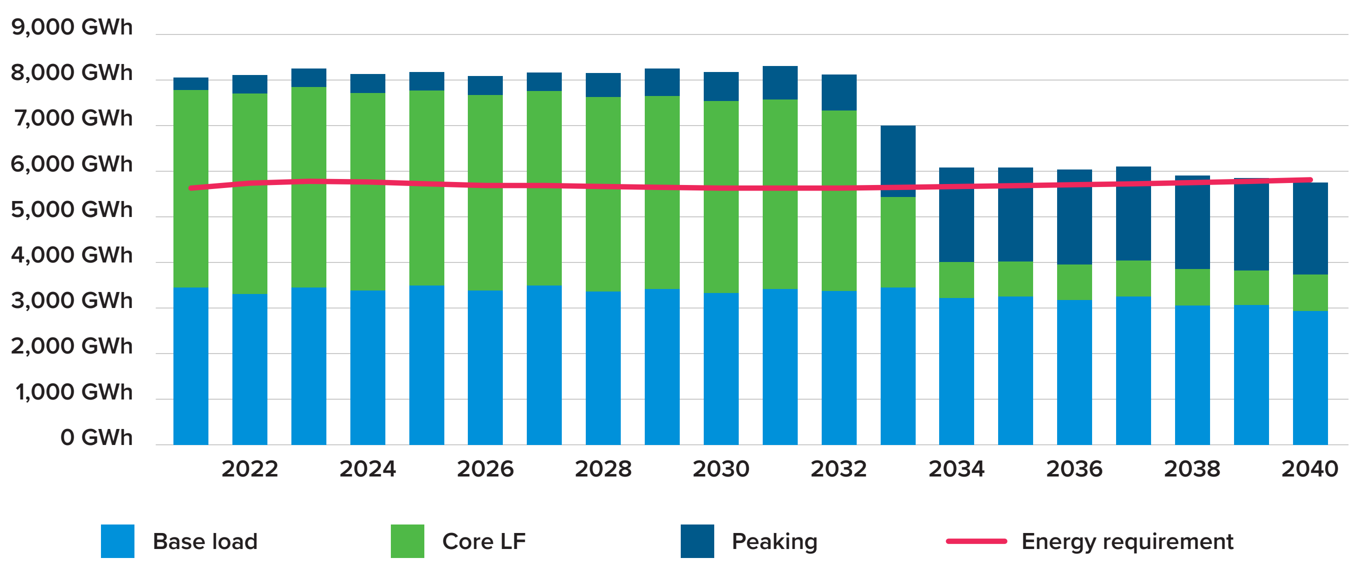


Figure 7: ENO Energy Requirements

Customer Usage - Of course, both capacity and energy resource needs are driven by customers' consumption and preferences. Customer conservation efforts, some of which are currently driven by EE programs, have already directly affected resource needs as discussed further in Chapter 3. The type, size and timing of future resource needs may be affected as customers gain additional resources to manage consumption, such as those that will be enhanced by AMI or those affected by increased accessibility to rooftop solar or battery storage technology.

ENO's long-term planning process and the evaluation outlined in this IRP help inform how ENO will meet the future capacity and energy requirements needed to continue reliably serving its customers. Consistent with the resource planning objectives outlined in Chapter 2, ENO's planning approach is to employ a diverse portfolio of energy generation resource alternatives, located when possible in relatively close proximity to customer load, with flexible attributes to help provide sufficient capacity during peak demand periods as well as adequate reserves. Given the objective of risk mitigation, these practices ensure that ENO is able to continue providing safe and reliable service to its customers at a reasonable cost.

Locational Considerations - The location of resources can have a significant impact on the electric grid. Resources, both supply-side and demand-side, can have an impact on the pattern of power flowing on the transmission system and on the voltage at the substations in the vicinity of the resource. The addition of a generating resource injects power into the electric grid; this additional power might help alleviate congestion on the electric grid, but the incremental power might also result in thermal constraints that have to be alleviated with transmission upgrades. The addition of resources may also add reactive power to or absorb reactive power from the system which can provide voltage regulation. This effect on the electric grid is particuarly beneficial for large industrial loads and other similar loads that impose reactive power demands. Deactivations of resources can similarly change the power flow through the electric grid and may result in overloads or voltage constraints, and any resource additions or replacements in lieu of resource deactivations alone may be strategically located on the electric grid to minimize any detrimental impacts. Finally, the location of resources may also have a broader impact on the MISO annual Planning Resource Auction ("PRA"). A location within a LRZ allows a resource to contribute to the local clearing requirement of that LRZ in the MISO PRA.

Flexibility Considerations - The portfolio design analytics explore the value of renewable energy projects, energy storage, peaking, and CCGT capacity. Based on these analyses, the long-term planning horizon will likely include additions of both renewable and energy storage technologies to ENO's portfolio. As intermittent additions increase and ENO's legacy fleet deactivates, ENO also may see increased value in additional flexible peaking and quick-response technologies such as solar and battery hybrid and standalone battery storage technology. ENO continues to be committed to exploring clean, alternative technologies to ensure adaptability and longevity of these resources.

ENO will continue to assess the likely increasing capacity, energy and operational flexibility required over the long-term planning horizon. This on-going assessment of the generation supply plan against dynamic factors like capacity requirements, operation roles, grid reliability and evolving technologies will enable ENO to continually improve efficiencies to develop solutions to address our customers' needs while mitigating risk.

2.9. Transmission Planning

Transmission planning ensures that the transmission system: (1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") reliability standards, and related Southeastern Electric Reliability Council ("SERC") and ENO's local transmission planning criteria, and (2) is designed to efficiently deliver energy to end-use customers at a reasonable cost. Since December 2013, ENO has been a

Transmission Owning member of MISO, a Regional Transmission Organization ("RTO"). MISO was approved as the nation's first RTO in 2001 and is an independent nonprofit member-based organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba. In cooperation with stakeholders, MISO manages 65,800 miles of high voltage transmission and 198,933 megawatts of power generating resources across its footprint. Since joining MISO, ENO has planned its transmission system in accordance with the MISO Tariff.

A key responsibility of MISO is the development of the annual MISO Transmission Expansion Plan ("MTEP"). ENO is an active participant in the MISO MTEP development process, which is currently in development of the MTEP 22 cycle. Participation in the MISO MTEP process allows ENO's transmission system to remain reliable and ENO's transmission plan is incorporated into the annual MTEP process. The overall planning process can be described as a combination of "Bottom–Up" projects identified in the individual MISO Transmission Owner's (such as ENO) transmission plans which address issues more local in nature and are driven by the need to provide service safely and reliably to customers, and projects identified during MISO's "Top-Down" studies, which address issues more regional in nature and provide economic benefits or address public policy mandates or goals.

Through these MTEP-related activities, ENO works with MISO, other MISO Transmission Owners, and stakeholders to promote a robust and beneficial transmission system throughout the MISO region. ENO's participation helps ensure that opportunities for system expansion that would provide benefits to ENO customers are thoroughly examined. This combination of Bottom-Up and Top-Down planning helps ensure all issues are addressed in an effective and efficient manner.

ENO's transmission strategy is centered upon meeting the evolving needs of its customers for safe and reliable energy. Each year the ENO transmission system is thoroughly studied to verify that it will continue to provide customers with reliable and safe service through compliance with all applicable NERC reliability standards as well as ENO's local transmission planning criteria and guidelines.

These studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to develop projects and determine what, where, and when system upgrades are required to address any future reliability concerns. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, retirements of existing generation resources, implementation of new generating resources, the adequacy of new and existing substations to serve local load, the expected power flows on the bulk electric system, and the resulting impacts on the reliability of the ENO transmission system.

These reliability studies result in projects which are presented annually to the ENO Operating Committee for approval. Once approved, these reliability projects are submitted to MISO for regional study, to 1) verify that the reliability need exists, 2) verify that the proposed solutions solve the reliability need, and 3) provide stakeholders the opportunity to propose alternatives. Additionally, MISO performs other studies each year to consider transmission planning issues including Market Efficiency Projects, Multi-Value Projects, and customer driven projects, such as those driven by generator interconnection requests, and opportunities for interregional projects with neighboring planning regions.

The result of the MISO MTEP process is a compilation of transmission projects that are needed to address system reliability requirements, improve market efficiency, and/or provide specific system benefits as delineated in the MISO Tariff. The MTEP identifies solutions to meet regional transmission needs and to create value opportunities through the implementation of a comprehensive planning approach.

Each MTEP document is identified by the year in which it was completed. Appendix A of the MTEP report developed for each cycle lists and briefly describes the transmission projects that have been evaluated, determined to be needed, and subsequently approved by the MISO Board of Directors.

2.9.1. Integration of Transmission and Resource Planning

The availability and location of current and future generation on the transmission system can have a significant impact on the long-term transmission plan, requirements for meeting NERC reliability standards, and efficiently delivering energy to customers at a reasonable cost. The continued evaluation and condition of ENO's generation fleet must be considered for integrated generation and transmission planning. ENO's planning assumptions include deactivation of existing generation resources during the planning horizon, which could have an impact on transmission reliability without proper siting of replacement generation. Like transmission, new generation must be planned well in advance, and due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential generation needs is critical in meeting ENO's planning objectives of low cost, improved reliability, and reduced risk.

Inverter-based technology, including solar PV, can produce significant energy benefits and fill an important role as part of ENO's resource mix. However, consideration must be given to the increased role that dispatchable resources may need to play in maintaining regional reliability as reliance on such inverter-based resources increase. First, it is important to note that the load in the region just after sunset is often only slightly less than the peak load for that day. In fact, there are times when the daily peak for the city of New Orleans actually occurs at night. Thus, conventional resources must be capable of quickly ramping up to offset the loss of solar PV energy as the sun sets. Second, inverter-based resources do not contribute to system inertia, which is produced by the rotating mass of conventional resources and which allows the entire electrical system to resist changes to system frequency and maintain stable operating characteristics. Going forward, as the amount of renewables increases in ENO's resource portfolio, it will be important to consider transmission projects and the need for supportive dispatchable generation and resources to ensure reliability and economic planning principles are met.

Resource planning in the IRP also incorporates inputs from the transmission system. The Resource Portfolios identified through the IRP analysis are designed primarily to meet projected capacity and energy needs as prescribed by ENO's planning principles and Council policies. While the implementation of a sound transmission plan is necessary to ensure reliability and can facilitate the efficient flow of energy within a system, it does not address capacity needs. Additionally, other analyses, which are part of ongoing planning processes, such as for the siting of specific future generation resources, will take into account transmission planning by applying the transmission topology, including approved MISO MTEP projects.

2.10. Distribution Planning Developments

2.10.1. DER/Distribution Planning Requirements

Section 6.E. of the Council's IRP Rules requires that ENO evaluate the extent to which reliability of the distribution system can be improved through the strategic location of distributed energy resources or other resources identified as part of the IRP planning process. To the extent ENO does not currently have the capability to meet this requirement, it is required to demonstrate progress toward developing this capability in its IRP report.

In response to this requirement, the following section builds on the information provided in the 2018 IRP and explains various steps being undertaken to implement foundational systems, software, and processes that will be necessary for ENO to develop the ability to evaluate locational and reliability benefits and impacts of DERs in the future.

2.10.2. Company Work to Develop DER Planning Capabilities

The Company discussed the three pillars of its plan for grid modernization in the Grid Modernization and Smart Cities Report filed April 10, 2018, in Docket UD-18-01, and in in the 2018 IRP: 1) Upgrading existing Grid Infrastructure with newer assets to improve reliability and support technologically advanced options for meeting customers' needs, 2) Deploying Grid Technology to collect, analyze, and deliver information for real time decision making and automation, and 3) Planning processes and analysis that will leverage the data received from the modern grid technologies to enable the Company to meet customer demands for interconnection of DERs while improving reliability and resiliency.[9]

2.10.3. Grid Infrastructure

The first pillar, upgrading existing grid infrastructure, is being addressed through reliability work the Company has identified in filings to the Council in Docket UD-17-04.[10] That work is ongoing in accordance with the plan developed in the Quanta report and continues to be the subject of periodic progress reports.

2.10.4. Smart Infrastructure & Software Systems

The second pillar, deploying grid technology, is being pursued through several deployments of smart infrastructure and software systems. The foundational investment of AMI, specifically implementation of the communications network, head-end system, and advanced meter installations as approved through Docket UD-16-04, has enabled enhanced sensing and awareness of the distribution grid. The advanced meters act as smart sensors on the distribution grid to inform other systems on the status of the grid. This information is integrated with other data sources such as customer phone calls and input from ENO's Supervisory Control and Data Acquisition ("SCADA") system into the new Distribution Management and Outage Management ("DMS/OMS") system.

The distribution management system ("DMS") is a software platform that supports the full suite of distribution management and the optimization of the distribution grid. The DMS platform utilizes all available information collected from AMI meters, Distribution Automation ("DA") enabled devices, asset topology, and SCADA to perform load flow modeling. Future use cases of the DMS system include smart grid capabilities such as fault location, isolation, and restoration ("FLISR"), volt/volt-ampere (var) optimization, and integration of distributed resources. The ability to monitor and actively manage the distribution grid with real time sensing and analysis is foundational to enable future safe and reliable operation for all of ENO's customers.

An outage management system ("OMS") is a utility network management software application that models network topology for safe and efficient field operations related to outage restoration. The OMS tightly integrates with the call centers to provide timely, accurate, customer-specific outage information, and with the SCADA system for real-time confirmed switching and breaker operations. These systems track, group, and display outages to safely and efficiently manage service restoration activities.

The DMS/OMS deployment was coordinated with the deployment of the AMI meters and was completed in 2020. Work continues towards integrating AMI data into the distribution planning process. Integrated AMI

9. Grid Modernization and Smart Cities Report, at 5-6.
10. See, ENO Reliability Plan (November 11, 2017), Quanta Assessment (October 31, 2018), and ENO 2019 Reliability Plan (January 18, 2019), and subsequent periodic update filings.

data is expected to ultimately provide the ability to look at historical feeder voltage profiles, increase granularity of data to help validate modeling assumptions, and increase access to more detailed point-in-time data from the customer meters.

To help facilitate transition to the new Distribution Management system, additional important functionality has been deployed through the Enterprise Asset Management ("EAM") project. EAM installed an integrated system to manage the asset, maintenance, renewal, and replacement records of all distribution, transmission, gas, and transportation fleet assets.

Integration of work processes and systems allows a more streamlined approach to, and greater ability to track, work across field operations, customer contact centers, and back office operations to provide an improved overall customer experience. The EAM project included the following components: 1) EAM System, 2) a modernized Workforce Management System ("WFMS"), 3) Field Mobility Devices, 4) verification, collection, and correction of the current asset records, and 5) an advanced Geospatial Information System ("GIS"). The distribution integration was completed in January 2020 and the transmission integration in December 2021. Data for both work management and asset management across these Distribution and Transmission is now available on the consolidated platform.

Other smart grid technologies being deployed are DA devices that are installed on the distribution grid and communicate the status and configuration of the grid through the AMI integrated communication network to the DMS/OMS. The DA devices work in conjunction with the AMI meter data and the DMS/OMS system to automatically reconfigure the path of power to isolate any outage conditions and restore power to unaffected customers. The DA devices will provide additional monitoring of the system and introduce control of the distribution grid. DA devices are another foundational technology required to safely and reliably incorporate distributed resources on to the distribution grid. Since 2020, there have been 134 distribution automation devices installed in ENO. To date, these devices have eliminated an estimated 15,000 customer interruptions.

Additionally, the Company is actively monitoring the commercial availability of products and components for a Distributed Energy Resource Management System ("DERMS"). A DERMS is a system that integrates with ENO's other new technologies to enable the monitoring and control of distributed energy resources on the distribution grid. The Company is also exploring the development of IT system architecture to support the implementation of an in-house DERMS.

2.10.5. Advanced Planning

The third pillar, developing advanced planning processes, is focused on providing planning, engineering, and related technical services to support adoption of both customer-owned and Company-owned DERs.

To support DER integration and other advanced planning processes, a new department within Entergy Services, LLC named Enterprise Planning – Advanced Network Planning was formed in 2020. This department's responsibilities include performing Feasibility Studies and System Impact Studies for customers requesting interconnection of DERs to ENO's distribution grid. A primary focus of this department is to identify personnel, knowledge, and skills that will be needed to accommodate higher penetrations of DERs on the distribution grid. This includes reviewing how best to utilize existing tools, what new tools or analysis will be needed, how to work with transmission planning, and how to train engineers in these new areas. It is important to create effective interconnection processes and standards that use data to understand the effects and impacts of DERs on the grid. Many of these process improvements related to DERs have already been implemented by the Advanced Network Planning department over the past two years, including:

- Revisions to customer DER Interconnection Standards to allow more clear and consistent understanding of DER requirements for customers;
- Development of an internal DER Interconnection Guidebook for more clear and consistent understanding of internal DER related processes for Entegy personnel which will lead to faster DER request processing times and a better overall customer experience;
- Incorporating existing DERs into power flow models and increasing the use of time series data over traditional "peak only" modeling;
- Development of initial technical screening review criteria for DER requests, resulting in faster review and approval times for many projects;
- Development of in-house engineering expertise to perform detailed interconnection impact studies and streamline the process for prospective DER projects; and
- Development of new DER Witness Testing/Commissioning Guidelines to ensure DER systems are installed and operating according to Entergy Standards and requirements before being placed into service.

Additionally, the Advanced Network Planning department worked with Integral Analytics to deploy additional software to support the analysis of DER penetration. This software package, LoadSEER, is a spatial load forecasting tool which can integrate with the current planning analysis software, SynerGi. Together, along with AMI, its associated software applications, and resulting data, these tools will enable the Company in the future to prioritize distribution grid needs in light of planned DER and DSM projects, perform locational analyses, and develop traditional (i.e., distribution asset) or alternative (i.e., non-wires) solutions to address grid needs.

In summary, the investments, process improvements, and capabilities added over the past two years to implement the smart infrastructure of AMI and DA-enabled devices, the smart systems of DMS/OMS and LoadSEER, as well as the DER analysis and interconnection process improvements made, have provided essential components of the foundation for ENO to develop the capability of evaluating DERs for safe and reliable integration into the ENO grid in the future.

2.11. Carbon and Sustainability Goals

Entergy has been an industry leader in voluntary climate action for over two decades. Building on its longtime legacy of environmental stewardship, Entergy established a 2030 emission rate goal and a longer-term commitment: Entergy will work over the next three decades to reduce carbon emissions from its operations to net-zero by 2050. As ENO works to support the broader corporate goal, it will also be working towards the climate goals expressed by the Council in its RCPS rules of achieving net-zero emissions by 2040 and zero carbon emissions by 2050. ENO will pursue these goals by working with the Council and other stakeholders to balance reliability, affordability, and sustainability. ENO's generation portfolio already emits far less CO_2 than the national utility average, with a 2021 rate of 548 lbs/MWh. This value includes emissions for all owned and contracted generating resources attributable to ENO, as well as market purchases.

In 2001, Entergy was the first U.S. utility to voluntarily limit its carbon dioxide emissions. Entergy renewed and strengthened this commitment twice and beat the 2020 target on both a cumulative and annual basis by eight percent. In 2019, Entergy announced a goal to emit half the carbon per MWh in 2030 versus 2000 and in 2020 announced its commitment to achieve net-zero emissions by the year 2050.

2001	2006	2011	2019	2020
First U.S. utility to voluntarily set goals to stabilize greenhouse gas emissions	Intensified commitment with a goal to reduce CO_2 emissions to 20% below year-2000 levels through 2010	Extended CO_2 reduction commitment through 2020	Introduced new goal to reduce CO_2 emission rate to 50% below year-2000 levels by 2030	Commited to achieve net-zero emissions by 2050

Figure 8: Carbon and Sustainability Timeline

Entergy is taking action now toward a carbon-free future and expects to achieve its 2030 goal five years early primarily by planning to add 11 gigawatts of renewable resources across all five operating companies by 2030. Regarding the commitment to net-zero by 2050, the company is defining our path, but is taking actions today to advance the technologies necessary. The company expects to meet this net-zero 2050 commitment by enhancing its transformation strategy with emerging technology options, working with customers, key suppliers and partners to advance new technologies necessary to reduce emissions, continuing to engage with partners and gain experience on enhancing natural systems like forests and wetlands that absorb carbon, and partnering with customers to electrify other sectors like transportation and industry for net emissions reductions and community benefits.

Additional details are available in ***Entergy's 2021 Integrated Report***.[11]

11. https://integratedreport.entergy.com/

Chapter 3

Model Inputs and Assumptions

3.1. Resource Planning Considerations

Guided by its Resource Planning Objectives, ENO's resource planning process seeks to maintain a portfolio of resources that reliably meets customer power needs at a just and reasonable supply cost while minimizing risk exposure. The landscape within the electric utility industry is changing, and this IRP offers insights for opportunities to respond to this evolving environment.

ENO recognizes the way customers consume energy and the type of energy they prefer is changing, so the way the Company plans for, produces, and delivers the power on which customers rely must continue to evolve as well. ENO strives to have a planning process that provides the flexibility needed to better respond to this constantly evolving environment.

3.2. Load Forecasting Methodology

Each year, ENO develops a forecast that is used for financial and resource planning. That forecast is often used as the Base Case or Reference Case for scenario analysis such as the IRP process. The Reference Case is developed sequentially starting with a forecast of monthly billed sales, which is then converted to a calendar month view, which is then converted into hourly loads across each month. Scenario forecasts are then developed in a similar manner starting with monthly energy and then converting those levels to hourly loads. ENO developed three load forecasts for the 2021 IRP —Scenario 1, which is based on the Reference Case, Scenario 2 which is a lower load forecast, and Scenario 3, which is a higher load forecast. These are discussed in further detail below.

3.2.1. Load Forecast Uncertainty

Electric load in the long term will be affected by a range of factors, including:

- Increases in EE, brought about by:
  - Technological changes – lighting, heating, ventilation, and air conditioning, appliance efficiency
  - Structural changes – changes in building codes or state/national requirements
  - Other conservation measures – changes in personal behavior
- Increased adoption of Electric Vehicles (EVs) in place of vehicles using internal combustion engines
- Other electrification opportunities brought about by reductions in natural gas usage in favor of electric end-use equipment
- Levels of economic activity and growth, including expansion or contraction with large loads as well as changes in population affecting residential and commercial classes
- Potential adoption of behind-the-meter self-generation technologies (e.g., rooftop solar)
- Changes in temperature and weather patterns over time

Such factors may affect the levels of electricity consumption over the term of a study period as well as the hourly patterns of consumption across individual days. Annual peak loads could be higher or lower, and daily peaks could shift to later hours in the day. Uncertainties in these load levels and patterns may affect both the amount and type of resources required to efficiently meet customer needs in the future.

3.2.2. Reference Case Energy Forecast

The Reference Case forecast was developed in 2020 using a bottom-up approach by customer class: residential, commercial, industrial, and governmental. The forecast was developed using historical sales volumes, customer counts, and temperature inputs from January 2010 through February 2020, as well as future estimates for normal weather and EE. In addition, the forecast includes estimates for changes in customer counts, future growth in large industrial usage, and estimates of future consumption growth from EVs and declines due to future rooftop solar adoption.

3.2.3. Regression Models for Non-Large Industrial Forecasts

The sales forecasts for the residential, commercial, small industrial, and governmental classes are developed individually using statistical regression software and a mix of historical data and forward-looking data. The historical data primarily includes monthly sales volumes by class and temperature data expressed as cooling degree days ("CDDs") and heating degree days ("HDDs"). Some of the forecasts also use historical indices for elements such as population, employment, and levels of end-use consumption for things such as heating/cooling, refrigeration, and lighting. These historical data are used in the Metrix ND® forecasting software, which is licensed from Itron. This software is used to develop statistical relationships between historical consumption levels and explanatory variables such as weather, economic factors, and/or month-of-year, and those relationships are applied going forward to estimates of normal weather, economic factors, and/or month-of-year to develop the forecast. Explanatory variables are included in each class-level forecast model if the statistical significance is greater than 95%.

3.2.4. Residential Forecasts

The long-term residential forecast projects a slight decrease in electricity consumption with (0.1%)/yr. CAGR over the planning period. This forecasted decrease is largely due to decreasing average UPC (0.4%)/yr offset by expected slight growth in residential customer counts.

The monthly model for residential UPC, taking into account expected efficiency is:

Residential UPC per day =
Heating Degree Days * Heating efficiency index * Heating coefficient +
Cooling Degree Days * Cooling efficiency index * Cooling coefficient +
other use coefficient * other use efficiency index

The residential forecasts use variables for individual months rather than using heating or cooling indices with monthly values across a year, allowing for greater precision with each monthly result. The regression uses actual historical weather, and the resulting coefficients are applied to estimates for normal weather levels in the future.

Trended Normal Weather - Analysis of historical data reveals that trends in average temperatures, expressed as CDDs and HDDs, have not been flat over the last few decades, and there is no evidence at this time to support an assumption of future temperatures remaining flat versus current (2020/2021) levels. As such, ENO has calculated a "trended normal" assumption for long-term energy planning using trends in 20-year rolling averages of monthly temperatures from 2000-2019, which are used in the Reference Case forecast. The use of 20 years strikes a reasonable balance between longer periods (30 years), which may take longer to pick up changing weather trends and shorter periods (10 years), which may not provide enough data points to smooth out volatility. The 20-year trended normal temperatures are built from hourly temperatures and are allocated to each calendar month. By 2041 the effect of the trended normal temperature assumption increases summer (July - September) residential and commercial energy consumption by 60 GWh (4.5%) and decreases winter (January, February, December) energy consumption by 19 GWh (-2%).

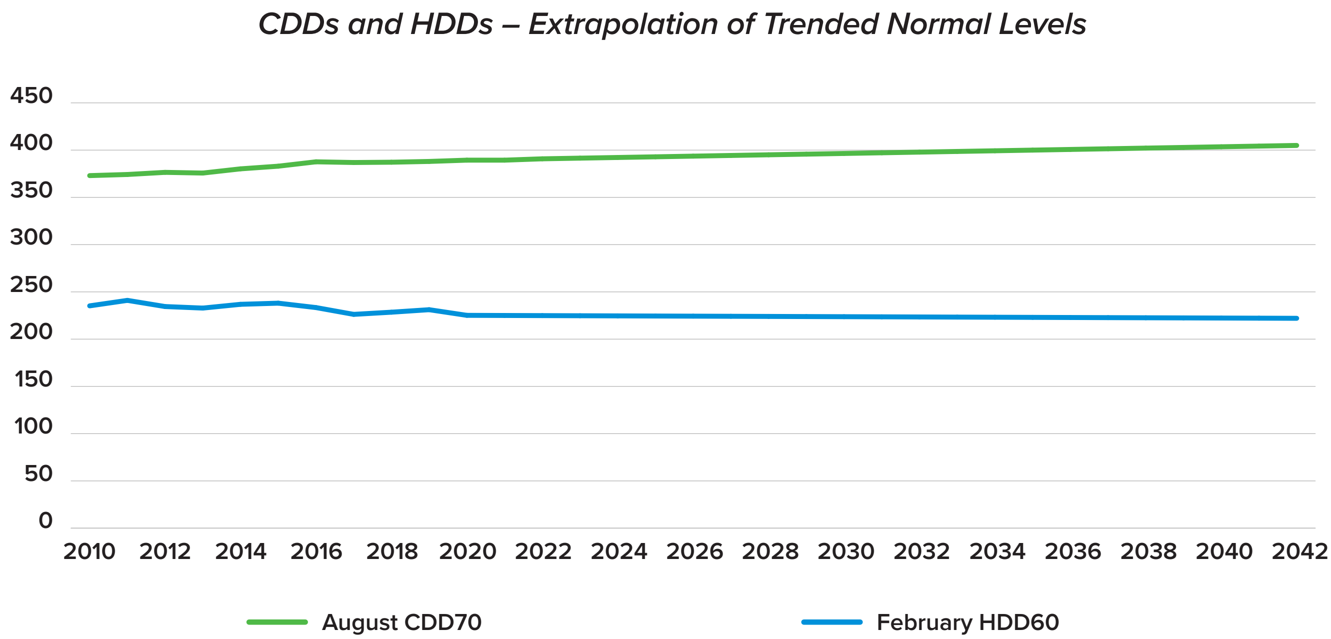


Figure 9: CDDs and HDDs – Extrapolation of 20 Year Rolling

Residential Forecast - Offsetting the declines in average residential UPC, residential customer counts are expected to grow. Based on expected future growth in customer counts in ENO's service territory, ENO is expected to have positive growth in residential energy starting in the mid-2030 and expected growth in EV adoption. For the period overall, the forecast shows declining residential UPC of -0.4%/yr. for 2022-2041. The combined effect of higher customer counts and a slight decrease in UPC leads to a net forecasted CAGR in residential energy of -0.1%/yr. The sales forecast includes a net 1.5% decrement to the residential sales, phased-in between 2020 and early 2022 based on expected effects of the AMI deployment and related customer programs per the latest AMI deployment schedule available at the time of the forecast development plus a time allowance for the AMI-related customer information programs to show an effect.

See Table 3 showing the year-over-year changes and CAGRs in residential energy, customer counts, and UPC.

Table 3: YoY Growth Residential

Year	Energy	Customers	UPC
2023	-0.5%	0.6%	-1.1%
2026	-0.3%	0.5%	-0.8%
2029	-0.2%	0.3%	-0.5%
2032	-0.1%	0.2%	-0.3%
2035	0.1%	0.2%	-0.1%
2038	0.1%	0.2%	-0.1%
2041	0.2%	0.2%	0.1%
2022-2041 CAGR	**-0.1%**	**0.3%**	**-0.4%**

3.2.5. Commercial Forecast

Commercial use of electricity is forecasted to be flat for 2022-2041 with a CAGR of 0.0%/yr. This is primarily driven by forecasted UPC of -0.3%/year offset by the growth in customer counts.

Table 4: YoY Growth Commercial

Year	Energy	Customers	UPC
2023	-1.2%	0.5%	-1.7%
2026	-1.1%	0.4%	-1.5%
2029	-0.4%	0.3%	-0.7%
2032	0.2%	0.3%	-0.1%
2035	0.7%	0.2%	0.5%
2038	1.0%	0.2%	0.8%
2041	1.0%	0.2%	0.9%
2022-2041 CAGR	**0.0%**	**0.3%**	**-0.3%**

The commercial sales forecast is developed using a similar methodology to the residential forecast with the exception that commercial sales are forecasted in total rather than by UPC because of the diversity of commercial customers within a small footprint, such as large hospitals, office buildings, and hotels versus smaller retail and commercial spaces. The commercial forecast accounts for organic EE, primarily from HVAC and refrigeration efficiency, as well as Company-sponsored DSM programs discussed further below. The commercial forecast also includes the same type of AMI-related decrement phased-in from 2020-22 and then at the full 1.5% for the remainder of the study period.

Commercial Sales$_m$=

Heating Degree Days * Heating efficiency index * Heating coefficient$_m$ +
Cooling Degree Days * Cooling efficiency index * Cooling coefficient$_m$ +
other use coefficient * other use efficiency index$_m$

See Table 4 for estimated year-over-year changes and CAGRs for commercial sales, commercial customer counts, and UPC.

3.2.6. Governmental Forecast

Governmental energy usage is forecasted to have a slight decrease for 2022-2041 with a CAGR of -0.3%/yr. This is largely due to the effects of slight decreases expected for both customer counts and UPC.

3.2.7. Small Industrial Forecast

The small industrial forecast includes industrial sales that are not forecasted individually as part of the large industrial forecasts, described below. Forecasts are based on historical trends in consumption and IHS economic indices for segments of industrial production. Small industrial sales comprise less than 3% of ENO's sales volume mix.

3.2.8. Large Industrial Growth

The 2022-2041 CAGR for ENO's large industrial sales is 0.9%/yr. Due to their size, customers in the large industrial class are forecasted individually. Existing large industrial customers are forecasted based on historical usage, known or expected future outages, and information about expansions or contractions. Forecasts for new or prospective large industrial customers are based on information from the customer and from ENO's Economic Development team as to each customer's expected MW size, operating profile, and ramping schedule. The forecasts for new large customers are also risk-adjusted based on the customer's progress towards achieving commercial operation.

Table 5 shows the forecasted year-over-year growth in sales attributable to large industrial customers.

Table 5: YoY Large Ind Growth

Year	Energy
2023	0.0%
2026	3.1%
2029	0.9%
2032	1.0%
2035	1.0%
2038	0.9%
2041	0.9%
2022-2041 CAGR	**0.9%**

3.2.9. Energy Consumption by Class

ENO's energy consumption comes mostly from residential and commercial customer classes that account for 41% and 37%, respectively, of the forecasted sales for 2022. Governmental customers consume 14% of the energy with industrial customers consuming the remaining 8%.

2022 Customer Mix

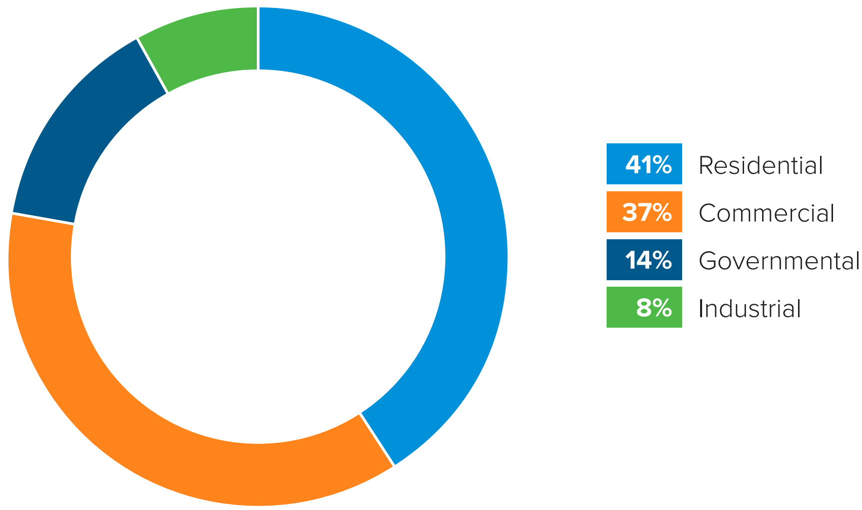


Figure 10: 2022 Energy Class Mix

This consumption mix by class is expected to remain largely unchanged throughout the study period, apart from some slight increases in the commercial sector. See Figure 11 below for the projected 2041 energy mix by customer class.

2041 Customer Mix

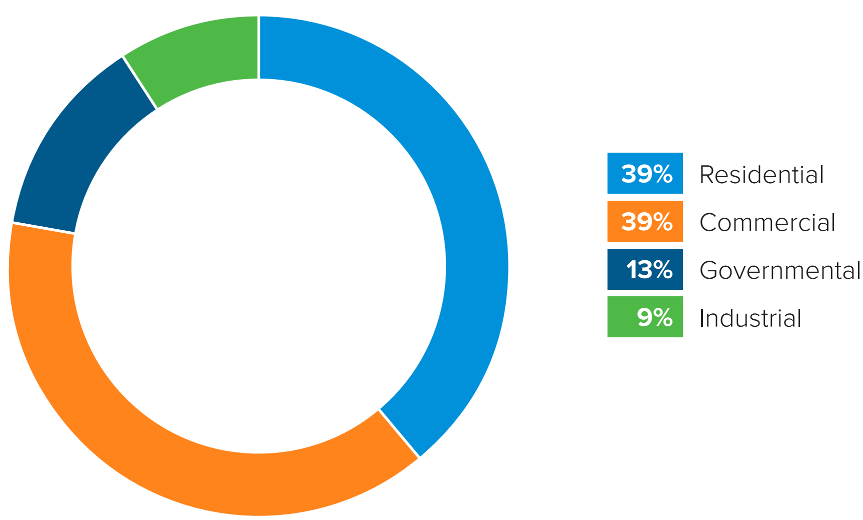


Figure 10: 2041 Energy Class Mix

3.2.10. Demand Side Management

ENO has offered company-sponsored DSM programs through Energy Smart since 2011, such as for lighting, appliances, and HVAC efficiency.

DSM programs from one year have effects that carry forward into future years. For example, a program to encourage customers to switch from using incandescent lighting to LED lighting in one year will result in lower electricity consumption for years to come. As such, to develop an estimate of the DSM effects on the forecast, ENO starts with the historical (by year) DSM levels and develops an estimate of the cumulative effects of each year's programs on future years.

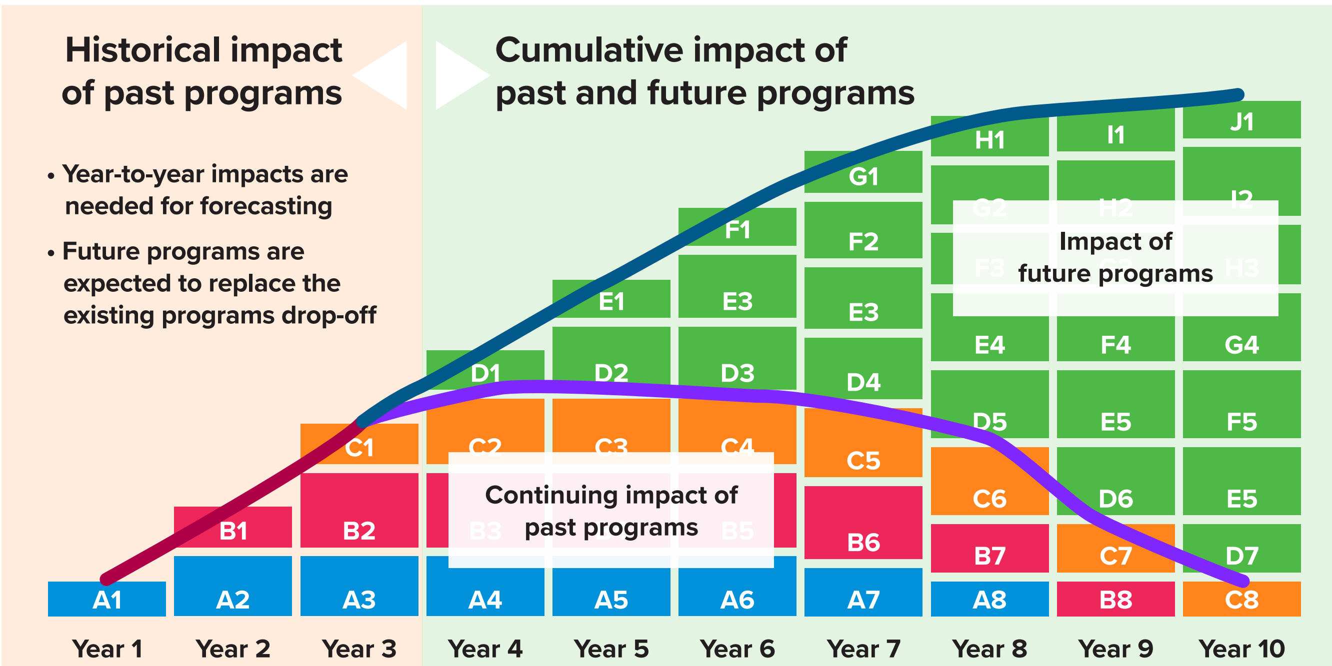


Figure 12: Chronological DSM Impacts

An add-back method was employed to develop the load forecast. See Figure 13 below. The add-back method takes the estimated cumulative historical volume of DSM savings in kWh and adds those amounts back to monthly billed-sales to develop a forecast as if there had never been DSM programs. From that forecast, the expected future levels of DSM are subtracted from the No-DSM forecast to arrive at the net forecast levels. This method was used for the Residential, Commercial, and Small Industrial forecasts.

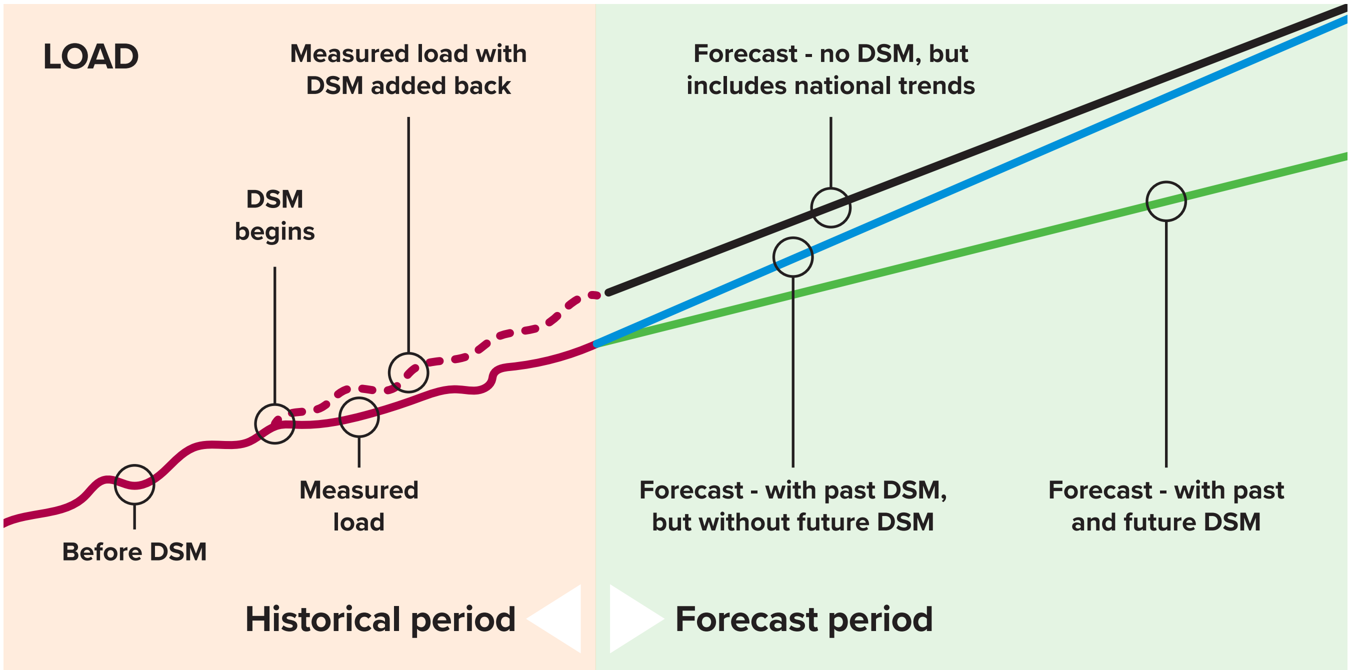


Figure 13: Add-Back Method

Using this methodology, new programs in future years are expected to reduce nearly 1% of the total annual sales for ENO by 2022 in the Reference Case forecast. Table 6 below shows ENO's expected incremental savings from pre-approved programs. These programs were assumed to save the same amounts of energy for years 2020 through 2022. After 2022, it is assumed these incremental savings remain consistent with the latest data provided (2022 levels).

Table 6: Annual MWh Designed Savings 2020 - 2022 (Incremental Assumptions)

	Annual Value
Small C&I	6,296
Large C&I	25,003
Publicly Funded Institutions	3,179
Home Performance with Energy Star	3,078
Residential Lighting & Appliances	3,608
Energy Smart for Multi-Family	771
Low Income Audit & Wx	1,414
School Kits & Education	683
High Efficiency Tune Up	1,862
Behavioral	8,000

Figure 14 below shows the estimated levels of annual energy savings included in the Reference Case forecast as a result of ENO's historically implemented DSM programs as well as savings from future DSM programs based on the incremental levels laid out in Table 6 above. DSM levels are expected to increase gradually through the early 2030s, and then level off by the mid-2030s and slightly decrease thereafter.

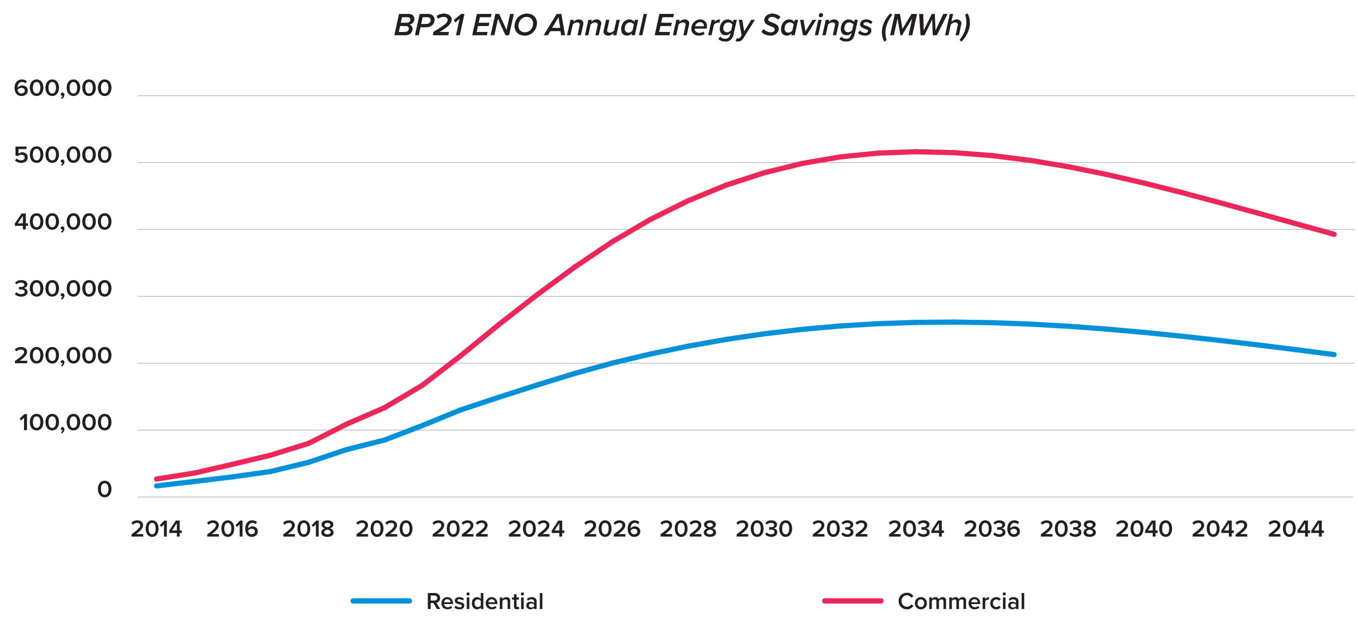


Figure 14: ENO Annual Energy Savings

3.2.11. Electrification and Conversions

The Reference Case forecast includes an assumption for sales growth as a result of programs sponsored by ENO to encourage electrification. The programs include electrification of various industrial and commercial processes as well as gas or diesel conversion of equipment. Based on estimates from May 2020, these projects are expected to add nearly 54 GWh to commercial sales by 2041.

3.3. Hourly Load Forecast

3.3.1. Methodology

The load forecast is the result of combining three elements: the volumes from the monthly sales forecasts described above, the estimated monthly peak loads, and the hourly consumption profiles or shapes. These elements are developed using Itron's Metrix ND® software.

The forecasted monthly sales provide the monthly MWh volume for the load forecasts and reflect the expected effects of a few elements such as customer growth or declines, new large industrial customers, and EE. The monthly volumes are also used to develop the peak forecasts, which are estimated based on the historical relationship of peaks to energy while also considering the effects of weather. Hourly load shapes are developed from historical hourly load by customer class and in total. Those historical shapes are used along with historical weather data (HDD and CDD), calendar data to account for differences in usage on weekends or holidays, and other data to develop "typical load shapes" by customer class to be used for the forecast period.

The final step in producing the hourly load forecasts is to combine – or calibrate – the monthly energy, monthly peak, and the hourly shapes described above. Using Itron's Metrix LT® software, the energy volumes, the estimated peaks, and the typical hourly shapes are calibrated such that the three elements fit together in a way that the result preserves the volume of energy while fitting it to the hourly profiles while maintaining, as closely as possible, the relationship of peak MW to monthly MWh. This process also reallocates the forecasted solar and EV energy using specific profile hours for each product technology. The result is a set of hourly load values, by class, for the forecast period from which a peak level can be determined.

3.3.2. Reference Case Peak Comparison to Previous IRP

Since ENO's 2018 IRP cycle there have been increases in the peak load forecast levels. This increase is largely due to increases in estimated levels of customer counts for commercial and governmental customer classes and increases in average UPC.

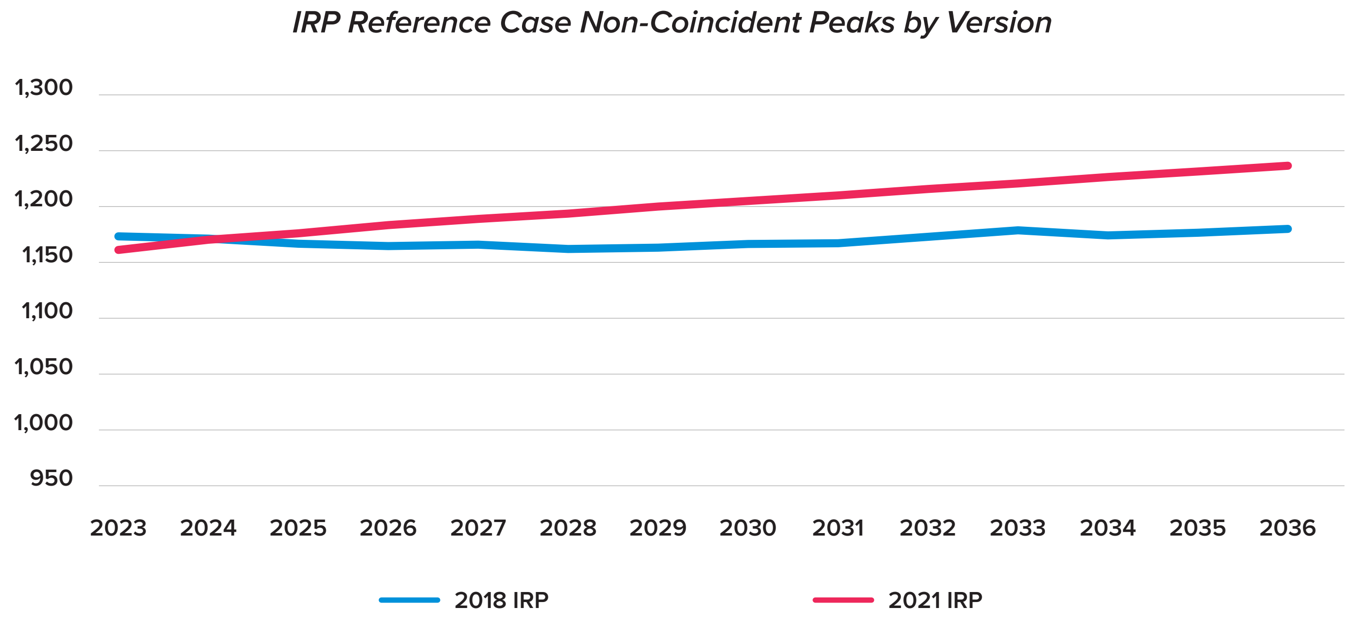


Figure 15: ENO IRP Reference Case Peaks by Version

3.3.3. Load Forecasts for IRP Planning Scenarios

In previous IRPs, ENO created "High" and "Low" sensitivity forecasts by adjusting the Reference Case forecasts up or down by percentages to reflect a range of load possibilities. For this IRP, forecast Scenarios were developed by adjusting the likely levers present based on the characteristics of each Planning Scenario. Scenario 1 used the Reference Case forecast described above with a modification to remove the effects of incremental, new DSM programs. This was done so that the new incremental programs could be considered in the Scenarios as supply-side resources. See Table 7 below for a list of the other levers used to adjust the Reference load forecast to create Scenario 2 and Scenario 3. The Scenario load forecasts for ENO include both transmission and distribution losses to estimate the amount of energy needed to be produced at-plant in order to serve the at-the-meter loads. The losses levels are based on the most recently estimated class-level losses levels at the time of the Reference Case forecast development. For ENO, the average total company losses levels were 3.9% for distribution only and 4.4% for transmission and distribution. Estimates of the MISO coincident peaks include distribution losses only. Additional information for each Scenario used within the IRP analytics is described in Chapter 4.

Table 7: Load Levers by Scenario

	Item	Scenario 1 Reference Case	Scenario 2 Decentralized Focus (DSM and Renewables)	Scenario 3 Stakeholder
Traits	Policy Traits		More utility DSM; More BTM solar; Lower battery costs due to incentives; Increased EV adoption	More utility DSM; Higher EV and non-EV electrification
	Other Traits		Healthy economic conditions; Res & Com growth	Higher economic growth; High CO2 costs and power prices
Results	Peaks / Energy	Same as Reference	Lower: Increased EV adoption is offset by increases in BTM solar and increased OpCo DSM	Higher: High EV adoption, higher building electrification, higher growth in Res/Com/Ind offset increased BTM solar adoption
	Load Shapes	Same as Reference	Intra-day shifts due to higher EV and higher BTM solar	Higher with intra-day shifts due to higher EV and higher BTM solar
Inputs	BTM Solar	Same as Reference	High	High
	Electric Vehicles (EVs)	Reference (2100)	Reference (2100)	High (2040)
	Building Electrification	Same as Reference	Same as Reference	High
	Res. & Com. Growth	Same as Reference	Lower	Higher
	Refinery Utilization from EVs	Same as Reference	Lower (opposite of EVs)	Lower (opposite of EVs)
	Industrial Growth	Same as Reference	Lower	Higher

In Scenario 2, there are high incentives for energy saving measures such as behind-the-meter solar coupled with more utility DSM. Offsetting these energy saving measures is an attempt to curb carbon emissions in other industries with higher adoption of EVs whereby an assumed 100% of new vehicle sales are electric by 2055. Due to this increase in EV adoption, there is an inverse reaction from the refinery industry, decreasing their demand.

In Scenario 3, there are similar renewable incentives as in Scenario 2, although a large focus on solar energy is directed towards utility scale solar. Offsetting these energy saving measures is an attempt to curb carbon emissions in other industries by even higher adoption of electric vehicles whereby an assumed 100% of vehicle sales are electric by 2040. In addition, there is a high level of building electrification and industrial growth due to economic growth and new technology adoption.

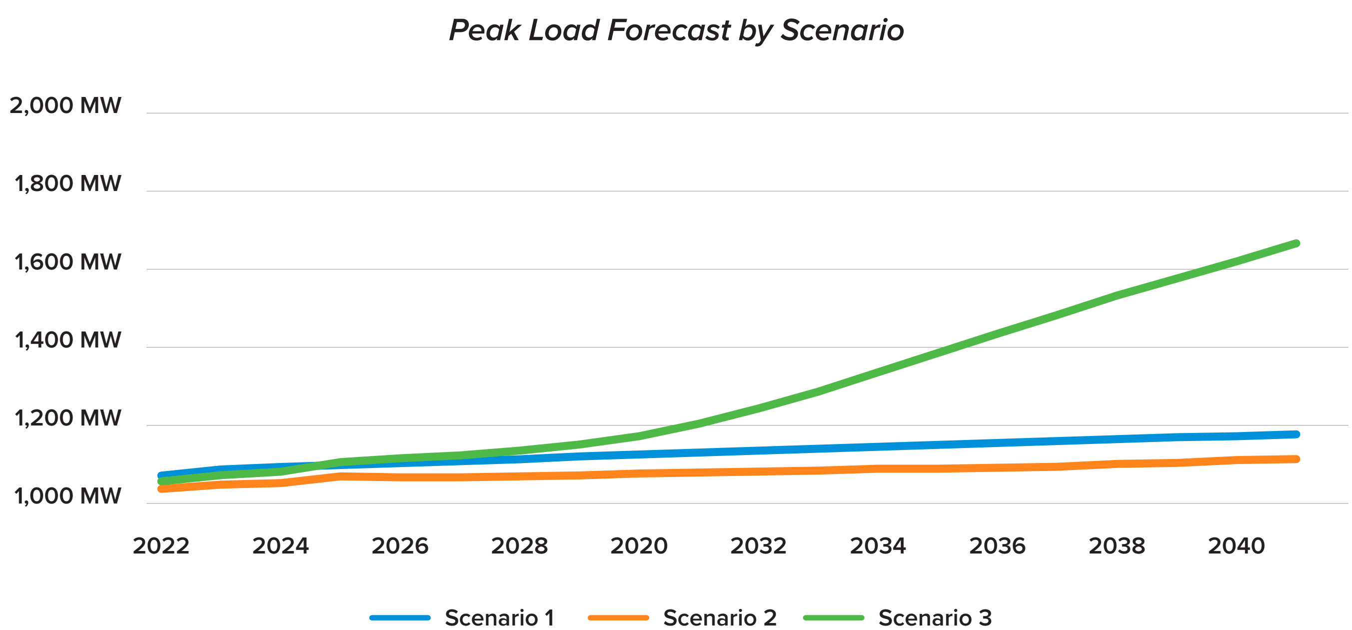


Figure 16: ENO IRP Peak Load Forecast by Scenario

3.3.4. Behind-the-meter Solar Generation

The Reference Case forecast was used for Scenario 1 and a High Case level was used for Scenario 2 and Scenario 3. Residential rooftop solar adoption is estimated to increase in the late-2030s for Scenario 1, and a more aggressive adoption is expected in the early-2030s for Scenario 2 and 3. Commercial solar adoption levels are relatively modest for Scenario 1, starting to increase significantly towards early-2030s for Scenario 2 and Scenario 3.

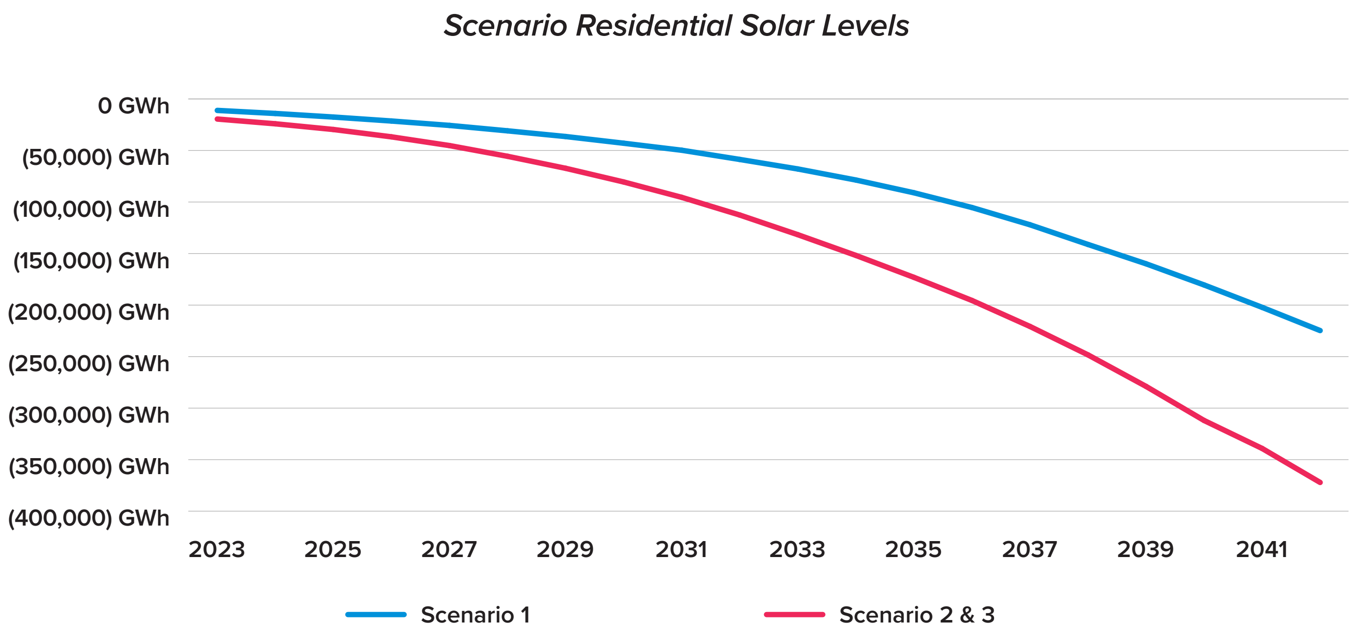


Figure 17: Residential Solar Levels

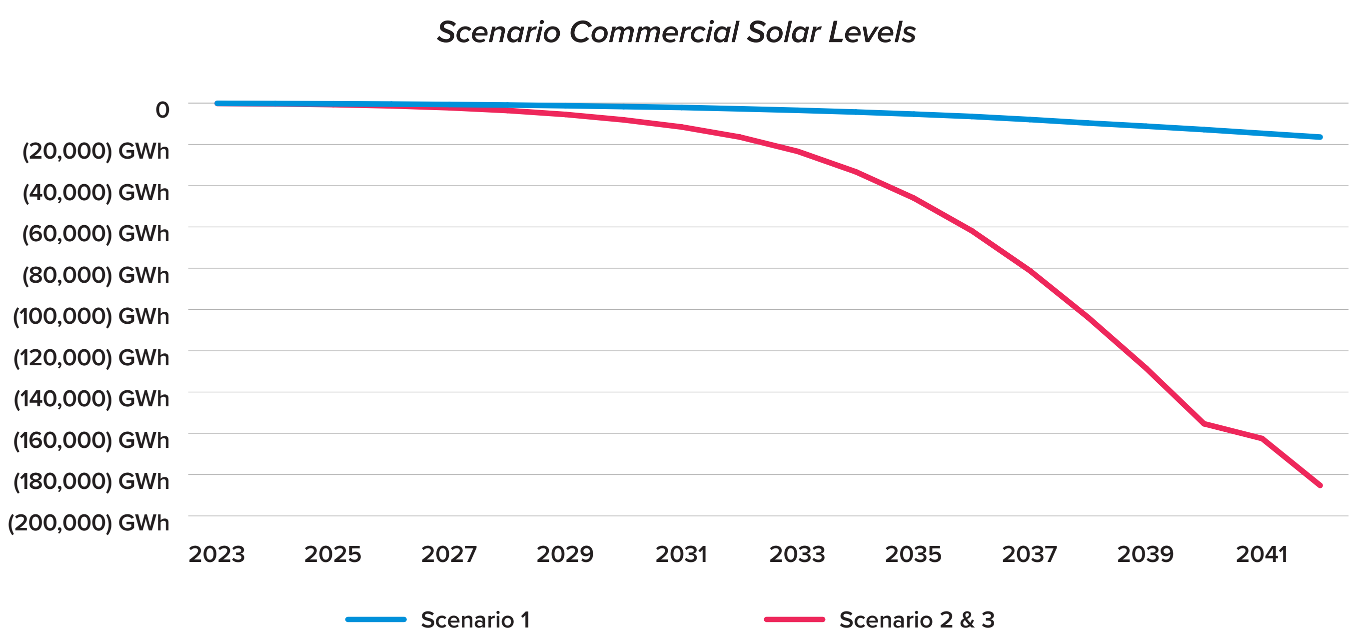


Figure 17: Commercial Solar Levels

3.3.5. Electric Vehicles

The Reference Case forecast includes an assumed level of additional energy consumption resulting from the adoption of EVs as well as growth in the numbers of total on-road vehicles over time as overall population is expected to continue to increase. The adoption over time is gradual based on an S-curve that assumes 99% of all light-duty vehicle sales will be EVs by 2100. The effects for ENO are based on the estimated proportional numbers of vehicles in each of the Entergy operating companies.

Overall, the additional GWh volumes from the EV forecast in the Reference Case are minimal in the near term with growth to the residential and commercial consumption volume estimated to start increasing more in the late-2030s. These levels were used for the EV forecast inputs for Scenario 1 and 2.

Scenario 3 used more aggressive forecasts in which 100% of new vehicle sales are expected to be EVs by 2040. These forecasts consider EV adoption for both light-duty vehicles and medium to heavy-duty vehicles as well as expected population growth and vehicle per capita increases. EV market share growth in new vehicle sales is based on an S-curve. Overall, the additional GWh volumes for the 2040 EV forecast is accelerating higher in the near-term compared to the Reference Case estimate and is adding 30% to ENO's sales totals by 2041.

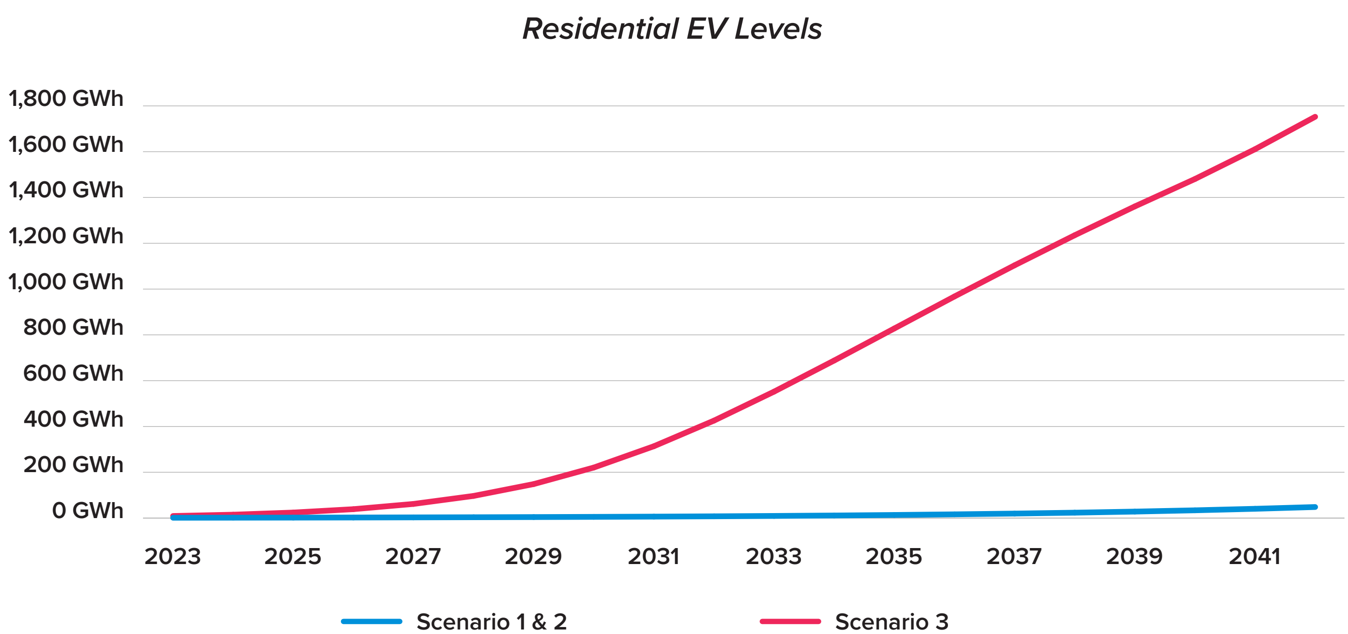


Figure 19: Residential EV Levels

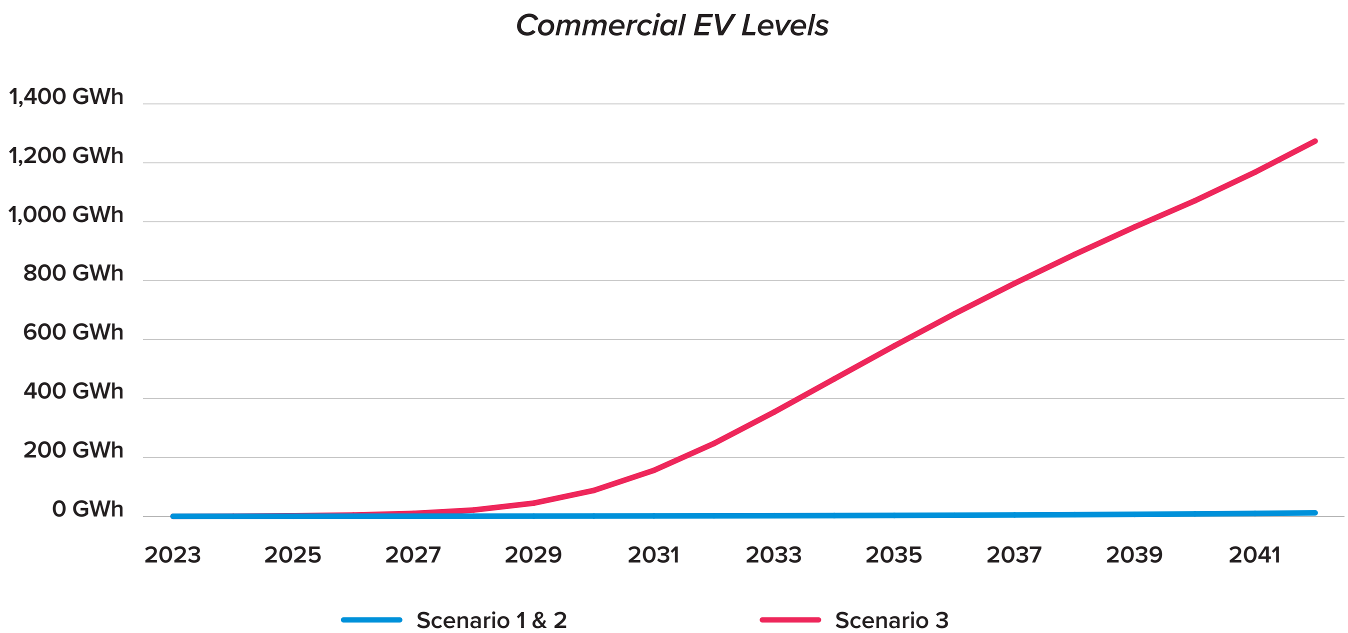


Figure 20: Commercial EV Levels

3.3.6. DSM and EE Measures

For details regarding DSM methodology, refer to the DSM section above. ENO's Reference case forecast includes Council-approved levels of Company-sponsored DSM/EE programs as well as assumptions for continued program effects in the future. For this IRP, incremental levels of new programs were treated as supply-side options and were therefore removed from the load forecast Scenarios. See section 3.5, below, for discussion of this IRP's incremental DSM assumptions.

3.3.7. Industrial Growth

Regarding industrial growth, Scenarios 2 and 3 have different levels of growth than the Reference Case. Scenario 2 has lower industrial expectations, while Scenario 3 has higher expected industrial growth.

3.4. Capacity Resource Options

3.4.1. Generation Technology Assessment

The commitment by Entergy to reduce its utility-generated CO_2 emission rate by 50% below 2000 levels and achieve net-zero emissions by 2050, and the efforts of ENO to meet the Council's more aggressive emissions goals, require a continued transformation of its generation portfolio. The IRP process evaluates available generation alternatives to meet customer energy needs in accordance with planning objectives, including the existing generation fleet, DSM, and supply-side resources. As part of this process, the Generation Technology Assessment was prepared to identify a range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet ENO's planning objectives of balancing reliability, affordability, and environmental stewardship.

Screening Approach and Technology Selection - In this IRP, ENO implemented a screening approach (see Figure 21) to evaluate the cost-effectiveness and feasibility of deployment of potential resources. This approach includes quantitative and qualitative criteria, including a technical and economic screening, leading to a final selection of supply-side resources to be evaluated in capacity expansion models.

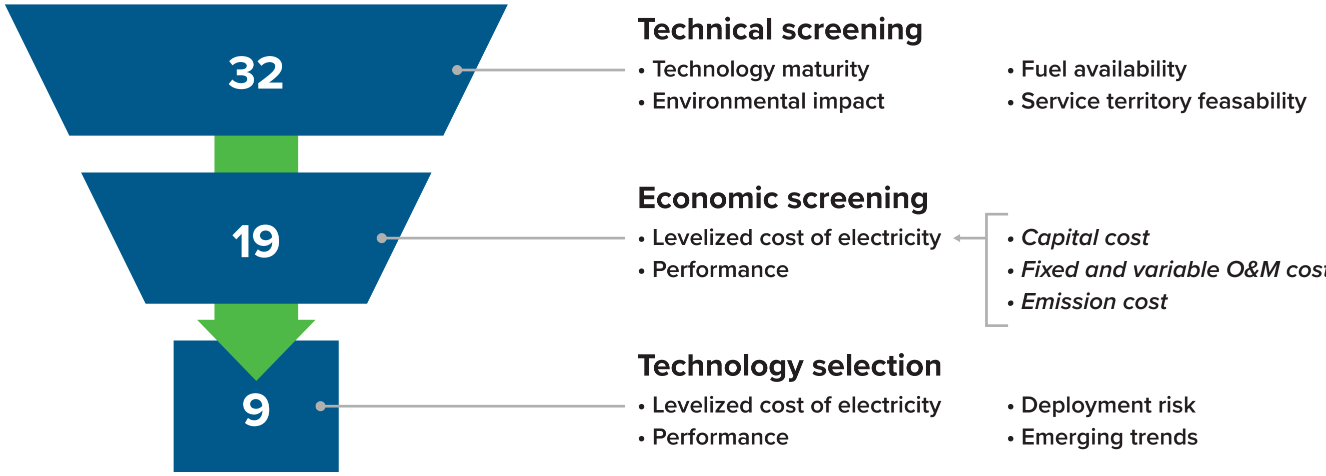


Figure 21: Screening Approach and Technology Selection Process

In the technical screening, 32 generation alternatives were evaluated (see Figure 22) for technology maturity, environmental impact, fuel availability, and service territory feasibility.

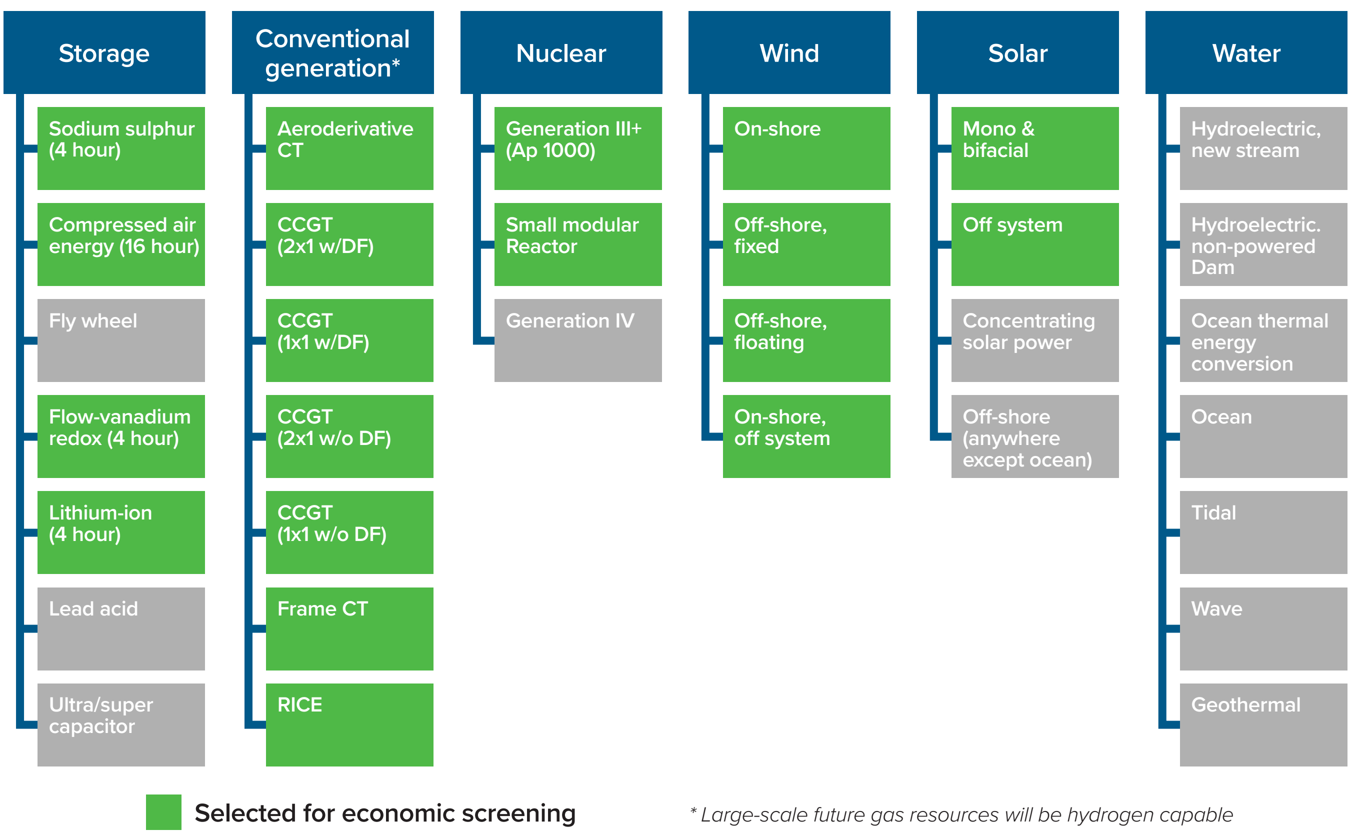


Figure 22: Potential Supply-Side Resource Alternatives (Technical Screening)

From the technical screening, 19 potential supply-side resources were selected for the economic screening. The economic screening evaluated Levelized Cost of Electricity ("LCOE") metrics and key performance parameters for diverse resource types, including renewables, energy storage, hydrogen-capable conventional generation, as well as consideration for off-system (i.e. resources not located with ENO's service territory) wind and solar.

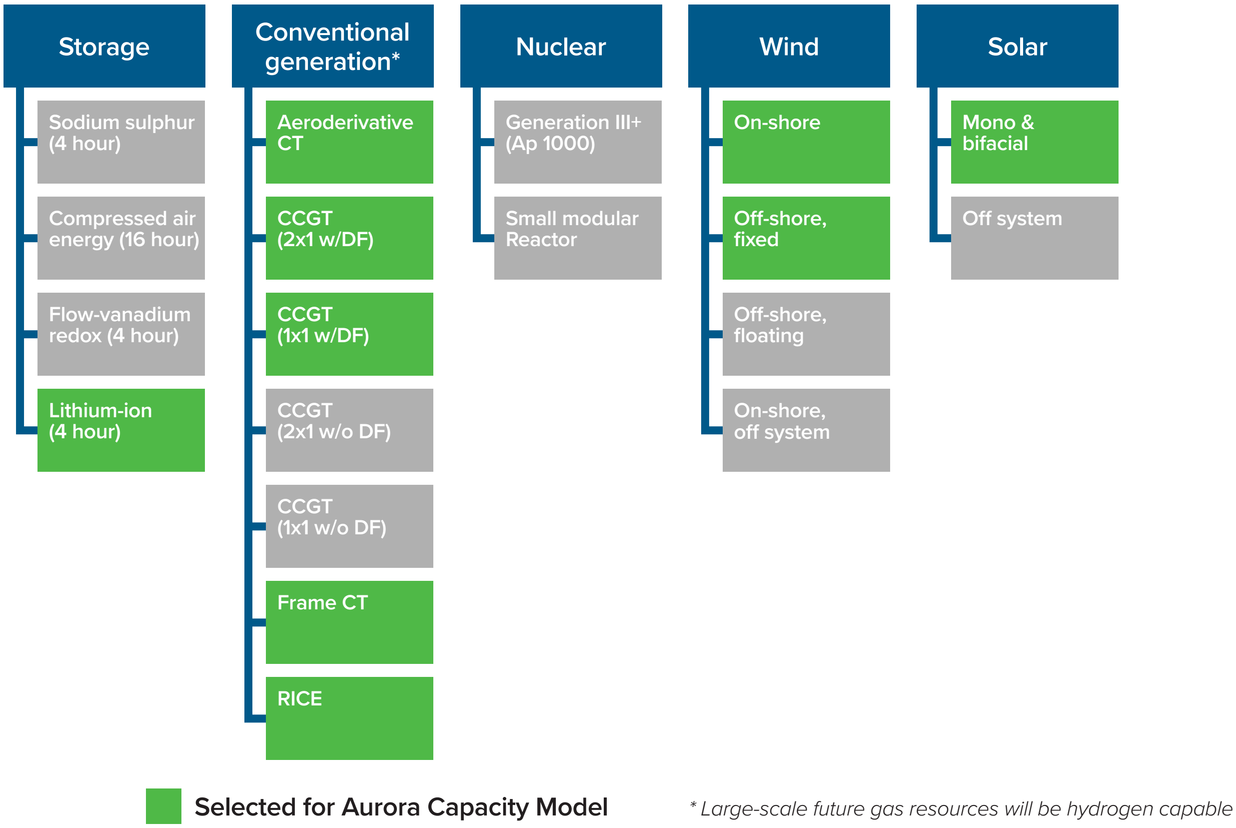


Figure 23: Potential Supply-Side Resources Selected for Economic Screening

Following the economic screening, generation alternatives are narrowed down for evaluation in the capacity expansion models. The technologies selected are those deemed to be most feasible to serve ENO's generation needs based on comparative LCOE and performance parameters, deployment risks (cost / schedule certainty), and emerging commercial, technical, and policy trends. In addition to the technologies specifically evaluated in this IRP and those that are selected for evaluation in the capacity expansion models, ENO continually evaluates existing, new, and emerging technologies to inform deployment decisions and a balanced generation portfolio that optimizes our planning objectives. Figure 24 lists the technologies selected for evaluation in the capacity expansion models.

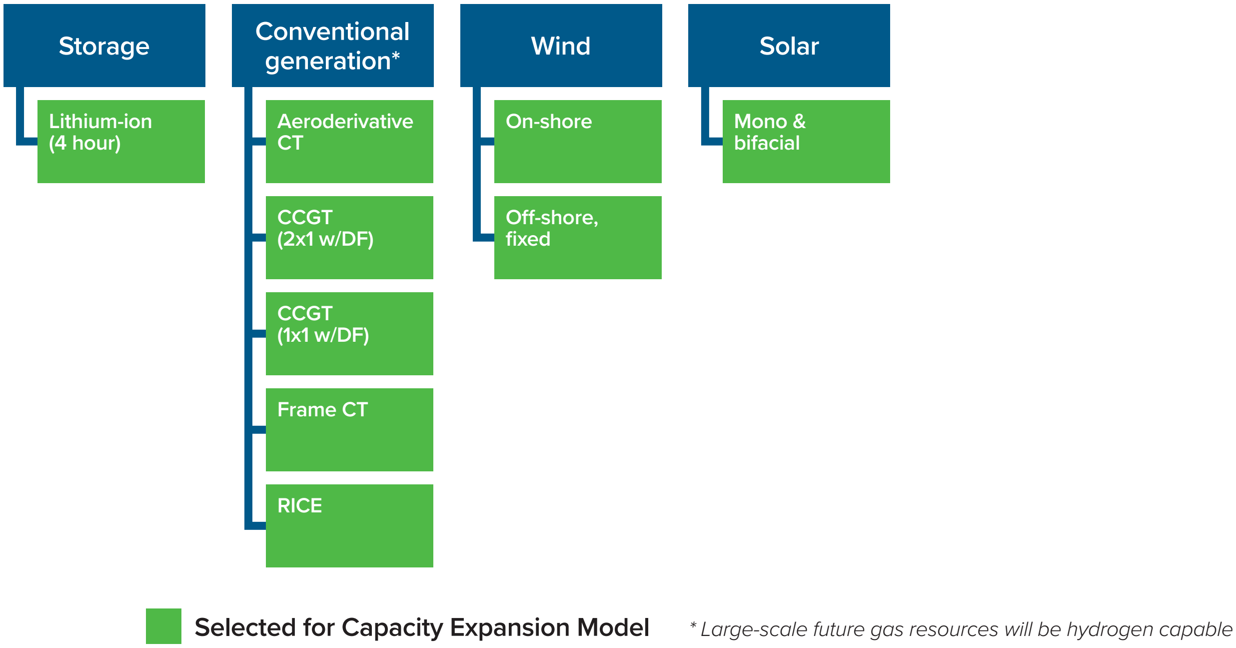


Figure 24: Supply-Side Resources Selected for Capacity Expansion Model

In the sections that follow, the selected technologies are discussed in more detail as well as the key emerging supply trends and implications that will shape the future of ENO's resource portfolio.

Conventional Generation w/Hydrogen Capability - Natural gas-powered generation technologies are a competitive supply-side resource alternative due to current relatively lower natural gas prices in ENO's service territory and suitability to serve a variety of supply roles (baseload, load-following, limited peaking). The long-term suitability of natural gas-powered generation technologies to meet planning objectives is largely dependent on natural gas prices and technology improvements, specifically, development of hydrogen co-firing capabilities (30% and eventually 100%) that can support ENO's sustainability objectives. ENO continues to track the development of hydrogen-fueled power generation technologies as developers continue to make advancements. To successfully deploy these technologies, necessary advancements need to be made in areas that include, but are not limited to, combustor systems, Nitrogen Oxide ("NOx") emissions reduction technologies, building hydrogen production, and delivery infrastructure.

Table 8 below summarizes the assumptions for the selected natural gas-powered w/hydrogen capability generation alternatives, followed by a comparison of relative benefits of each alternative along with a description of each technology.

Table 8: Conventional generation with Hydrogen capable-powered resource assumptions[12]

Technology	Hydrogen capability (%)	Net max summer capacity [MW-ac]	Installed capital cost [2021$/KW]	Fixed O&M [2021$/KW]	Variable O&M [2021$/MWh]	Full HHV summer heat rate[13] [Btu/kWh]
CT M501JAC	30%	380	$935.10	$6.53	$14.45	9,192
1x1 CCGT M501JAC w/duct firing	30%	667	$1,143.35	$15.39	$3.40	6,343
2x1 CCGT M501JAC w/duct firing	30%	1333	$994.60	$10.09	$3.41	6,343
Aero-CT LMS100PA + 5%H2	5%	102	$1,735	$6.34	$3.14	9,397
RICE 7x Wartsila 18V50SG + 25%H2	25%	129	$1,673	$22.89	$7.90	8,464

Combined Cycle Gas Turbines with 30% Hydrogen Firing Capability - CCGT plants included in the analysis are composed of either one or two frame CTs and a steam turbine plant to recover the thermal energy from the CTs. This recovery of thermal energy provides an efficient heat rate and moderate flexibility. Driven by economies of scale and low gas prices, CCGT fleet operators have generally remained competitive with solar and wind in terms of $/MWh. CCGTs are suitable to efficiently serve as baseload and load-following with flexibility that is expected to continue to gradually improve. Hydrogen capability of CCGT plants is expected to be dependent on the technology development of hydrogen fired CTs. Depending on the relative hydrogen co-firing volume, system modifications would be required in the CT and steam system portions of the plant. In addition to CT modifications described below, potential modifications for a future hydrogen fueled CCGT plant could include, but not be limited to, modifications to the heat recovery steam generator system and post-combustion NOx control systems.[14]

Combustion Turbine (Frame) with 30% Hydrogen Firing Capability - Combustion Turbines ("CT") have historically functioned as the technology of choice to support peaking applications due to low gas prices and technological improvement. Renewable energy resources (e.g., solar), however, have continued to become more competitive for peaking applications. While renewable energy resources are expected to continue playing a larger part in peaking applications and a balanced generation portfolio, CTs can play a role in the integration of renewable energy by offering quick-start (~30 minutes) backup power when renewable sources cannot meet peak demands.

12. Natural gas-powered resources shown are hydrogen capable. Assumptions do not include costs associated with firing hydrogen.
13. Heat Rate in Full HHV Summer Condition. CCGT w/ Duct Firing heat rate is reflective of the base capacity without duct firing.
14. Source: GE, Gas Power, Gas Turbines: Hydrogen Capability and Experience, A presentation to the DOE Hydrogen and Fuel Cell Technology, 9 March 2020, https://www.hydrogen.energy.gov/pdfs/06-Goldmeer-Hydrogen%20Gas%20Turbines.pdf.

Many frame CT OEMs have experience with developing CTs capable of burning hydrogen at various blends. Current CT model hydrogen co-firing potentials are dependent upon their combustor designs, among other systems. Most dry, low-NOx designs can accommodate hydrogen blends in the range of 20%-30% with advanced dry, low-NOx technologies under development to enable higher blend rates up to 100% hydrogen fired systems.[15] In addition to combustor modifications to achieve higher hydrogen firing rates other system modifications may need to be considered. These include fuel management systems, CT enclosure modifications, and control system updates.

Aeroderivative Combustion Turbine with 5% Hydrogen Firing Capability - AERO CTs have gained market share in applications for peak and intermittent power. The inherent flexibility of these technologies is a product of application from the aviation to the power industry. Traditionally, AERO CTs provide higher relative flexibility than frame CTs due to their hot start time (10 minute), minimum up/down time (5/5 minute), and ramp rate (102 MW/minute).

As is the case for Frame CTs, OEMs are continuing to develop AERO CT combustion systems to enable higher hydrogen blend rates. Current dry, low-NOx systems utilized within AERO CTs enable blending of hydrogen in the range of 5% with ongoing development of advanced combustor systems to enable higher blending rates, up to 100%.

Reciprocating Internal Combustion Engine with 25% Hydrogen Firing Capability - As renewable penetration increases, RICE units like the ones used at NOPS will likely see increased deployment across North America. RICE units can meet increased demand for reliability, place dispatchable power online rapidly, and be started/stopped frequently in response to changing load conditions. RICE units can ramp up to full load in less than 5 minutes and operate at about 33% of nominal rating without compromising heat rate. On the other hand, CTs generally ramp at a slightly slower rate (10 – 15 minutes) and while they can turn down to approximately 40% of their rated output, heat rate is compromised.

Current RICE OEMs have claimed that existing models are able to accommodate blends of hydrogen up to 25%.[16] As is the case for CT and AERO CT OEMs, RICE technology developers are working on technology advancements and identifying necessary plant modifications which would be required to increase the hydrogen blend capability above 25%. RICE OEMs are also working to develop models compatible with other potential low-carbon fuels such as ammonia, which is anticipated to provide another renewable fuel choice in addition to pure hydrogen.

Renewables and Battery Energy Storage Systems ("BESS") - Over the past decade, driven by technology improvements resulting in lower costs and improved performance, renewable and energy storage technologies have been increasingly deployed around the world, particularly utility-scale solar, on-shore wind, and BESS. Renewable energy resources add fuel diversity to gas-centric resource portfolios that were once supported by coal generation.

When paired, renewable energy projects and energy storage technologies have zero net emissions and fuel costs and provide increased diversity to the resource portfolio. Due to the intermittent nature of renewable generation, a balanced portfolio must maintain the ability to meet the changing instantaneous nature of customer usage and renewable production curves (e.g., on-peak production versus off-peak production).

Table 9 below summarizes the renewable and energy storage resource assumptions used in this IRP followed by a discussion of each technology.

15. Source: EPRI, Technology Insights Brief: Hydrogen-Capable Gas Turbines for Deep Decarbonization, Palo Alto, CA:2019. 3002017544. https://www.epri.com/research/products/000000003002017544.
16. https://www.wartsila.com/docs/default-source/power-plants-documents/pps-catalogue.pdf.

Table 9: Renewable and Energy Storage Resource Assumptions[17]

Technology[18]	Net Max Summer Capacity [MW-ac]	Installed Capital Cost [2021$/ KW]	Fixed O&M [2021$/ KW-yr.]	Capacity Factor [%]	Useful Life [yr.]	Factor [% in yr. 2021]
Utility-scale Solar[19, 20] (single axis tracking)	100	$1,103	$10.31 (U.S. Generic)	25.5% (MISO South)	30	25.5% (MISO South)
Onshore Wind	200	$1,441	$37.59 (U.S. Generic)	36.8% (MISO South)	30	36.8% (MISO South)
Offshore Wind	600	$4,253	$88.71 (GOM)	37.1% (GOM)	25	37.1% (GOM)
BESS[21] (Li-ion, 4hr)	50MW/ 200MWh	$1,380*	$13.17 (U.S. Generic)	N/A	20	N/A

** with augmentation*

Solar - Solar energy resources continue to rapidly increase. The US Energy Information Administration ("EIA") expects 15.4 GW of grid connected solar to be added in 2021, an increase of 3.4 GW relative to 2020 additions. From 2014 to 2020, utility-scale solar capital costs declined by more than 50% resulting primarily from declines in global PV module prices and economies of scale from larger project capacities. Beyond 2030, project costs are expected to continue to decline, albeit at a slower pace than in the prior decade as the industry continues to mature. In addition to technology cost declines realized as the industry matures, new module designs and configurations continue to be developed to improve efficiency and reduce overall costs. Over the next 30 years, costs are expected to decrease for both solar and wind, and renewable resources are expected to become a larger share of the generation portfolio mix. However, because solar energy production is variable in nature, grid flexibility and quick start backup generation are necessary to ensure reliability. Additionally, as part of the planning considerations for utility-scale facilities, land size requirements and site-specific needs must be evaluated.

Onshore Wind - Onshore wind continues to be, and is expected to remain, one of the fastest growing resources in the US. Onshore wind capital costs continue to decline. Between 2014 and 2020, onshore wind capital cost decreased by approximately 18%, resulting primarily from turbine cost reductions and economies of scale from larger turbines and higher capacity projects. Larger wind turbine blade diameters have rapidly entered the market. In 2010 there were no projects which utilized blades 115 meters or larger. However, in 2020, 91% of the installed wind turbines were 115 meters in diameter or larger.[22] With the wind industry being more mature and established versus the solar industry, any cost improvements are expected to be incremental as developers improve efficiency and increase market penetration for larger turbine models . As is the case for solar energy, because wind energy is also variable in nature, this requires consideration of its role in a portfolio composed of other resources.

17. Source: IHS 12.2019 (Solar & Wind): All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit. IHS 01.2020 (BESS): All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.
18. Solar, wind, and BESS fixed O&M excludes property tax and insurance. Solar includes inverter replacement in year 16.
19. Utility-scale solar shown in single-axis tracking. Utility-scale solar size: 100MW, on-shore wind size: 200MW, 4-hr BESS size: 20MW. Utility-scale solar life: 30-year, on-shore wind life: 30-year, 4-hr BESS life: 20-year
20. Solar capacity value is representative of year 1. Further explanation of solar capacity value as evaluated in the 2021 ENO IRP is summarized in the "Portfolio Design Analytics" section.
21. BESS round-trip efficiency is assumed as 86%. BESS installed capital cost includes module replacement in year 11. BESS capacity credit is representative of year 1. Modeling assumes 2% annual degradation, returning to full output in year 11 due to module replacements.
22. Source: Lawrence Berkley National Lab, https://emp.lbl.gov/wind-technologies-market-report/.

Offshore Wind - Offshore wind continues to be a developing industry within the US with most of the activity occurring off the US East Coast. Internationally, offshore wind industries are considered mature given widespread deployment in Europe. In 2016, the 30 MW Block Island Wind Farm off the coast of Rhode Island became the first US commercial offshore wind farm. There are several US offshore wind projects in various stages of development. The Bureau of Ocean Energy Management has proposed to identify potential wind energy areas and hold the first federal lease auction in the Gulf of Mexico in 2022. Offshore wind technologies include both fixed and floating foundations. The conditions in the Gulf of Mexico are expected to be able to utilize fixed foundation turbines, which are relatively more mature than floating foundations and are suitable for deployment in areas of shallower depth. As the US offshore wind market continues to mature and additional projects achieve commercialization, additional technology cost and performance improvements are expected, but transmission costs to get the power to the onshore grid will need to be considered. As is the case for onshore wind technology development, OEMs are continuing to develop larger and more efficient systems which result in cost reductions due to economies of scale. Offshore turbine capacity has increased significantly in recent years with OEMs offering larger diameter systems in the range of 14 MW per turbine. Assuming the US offshore wind industry evolves like solar and onshore wind industries, and reasonably priced transmission is available to connect projects to the main land, offshore wind could potentially become a significant contributor to the energy system.

Battery Energy Storage Systems - From 2015 to 2020, utility-scale BESS capital costs declined by 180%, with battery modules contributing to two-thirds of the decline (ATB NREL). As illustrated in Figure 25, forecasts suggest costs will fall another 78% by 2030, partially attributable to a decline in battery prices. Current use cases of battery technology are applied to discharge times that are four-hour or less to provide peak shaving capabilities. When efficiently integrated into the electric grid, BESS have the potential to provide transmission and distribution grid benefits by avoiding investments required due to line overloads that occur under peak conditions. In addition to these peak shaving applications, BESS can provide voltage support, which mitigates the effects of electrical anomalies and disturbances. If paired together with solar projects, BESS have the potential to shift some solar energy production to late afternoon hours, mitigating the ramping requirement on dispatchable generators created by the decline in solar energy production.

In addition to the above, BESS have the potential to offer stacked values through MISO markets to benefit customers by effectively enabling an intra-day temporal shift between energy production and energy use. Through this process, energy can be absorbed and stored during off-peak/low-cost hours and discharged during on-peak/high-cost hours. The spread (i.e., cost difference) between the time periods creates cost savings for customers. BESS qualify in some markets for various ancillary service applications such as frequency regulation, reserves, voltage regulation, and given enough discharge duration, qualify for MISO's capacity market. As the industry learns more and further deploys this technology, safety considerations and practices are becoming clearer, including fire prevention. Because Li-ion batteries are classified as hazardous waste, disposal and recycling of this equipment requires further research.

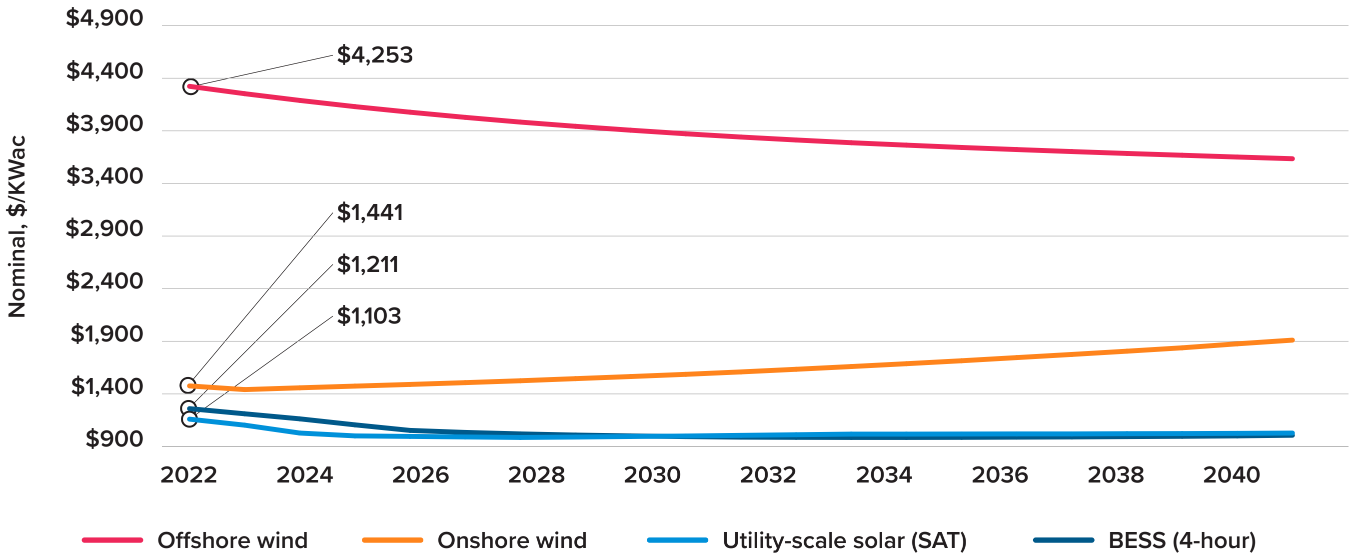


Figure 25 [23] : Renewable and Energy Storage Installed Capital Costs [24]

Summary of Emerging Supply Trends and Implications - Advancement in generation technologies provides new opportunities to meet customer needs reliably and affordably, as more supply-side generation alternatives become viable options to address planning objectives.

Renewables and energy storage system technologies have emerged as viable economic alternatives and are expected to continue to improve through the planning horizon. Increased deployment of intermittent generation will need to be balanced with flexible, dispatchable and diverse supply alternatives to maintain reliability. Smaller, more modular resources, such as Aero-CT, RICE, and battery storage, provide an opportunity to reduce risk and better address locational, site-specific reliability requirements while continuing to support overall grid reliability. Looking ahead, ENO will endeavor to maximize clean energy options while balancing reliability, affordability, and environmental stewardship.

3.5. Demand-Side Management Studies and Input Cases

For the 2021 IRP, ENO again engaged Guidehouse Consulting Inc. ("Guidehouse") to prepare a demand side management (DSM) potential study.[25] The study assessed the long-term potential for reducing energy consumption in the residential and commercial and industrial (C&I) sectors by using energy efficiency and peak load reduction measures and improving end-user behaviors. Additionally, the Council engaged GDS, Inc. ("GDS") to perform a DSM potential study to assess potential for energy savings and peak demand reduction in the city through utility-run energy efficiency, peak demand, and rate design programs.

In order to ensure that both studies based their findings on consistent inputs, Guidehouse and GDS received the same sets of data from ENO, relied on the New Orleans Technical Resource Manual ("NOTRM") as a source document for measure information, and considered the historical results and current implementation plans for the Energy Smart programs. ENO hosted a stakeholder meeting on March 26, 2021, with GDS, Guidehouse, and the parties to the docket to review the input files and address questions so that both consultants and the parties would be aligned. Additionally, ENO responded to ad hoc questions from GDS that arose as part of GDS's review of the input files and development of its study.

23. Utility-scale solar shown in single-axis tracking. Utility-scale solar size: 100MW, on-shore wind size: 200MW, 4-hr BESS size: 20MW. Utility-scale solar life: 30-year, on-shore wind life: 30-year, 4-hr BESS life: 20-year.
24. Source: IHS 2021: All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit. ATB NREL 2020: Offshore Wind only.
25. Guidehouse is the new name for the firm known previously as Navigant Consulting, which performed ENO's DSM potential study for the 2018 IRP.

Unlike in the 2018 IRP, where there was significant divergence between the two studies regarding identified EE potential, the two 2021 studies presented more consistent conclusions about available MWh savings. For example, a comparison of the potential 20 year MWh savings identified by the Guidehouse 2% Program case and the GDS 2% Council Policy case shows that the two are within about 6% of each other, with Guidehouse identifying 1,994 MWh and GDS 1,882 MWh. Across the 10 years that show the most savings under the 2% cases, 2023 to 2032, it should be noted that Guidehouse's budget estimates for achieving the projected savings are consistently lower, tracking in the $17-$22 million range each year while GDS's estimates track in a range from approximately $26-$31 million per year.

Comparing the Guidehouse Low case to the GDS Reference case shows that these cases are within about 5% of each other on estimated energy savings, with Guidehouse identifying 1,623 MWh and GDS 1,699 MWh. From 2023 to 2032, the Guidehouse Low case budget totals $14-$18 million annually, while the GDS Reference case budget totals approximately $19-$25 million annually.

A comparison of the Guidehouse High case to the GDS High Case (HCAP) shows a similar evaluation of savings potential and a spread of about 5% between the two, with Guidehouse totaling 2,142 MWh and GDS totaling 2,245 MWh over the study period. As in the other cases, GDS projects consistently higher costs to achieve the identified savings. Over the first ten years of the study period, GDS estimates a range of annual costs starting around $30 million and rising to about $55 million per year. Guidehouse's annual cost estimates for those years fall in a range starting at $17 million and rising to $25 million per year.

For demand response, a comparison of the Guidehouse Mid case to the GDS Reference case shows that both identified significant savings potential from direct load control, dynamic/critical peak pricing, and C&I curtailment/interruptible rates. Guidehouse identified 70 MW of achievable potential from these three programs in 2040. GDS studied several additional programs beyond these three, which contributed to an overall reference case achievable potential of 130 MW by 2040.

As directed by the IRP Initiating Resolution,[26] both Guidehouse and GDS evaluated a demand response measure that would pay participating customers an incentive to install battery storage systems that could be controlled by ENO for DR purposes. Both studies evaluated a behind-the-meter ("BTM") storage demand response program, included discussions of the parameters and assumptions of the programs studied, and provided descriptions of the analysis. Both studies evaluated the program using the total resource cost ("TRC") test required under the Council's IRP rules, which indicates a program represents a net economic benefit to customers if the result of the cost/benefit calculation meets or exceeds a ratio of 1.0. GDS calculated a TRC ratio of 0.15 for the residential BTM storage program, indicating that the program would not be cost effective; customers would expect to receive $0.15 of benefits for every $1.00 spent on the program.[27] Guidehouse calculated a TRC ratio of 0.08 for the residential BTM storage program, which also indicated the program would not be cost effective.[28]

In the context of short-term DSM implementation planning, ENO can consider the different perspectives offered by the studies as it designs an Energy Smart Implementation Plan for Program Years 13-15 that it believes is reasonable, cost-effective, and achievable for the Council to review. To that end, ENO intends to develop the Energy Smart Implementation Plan by drawing on information from both studies.

26. IRP Initiating Resolution at 12.

27. See, GDS 2021 DSM Market Potential Report, Table 3-7.

28. See, Guidehouse 2021 Integrated Resource Plan DSM Potential Study Report, Table 4-1.

Guidehouse Potential Study for ENO - The 2018 IRP DSM study prepared by Navigant projected certain levels of achievable energy savings and program costs based on business assumptions and historical results of Energy Smart at the time. The PY10-12 Implementation Plan developed with ENO's Third-Party Administrator, Aptim, and subsequent actual program results, reflect more aggressive splits between incentive and administrative costs and greater utilization of behavioral efficiency programs than were identified in the 2018 study. The 2021 study highlights the long-term effects of such aggressive incentives. For the 2021 study, Guidehouse approached the energy efficiency (EE) component of the potential study with a rigorous analysis of input data. This data was necessary for Guidehouse to run its proprietary DSM Simulator (DSMSim™) model, which calculated various levels of EE savings potential across the ENO service area. Guidehouse further delineated the achievable potential using a range of assumptions in four alternative cases to estimate the effect on customer participation of funding for customer incentives, awareness, and other factors. The four achievable cases included:

2% Program Case - The 2% program case is defined by the approved Energy Smart PY10-12 implementation plan, Scenario 2. Guidehouse set incentives at 86% and 32% of the full measure cost for residential and C&I measures, respectively. Guidehouse calibrated the model results by adjusting adoption parameters and behavior program rollout to align with the historical program achievements and planned savings as documented in the implementation plan.

Low Program Case - The low case uses the same inputs as the 2% program case, (ENO implementation plan, Scenario 2) except for lower levels of behavior program participation rollout (50% of the 2% program case). Incentives are set to 50% of full measure cost for residential and 25% for C&I. Administrative costs on a dollar per kWh saved basis are the same as the 2% program case.

High Program Case - The high case is based off the 2% program case but with higher incentives as a percent of full measure cost at 100% for residential and 50% for C&I. Additionally, there is a more aggressive plan for behavior program rollout. Behavioral program rollout for the residential sector increases slightly compared to the 2% case and reaches the maximum achievable level. Administrative costs on a dollar per kWh saved basis are relatively equal to those in the 2% program case.

Reference Case - In an effort to develop a case reflecting an industry-standard level of incentives, and because the actual program results for the approved PY10-12 plan were tracking to higher levels of administrative costs and kWh savings than are often seen in long term potential studies, it was useful to provide a Reference Case that tied back to the Base case from the 2018 study. This Reference case reflects the Base case from the 2018 study where the program administrative costs reflected current spend targets on a dollar per kWh saved basis and the incentives were set at 50% of incremental measure costs. In Guidehouse's experience in incentive level setting and potential study analysis, others have set incentives or cap incentives at 50% of incremental measure cost. Behavior program roll out matches the low program case levels as a conservative assessment of the potential roll out of the recommended programs for the ENO portfolio.

Guidehouse identified the following achievable potential energy savings over the four cases:

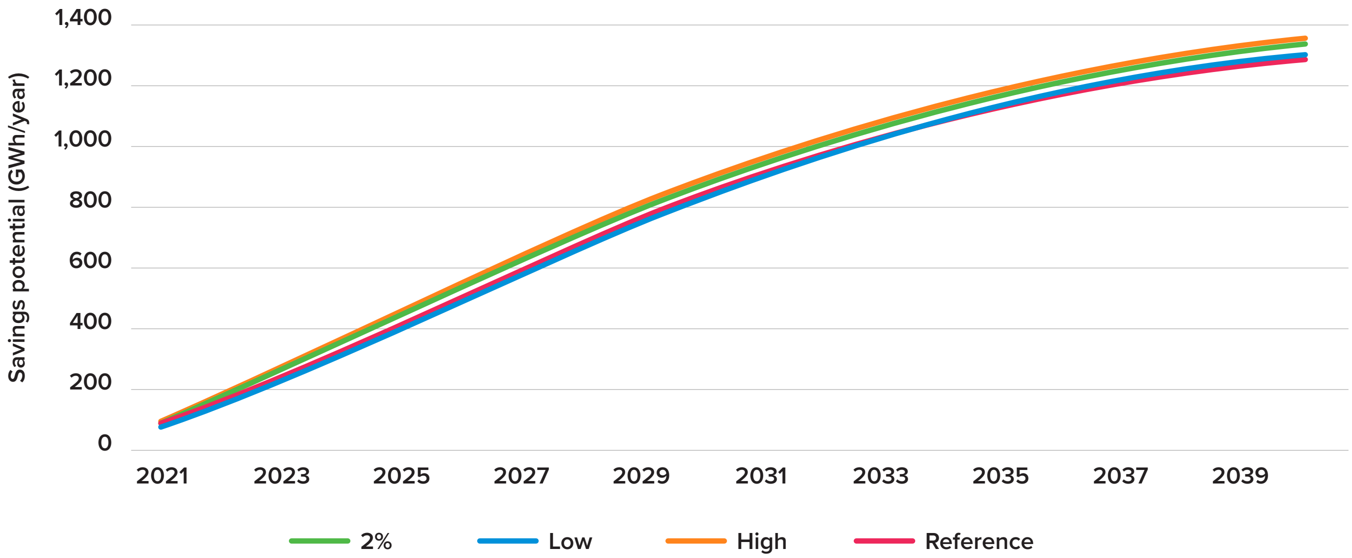


Figure 26: Electric Energy Cumulative achievable Savings Potential by Case (GWh/year)

Table 10: Annual Incremental Achievable Energy Efficiency Savings by Case

	Electric energy (GWh/year)				Peak demand (MW)			
Year	2%	Low	High	Reference	2%	Low	High	Reference
2021	89	77	93	79	22	20	23	21
2022	98	86	104	88	22	21	22	21
2023	105	91	111	93	23	22	24	23
2024	112	96	119	99	25	24	25	24
2025	119	101	126	103	26	25	26	25
2026	124	105	132	106	27	26	27	26
2027	122	104	130	104	27	26	27	26
2028	121	102	128	102	27	26	27	26
2029	120	101	128	102	26	25	26	25
2030	115	96	123	96	25	25	26	24
2031	109	90	117	89	24	23	24	23
2032	103	84	110	83	23	22	23	22
2033	97	77	104	76	21	20	21	20
2034	91	71	99	70	20	19	20	18
2035	86	66	94	65	18	17	18	17
2036	83	62	91	61	17	16	17	16
2037	79	58	87	57	16	15	15	14
2038	76	54	84	53	15	13	14	13
2039	72	51	81	50	13	12	13	12
2040	73	51	81	50	13	12	13	12
Total	**1,344**	**1,299**	**1,359**	**1,302**	**429**	**409**	**432**	**408**

The demand response (DR) potential component of the Guidehouse study began with a rigorous analysis of the input data necessary to run Guidehouse's proprietary DRSim™ model. Inputting a range of reasonable assumptions, Guidehouse used the DRSim™ model to estimate the DR potential for three achievable DR cases—a mid (base) case, a low case, and a high case.

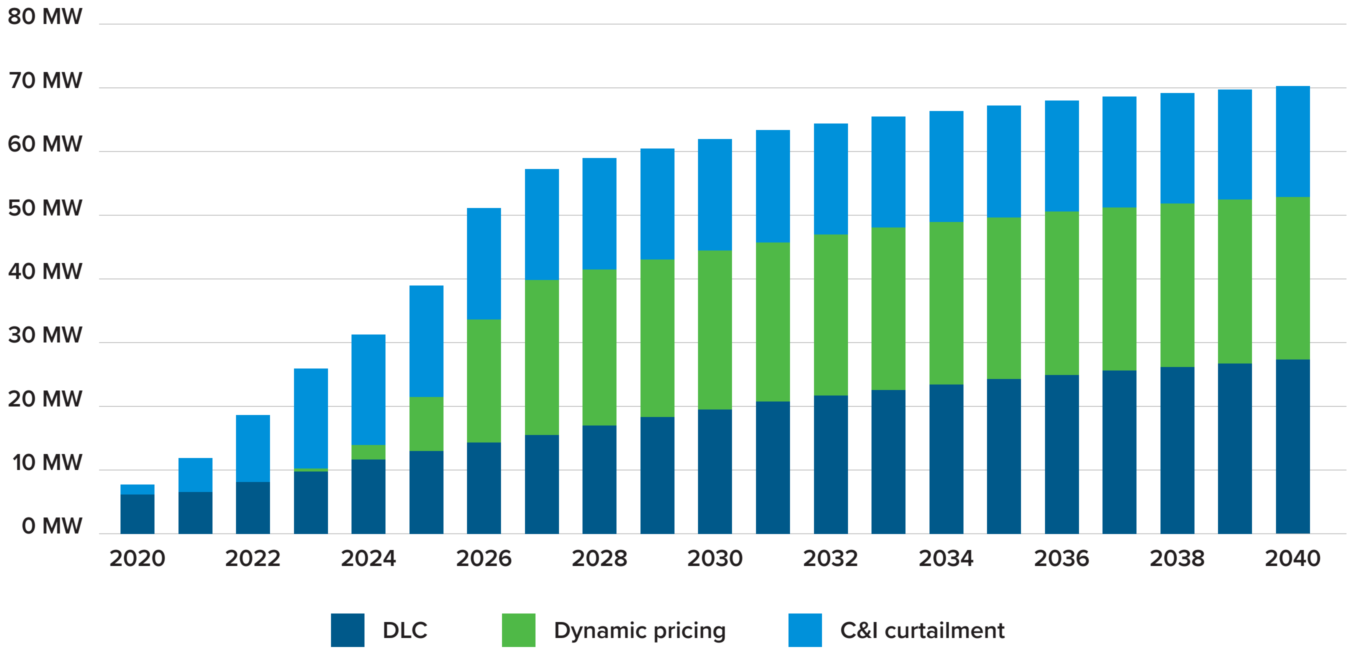


Figure 27: Summer Peak Achievable Potential by DR Option (MW)

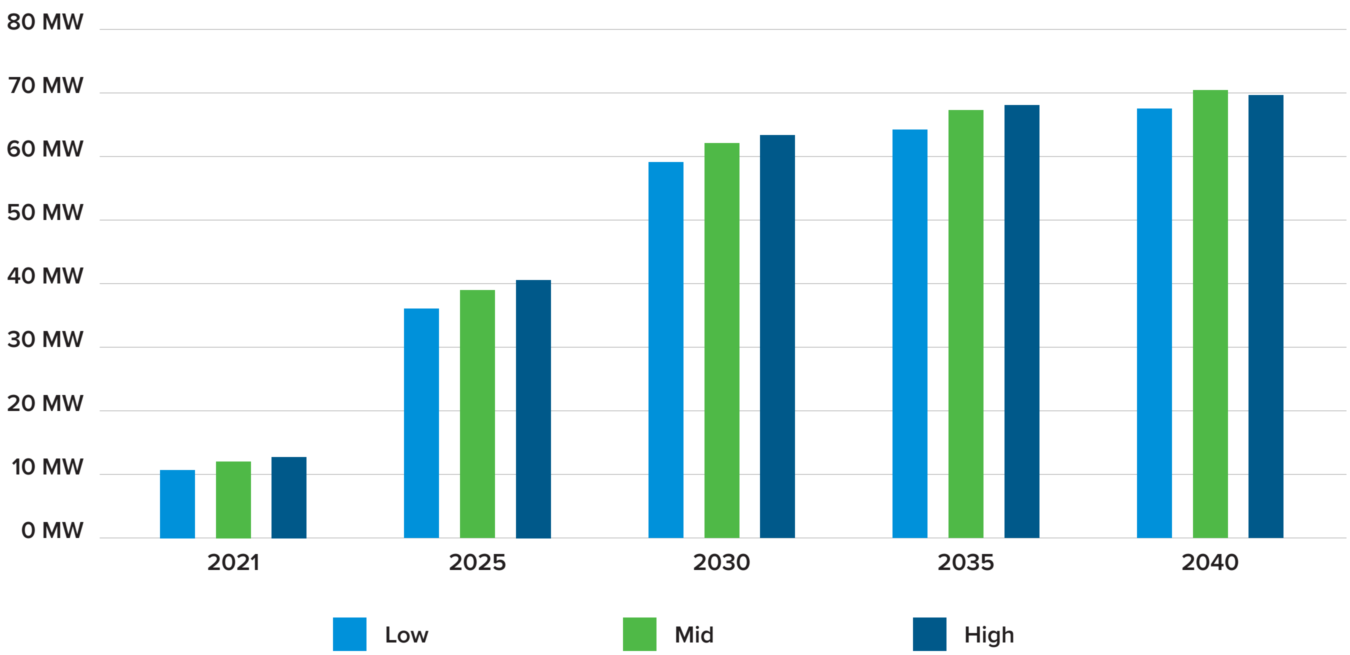


Figure 28: Summer DR Achievable Potential by Case (MW)

GDS Study for the Council

GDS developed three achievable potential DSM cases:

High Case Achievable Potential (HCAP) - estimates achievable potential from aggressive adoption rates based on paying incentives equal to 100% of measure incremental costs and increased program awareness.

2% Council Policy Case (2% Case) - estimates achievable potential in-line with Council policy, reflecting a 0.2% increase in savings as a percent of sales until savings as a percent of sales achieves 2%.

Reference Achievable Potential (RAP) - estimates achievable potential with Entergy paying incentive levels (as a percent of incremental measure costs) and program awareness closely calibrated to historical levels but is not constrained by any previously determined spending levels.

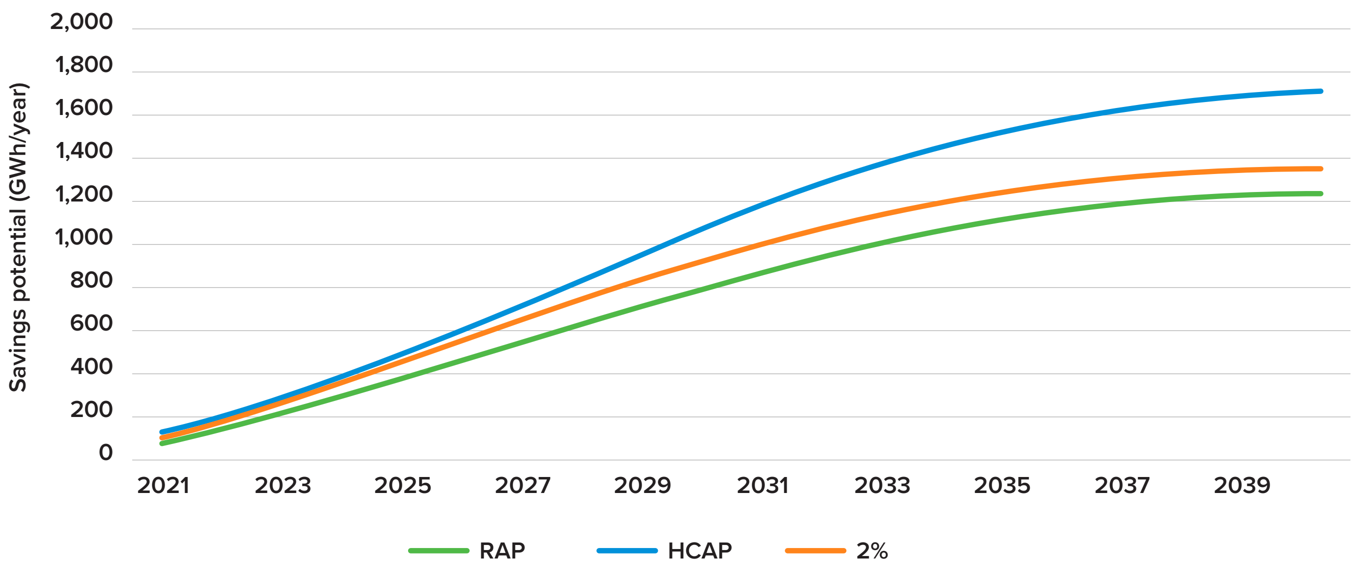


Figure 29: Cumulative Annual Achievable Electric Energy Savings Potential by Case

Table 11: Annual Incremental Achievable Energy Efficiency Savings by Case

	Energy (GWh/year)			Peak demand (MW)		
Year	RAP	HCAP	2%	RAP	HCAP	2%
2021	79	98	86	17	19	19
2022	87	106	98	21	23	24
2023	90	110	110	22	23	24
2024	91	115	116	23	26	29
2025	94	121	116	24	27	30
2026	99	128	116	27	30	31
2027	103	136	116	30	33	33
2028	106	142	109	33	35	32
2029	107	145	111	35	37	34
2030	105	143	109	36	38	35
2031	101	137	106	35	37	35
2032	94	129	100	33	35	33
2033	86	118	92	30	32	30
2034	79	106	84	26	28	36
2035	71	96	76	23	24	23
2036	72	99	79	20	22	21
2037	66	90	71	17	19	18
2038	60	80	66	15	16	16
2039	56	75	63	13	15	14
2040	53	71	58	11	13	12

GDS also assessed DR program achievable potential in two cases—a reference case and a high case. The results for the reference case are shown below:

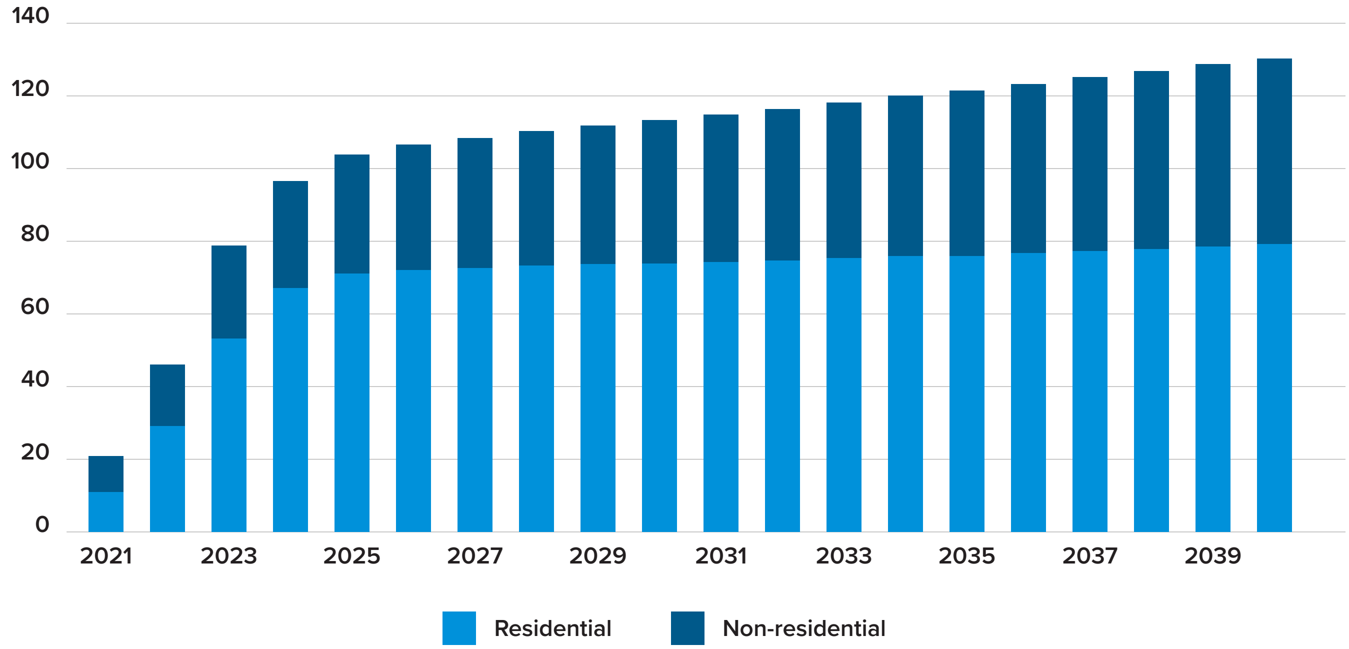


Figure 30: Total Annual Summer Peak MW Reference Base Potential by Sector

3.6. Fuel and CO_2 Price Forecasts

3.6.1. Natural Gas Price Forecasts

Three natural gas price forecasts were used in the development of the 2021 IRP. The near-term portion (year one) of the natural gas price forecast is based on NYMEX Henry Hub forward prices, which are market future prices as of December 2020. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long term. Due to this limitation, the long-term point of view regarding future natural gas prices utilizes a consensus across several independent, third-party consultant forecasts. Gas markets are influenced by a number of complex forces; consequently, long-term natural gas prices are highly uncertain and become increasingly uncertain as the time horizon increases. Therefore, ENO presents and uses three alternatives for natural gas prices to address this uncertainty. In levelized 2022 dollars per MMBtu throughout the IRP period, the reference case natural gas price forecast is $4.08, the low case is $2.73, and the high case is $5.55.

Described in more detail later in this section, each of the IRP Scenarios assumes the natural gas price forecast sensitivity appropriate for the future world envisioned.

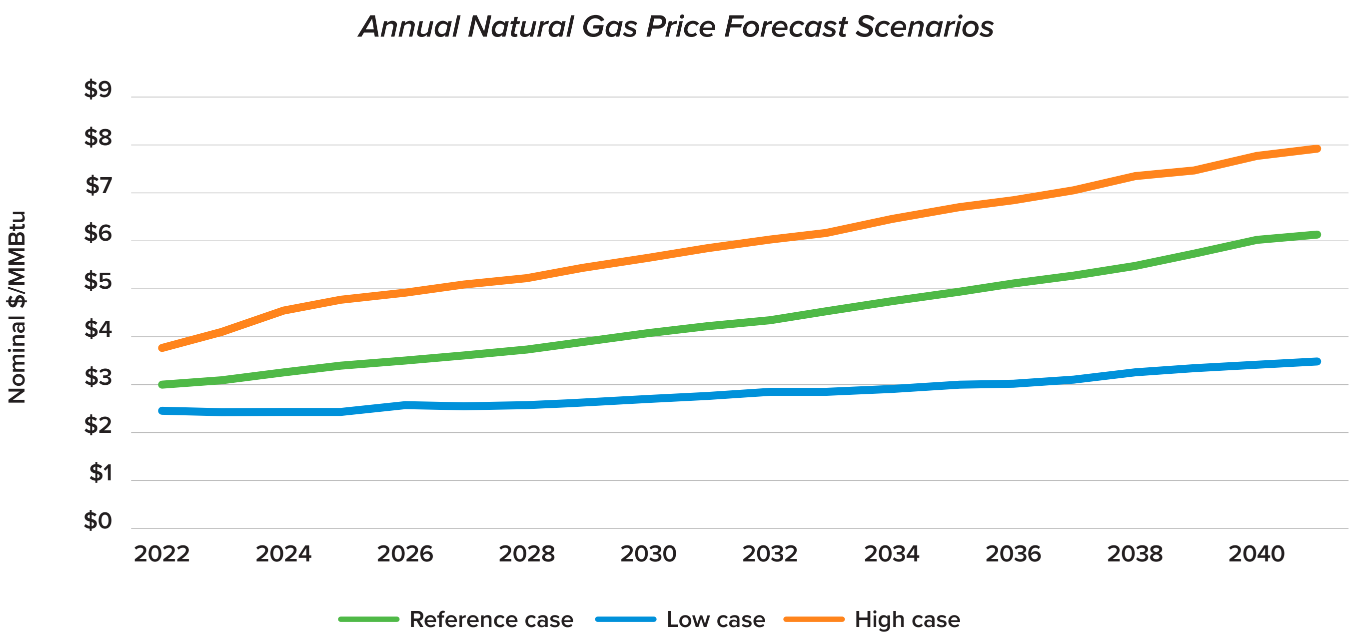


Figure 31: Natural Gas Price Forecast

3.6.2. CO2 Price Assumptions

ENO's point of view is that national carbon regulation for the power generation sector will occur; however, the timing, design, and outcome of any carbon-control program remain uncertain.

CO2 Price Forecasts – ENO's CO2 point of view is based on the following four cases:

1. **No CO2 or clean energy policy case** represents either no carbon pricing program at the federal level or a program that requires inside-the-fence measures that do not result in a tradable CO2 price, such as the ACE Rule that replaced the Clean Power Plan (CPP).
2. **A regulatory case** reflects a low price on carbon representative of action under the Clean Air Act (similar to Clean Power Plan approach) in stringency.
3. **A 50% reduction case** assumes a national cap and trade program that begins in 2024 and targets a 50% percent national reduction from 2005 sector emissions by 2050.
4. **A Legislative case** is based on the Climate Leadership Council's Carbon Dividend proposal.

After deriving projections of CO2 allowance prices for each of these four cases, the following probability weightings were applied to each to arrive at ENO's Reference point of view:

Table 12: CO2 Reference Case Probability Weightings

Case	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045
No CO_2 Policy/ Clean Energy	100%	100%	85%	75%	70%	50%	40%	35%	30%	20%	10%	5%
Regulatory	0%	0%	5%	10%	20%	27.5%	30%	32.5%	35%	40%	50%	50%
50% Reduction	0%	0%	15%	20%	20%	30%	32.5%	32.5%	35%	40%	50%	50%
Legislative	0%	0%	0%	0%	0%	0%	0%	2.5%	5%	15%	20%	25%

The Reference case used in Planning Scenarios 1 and 2 assumes the ENO point of view CO2 price based on the weighted probabilities shown in Table 12. The High case used in Planning Scenario 3 assumes the Legislative case CO2 Price case as shown below:

CO_2 Price Forecast Scenarios

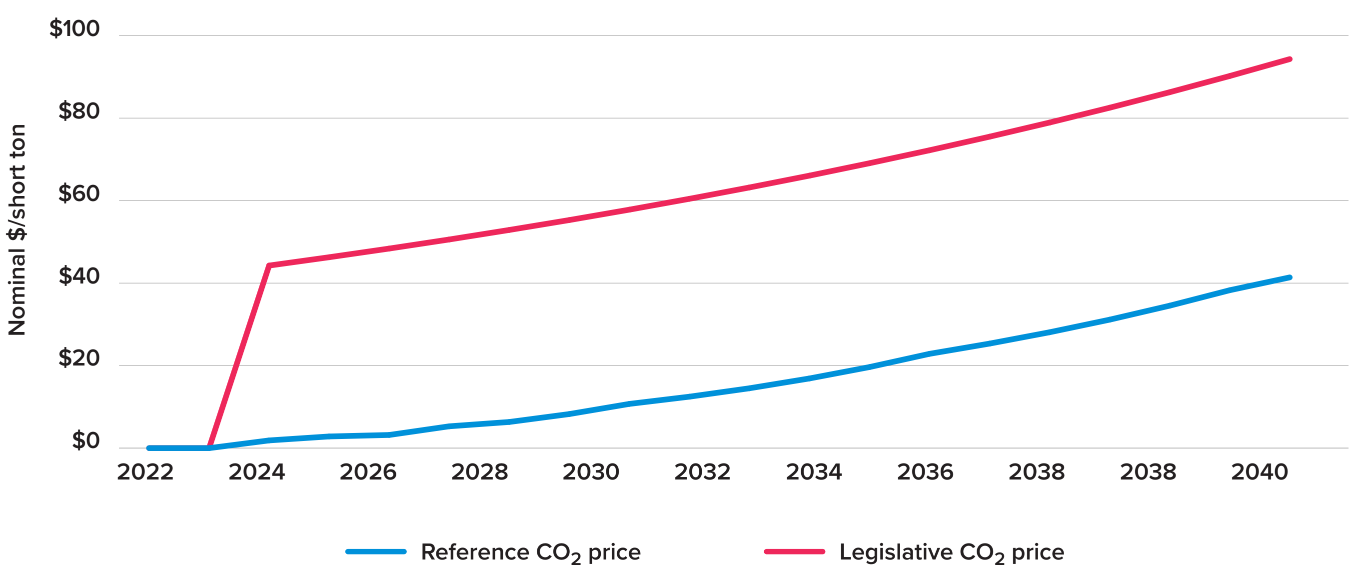


Figure 32: CO2 Price Forecast

Chapter 4

Modeling Framework

4.1. Scenario- and Strategy-Based Approach

To support the evaluation of a broad range of resource portfolios, ENO, the Advisors, and the Intervenors agreed on three planning Scenarios representing a range of market drivers and possible futures. Additionally, the parties came to consensus on four planning Strategies (one of which included a sensitivity) that informed or constrained the Portfolio development process consistent with defined objectives or policies. Using the AURORA Capacity Expansion Model, twelve optimized Portfolios were developed based on a combination of each Scenario and Strategy. Additionally, three manual portfolios were developed under Strategies 1, 3, and 4.

4.1.1. Planning Scenarios

For the 2021 IRP, ENO utilized a set of three Scenarios which vary based on economic, policy, and customer behavior assumptions that impact market prices, including:

- Peak load and energy growth
- Customer usage trends with regards to DR/EE/DER
- Natural gas and CO_2 prices
- Unit life assumptions
- Renewable resource cost assumptions

The three Scenarios agreed to among the parties for inclusion in the 2021 IRP are given below.

Table 13: Overview of Scenarios

	Scenario 1	Scenario 2	Scenario 3
Description	Reference	Decentralized Focus (DSM & renewables)	Stakeholder
Peak / Energy Load Growth	Reference	Low	High
Basis of DR / EE / DER Additions (Adjustment to Load)	Entergy (Medium)	Entergy (High)	Entergy (High)
Natural Gas Prices (Levelized Real, 2021$/MMBtu)	Reference	Low	High
Market Coal Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (30 Years)
Legacy Gas Fleet Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (30 Years)
CO_2 Tax Assumption (Levelized Real, 2021$/short ton)	Reference	Reference	High
New-Build Resource Alignment with MTEP Future #3	No, Aurora capacity expansion tool will be used	No, Aurora capacity expansion tool will be used	Yes, via a manual MISO market portfolio buildout
Renewable Resource Costs	Entergy Technology Assessment	Entergy Technology Assessment	NREL 2020 ATB

Scenario 1: Reference - Scenario 1 is defined by reference load growth and gas prices, DSM additions, and CO_2 reductions targets.

Scenario 2: Decentralized Focus – Scenario 2 is defined by low load growth and gas prices, high DSM additions, and moderately accelerated coal and legacy gas retirements. The aggressive deployment of DERs and DSM contribute to the lower peak load and energy projections. Continued political support for domestic gas production leads to sustained low gas prices.

Scenario 3: Stakeholder Focus - Scenario 3, as defined by the Intervenors, is characterized by high load growth, gas prices and DSM additions, as well as lower renewables costs sourced from the NREL 2020 ATB instead of the Entergy Technology Assessment. Social trends and corporate initiatives shift, demanding high penetration of DERs, DSM, and EE. Non-ENO coal and legacy gas plants are driven to retire much earlier than anticipated resulting from stringent carbon mandates.

4.1.2. Planning Strategies

The Strategies were developed to support a range of potential planning objectives, Council policies, and clean energy priorities. Portfolios developed under all four Strategies were designed to meet the forecasted MISO-coincident peak load plus a planning reserve margin of 12.69% based on unforced generation capacity (UCAP). The details provided in Table 14 below were used to constrain the capacity expansion modeling to conform to the objectives defined by each Strategy.

Table 14: Overview of Strategies

	Strategy 1	Strategy 2	Strategy 3	Strategy 4
Description	Least Cost Planning	But For RCPS (Reference)	RCPS Compliance	Stakeholder Strategy
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and meet long-term PRM target	Include a portfolio of DSM programs that meet the Council's stated 2% goal and meet long-term PRM target in compliance with RCPS policy goals	Include a portfolio of DSM programs that meet the Council's stated 2% goal and meet long-term PRM target in compliance with RCPS policy goals; NREL 2020 ATB LCOE values for renewables costs provided by Stakeholders
Objective	Assess demand and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.
DSM Input Case	Low Case (Guidehouse)	2% Program Case (Guidehouse)	2% Program Case (Guidehouse)	High Case (GDS)
Manual Portfolio	Alternative Deactivation Union 1 (2025) (Manual Portfolio 1a)	N/A	Held Union 1 deactivation at 2033 and accelerated renewable generation additions to comply with near-term RCPS mandates (Manual Portfolio 3a)	Alternative Deactivation Union 1 (2025) (Manual Portfolio 4a)
Sensitivity	N/A	N/A	N/A	Lower renewables costs provided by Stakeholders (Sensitivity 4b)

Strategy 1: Least Cost Planning - Strategy 1 focuses on least cost alternatives to meet planning needs as required by Section 7.D.1. of the Council's IRP Rules. Demand- and supply-side alternatives are selected based solely on need and cost. Strategy 1 utilizes the Guidehouse low case EE and DR program penetration and costs and allows the AURORA model to select only the economic EE programs, whereas all DR programs are assumed to be economic and are included.[29]

29. While the original design for Strategy 1 called for the Guidehouse Reference case to be used, the Guidehouse "low" DSM case was ultimately adopted based on a comparison of each incentive case's aggregated portfolio RIM test results. The "low" incentive level's aggregate RIM result identified the highest benefit across the programs.

Strategy 2: But for RCPS (Reference) - Strategy 2 is described as the "But For RCPS" strategy and is intended to represent the resource plan that would comply with regulatory policies in New Orleans that existed before Council approval of the RCPS rules. Strategy 2 incorporates the Guidehouse 2% Program case and allows the model to select other least cost resources required to meet identified capacity needs. The Strategy forces the selection of all EE and DR programs to meet the 2% goal. Additionally, Strategy 2 allows the selection of any available generation technologies as capacity resources to satisfy the Planning Reserve Margin Requirements. This strategy will be included in future IRPs to provide this same "But For RCPS" point of comparison as required by the RCPS rules.

Strategy 3: RCPS Compliance –Strategy 3 is focused on meeting the requirements of the Council's stated RCPS policy as well as the 2% DSM savings goal. The Strategy utilizes the Guidehouse 2% Program Case and forces the selection of all EE and DR programs to meet the 2% goal. The primary difference between Strategy 2 and 3 is that Strategy 3 excludes new capacity resources that would not be RCPS compliant, i.e., fossil-fueled resources.

Strategy 4: Stakeholder Strategy - Strategy 4, defined by the Intervenors, uses the GDS High case DR and EE programs, as well as NREL 2020 ATB renewables costs provided by the Intervenors that are lower than those developed through the Entergy Technology Assessment. The Strategy forces the selection of all EE and DR programs into the optimized Portfolios.

Manual Portfolios – In addition to the twelve optimized portfolios produced through Aurora, two manual portfolios were produced that accelerated the assumed deactivation date of Union 1 from 2033 to 2025.[30] The first, Manual Portfolio 1a, was informed by the optimized portfolio developed under Scenario 1/Strategy 1. The second, Manual Portfolio 4a, was informed by the optimized portfolio developed under Scenario 3/ Strategy 4. Additionally, a third Manual Portfolio 3a agreed to among the parties at Technical Meeting #4 was based on Scenario 1/Strategy 3 and kept the Union 1 deactivation in 2033 while accelerating renewable resource additions to examine options for compliance with the annual mandates set forth in the RCPS rules without procurement of additional unbundled RECs.

> **Sensitivity 4b** - The Stakeholders requested inclusion of a sensitivity case, identified as Sensitivity 4b, using an additional set of even lower renewables cost inputs than those provided for Strategy 4. Sensitivity 4b was produced based on Manual Portfolio 4a, which was originally derived from the Scenario 3/Strategy 4 optimized portfolio.

Renewables Capacity Credit - The solar capacity credit assumption used in the IRP aligns with the solar assumption detailed in the 2021 MISO MTEP Futures Report. Under this assumption, all solar units have a 50% capacity credit at the beginning of the study period that decreases by 2% starting in year 2026, until the capacity credit reaches a minimum of 30%.

30. The parties agreed during the technical meetings that these manual portfolios would address the Advisors' recommendation from the Initiating Resolution concerning analysis of alternative retirement dates for ENO's existing generators.

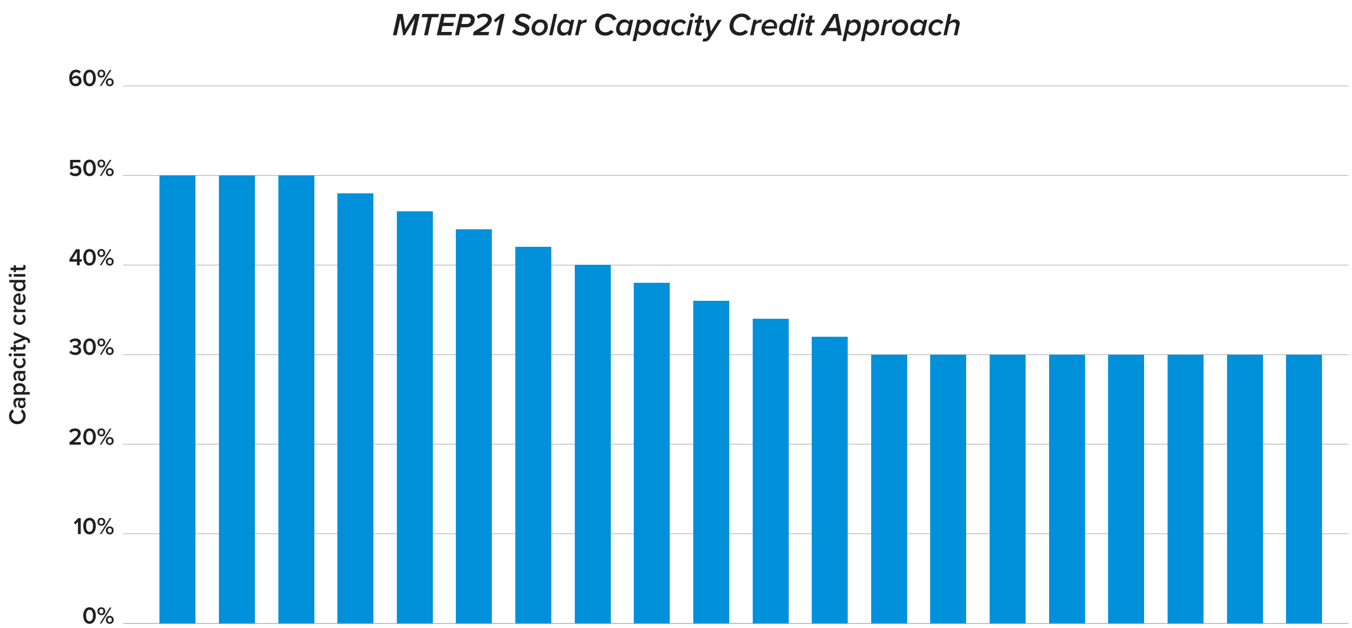


Figure 33: MISO MTEP Solar Capacity Credit

The 16.6% wind capacity credit assumption used in the IRP is sourced from MISO's 2020/2021 PY Wind & Solar Capacity Credit Report. The MISO system-wide wind capacity credit is calculated using a probabilistic approach to find the Effective Load Carrying Capability ("ELCC") value for all wind resources in the MISO footprint.

4.2. Market Modeling

The 2021 IRP relied on Aurora[31] to develop market energy prices ("LMPs") for the MISO energy market and to develop optimized portfolios for ENO under the identified Scenario and Strategy combinations. Aurora is a production cost and capacity expansion optimization tool that simulates energy market operations using hourly demand and individual resource operating characteristics in a chronological dispatch algorithm and uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, available DSM program alternatives, environmental constraints, and future demand forecasts. Aurora's optimization process identifies the set of future resources that most economically meets the identified requirements given the defined constraints.

The first step within the market modeling process is to develop a projection of the future market supply based on the specific characteristics of each Scenario. For Scenarios 1 and 2, Aurora was utilized to perform capacity expansion using viable generation alternatives to meet the peak load plus an 18% target reserve margin. Per the Intervenors' specification in designing the Stakeholder Scenario, Scenario 3's capacity expansion referenced MISO's MTEP 2021 Future 3 capacity expansion results. Once the market supply resources were determined for each Scenario, energy market simulations were performed, which resulted in hourly energy prices for each of the three Scenarios. These projections encompass the power market for the entire MISO footprint (excluding ENO). MISO (excluding ENO) projected power prices are extracted from the energy market simulations to later assess potential portfolio strategies for ENO within each Scenario. Figures 34 - 39 below show the projected market supply for each of the three Scenarios. Figure 40 represents projected annual MISO (excluding ENO) power prices for each Scenario.

31. The Aurora model is the primary production cost tool used to perform MISO energy market modeling and long-term variable supply cost planning for ENO. Aurora supports a variety of resource planning activities and is well suited for scenario modeling and risk assessment modeling through hourly simulation of the MISO market. It is widely used by a range of organizations, including large investor-owned utilities, small publicly owned utilities, regulators, planning authorities, independent power producers and developers, research institutions, and electric industry consultants.

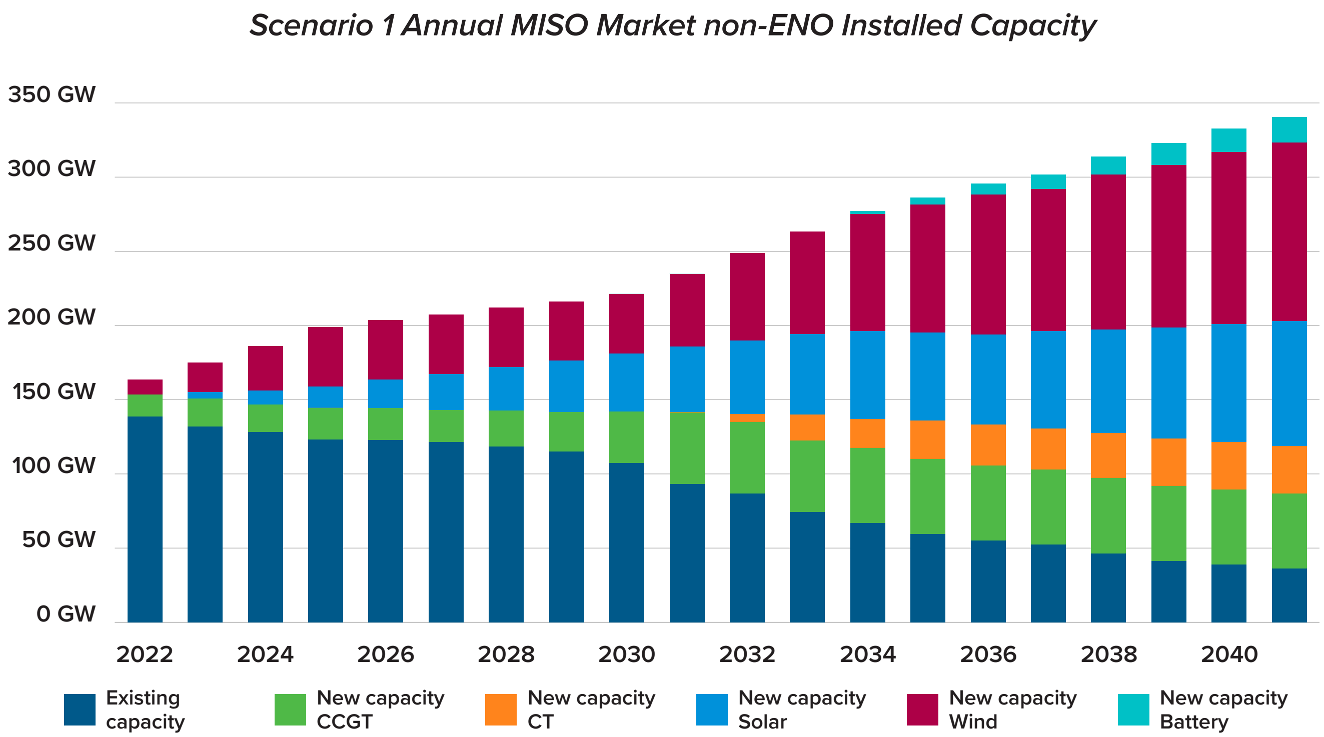


Figure 34: Scenario 1 Projected Future Market Installed Capacity

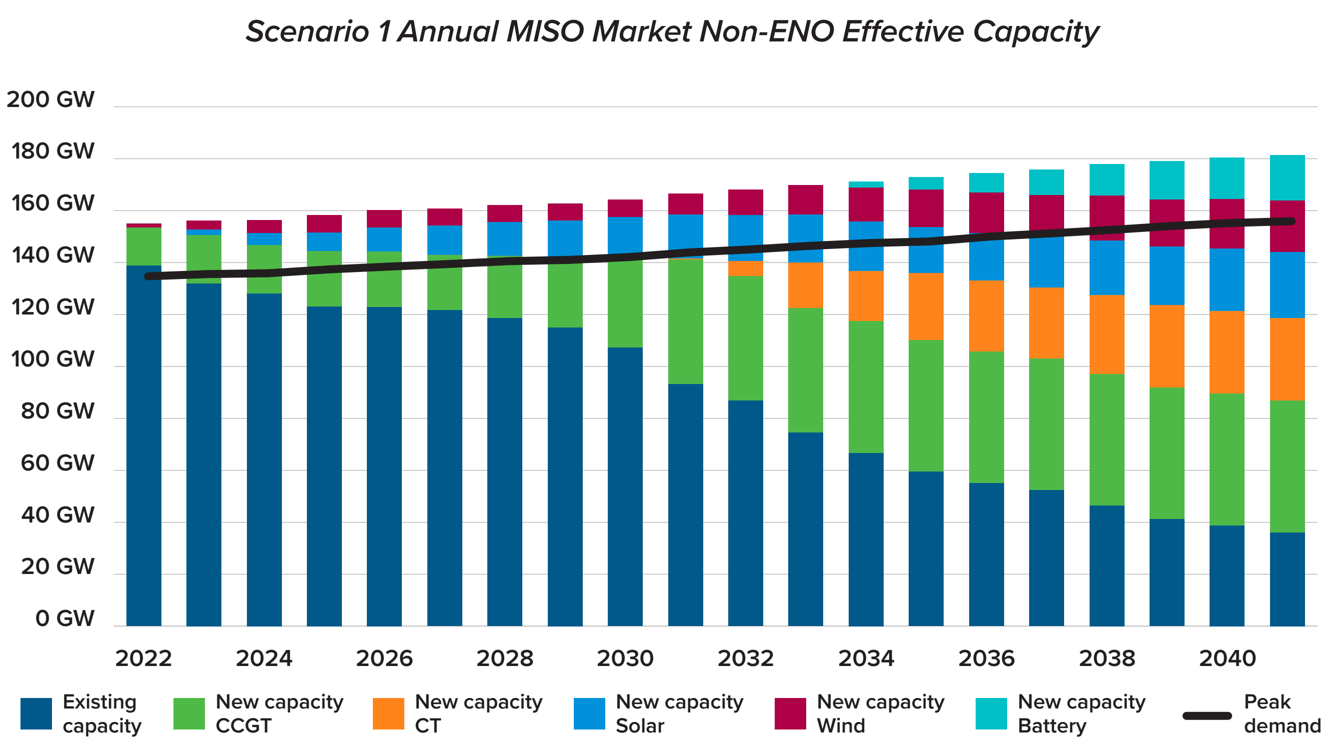


Figure 35: Scenario 1 Projected Future Market Effective Capacity

Scenario 2 Annual MISO Market non-ENO Installed Capacity

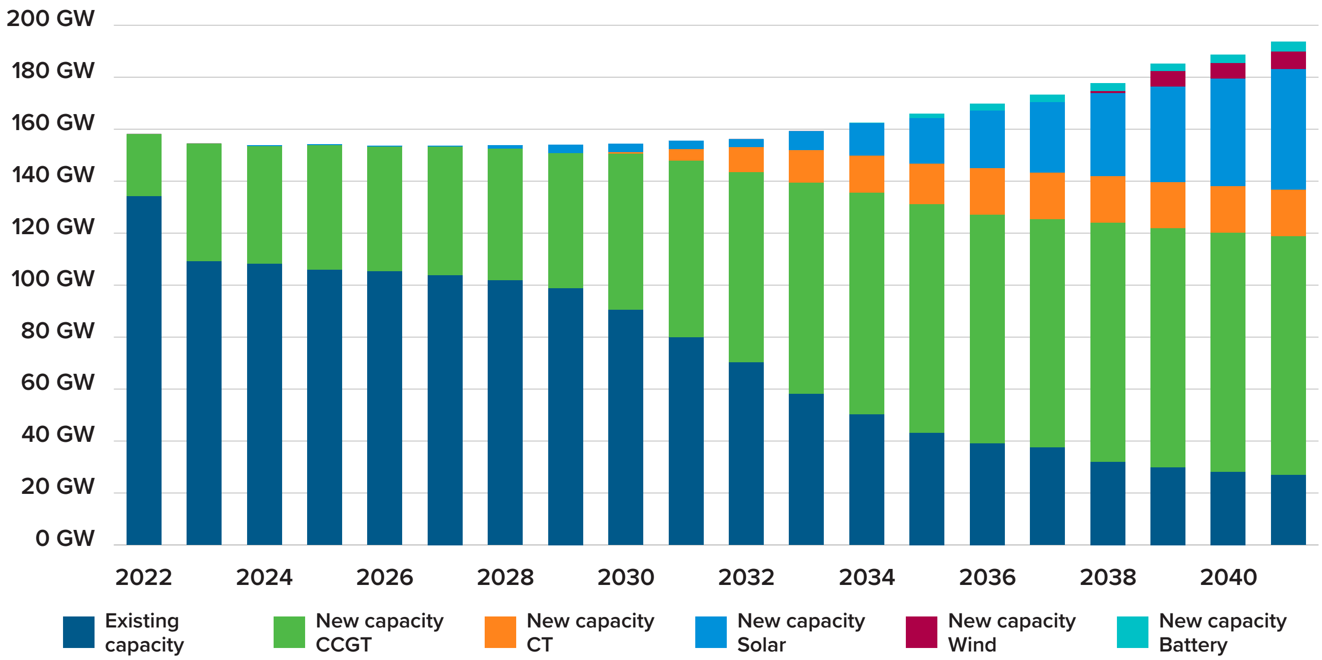


Figure 36: Scenario 2 Projected Future Market Installed Capacity

Scenario 2 Annual MISO Market Non-ENO Effective Capacity

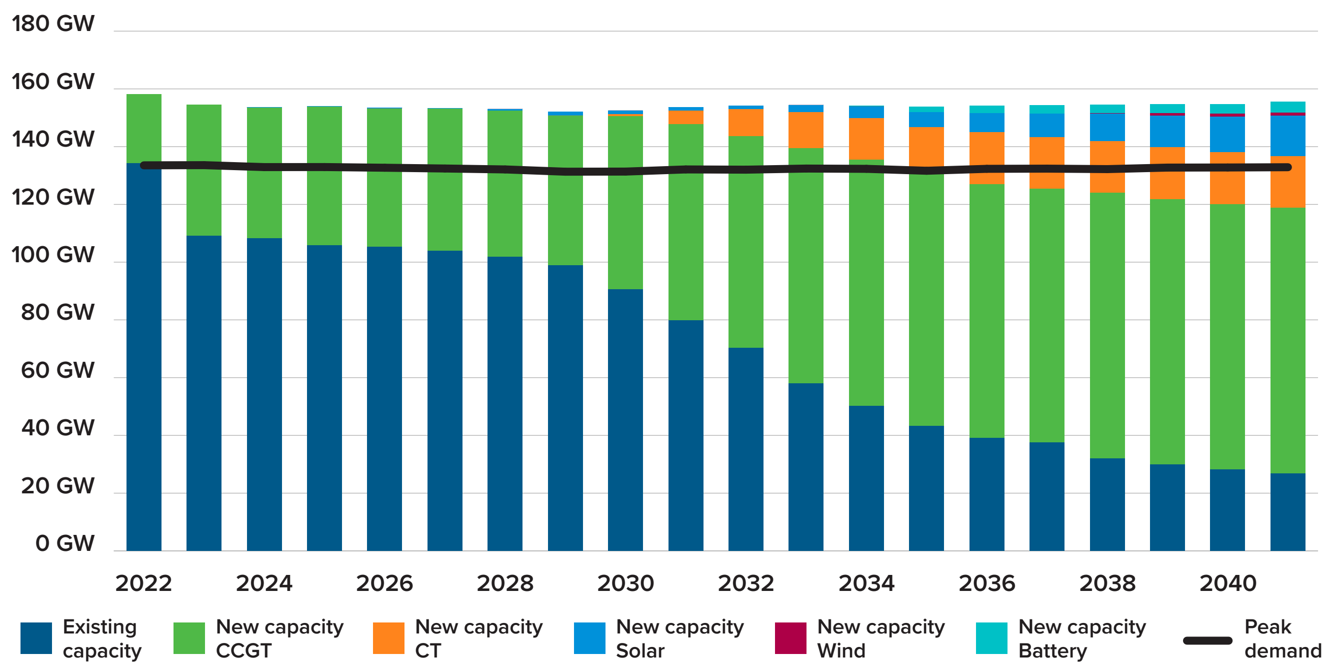


Figure 37: Scenario 2 Projected Future Market Effective Capacity

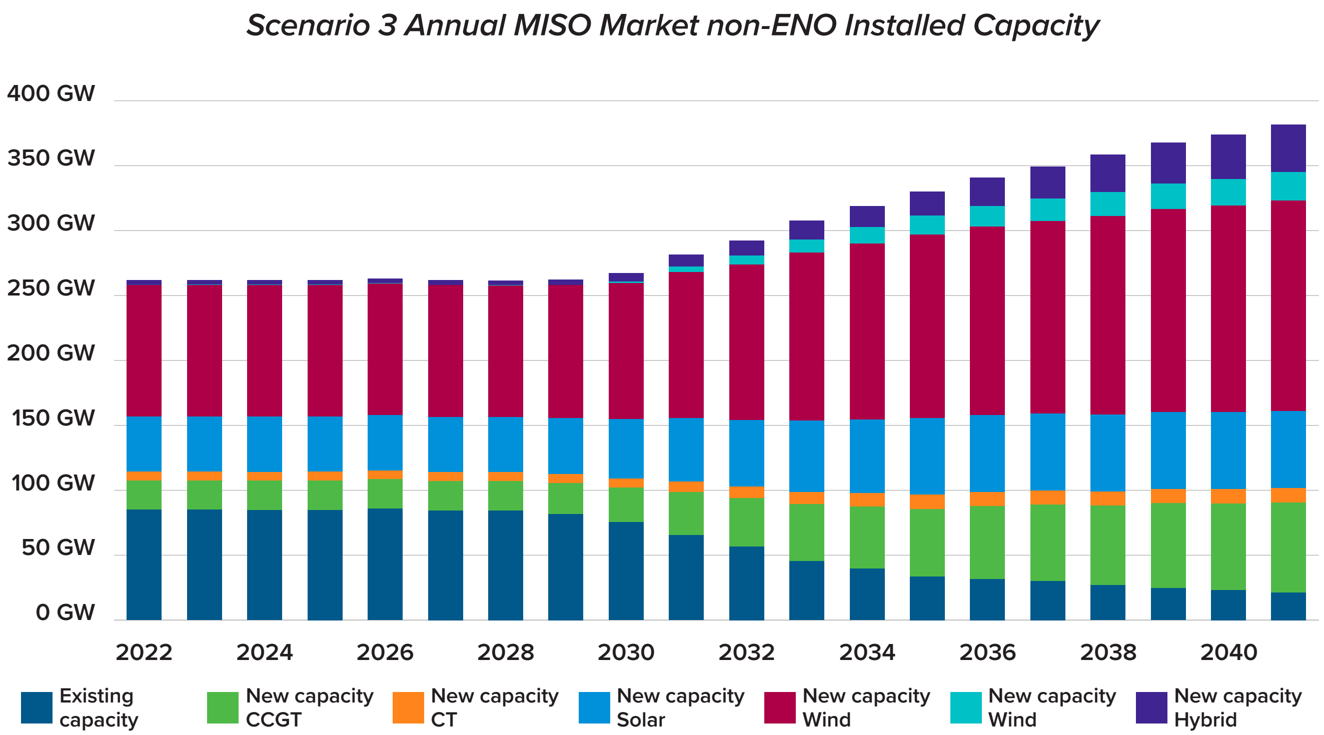


Figure 38: Scenario 3 Projected Future Market Installed Capacity

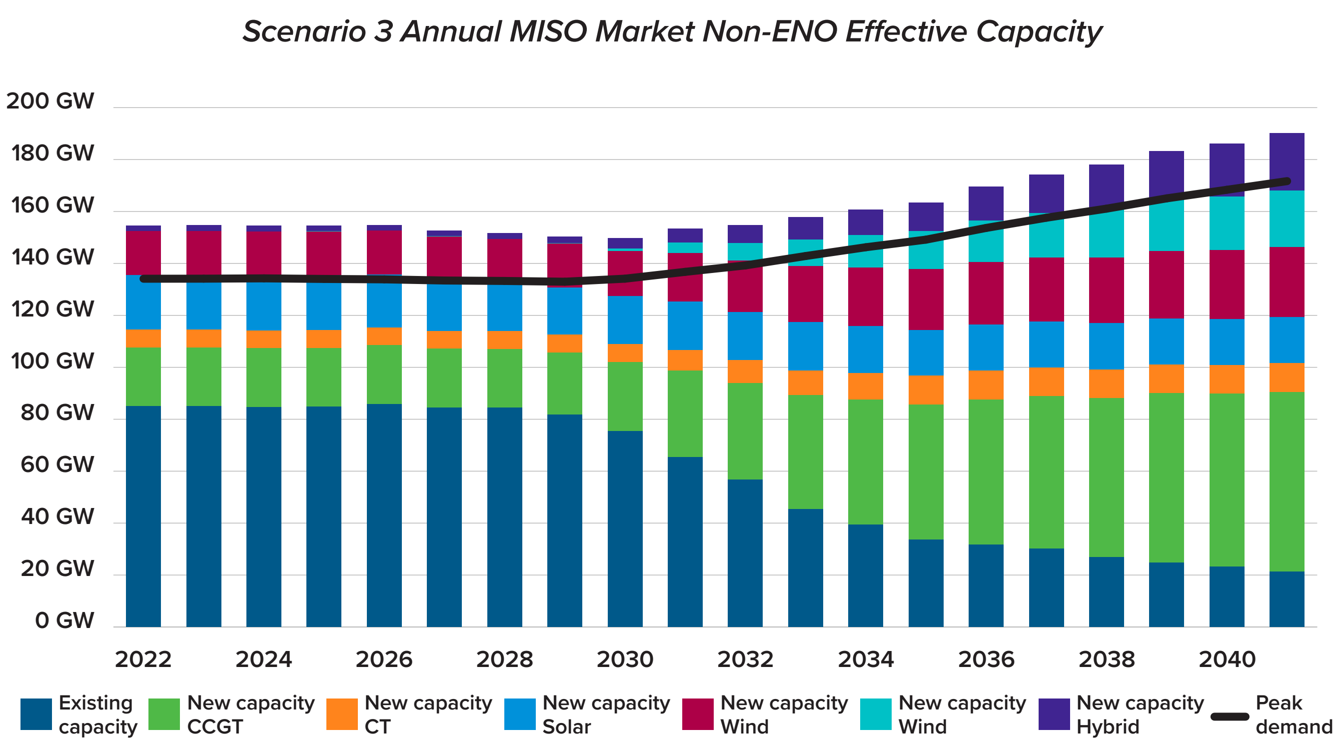


Figure 39: Scenario 3 Projected Future Market Effective Capacity

Average Annual MISO Market Non-ENO LMPs

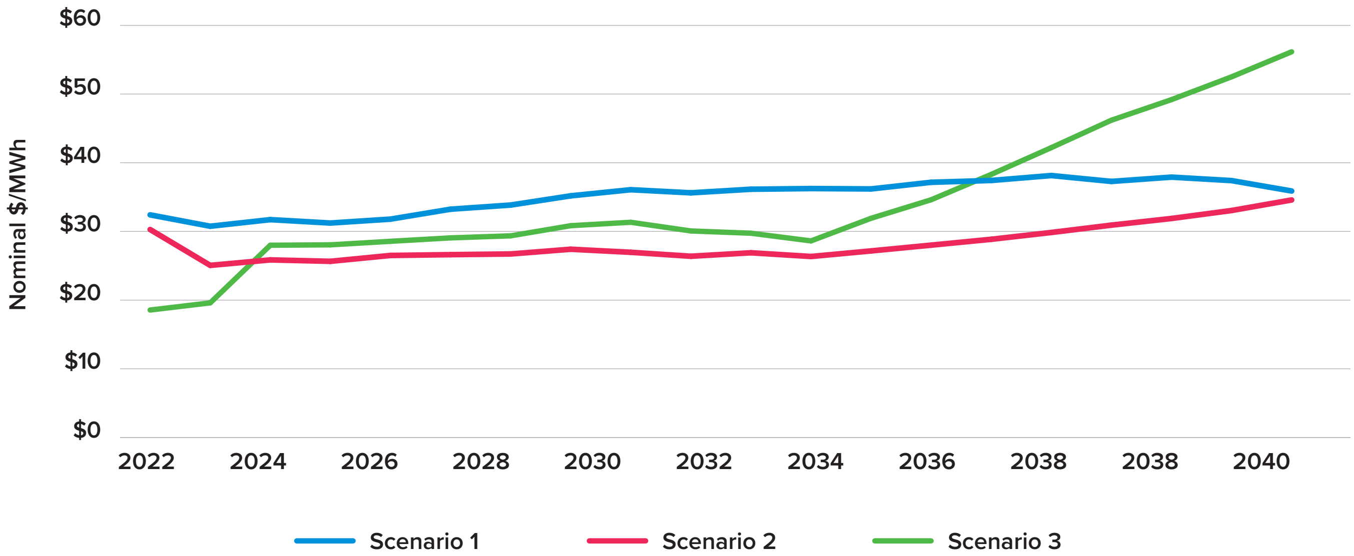


Figure 40: Average Annual MISO Non-ENO LMP

4.3. ENO Optimized and Manual Portfolios

Optimized Portfolios - Following the market modeling process, which resulted in LMPs for the non-ENO MISO region, the Aurora long-term capacity expansion logic was used to identify economic type, amount, and timing of demand-side resources (as noted earlier, DSM was forced in for Strategies 2 – 4 consistent with the defined objectives of those strategies) and supply-side resources needed to meet ENO's capacity needs for each Strategy under each Scenario. The result of this process was a portfolio of demand-side resources and supply-side resources that produces the lowest total supply cost to meet the identified need within the constraints defined in each of the 12 Strategy and Scenario combinations. Each of the Strategy 1 – 3 Optimized Portfolios included a mix of solar and/or wind resources along with battery storage while Strategy 4 only included solar and wind resources because the cost and performance assumptions for battery storage were not provided.[32] Figure 41 below depicts the incremental supply-side resource additions of the Optimized Portfolios that resulted from each Scenario and Strategy Combination.

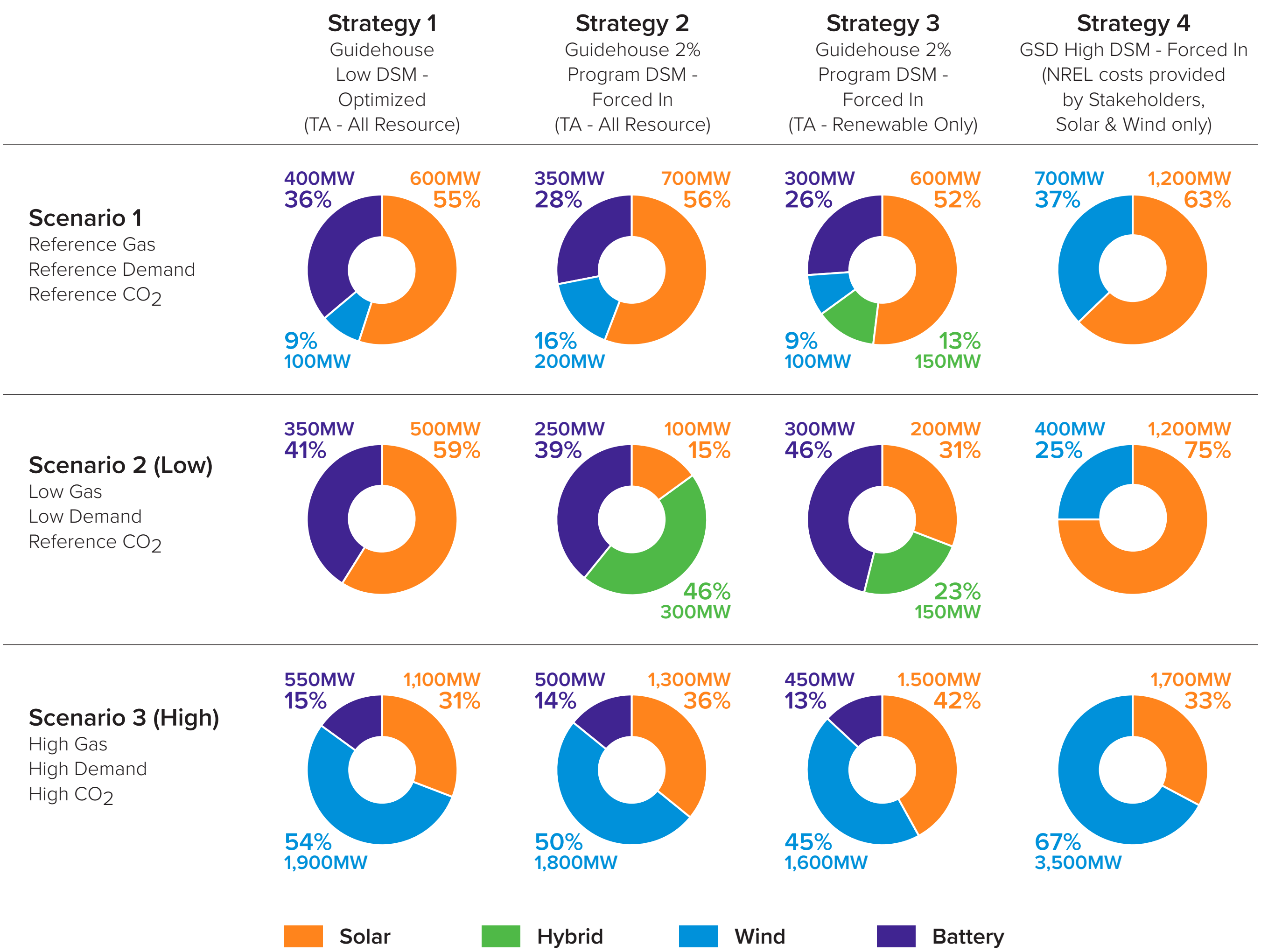


Figure 41: Capacity Expansion Results

32. Aurora was constrained to select only solar and wind resources when creating the optimized portfolios under the Stakeholder Strategy 4 because the input file provided by the Intervenors only included NREL costs for those two types of resources. At Technical Meeting #4 the parties discussed the fact that if the Intervenors had provided the NREL costs for storage then the resource mix selected by Aurora for the Strategy 4 portfolios would have been substantially similar to those selected for Strategy 3. Once the parties agreed to the creation of Manual Portfolio 3a and the inclusion of all three Manual Portfolios in the TRSC analysis, the Intervenors were satisfied that the outputs would present a suitable range of options for Council consideration and concurred with proceeding.

Manual Portfolios – In addition to the Optimized Portfolios shown above, and as discussed in the Planning Strategies section 4.1.2 above, three Manual Portfolios were developed based on specified Optimized Portfolios. Figures 42 - 47 below are representations of the modifications from the Optimized Portfolios to the Manual Portfolios.

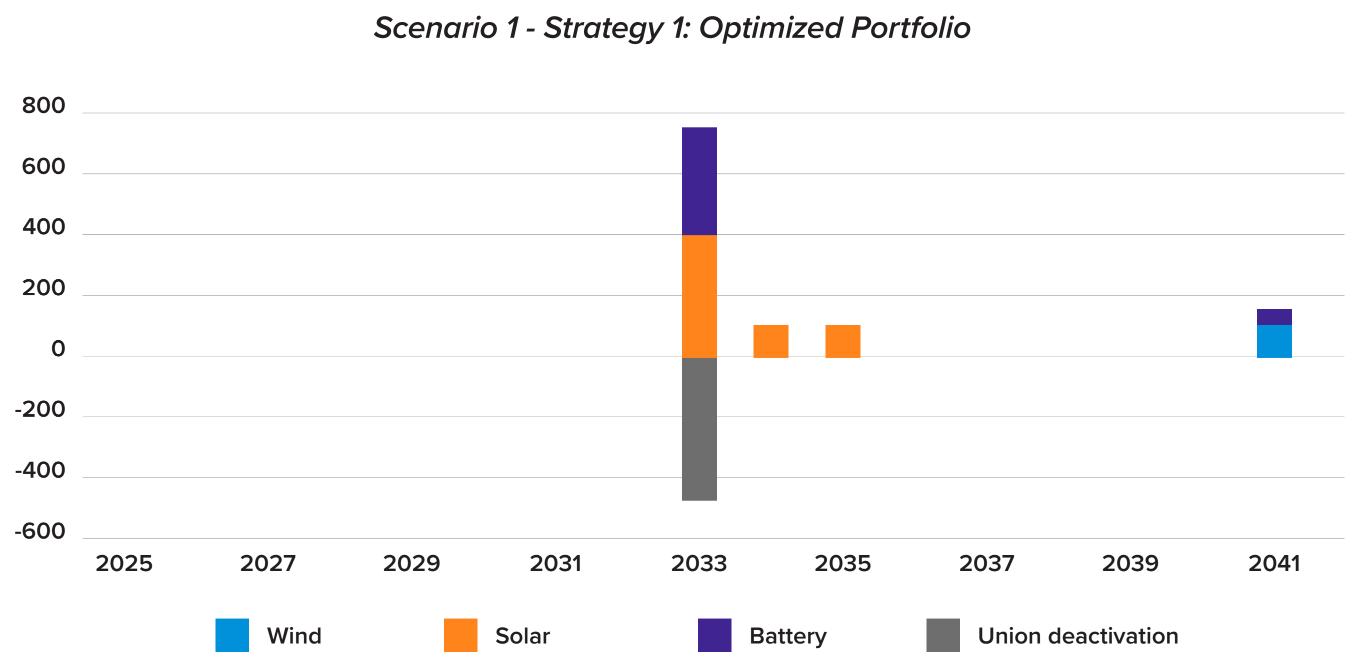


Figure 42: Scenario 1/Strategy 1: Optimized Portfolio

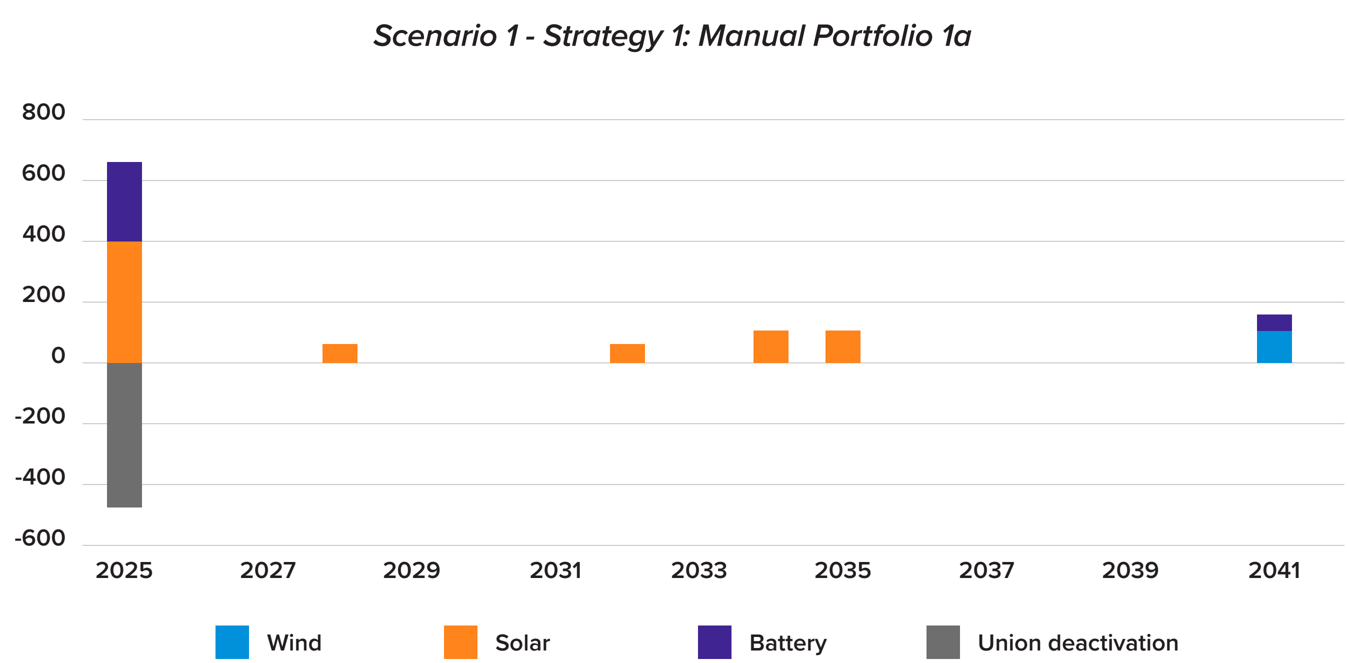


Figure 43: Scenario 1/Strategy: 1 Manual Portfolio

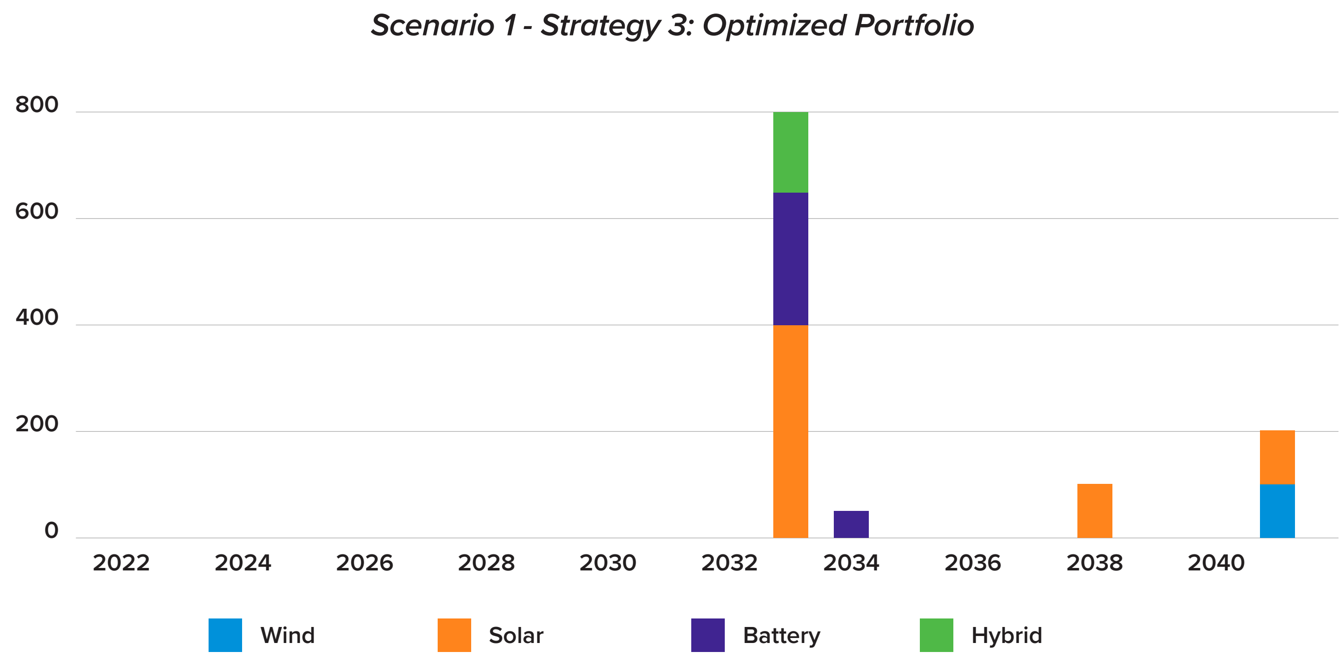


Figure 44: Scenario 1/Strategy 3: Optimized Portfolio

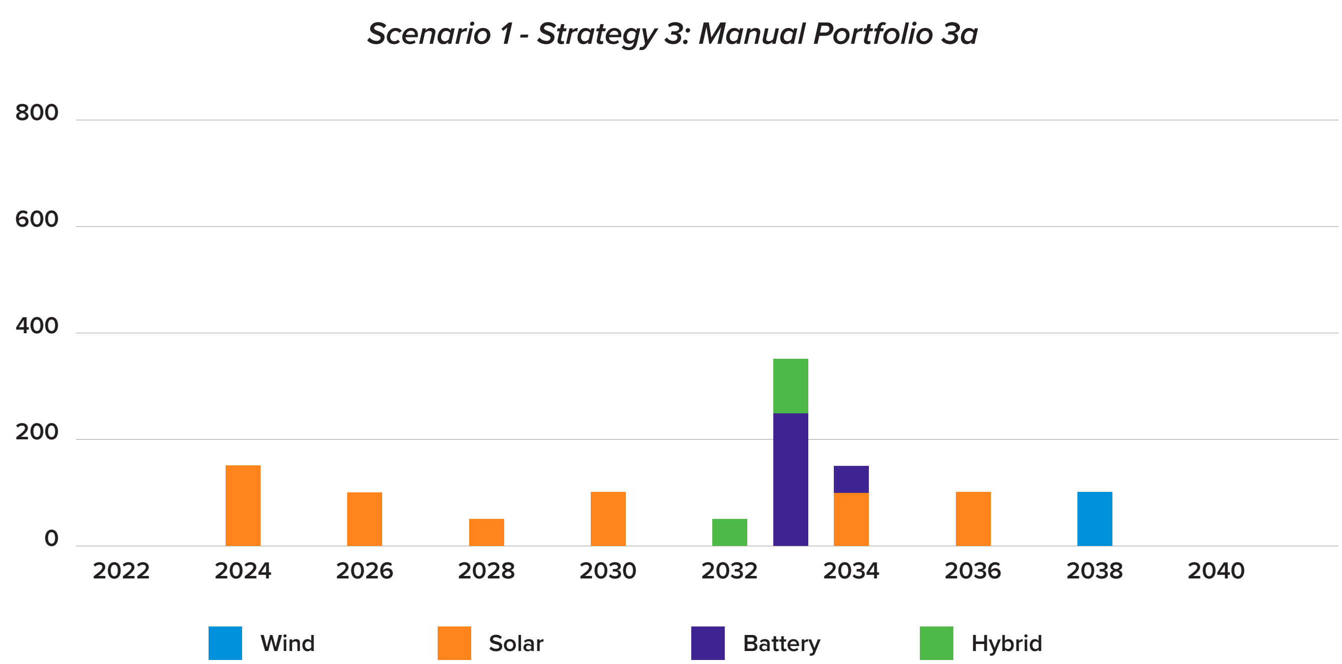


Figure 45: Scenario 1/Strategy 3: Manual Portfolio

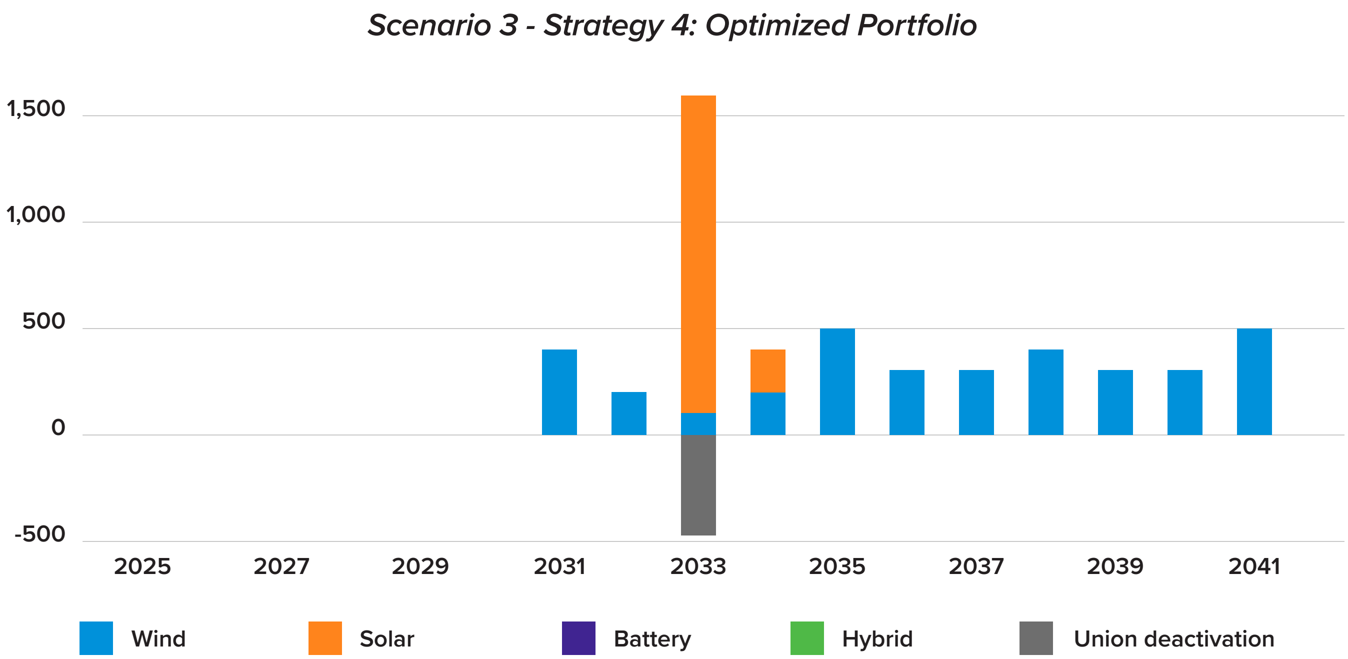


Figure 46: Scenario 3/Strategy 4 Optimized Portfolio

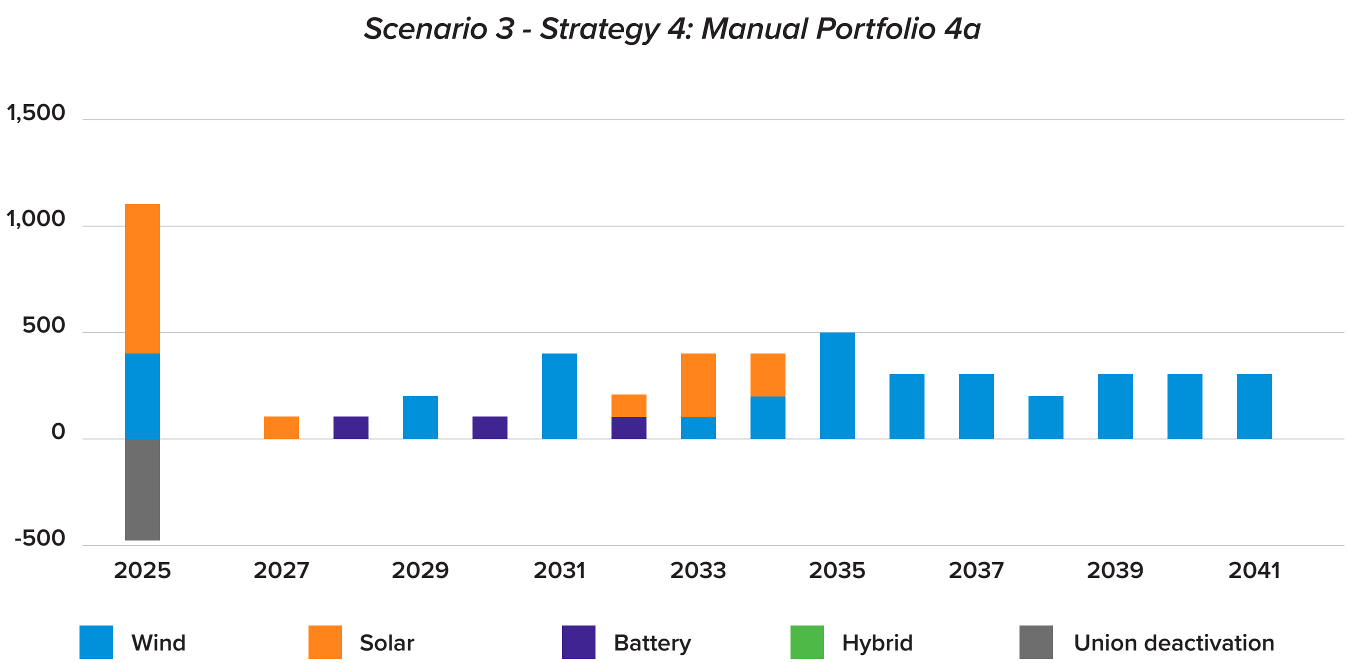


Figure 47: Scenario 3/Strategy 4 Manual Portfolio

DSM Modeling – For Strategy 1, the EE Potential Programs from the Guidehouse low case were evaluated as resource alternatives in the Aurora capacity expansion optimization in order to identify the programs that indicated the potential for positive net benefits to be included in ENO's portfolio. Secondarily, any programs that were not economically selected were sent back to Guidehouse for redevelopment in the first year of capacity need. These programs were evaluated a second time along with supply-side resource alternatives to identify the most economic resource additions to meet ENO's capacity need. The DR Potential Programs indicated a positive net benefit based on fixed costs and as a result, were included in the Portfolios. For Strategies 2 and 3, each of the EE and DR programs of the Guidehouse 2% Program case was forced in to the resource portfolio.

Potential DSM programs were developed and evaluated by Guidehouse based on the characteristics and attributes described in Chapter 3. Each EE program was modeled in Aurora based on annual program costs, hourly demand reduction profiles, program start date, and assumed program life and evaluated to identify the EE programs that are economic (i.e., have a positive net benefit). For Strategies 1, 2, and 3, the following Guidehouse Reference EE potential programs were modeled to begin in 2022:

EE Programs

1. Residential – HPwES
2. Residential – Retail
3. Residential – LI_MF
4. Residential – HVAC
5. Residential – School Kit
6. Residential – Res Behavior
7. Residential – Recycling
8. Commercial & Industrial – Small C&I
9. Commercial & Industrial – Large C&I
10. Commercial & Industrial – COM Behavior

The following Guidehouse Reference DR potential programs indicated a positive net benefit based on fixed costs and as a result, were included in the Portfolios:

DR Programs

1. Dynamic Pricing with enabling tech.
2. DLC-Thermostat-HVAC
3. C&I Curtailment- Auto-DR HVAC Control
4. Dynamic Pricing w/o enabling tech.
5. DLC-Thermostat-Res
6. C&I Curtailment- Standard Lighting Control
7. DLC-Switch-Central Air Conditioning
8. C&I Curtailment- Industrial
9. C&I Curtailment- Other
10. C&I Curtailment- Water Heating Control
11. C&I Curtailment- Advanced Lighting Control
12. C&I Curtailment- Refrigeration Control

For Strategy 4, the DSM programs used were provided by GDS and all programs provided were forced into the Strategy 4 portfolios. The following GDS high case EE potential programs were included in the Strategy 4 portfolios to begin in 2022:

EE Programs

1. EE - C&I (MW)
2. Home Performance
3. Residential Lighting & Appliance
4. Low Income
5. Multifamily
6. High Efficiency Tune Ups
7. Scorecard
8. No Program[33]

The following GDS high case DR potential programs were included in the Strategy 4 portfolios to begin in 2022:

DR Programs

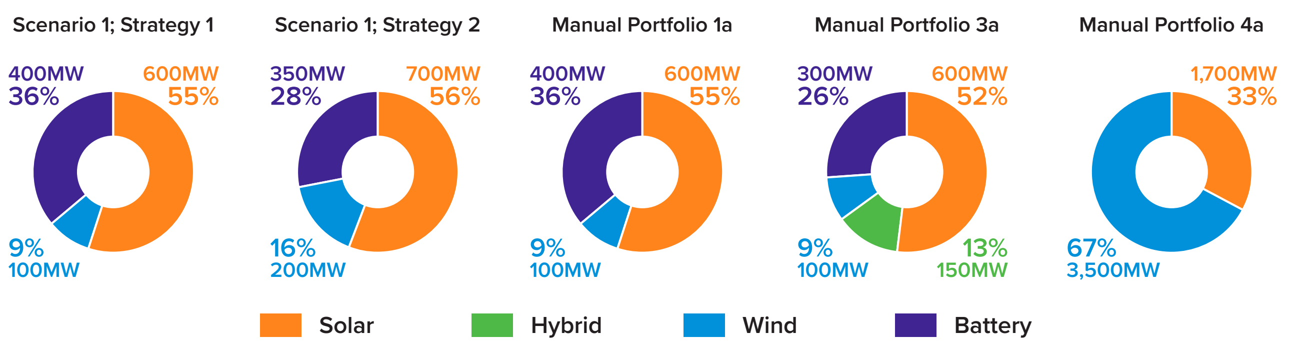
1. Residential – Peak Time Rebate
2. Residential – Direct Load Control – Smart Thermostat
3. Residential – Direct Load Control – Pool Pump
4. Residential – Critical Peak Pricing
5. Residential – PEV Charging
6. Non- Residential – Smart Thermostat
7. Non- Residential – Interruptible/Curtailable
8. Non- Residential – Capacity Bidding
9. Non- Residential – Demand Bidding
10. Non- Residential – Critical Peak Pricing

For the DSM programs that were not forced into the portfolios, Aurora considers the cost and revenue of energy and capacity in the context of the MISO market for each DSM alternative. Due to the nature of the forecasted DSM programs that gain adoption by customers over time, each program was designed to start in 2022 and continue through the end of the technical life of the technology, if applicable, or through the end of planning horizon. Because ENO is not projected to have a need for incremental capacity in 2022, the initial selection of the DSM programs in the model was based strictly on economics, and not capacity position. The capacity credit of selected DSM programs is counted toward meeting ENO's capacity needs through reduction of peak load.

In Strategy 1, the School Kit program was the only program that was not selected by Aurora initially, based solely on potential economic benefits and subsequently, based on lowest net cost to meet capacity needs.

33. The "No Program" EE measures were smaller miscellaneous measures that were included in the study because they do have EE potential but are not mapped to, or part of, an existing program. "No Program" measures could be candidates for being added to programs.

4.4. Total Relevant Supply Cost Results



Resource	Year	Cap (MW)
Solar	2033	400
Battery	2033	350
Solar	2033	100
Solar	2035	100
Wind	2041	100
Battery	2041	50

Resource	Year	Cap (MW)
Solar	2033	500
Battery	2033	300
Solar	2034	100
Battery	2035	50
Wind	2038	200
Solar	2041	100

Resource	Year	Cap (MW)
Solar	2025	400
Battery	2025	250
Battery	2028	50
Battery	2032	50
Solar	2034	100
Solar	2035	100
Wind	2041	100
Battery	2041	50

Resource	Year	Cap (MW)
Solar	2024	150
Solar	2026	100
Solar	2028	50
Solar	2030	100
Hybrid	2032	75
Battery	2033	250
Hybrid	2033	75
Battery	2034	50
Solar	2034	100
Solar	2036	100
Wind	2038	100

Resource	Year	Cap (MW)
Solar	2025	700
Wind	2025	400
Solar	2027	100
Solar	2028	100
Wind	2029	200
Solar	2030	100
Wind	2031	400
Solar	2032	200
Wind	2033	100
Solar	2033	300
Wind	2034	200
Solar	2034	200
WInd	2035	500
WInd	2036	300
WInd	2037	300
WInd	2038	200
WInd	2039	300
WInd	2040	300
WInd	2041	300

Figure 48: Five Portfolios Selected for Total Relevant Supply Cost Analysis

Through discussions at, and following, Technical Meeting #4, ENO, the Intervenors, and the Advisors agreed upon a representative subset of five of the fifteen Optimized and Manual Portfolios to be evaluated through a Total Relevant Supply Cost Analysis. The Total Relevant Supply Cost ("TRSC") for each of the five selected Portfolios shown in Figure 48 above was calculated in each of the three planning Scenarios. The TRSC is calculated using:

- **Variable Supply Cost** - The variable supply cost projections from the AURORA model for each Portfolio in each of the scenarios, which includes fuel costs, variable O&M, CO_2 emission costs, startup costs, energy revenue, load payments, and uplift revenue.
- **Levelized Real Non-Fuel Fixed Costs** - Return of and on capital investment, fixed O&M, and property tax for the incremental resource additions in each Portfolio.
- **Demand Side Management (DSM) Costs**
- **Capacity Purchases/(Sales)** - The capacity surplus (or deficit) in each Portfolio multiplied by the assumed capacity price.
- **Avoided Costs of Union 1 deactivating early** - The avoided costs of the return of and on future capital investment, fixed O&M and property taxes attributable to Union 1 deactivating in 2025 rather than 2033.

Figure 49 shows the present value of the total relevant supply cost for each Portfolio by Scenario. The shading indicates the Scenario under which the portfolio was originally optimized.

Strategy 1 : Scenario 1 (Least Cost Planning)	**Scenario 1 ($MM)**	**Scenario 2 ($MM)**	**Scenario 3 ($MM)**
Net Variable Supply Cost (Benefit)	$1,125	$813	$1,596
Resource Additions Levelized Fixed Costs [6/1 COD]	$324	$324	$324
DSM Levelized Fixed Cost	$202	$202	$202
Capacity Purchases (Benefit)	($125)	($125)	($125)
Avoided Levelized Union Costs (Benefit)	$0	$0	$0
Total Relevant Supply Cost	**$1,526**	**$1,214**	**$1,997**

Strategy 2 : Scenario 1 (But for RCPS)	**Scenario 1 ($MM)**	**Scenario 2 ($MM)**	**Scenario 3 ($MM)**
Net Variable Supply Cost (Benefit)	$1,077	$772	$1,540
Resource Additions Levelized Fixed Costs [6/1 COD]	$370	$370	$370
DSM Levelized Fixed Cost	$250	$250	$250
Capacity Purchases (Benefit)	($138)	($138)	($138)
Avoided Levelized Union Costs (Benefit)	$0	$0	$0
Total Relevant Supply Cost	**$1,560**	**$1,254**	**$2,023**

Manual Portfolio 1a	**Scenario 1 ($MM)**	**Scenario 2 ($MM)**	**Scenario 3 ($MM)**
Net Variable Supply Cost (Benefit)	$980	$701	$1,378
Resource Additions Levelized Fixed Costs [6/1 COD]	$690	$690	$690
DSM Levelized Fixed Cost	$202	$202	$202
Capacity Purchases (Benefit)	($115)	($115)	($115)
Avoided Levelized Union Costs (Benefit)	($106)	($106)	($106)
Total Relevant Supply Cost	**$1,650**	**$1,372**	**$2,049**

Manual Portfolio 3a	Scenario 1 ($MM)	Scenario 2 ($MM)	Scenario 3 ($MM)
Net Variable Supply Cost (Benefit)	$1,226	$906	$1,691
Resource Additions Levelized Fixed Costs [6/1 COD]	$530	$530	$530
DSM Levelized Fixed Cost	$250	$250	$250
Capacity Purchases (Benefit)	($205)	($205)	($205)
Avoided Levelized Union Costs (Benefit)	$0	$0	$0
Total Relevant Supply Cost	**$1,802**	**$1,481**	**$2,266**

Manual Portfolio 4a	Scenario 1 ($MM)	Scenario 2 ($MM)	Scenario 3 ($MM)
Net Variable Supply Cost (Benefit)	($910)	($888)	($385)
Resource Additions Levelized Fixed Costs [6/1 COD]	$2,165	$2,165	$2,165
DSM Levelized Fixed Cost	$598	$598	$598
Capacity Purchases (Benefit)	($101)	($101)	($101)
Avoided Levelized Union Costs (Benefit)	($106)	($106)	($106)
Total Relevant Supply Cost	**$1,645**	**$1,667**	**$2,170**

Figure 49: Total Relevant Supply Cost Results (2022$ NPV) by Portfolio

The spread in TRSC results from the lowest (Strategy 1/Scenario 1 with the Guidehouse low achievable case) to the highest (Manual Portfolio 4a with the GDS high case) is about 29% on average across the Scenarios. However, the comparative value of the analyses comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a guide for the future, not from focusing on the costs of one Portfolio versus another, particularly given that actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current, actual market costs.

The TRSC analysis presents an interesting range of results for the Council to consider. The various portfolios analyzed in the 2021 IRP indicate that once a capacity need arises for ENO, it can likely be met by a combination of renewable and storage resources rather than additional fossil generation. The timing of capacity needs, as well as the amounts and types of resources best suited to fill the needs, varied based on the Scenario and Strategy constraints imposed. This finding is important given the climate goals articulated in the RCPS, the Council's policy goal articulated in Resolution R-22-11 of pursuing 100% renewable energy for City of New Orleans and SWB operations by 2025, and Entergy's own corporate sustainability goals.

The analysis also indicates that it is more beneficial for customers for ENO to operate Union 1 until 2033 instead of deactivating it early in 2025. Both manual portfolios that assumed a 2025 deactivation date (Manual Portfolios 1a and 4a) resulted in higher TRSCs across each of the Scenarios than the optimized portfolios that used the current 2033 assumption (Optimized Portfolios for Scenario 1/Strategy 1 and Scenario 1/Strategy 2).

Another point to consider is the TRSCs for Manual Portfolio 3a are higher across each Scenario relative to the TRSCs for the other three portfolios that use Guidehouse DSM programs. The goal in creating Manual Portfolio 3a was to evaluate the viability of achieving near-term RCPS compliance by keeping Union 1's deactivation at 2033 while accelerating the addition of renewable resources as an alternative to relying on the purchase of unbundled RECs. This result suggests that, while there could be benefits to accelerating renewable resources under some circumstances, completely excluding the use of RECs from near-term RCPS compliance could result in added costs for customers depending on the cost of unbundled RECs.

The Stakeholder Manual Portfolio 4a, developed with GDS DSM programs, included the lower renewables cost assumptions provided by the Intervenors instead of the Entergy Technology Assessment cost assumptions used in the other four downselected portfolios. These costs, coupled with the fact that the Aurora capacity expansion was limited to selecting solar and wind because battery cost and performance assumptions were not provided, result in a markedly different portfolio for Council consideration from the others, one that focuses on large-scale renewables buildout as a potential alternative following an early deactivation of Union 1. These results highlight the need for dispatchable resources, such as Union 1 and battery storage, to facilitate the inclusion of intermittent renewable resources into a cost effective portfolio to serve the time-varying customer needs. While the analysis in this IRP indicates it would not benefit customers to deactivate Union 1 in 2025, Manual Portfolio 4a suggests that any future replacement of the Union capacity should consider diverse combinations of resources based on customer needs.

As mentioned in the Planning Strategies Section 4.1.2., a sensitivity was performed on Manual Portfolio 4a to assess the impact of even lower renewables costs derived from NREL ATB assumptions. As expected, holding all other variables constant, the sensitivity case resulted in lower total relevant supply costs compared to MP4a with the only difference being the levelized fixed cost of resource additions. The sensitivity decreased the cost of Manual Portfolio 4a from $2,170 MM to $1,847 MM and was the lowest cost portfolio in Scenario 3.

Scenario 3 - High	**Manual Portfolio 4a**	**Manual Portfolio 4b Sensitivity**
Net Variable Supply Cost (Benefit)	($385)	($385)
Resource Additions Levelized Fixed Costs [6/1 COD]	$2,165	$1,841
DSM Levelized Fixed Cost	$598	$598
Capacity Purchases (Benefit)	($101)	($101)
Avoided Levelized Union Costs (Benefit)	($106)	($106)
Total Relevant Supply Cost	**$2,170**	**$1,847**

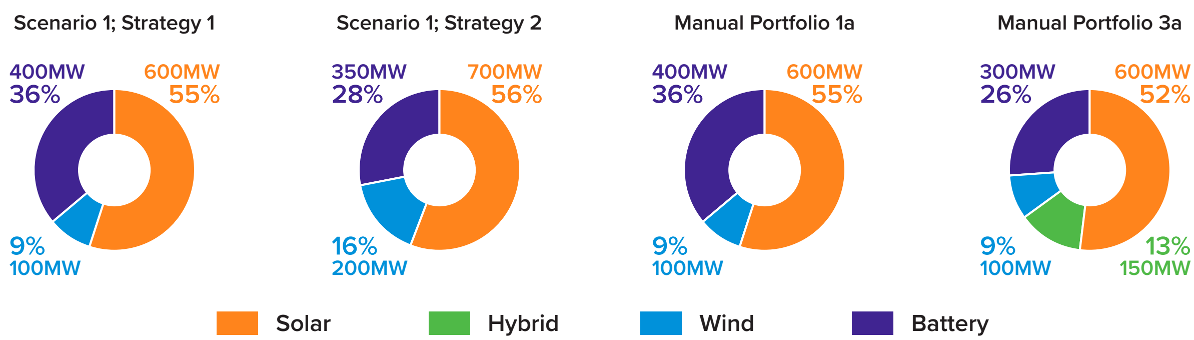
Four of the downselected portfolios incorporated Guidehouse Low and 2% program DSM cases while the fifth used the GDS High case. As discussed in Section 3.5, these three cases from the two different studies estimate a range of increasing DSM potential savings, albeit at notably different costs. These findings from the two DSM studies suggest there is still a significant level of achievable DSM and DR potential in the city, and that the Energy Smart Implementation Plan for Program Years 13-15 should draw on concepts from both in presenting options for the Council's consideration.

The total relevant supply cost calculated for the optimized portfolio produced for Scenario 1/Strategy 2 (designated as the "But For RCPS" portfolio) under Scenario 1 (the Scenario under which the portfolio was originally developed) will be used as the baseline for calculating incremental costs associated with its three-year RCPS compliance plan for 2023-2025 in accordance with Section 4.d.1 of the RCPS rules.

Because the IRP rules do not require the identification of a preferred portfolio, the comparative value of this IRP report comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a guide for the future, not from focusing on the costs of one Portfolio versus another. Actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current market costs.

4.5. Stochastic Assessment of Risks

The stochastic risk assessment gives an indication of the variability of a Portfolio's costs as underlying assumptions change (e.g., gas, CO_2). Given schedule and resource constraints, the parties agreed following Technical Meeting #4 to run the stochastic assessment for the following four optimized Portfolios.



Resource	Year	Cap (MW)
Solar	2033	400
Battery	2033	350
Solar	2033	100
Solar	2035	100
Wind	2041	100
Battery	2041	50

Resource	Year	Cap (MW)
Solar	2033	500
Battery	2033	300
Solar	2034	100
Battery	2035	50
Wind	2038	200
Solar	2041	100

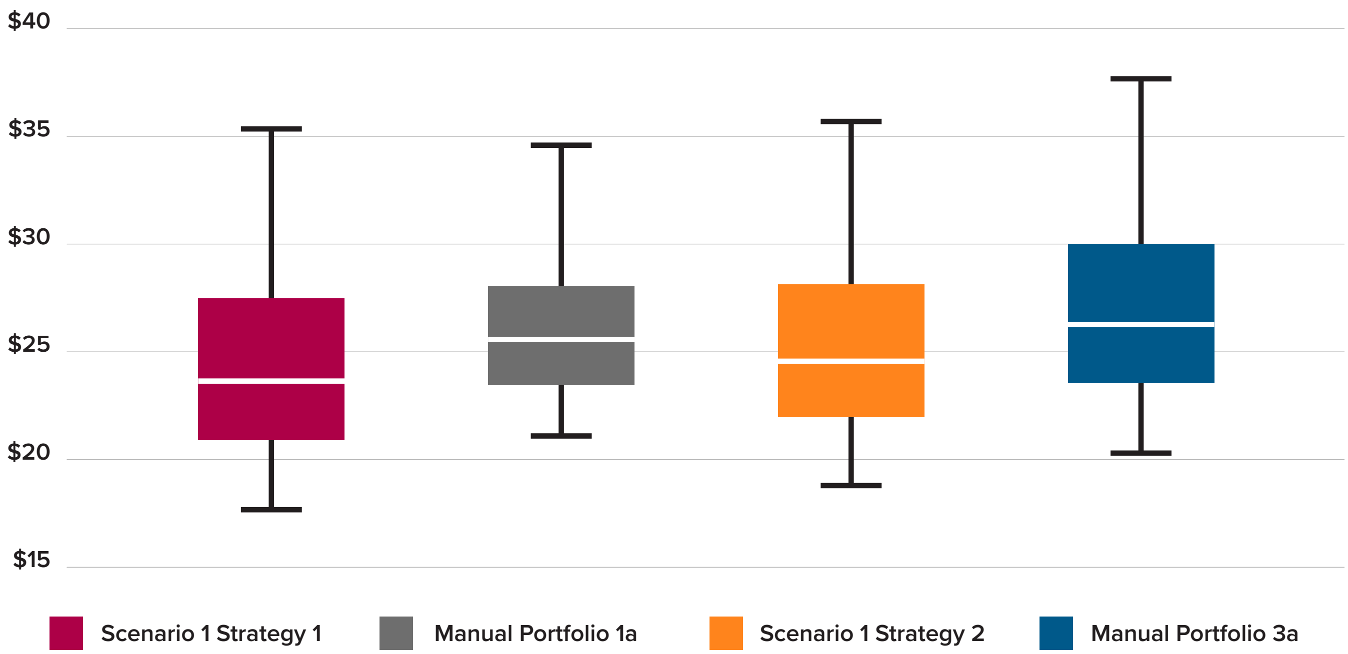
Resource	Year	Cap (MW)
Solar	2025	400
Battery	2025	250
Battery	2028	50
Battery	2032	50
Solar	2034	100
Solar	2035	100
Wind	2041	100
Battery	2041	50

Resource	Year	Cap (MW)
Solar	2024	150
Solar	2026	100
Solar	2028	50
Solar	2030	100
Hybrid	2032	75
Battery	2033	250
Hybrid	2033	75
Battery	2034	50
Solar	2034	100
Solar	2036	100
Wind	2038	100

Figure 50: Four Portfolios Selected for Stochastic Analysis

The sensitivity of a Portfolio's performance was assessed relative to changes in assumptions for natural gas prices or CO_2 emission prices through stochastic analysis. Distributions of potential prices for each variable were developed that were lower-bounded by zero and positively skewed toward higher prices, which is consistent with the expectation that commodity prices would not be less than zero and would have some potential for high price spikes. In total, 400 production cost simulations were performed for each of the four Portfolios using the same set of 200 gas price outcomes and 200 CO_2 price outcomes. A resulting total relevant supply cost expressed in $/MWh was determined for each price variant, as described by the following box plot charts.

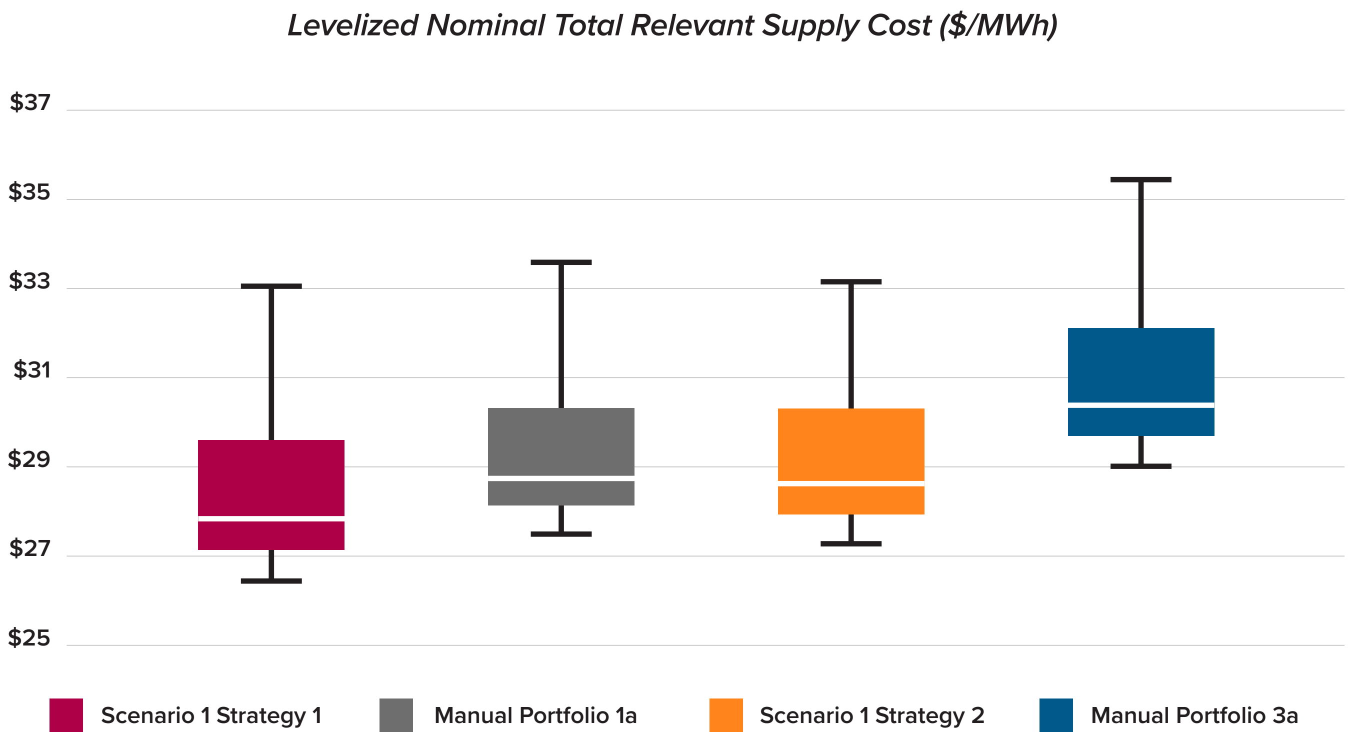
Levelized Nominal Total Relevant Supply Cost ($/MWh)



Percentile	Levelized Real Gas Price (2022 $/mmBtu)
1	$0.75
5	$0.92
10	$1.17
20	$1.46
30	$1.68
40	$2.07
50	$2.61
60	$2.95
70	$3.68
80	$4.49
90	$6.17
95	$8.14
99	$18.43

Figure 51: Natural Gas Price Stochastic Results

The lowest and highest value excluding outliers, 1st quartile, median, and 3rd quartile are denoted by the horizontal markers for each Portfolio. The natural gas price variation is described by the distribution shown in the table below. The variance of total relevant supply cost for each Portfolio indicates the sensitivity of that Portfolio to natural gas prices.



Percentile	Levelized Real CO_2 Price $2022
1	$0.65
5	$0.96
10	$1.49
20	$2.22
30	$3.31
40	$4.32
50	$5.56
60	$8.35
70	$11.95
80	$17.54
90	$25.28
95	$33.96
99	$64.04

Figure 52: CO_2 Price Stochastic Results

The lowest and highest value excluding outliers, 1st quartile, median, and 3rd quartile are denoted by the horizontal markers for each Portfolio. The CO_2 price variation is described by the distribution shown in the table below the chart. The variance of total relevant supply cost for each Portfolio indicates the sensitivity of that Portfolio to CO_2 prices. Due to the makeup of the Portfolios, market assumptions, and the assumed trajectory of carbon prices, the Portfolios are more sensitive to natural gas price variance (which can occur throughout the planning period) than CO_2 price variance.

4.6. Scorecard Metrics and Results

As required by the IRP Rules, ENO, with the help of the Advisors and Intervenors, developed for the 2018 IRP a scorecard to assist the Council in assessing the downselected Resource Portfolios. For the 2021 IRP, the parties updated the 2018 scorecard metrics in two areas based on discussions at Technical Meetings #3 and #4. First, the metrics in the "Consistency with City Policies/Goals" section were updated to refer to the RCPS rules that were adopted in 2021. Second, the "Reliability" section was updated to include a new "Relative Loss of Load Expectation" metric. The scorecard metrics agreed upon by the parties for the 2021 IRP are shown below.

Table 15: Scorecard Metrics

Metric	Description	Measure
Expected Value	The average total relevant supply cost of Portfolios across Scenarios and relative to other optimized Portfolios (all Scenarios are weighted equally)	1-10 Grading Scale
Net Present Value	The Total Relevant Supply Cost of the Portfolio in the Scenario it was optimized in	1-10 Grading Scale
Nominal Portfolio Value	A sum of the initial 5 years of the planning period	1-10 Grading Scale
Distribution of Potential Utility Costs	The standard deviation of total relevant supply cost across Scenarios divided by the expected value to get to a coefficient of variation	1-10 Grading Scale
Range of Potential Utility Costs	The sum of the total relevant supply cost upside and downside risk of Portfolios	1-10 Grading Scale
Probability of High CO_2 Intensity	Probability of high CO_2 intensity in the initial 5 years of the planning period	1-100% Grading Scale
Probability of High Ground Usage	Probability of high groundwater usage in the initial 5 years of the planning period	1-100% Grading Scale
Relative Loss of Load Expectation	The relative amount of perfect capacity added or subtracted to obtain the 0.1 Loss of Load Expectation target in the final year of the planning period	1-10 Grading Scale
Flexible Resources	The total MW of ramp available in the final year of the planning period	1-10 Grading Scale
Quick-Start Resources	The total MW of quick start available in the final year of the planning period	1-10 Grading Scale
CO_2 Intensity	The cumulative tons of CO_2/GWh over the planning period	1-10 Grading Scale
Groundwater Usage	The cumulative percentage of energy generated by resources that use ground water	1-100% Grading Scale
Renewable and Clean Portfolio Standard (RCPS) – Compliance with Schedule in 3.a.	The average annual percent of a portfolios clean energy targeted to align with Schedule 3.A. of the RCPS.	0-(-15)% Grading Scale
Macroeconomic Factors	DSM spending represents only quantifiable macroeconomic impact at this time. Future ability to evaluate/model DERs could provide additional basis for comparison.	N/A

Based on the metrics discussed above, the downselected Portfolios were assigned a grade determined by how the given Portfolio performed in relation to the others. Due to differing Scenario and Strategy characteristics, a review of the grades requires consideration of the inherent compositional differences among the Portfolios. As contemplated by the IRP rules, these grades are intended to assist the Council in assessing the results of the overall IRP analysis, not stand on their own as any kind of definitive statement about the modeled portfolios. The results of the scorecard are outlined in Table 16 and key takeaways are described below.

Utility Cost measured the relative economics of each portfolio in both the Scenario for which it was created as well as the other Scenarios. Optimized Portfolios 1 and 2 had a lower cost than the other portfolios and resulted in the highest grade. Manual Portfolio 1a's cost was slightly higher relative to Optimized Portfolio 1 due to the amount of cost associated with accelerating the addition of resources needed to satisfy the capacity deficit created by the early deactivation of Union. Manual Portfolios 3a and 4a resulted in the highest cost and were given the lower grades for the Utility Cost metrics. For additional analysis regarding cost, please refer to the Total Relevant Supply Cost section as detailed above in the report.

Risk/Uncertainty assessed the distribution, range, and probabilities associated with each portfolio's costs, CO_2 intensity, and groundwater use across each Scenario. Manual Portfolios 3a and 4a were given the highest grades because of lower distribution and tighter range of costs across all scenarios. Because none of the portfolios present a risk of high CO_2 emissions or high groundwater usage within the first five years of the study period, they all received the same grade for these metrics.

Reliability introduced a new metric for the 2021 IRP cycle in the form of a Relative Loss of Load Expectation analysis as requested by the Advisors and some Intervenors. The study concluded that Optimized Portfolios 1 and 2 as well as Manual Portfolios 1a had higher relative reliability compared to the other portfolios and were given the highest grade. Except for Portfolio 4a, which had no added dispatchable resources, each of the other portfolios included similar amounts of dispatchable resources and were assigned high grades.

Environmental Impact highlights a difference in grades among portfolios that modify the assumed deactivation date of Union from 2033 to 2025. Portfolios that accelerated the deactivation date received higher grades relative to the portfolios that held Union's deactivation date constant in 2033.

RCPS Compliance. There is a direct correlation of the grades from the Environmental Impact section to the RCPS Compliance metric. Two of the three highest graded portfolios accelerated the deactivation of Union to 2025 and the other was designed with RCPS rules as a constraint. It is important to note that a Portfolio within 5% of meeting the requirements of Schedule 3.a. in the RCPS rule was assigned a grade of B. Additionally, a grade of A was only assigned to Portfolio 4a that exceeded the RCPS requirement.

Table 16: Scorecard Results

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Scoring Parameters / Descriptions[1]	Scenario 1: Strategy 1	Scenario 1: Strategy 2	Manual Portfolio 1a	Manual Portfolio 3a	Manual Portfolio 4a
Utility Cost (Portfolio optimization in Aurora model)					
Expected value (average cost across Scenarios & relative to other optimized portfolios)	A	A	B	D	D
Utility Costs Impact on ENO's Revenue Requirements					
Net present value of revenue requirements	A	A	A	B	D
Nominal Portfolio Value (residential/ other customer classes) - initial 5 years of planning period	A	A	A	B	D
Risk/Uncertainty					
Distribution of potential utility costs	D	D	B	C	A
Range of potential utility costs	D	D	C	D	A
Probability of high CO_2 intensity - initial 5 years of planning period	A	A	A	A	A
Probability of high groundwater usage - initial 5 years of planning period	A	A	A	A	A
Reliability					
Relative Loss of Load Expectation	A	A	A	B	D
Flexible resources (MW of ramp)	A	A	A	A	D
Quick-Start resources (MW of Quick-Start)[2]	A	A	A	A	D
Environmental Impact					
CO_2 intensity (tons CO_2/GWh)	D	D	B	D	A
Groudwater usage (% of energy generated using Groundwater)	B	B	A	B	A
Consistency with City Policies/ Goals					
Renewable and Clean Portfolio Standard (RCPS) -- Compliance with Schedule in 3.A. of the RCPS	C	C	B	B	A
Macroeconomic Impact to CNO					
Macroeconomic Factor (Jobs, local economy impacts)[3]	N/A	N/A	N/A	N/A	N/A

Notes on this Scorecard:

1. Except as otherwise noted, A is the top quartile of portfolios, B is the second quartile, C is the third quartile and D is the bottom quartile.
2. Quick-Start includes supply and demand side dispatchable resources
3. DSM spending represents only quantifiable macroeconomic impact at this time. Future ability to evaluate/model DERs could provide additional basis for comparison.

Chapter 5

Action Plan

2021 IRP Action Plan

The following table describes various actions ENO intends to pursue following the submission of this 2021 Integrated Resource Plan.

Description	Action to be taken
90 MW Portfolio Completion	The projects underlying the Iris and St. James PPAs approved in Docket UD-18-06 have been delayed and sustained damage in Hurricane Ida. ENO continues to monitor counterparty efforts to achieve commercial operation for both projects by the updated estimated dates of August 2022 (Iris) and October 2022 (St. James). Upon commencement of the two PPAs, ENO will have fulfilled approximately 95 MW of the 100 MW renewables commitment it previously made to the Council. ENO will seek to identify a suitable small project to help it meet or exceed the 100 MW threshold. Possible options could include an expansion of the commercial rooftop solar or ReNEWable Orleans residential rooftop programs, possibly with battery storage components.
City Clean Power Plan (100% Renewables Options for City and SWB)	ENO plans to engage with the Council and City stakeholders to discuss possible offerings for a City Clean Power Plan responsive to Resolution R-22-11 that directed the City and SWB to serve their operations with 100% renewable energy by 2025.
RCPS Compliance Plan	ENO will develop and file its first three year RCPS compliance plan for 2023-25 within 90 days after submission of the IRP Report as required under the RCPS rules.
Electric Vehicle Charging Infrastructure Plans	ENO will continue to work towards completion of the 25 site Public Charging pilot approved through the 2018 Rate Case. ENO will also continue to work with the Advisors and stakeholders regarding the filing made in January 2022 seeking modifications to Rider EVCI and other regulatory policies necessary to support more robust adoption of electric vehicles in New Orleans. Additionally, ENO will seek to develop proposals to the Council that would expand public access to Direct Current Fast Chargers (DCFC) and Level 2 chargers throughout the city and foster greater adoption of EVs in the city.
Bring Your Own Battery (BYOB) Demand Response Pilot	ENO will pursue approval of the application for a BYOB DR pilot program filed in March 2022. If approved, ENO will work with Honeywell, the program implementer, to execute the program during Energy Smart PY12 and develop experience to possibly inform a similar program during PY 13-15.
DSM/DR Implementation	File Implementation Plan for Energy Smart Program Years 13-15 as required under Resolution R-20-257 and the subsequent Order amending the procedural schedule in the IRP docket.
Expansion of Green Power Option for Large Customers	In response to interest expressed by several large electric customers in New Orleans, ENO will evaluate a possible expansion of the current Green Power Option program to accommodate larger usage offsets.
Customer Backup Generation Solutions	In response to growing customer interest in backup generation following Hurricane Ida, ENO will consider solutions that could be offered to residential and commercial customers. Solutions could include make ready infrastructure and other equipment that would facilitate the safe and quick installation of temporary backup generation in response to storm events, or permanently installed backup generation for customers requiring continuous power to support their operations.
System Resiliency and Storm Hardening Plan	File plan detailing investments and projects to support system resiliency and storm hardening as required by Resolution R-21-401.

List of Appendices

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX A

2021 IRP RULES COMPLIANCE MATRIX

MARCH 2022

Requirement No.	Section No.	Page No.	Key phrase or Issue	Excerpt	Response and/or Citation to IRP Report
1	1.C.	1	Rules Matrix	Each Utility IRP shall include a matrix of these rules, the corresponding section of the IRP responsive to that rule, and a brief description of how the Utility complied with the rules.	Appendix A
2	3.A.	4	Specific Objectives	The Utility shall state and support specific objectives to be accomplished in the IRP planning process, which include but are not limited to the following:	
3	3.A.1.	4	Integration of Supply Side and Demand Side Resources	optimize the integration of supply-side resources and demand-side resources, while taking into account transmission and distribution, to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost given an acceptable level of risk;	Pg 7: Planning Objectives; Pg 17: Transmission; Pg 19: Distribution; Chapter 4: Modeling Framework
4	3.A.2.	4	Maintain Financial Integrity	maintain the Utility's financial integrity;	Pg 7: Planning Objectives
5	3.A.3.	4	Mitigate Risks	anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors;	Pg 75: Stochastic Assessment of Risks
6	3.A.4.	4	Support Resiliency and Sustainability	support the resiliency and sustainability of the Utility's systems in New Orleans;	Pg 17: Transmission; Pg 19: Distribution; Pg 78: Scorecard Metrics and Results
7	3.A.5.	4	Comply with Requirements and Council Policies	comply with local, state and federal regulatory requirements and regulatory requirements and known policies (including such policies identified in the Initiating Resolution) established by the Council;	Pg 57: Planning Strategy Overview; Pg 78: Scorecard Metrics and Results
8	3.A.6.	4	Evaluate Incorporation of new technology	evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and DERs, among others;	Pg 38: Generation Technology Assessment
9	3.A.7.	4	Acceptable Risk	achieve a range of acceptable risk in the trade-off between cost and risk;	Pg 75: Stochastic Assessment of Risks
10	3.A.8.	4	Transparency and Engagement	maintain transparency and engagement with stakeholders throughout the IRP process by conducting technical conferences and providing for stakeholder feedback regarding the Planning Scenarios, Planning Strategies, input parameters, and assumptions.	Technical Meeting #1: 12/9/20; DSM Input Stakeholder Meeting: 3/26/21; Technical Meeting #2: 4/29/21; Technical Meeting #3: 8/12/21; Technical Meeting #4: 1/20/22;
11	3.B.	4	Efforts to Achieve Objectives	In the IRP Report, the Utility shall discuss its efforts to achieve the objectives identified in Section 3A and any additional specific objectives identified in the Initiating Resolution.	Pg 7: Planning Objectives; Chapter 4, Modeling Framework
12	4.A.	5	Reference Load Forecasts and alternatives	The Utility shall develop a reference case Load Forecast and at least two alternative Load Forecasts applicable to the Planning Period which are consistent with the Planning Scenarios identified in Section 7C. The following data shall be supplied in support of each Load Forecast:	Pg 24: Load Forecasting Methodology

13	4.A.1.	5	Forecast of Demand and Energy by Customer Class	The Utility's forecast of demand and energy usage by customer class for the Planning Period;	Pg 24: Load Forecasting Methodology; Appendix B
14	4.A.2.	5	Methodology	A detailed discussion of the forecasting methodology and a list of independent variables and their reference sources that were utilized in the development of the Load Forecast, including assumptions and econometrically evaluated estimates. The details of the Load Forecast should identify the energy and demand impacts of customer-owned DERs and then existing Utility-sponsored DSM programs;	Pg 24: Load Forecasting Methodology
15	4.A.3.	5	Independent Variables	Forecasts of the independent variables for the Planning Period, including their probability distributions and statistical significance;	Pg 24: Load Forecasting Methodology
16	4.A.4.	5	Expected Value of forecast	The expected value of the Load Forecast as well as the probability distributions (uncertainty ranges) around the expected value of the Load Forecast;	Pg 24: Load Forecasting Methodology; Appendix B
17	4.A.5.	5	Line Losses	A discussion of the extent to which line losses have been incorporated in the Load Forecast.	Pg 33: Load Forecasts for IRP Planning Scenarios
18	4.B.	5	Composite Customer Hourly Load Profiles	The Utility shall construct composite customer hourly load profiles based on the forecasted demand and energy usage by customer class and relevant load research data, including the factors which determine future load levels and shape.	Pg 24: Load Forecasting Methodology; Appendix B
19	4.C.	5	Demand and Energy data for 5 preceding years	Concurrent with the presentation of the Load Forecasts to the Advisors, CURO, and stakeholders, the Utility shall provide historical demand and energy data for the five (5) years immediately preceding the Planning Period. At a minimum, the following data shall be provided:	Appendix B
20	4.C.1.	5	Monthly energy consumption by class	monthly energy consumption for the Utility in total and for each customer class;	Appendix B
21	4.C.2.	5	Monthly CP for utility and classes	monthly coincident peak demand for the Utility and estimates of the monthly coincident peak demand for each customer class;	Appendix B
22	4.C.3.	5	Monthly peak demand by class	estimates of the monthly peak demand for each customer class;	Appendix B
23	4.D.	5	Section 4 data in attachment	The data and discussions developed pursuant to Section 4A and Section 4B, and Section 4C shall be provided as an attachment to the IRP report and summarized in the IRP report.	Pg 24: Load Forecasting Methodology; Appendix B
24	4.E.	6	Known cogen and >300kW DER resources	The Utility shall also provide a list of any known co-generation resources and DERs larger than 300 kW existing on the Utility's system, including resources maintained by the City of New Orleans for city/parish purposes, (e.g. Sewerage and Water Board, Orleans Levee District, or by independent agencies or entities such as universities, etc.).	New Orleans Solar Power Project; Sites constructed under Commercial Rooftop Project (UD-17-05)
25	5.A.	6	Identification of resource options	Identification of resource options. The Utility shall identify and evaluate all existing supply-side and demand-side resources and identify a variety of potential supply-side and demand-side resources which can be reasonably expected to meet the Utility's projected resource needs during the Planning Period.	Appendix D and E: Guidehouse and GDS Studies; Pg 38: Generation Resource Assessment
26	5.A.1.	6	Existing supply side resource costs	Existing supply-side resources. For existing supply-side resources, the Utility should incorporate all fixed and variable costs necessary to continue to utilize the resource as part of a Resource Portfolio. Costs shall include the costs of any anticipated renewal and replacement projects as well as the cost of regulatory mandated current and future emission controls.	Appendix C--Variable Supply Cost reflects the optimized run time of existing units

27	5.A.1.a.	6	Changes to resource mix	The Utility shall identify important changes to the Utility's resource mix that occurred since the last IRP including large capital projects, resource procurements, changes in fuel types, and actual or expected operational changes regardless of cause.	Pg 10: Figure 4 and Table 1
28	5.A.1.b.	6	Supply side resource info	Data supplied as part of the Utility's IRP filing should include a list of the Utility's existing supply-side resources including: the resource name, fuel type, capacity rating at time of summer and winter peak, and typical operating role (e.g. base, intermediate, peaking).	Pg 11: Table 2
29	5.A.2.	6	Load reductions from existing DSM resources	For existing demand-side resources, the Utility should account for load reductions attributable to the then-existing demand-side resources in each year of the Planning Period. Each existing demand-side resource will be identified as either a specific energy efficiency program or DR program with an individual program lifetime and estimated energy and demand reductions applicable to the Planning Period, or as a then-existing Utility owned or Utility-managed distributed generation resource with energy and demand impacts that are estimated for applicable years of the Planning Period. Data supplied as part of the Utility's IRP filing should include:	Pg 24: Load Forecasting Methodology; Pg 46: Demand-Side Management; Pg 81: Action Plan; Appendix H
30	5.A.2.a.	6	Projected reductions	Details of projected kWh/kW reductions from existing DSM programs based on quantifiable results and other credible support derived from Energy Smart New Orleans, or any successor program, using verified data available to the Utility from prior DSM program implementation years.	Pg 30: Demand Side Management
31	5.A.2.b.	6	Existing DSM resources	A list categorizing the Utility's existing demand-side resources including anticipated capacity at time of summer and winter peak.	Pg 30: Demand Side Management
32	5.A.3.	6	Potential SS resources	With respect to potential supply-side resources, the Utility shall consider: Utility-owned and purchased power resources; conventional and new generating technologies including technologies expected to become commercially viable during the Planning Period; technologies utilizing renewable fuels; energy storage technologies; cogeneration resources; and Distributed Energy Resources, among others.	Pg 38: Generation Resource Assessment
33	5.A.3.a.	7	Incorporate known policy goals	The Utility should incorporate any known Council policy goals (including such policy goals identified in the Initiating Resolution) with respect to resource acquisition, including, but not limited to, renewable resources, energy storage technologies, and DERs.	Pg 57: Planning Strategies; Pg 68: Action Plan
34	5.A.3.b.	7	Required data for resources	Data supplied as part of the Utility's IRP filing should include: a description of each potential supply-side resource including a technology description, operating characteristics, capital cost or demand charge, fixed operation and maintenance costs, variable charges, variable operation and maintenance costs, earliest date available to provide supply, expected life or contractual term of resource, and fuel type with reference to fuel forecast.	Pg 38: Generation Resource Assessment
35	5.A.4.	7	Potential DSM Resources	Potential demand-side resources. With respect to potential demand-side resources, the Utility should consider and identify all cost-effective demand-side resources through the development of a DSM potential study. All DSM measures with a Total Resource Cost Test value of 1.0 or greater shall be considered cost effective for DSM measure screening purposes.	Appendix D and E: Guidehouse and GDS Studies
36	5.A.4.a.	7	DSM Potential Study	The DSM potential study shall include, but not be limited to: identification of eligible measures, measure life expectancies, baseline standards, load reduction profiles, incremental capacity and energy savings, measure and program cost assumptions, participant adoption rates, market development, and avoided energy and capacity costs for DSM measure and program screening purposes.	Appendix D and E: Guidehouse and GDS Studies
37	5.A.4.b.	7	N.O. TRM	The principal reference document for the DSM potential study shall be the New Orleans Technical Reference Manual.	Appendix D and E: Guidehouse and GDS Studies
38	5.A.4.c.	7	CA Standard Practice Tests	In the development of the DSM potential study, all four California Standard Practice Tests (i.e. TRC, PACT, RIM and PCT) will be calculated for the DSM measures and programs considered.	Appendix D and E: Guidehouse and GDS Studies
39	5.A.4.d.	7	Known policy goals re: DSM	The Utility should incorporate any known Council policy goals or targets (including such policy goals or targets identified in the Initiating Resolution) with respect to demand-side resources.	Pg 57: Planning Strategy Overview; Pg 78: Scorecard Metrics and Results
40	5.A.4.e.	7	Cost effective DR programs	The cost-effective DR programs should include consideration of those programs enabled by the deployment of Advanced Meter Infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer classes.	Appendix D and E: Guidehouse and GDS Studies

41	5.A.4.f.	8	Required data for DSM analysis	Data supplied as part of the Utility's IRP filing should include: a description of each potential demand-side resource considered, including a description of the resource or program; expected penetration levels by planning year; hourly load reduction profiles for each DSM program utilized in the IRP process; and results of appropriate cost-benefit analyses and acceptance tests, as part of the planning assumptions utilized within the IRP planning process.	Appendix D and E: Guidehouse and GDS Studies; Pg 46: Demand-Side Management
42	5.B.	8	Stakeholder process	Through the Stakeholder Process, the Utility shall strive to develop a position agreed to by the Utility, the Advisors, and a majority of the Intervenors regarding the potential supply-side and potential demand-side resources and their associated defining characteristics (e.g., capital cost, operating and maintenance costs, emissions, DSM supply curve, etc.).	Consensus among parties reached at Technical Meeting #3
43	5.B.1.	8	Reference Planning Strategy	To the extent such a consensus can be achieved among the Utility, the Advisors, and a majority of the Intervenors, the resulting collection of potential supply-side and demand-side resources and their associated defining characteristics will be utilized in the reference Planning Strategy developed pursuant to Section 7D.	See #44, below
44	5.B.2.	8	Stakeholder Strategy	To the extent such a consensus cannot be achieved, the Utility shall model, in coordination with the requirements in Section 7D, two distinct Planning Strategies: a reference Planning Strategy and a stakeholder Planning Strategy. The reference Planning Strategy will be based on the Utility's assessment of the collection of potential supply-side and demand-side resources and their associated defining characteristics. The stakeholder Planning Strategy will be determined by a majority of the Intervenors and modeled by the Utility based on inputs provided to the Utility describing the collection of potential supply-side and demand-side resources and their associated defining characteristics. To maintain consistency in the modeling process, the Advisors will work with the Intervenors and the Utility to ensure that input that is provided for the stakeholder Planning Strategy can be accommodated within the framework of the existing model and software.	Consensus among parties reached at Technical Meeting #3 regarding set of four Planning Strategies
45	6.A.	8	Integration of T&D planning into IRP	The Utility shall explain how the Utility's current transmission system, and any planned transmission system expansions (including regional transmission system expansion planned by the RTO in which the Utility participates) and the Utility's distribution system are integrated into the overall resource planning process to optimize the Utility's resource portfolio and provide New Orleans ratepayers with reliable electricity at the lowest practicable cost.	Pg 17: Transmission; Pg 19: Distribution Planning
46	6.B.	9	Planned transmission topology	Models developed for the integrated resource planning process should incorporate the planned configuration of the Utility's transmission system and the interconnected RTO during the Planning Period.	Pg 17: Transmission
47	6.C.	9	Major changes to T&D systems	To the extent major changes in the operation or planning of the transmission system and/or distribution system (including changes to accommodate the expansion of DERs) are contemplated in the Planning Period, the Utility should describe the anticipated changes and provide an assessment of the cost and benefits to the Utility and its customers.	Pg 17: Transmission; Pg 19: Distribution Planning
48	6.D.	9	Transmission solutions for reliability	To the extent that new resource additions are selected by the Utility for a Resource Portfolio based on reliability needs rather than as a result of the optimized development of a Resource Portfolio, the Utility shall identify reasonable transmission solutions that can be employed to either reduce the size, delay, or eliminate the need for the new reliability-driven resource additions and provide economic analyses demonstrating why the new reliability-driven resource addition was selected in lieu of the transmission solutions identified.	N/A
49	6.E.	9	Evaluation of DERs	It is the Council's intent that, as part of the IRP, the Utility shall evaluate the extent to which reliability of the distribution system can be improved through the strategic location of DERs or other resources identified as part of the IRP planning process. The Utility should provide an analysis, discussion, and quantification of the costs and benefits as part of the evaluation. To the extent the Utility does not currently have the capability to meet this requirement, the utility shall demonstrate progress toward accomplishing this requirement until such time as it acquires the capability.	Pg 19: Distribution Planning
50	7.A.	9	IRP Modeling parameters	The integrated resource planning process should include modeling of specific parameters and their relationships consistent with market fundamentals, and as appropriate for long-term Portfolio planning. This overall modeling approach is an accepted analytic approach used in resource planning considering the range of both supply-side and demand-side options as well as uncertainty surrounding market pricing. To represent and account for the different characteristics of alternative types of resource options, mathematical methods such as a linear programming formulation should be used to optimize resource decisions.	Chapter 4, Modeling Framework

51	7.B.	9	External Capacity sales	The optimization process shall be constrained to mitigate the over-reliance on forecasted revenues from external capacity market sales and external energy market sales driving the selection of resources.	Pg 60: Market Modeling; Pg 65: Optimized and Manual Portfolios
52	7.C.	9	Planning Scenarios	The Utility shall develop three to four Planning Scenarios that incorporate different economic and environmental circumstances and national and regional regulatory and legislative policies.	Consensus among parties reached at Technical Meeting #2
53	7.C.1.	10	Reference and Alternative Scenarios	The Planning Scenarios should include a reference Planning Scenario that represents the Utility's point of view on the most likely future circumstances and policies, as well as two alternative Planning Scenarios that account for alternative circumstances and policies.	Consensus among parties reached at Technical Meeting #2
54	7.C.2.	10	Scenario Assumptions	In the development of the Planning Scenarios, the Utility should seek to develop a position agreed to by the Utility, Advisors, and a majority of Intervenors regarding the assumptions surrounding each of the Planning Scenarios. To the extent such a consensus is not reasonably attainable regarding the Planning Scenarios, the Utility shall model a fourth Planning Scenario which is based upon input agreed to by a majority of the Intervenors.	Consensus among parties reached at Technical Meeting #2
55	7.C.3.	10	Data for Scenarios	For each IRP Planning Scenario, data supplied as part of the Utility's IRP filing should include:	
56	7.C.3.a.	10	Fuel Price Forecast	a fuel price forecast for each fuel considered for utilization in any existing or potential supply-side resource;	Pg 54: Natural Gas Price Forecast
57	7.C.3.b.	10	Hourly Market Price Forecast for Energy	an hourly market price forecast for energy (e.g. locational marginal prices);	Pg 64: Average Annual MISO LMPs
58	7.C.3.c.	10	Annual Capacity Price Forecast	an annual capacity price forecast for both a short-term capacity purchase (e.g. bilateral contract or Planning Resource Credit) and a long-term capacity purchase (e.g. long-run marginal cost of a new replacement gas combustion turbine);	Appendix F--Macro Inputs Workbook
59	7.C.3.d.	10	Other Price Components	forecasts of price for any other price related components that are defined by the Planning Scenario (e.g. CO2 price forecast, etc.).	Pg 55: CO2 Price forecast
60	7.D.	10	Strategies	Distinct from the Planning Scenarios, the Utility shall identify two to four Planning Strategies which constrain the optimization process to achieve particular goals, regulatory policies and/or business decisions over which the Council, the Utility, or stakeholders have control.	Consensus among the parties reached at Technical Meeting #3
61	7.D.1.	10	Lowest Cost Strategy	The Utility shall develop a Planning Strategy that allows the optimization process to identify the lowest cost option for meeting the needs identified in the IRP process.	Pg 57: Planning Strategies
62	7.D.2.	10	Reference Strategy	The Utility shall develop a reference Planning Strategy agreed to by the Utility, Advisors, and a majority of the Intervenors. To the extent such a consensus cannot be reasonably achieved, the reference Planning Strategy shall reflect the Utility's point of view on resource input parameters and constraints, and the Utility shall model a separate stakeholder Planning Strategy based upon input determined by a majority of the Intervenors.	Consensus among the parties reached at Technical Meeting #3 regarding Strategy #2 as the Reference and "But For RCPS" Strategy
63	7.D.3.	11	Alternate Strategies	As necessary, the Utility shall develop alternate Planning Strategies to reflect known utility regulatory policy goals of the Council (including such policy goals or targets identified in the Initiating Resolution) as established no later than 30 days prior to the date the Planning Strategy inputs must be finalized.	Consensus among the parties reached at Technical Meeting #3 regarding Strategy #3 as the "RCPS Compliance" Strategy
64	7.E.	11	Finalization of Scenario and Strategy Parameters	Prior to the development of optimized Resource Portfolios, the parameters developed for the Planning Scenarios and Planning Strategies shall be set, considered finalized, and not subject for alteration during the remainder of the IRP planning cycle. The IRP Report shall describe the parameters of each Planning Scenario and each Planning Strategy, including all artificial constraints utilized in the optimization modeling.	Pg 56: Planning Scenarios; Pg 57: Planning Strategies

65	7.F.	11	Portfolio Optimization	Resource Portfolios shall be developed through optimization utilizing the Utility's modeling software. The Utility shall identify the least-cost Resource Portfolio for each Planning Scenario and Planning Strategy combination, based on total cost. Resource Portfolios shall consist of optimized combinations of supply-side and demand-side resources, while recognizing constraints including transmission and distribution.	Pg 65: Optimized and Manual Portfolios
66	7.G.	11	Results of Scenario&Strategy combinations	The Utility shall provide a discussion and presentation of results for each Planning Scenario/Planning Strategy combination, the annual total demand related costs, energy related costs, and total supply costs associated with each least-cost Resource Portfolio identified under each Planning Scenario/Planning Strategy combination, a load and capability table indicating the total load requirements and identifying all supply-side and demand-side resources included in the Resource Portfolio (including identifying the impacts of existing demand-side resources on the total load requirements), and a description of the supply-side and demand-side resources that are planned and, if applicable, their principal rationale for selection (i.e., supply peak demand, supply non-peak demand or operational constraints, achieve more economical production of energy, etc.).	Pg 71: Total relevant supply Cost Results; Appendix C
67	7.G.1.	11	Annual and Cumulative portfolio costs	Data supplied as part of the Utility's IRP filing shall include a cumulative present worth summary of the results as well as the annual estimates of costs that result in the cumulative present worth to enable the Council to understand the timing of costs and savings of each least-cost Resource Portfolio.	Pg 71: Total relevant supply Cost Results; Appendix C
68	7.H.	11	Discussion of Portfolio Results	The IRP report's discussion and presentation of results for each Resource Portfolio should identify key characteristics of that Resource Portfolio and significant factors that drive the ultimate cost of that Resource Portfolio such that the Council may understand which factors could ultimately and significantly affect the preference of a Resource Portfolio by the Council.	Pg 71: Total relevant supply Cost Results
69	7.I.	11	Scorecard template	The Utility will develop and include a scorecard template or set of quantitative and qualitative metrics to assist the Council in assessing the IRP based on the Resource Portfolios. The scorecard should rank the resource portfolios by how well each portfolio achieves each metric. Such metrics should include but not necessarily be limited to: cost; impact on the Utility's revenue requirements; risk; flexibility of resource options; reasonably quantifiable environmental impacts (such as national average emissions for the technologies chosen, amount of groundwater consumed, etc.); consistency with established, published city policies, such as the City's sustainability plan; and macroeconomic impacts in New Orleans.	Pg 78: Scorecard Metrics and Results
70	8.A.	12	Cost/Risk Analysis	The Utility shall develop a cost/risk analysis which balances quantifiable costs with quantifiable risks of the identified least-cost Resource Portfolios. The risk assessment must be presented in the IRP to allow the Council to comprehend the robustness of each Resource Portfolio across the cost/risk range of possible Resource Portfolios.	Pg 75: Stochastic Assessment of Risks
71	8.A.1.	12	Assessment of social and environmental costs	In quantifying Resource Portfolio costs/risks, the IRP shall assess any social and environmental effects of the Resource Portfolios to the extent that: 1) those effects can be quantified and have been modeled for a Resource Portfolio, including the applicable Planning Period years and ranges of uncertainty surrounding each externality cost, and 2) each quantified cost must be clearly identified by the portion which relates to the Utility's revenue requirements or cost of providing service to the Utility's customers under the Resource Portfolio.	Pg 78: Scorecard Metrics and Results

72	8.A.2.	12	Probabilities of outcomes	It is the Council's intent that, as part of the IRP, a risk assessment be conducted to evaluate both the expected outcome of potential costs as well as the distribution and potential range and associated probabilities of outcomes. To the extent the Utility believes the risk assessment described herein is beyond the current modeling capabilities of the Utility or that the risk assessment cannot be accomplished within the procedural schedule set forth in the Initiating Resolution, the Utility shall so inform the Council and meet with the Intervenors and Advisors to agree upon an alternative form of risk analysis to recommend to the Council.	Pg 75: Stochastic Assessment of Risks
73	8.A.2.a.	12	Cost/MWh in future years	The risk assessment shall include the expected cost per MWh of the Resource Portfolios in selected future years, along with the range of annual average costs foreseen for the 10th and 90th percentiles of simulated possible outcomes.	Pg 75: Stochastic Assessment of Risks
74	8.A.2.b.	12	Supporting Methodology Included	The supporting methodology shall be included, such as the iterations or simulations performed for the selected years, in which the possible outcomes are drawn from distributions that describe market expectations and volatility as of the current filing date.	Pg 75: Stochastic Assessment of Risks
75	9.A.	12	IRP Process Requirements	At a minimum, the IRP process shall include, but not be limited to, the following elements:	
76	9.A.1.	12	Collaboration on IRP inputs	The opportunity for Intervenors to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with the Utility within the confines of the IRP timeline and procedural schedule.	Stakeholder process conducted in accordance with IRP Rules and Initiating Resolution
77	9.A.2.	12	Four Technical Meetings	At least four technical meetings attended by the parties in the Docket focused on major IRP components that include the Utility, Intervenors, CURO, and the Advisors with structured comment deadlines so that meeting participants have the opportunity to present inputs and assumptions and provide comments, and attempt to reach consensus while remaining mindful of the procedural schedule established in the Initiating Resolution.	Technical Meeting #1: 12/9/20; DSM Input Stakeholder Meeting: 3/26/21; Technical Meeting #2: 4/29/21; Technical Meeting #3: 8/12/21; Technical Meeting #4: 1/20/22; Technical Meeting #5: TBD
78	9.A.3.	13	Three Public Meetings	At least 3 public engagement technical conferences advertised through multiple media channels at a minimum of 30 days prior to the public technical conference.	Public Meeting #1: 10/14/20; Public Meeting #2: 4/13/22; Public Meeting #3: 5/3/22
79	10.A.	13	Public Review of IRP	The Utility shall make its IRP available for public review subject to the provisions of the Council Resolution initiating the current IRP planning cycle and referenced in Section 1B.	Public IRP Available on ENO IRP Website
80	10.B.	13	Filing of IRP	The Utility shall file its IRP with the Council consistent with and subject to the provisions of the Council Resolution initiating the current IRP planning cycle referenced in Section 1B.	IRP Report Filed: 3/25/22
81	10.C.	13	Discussion of Stakeholder engagement	The IRP report should discuss the stakeholders' engagement throughout the IRP process; the access to data inputs and specific modeling results by all parties; the consensus reached regarding all demand-side and supply-side resource inputs and assumptions; specific descriptions of unresolved issues regarding inputs, assumptions, or methodology; the formulation of the stakeholder Planning Scenario and/or stakeholder Planning Strategy as needed; and recommendations to improve the transparency and efficiency of the IRP process for prospective IRP cycles.	Pg 4: Executive Summary; Pg 56: Scenario- and Strategy-Based Approach
82	10.D.	13	Action Plan	The IRP shall include an action plan and timeline discussing any steps or actions the Utility may propose to take as a result of the IRP, understanding that the Council's acceptance of the filing of the Utility's IRP would not operate as approval of any such proposed steps or actions.	Pg 81: Action Plan

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX B

ACTUAL HISTORIC LOAD AND LOAD FORECAST

PUBLIC VERSION

MARCH 2022

Appendix B-- Actual Historic Load and Load Forecast (HSPM in Part)

Historic Peak Demand and Energy

Table 1: Annual Billed Sales at the Meter (GWh)

	Residential	Commercial	Industrial	Governmental	Total
2010	1,858	1,899	503	810	5,069
2011	1,888	1,939	498	795	5,120
2012	1,772	1,968	484	785	5,009
2013	1,867	1,998	481	758	5,105
2014	1,963	2,046	452	768	5,230
2015	2,104	2,167	461	814	5,547
2016	2,231	2,268	441	794	5,733
2017	2,155	2,248	429	790	5,621
2018	2,401	2,270	448	795	5,914
2019	2,353	2215	438	815	5,821
2020	2,294	1975	423	755	5,447
2021	2,258	1978	415	755	5,405

Table 2: Summer and Winter Historical Peaks with Distribution Losses (MW)

	Summer	Winter
2010	1,101	975
2011	1,115	993
2012	1,104	830
2013	1,104	903
2014	1,066	1,056
2015	1,161	1,008
2016	1,142	952
2017	1,118	1,023
2018	1,150	1,181
2019	1,151	924
2020	1,124	898
2021	1,155	1,098

Table 3: Historic Monthly Billed Sales at the Meter (MWh)

	Residential	Commercial	Industrial	Governmental	Total
1/1/2008	114,075	144,142	45,426	61,989	365,631
2/1/2008	112,563	138,661	43,559	60,235	355,018
3/1/2008	79,136	124,789	42,151	56,159	302,235

4/1/2008	82,457	143,731	45,492	59,039	330,719
5/1/2008	95,351	143,467	46,676	62,066	347,560
6/1/2008	144,455	165,163	46,912	70,427	426,957
7/1/2008	161,144	167,161	48,559	71,020	447,884
8/1/2008	166,402	177,352	50,306	71,864	465,924
9/1/2008	141,835	161,424	49,588	72,483	425,330
10/1/2008	112,074	148,510	39,117	65,853	365,554
11/1/2008	80,324	123,642	42,807	62,300	309,073
12/1/2008	104,454	136,389	39,950	59,980	340,773
1/1/2009	123,125	141,233	40,006	64,555	368,919
2/1/2009	107,916	126,821	37,515	58,241	330,493
3/1/2009	102,046	137,023	35,368	59,345	333,782
4/1/2009	80,599	130,193	42,528	60,631	313,951
5/1/2009	104,073	139,448	45,557	67,844	356,922
6/1/2009	151,812	169,688	46,329	61,938	429,768
7/1/2009	199,030	179,654	49,439	78,433	506,555
8/1/2009	182,792	176,060	51,567	76,915	487,333
9/1/2009	167,614	169,463	46,871	72,571	456,519
10/1/2009	145,142	159,632	45,045	73,643	423,462
11/1/2009	101,583	144,330	44,913	67,957	358,782
12/1/2009	111,043	139,135	40,936	63,776	354,890
1/1/2010	179,921	151,178	40,363	65,903	437,366
2/1/2010	159,381	142,735	32,322	59,204	393,643
3/1/2010	146,460	134,268	35,021	57,458	373,206
4/1/2010	92,298	135,186	43,730	57,566	328,780
5/1/2010	114,665	151,184	41,015	63,780	370,645
6/1/2010	172,176	171,779	49,094	69,876	462,925
7/1/2010	199,176	186,908	46,230	77,750	510,064
8/1/2010	216,973	188,679	50,137	77,149	532,938
9/1/2010	191,740	179,188	42,450	76,541	489,920
10/1/2010	147,993	161,356	42,863	76,771	428,983
11/1/2010	110,358	153,488	41,678	65,151	370,676
12/1/2010	127,019	142,588	38,240	62,425	370,273
1/1/2011	181,190	153,844	35,871	63,459	434,365
2/1/2011	164,921	139,287	38,053	58,554	400,815
3/1/2011	120,894	145,897	37,792	60,941	365,524
4/1/2011	107,134	147,743	41,150	62,692	358,718
5/1/2011	128,907	154,333	41,538	63,959	388,736
6/1/2011	187,998	177,707	46,731	69,557	481,993
7/1/2011	207,021	188,637	45,380	74,520	515,558
8/1/2011	207,089	186,587	47,720	74,318	515,715

9/1/2011	206,174	186,007	46,512	74,375	513,068
10/1/2011	147,396	169,136	41,381	70,540	428,453
11/1/2011	103,867	147,240	41,280	61,653	354,041
12/1/2011	125,248	142,290	34,472	60,837	362,847
1/1/2012	146,027	151,302	37,679	60,852	395,860
2/1/2012	120,258	144,784	37,216	59,637	361,897
3/1/2012	117,043	150,577	36,108	60,944	364,672
4/1/2012	110,747	151,841	37,289	63,109	362,986
5/1/2012	130,405	163,704	40,159	62,845	397,112
6/1/2012	194,937	191,287	46,755	71,588	504,567
7/1/2012	207,621	191,295	43,023	72,967	514,906
8/1/2012	196,602	187,542	43,944	72,930	501,018
9/1/2012	174,737	174,459	42,683	72,773	464,651
10/1/2012	145,664	168,165	44,742	66,937	425,508
11/1/2012	113,255	150,617	36,138	61,995	362,005
12/1/2012	114,992	142,360	38,576	57,998	353,925
1/1/2013	161,718	156,576	33,536	59,472	411,303
2/1/2013	140,035	149,482	34,265	62,904	386,685
3/1/2013	130,082	144,781	35,598	59,970	370,430
4/1/2013	109,798	141,019	37,511	57,269	345,597
5/1/2013	106,279	150,277	33,565	59,552	349,673
6/1/2013	176,880	183,333	44,523	65,513	470,249
7/1/2013	199,988	189,754	45,683	67,921	503,347
8/1/2013	206,422	190,508	45,739	67,432	510,101
9/1/2013	206,555	196,753	47,547	69,604	520,459
10/1/2013	172,771	185,164	43,988	68,988	470,911
11/1/2013	112,254	155,326	41,032	61,036	369,648
12/1/2013	144,472	155,452	38,258	58,608	396,790
1/1/2014	203,822	163,569	39,652	59,589	466,633
2/1/2014	199,387	159,754	30,515	57,316	446,972
3/1/2014	137,747	148,471	35,494	57,741	379,453
4/1/2014	106,718	152,772	36,419	57,670	353,580
5/1/2014	117,880	154,766	37,176	58,727	368,549
6/1/2014	169,678	183,369	40,333	64,815	458,195
7/1/2014	198,382	194,327	40,870	72,084	505,662
8/1/2014	211,035	198,126	41,264	70,154	520,580
9/1/2014	204,812	196,301	41,964	77,161	520,238
10/1/2014	152,295	173,345	38,716	67,667	432,022
11/1/2014	127,234	168,444	36,104	65,619	397,400
12/1/2014	134,386	153,250	33,975	59,297	380,907
1/1/2015	168,087	162,304	35,337	59,914	425,642

2/1/2015	176,838	159,758	33,355	59,578	429,530
3/1/2015	148,446	153,380	33,656	62,515	397,997
4/1/2015	118,379	162,760	38,132	61,054	380,325
5/1/2015	133,556	169,522	34,485	67,526	405,088
6/1/2015	175,745	183,660	42,760	65,792	467,957
7/1/2015	225,248	211,817	44,721	71,322	553,108
8/1/2015	249,885	210,776	43,165	83,999	587,825
9/1/2015	242,074	211,902	44,023	76,832	574,830
10/1/2015	187,021	195,552	40,933	70,740	494,247
11/1/2015	139,019	175,382	35,927	68,433	418,760
12/1/2015	139,562	170,363	34,742	66,596	411,264
1/1/2016	178,568	177,522	36,821	62,336	455,247
2/1/2016	175,616	160,036	31,585	55,476	422,711
3/1/2016	145,066	172,416	32,223	60,035	409,740
4/1/2016	119,352	165,316	34,945	59,261	378,873
5/1/2016	135,321	171,054	34,929	62,566	403,871
6/1/2016	204,623	201,329	37,081	67,746	510,780
7/1/2016	264,987	223,156	42,085	73,904	604,133
8/1/2016	239,623	209,788	40,528	75,202	565,141
9/1/2016	247,790	219,512	42,709	75,363	585,375
10/1/2016	220,888	209,712	38,250	72,836	541,685
11/1/2016	156,298	186,334	36,451	66,449	445,532
12/1/2016	142,745	171,370	33,001	63,157	410,273
1/1/2017	177,349	179,242	31,260	62,288	450,139
2/1/2017	144,210	166,961	35,949	62,623	409,744
3/1/2017	134,177	168,723	31,116	58,862	392,878
4/1/2017	135,116	170,949	34,094	59,930	400,089
5/1/2017	149,105	178,925	33,880	60,373	422,282
6/1/2017	183,982	191,567	36,783	67,370	479,702
7/1/2017	227,517	208,816	39,083	71,921	547,337
8/1/2017	249,650	216,178	39,204	71,035	576,068
9/1/2017	233,404	208,945	40,375	73,969	556,693
10/1/2017	210,577	206,058	38,924	70,943	526,502
11/1/2017	153,747	178,674	34,209	66,347	432,976
12/1/2017	155,809	172,821	33,989	64,397	427,016
1/1/2018	237,027	183,430	33,687	62,394	516,539
2/1/2018	206,863	174,067	31,683	59,377	471,991
3/1/2018	133,384	166,744	33,404	59,355	392,887
4/1/2018	121,577	156,580	34,884	58,840	371,882
5/1/2018	138,072	166,998	35,024	58,485	398,579
6/1/2018	229,864	202,967	41,466	67,743	542,040

7/1/2018	261,418	226,463	41,675	72,711	602,266
8/1/2018	267,772	213,686	43,081	75,663	600,201
9/1/2018	249,569	220,494	43,389	76,821	590,274
10/1/2018	225,794	211,439	40,343	74,443	552,019
11/1/2018	160,357	184,564	35,107	68,619	448,647
12/1/2018	169,266	162,711	33,942	60,528	426,447
1/1/2019	182,917	169,120	32,303	62,193	446,533
2/1/2019	180,315	161,801	32,348	58,532	432,996
3/1/2019	147,748	160,798	32,722	60,470	401,737
4/1/2019	133,266	162,553	35,239	61,174	392,233
5/1/2019	159,568	178,902	30,424	64,746	433,640
6/1/2019	224,127	207,744	38,853	71,539	542,264
7/1/2019	286,860	224,468	40,253	77,888	629,469
8/1/2019	249,439	208,767	41,123	75,517	574,846
9/1/2019	257,138	211,941	42,299	74,474	585,852
10/1/2019	224,164	199,350	41,257	79,450	544,220
11/1/2019	151,740	171,744	38,060	67,058	428,602
12/1/2019	155,927	158,204	32,730	62,131	408,993
1/1/2020	178,838	170,211	35,405	63,779	448,234
2/1/2020	162,147	158,598	33,295	60,528	414,568
3/1/2020	159,644	166,849	32,908	59,454	418,854
4/1/2020	154,820	144,486	36,068	57,430	392,805
5/1/2020	152,054	132,328	34,266	55,622	374,271
6/1/2020	213,079	163,110	35,871	63,734	475,794
7/1/2020	255,401	182,012	37,223	68,923	543,559
8/1/2020	257,275	186,943	41,927	71,618	557,764
9/1/2020	260,603	195,323	40,846	70,686	567,458
10/1/2020	193,572	180,609	37,188	66,646	478,015
11/1/2020	152,406	149,706	33,870	61,323	397,305
12/1/2020	154,495	145,133	23,774	54,975	378,377
1/1/2021	213,042	155,124	31,241	58,712	458,119
2/1/2021	177,420	147,458	29,908	57,263	412,049
3/1/2021	204,457	147,123	30,518	55,512	437,610
4/1/2021	128,601	147,959	31,166	59,470	367,195
5/1/2021	153,079	153,339	35,767	62,898	405,082
6/1/2021	210,374	182,445	41,043	67,104	500,965
7/1/2021	239,818	188,959	41,149	74,233	544,159
8/1/2021	254,897	199,331	39,159	74,260	567,648
9/1/2021	204,013	165,382	37,516	63,145	470,056
10/1/2021	174,376	177,065	32,319	62,093	445,852
11/1/2021	162,579	157,756	34,532	61,133	416,001

12/1/2021	135,652	155,695	30,341	58,682	380,370

Evaluation of Previous IRP Load Forecast

Table 4: Peak Forecasted vs Actual (Includes D losses only)

Peak (MW)	2019	2020	2021
Previous IRP Peak Forecast (BP19)	1,168	1,168	1,168
Weather Normalized Actual Peak	1,160	1,119	1,155
Deviation	-8	-49	-13
% Deviation	-1%	-4%	-1%

2021 IRP Load Forecast

Table 5: Annual Energy Forecasts (GWh) (Includes T&D Losses) **(HSPM)**

	Res	Com	Ind	Gov	Total
2022	[redacted]				
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
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2036					
2037					
2038					
2039					
2040					
2041					

Table 6: Monthly Energy Forecasts (GWh) (Includes T&D Losses) (HSPM)

	Res	Com	Ind	Gov	Total
1/1/2022	[redacted]				
2/1/2022					
3/1/2022					

4/1/2022	[redacted]
5/1/2022	[redacted]
6/1/2022	[redacted]
7/1/2022	[redacted]
8/1/2022	[redacted]
9/1/2022	[redacted]
10/1/2022	[redacted]
11/1/2022	[redacted]
12/1/2022	[redacted]
1/1/2023	[redacted]
2/1/2023	[redacted]
3/1/2023	[redacted]
4/1/2023	[redacted]
5/1/2023	[redacted]
6/1/2023	[redacted]
7/1/2023	[redacted]
8/1/2023	[redacted]
9/1/2023	[redacted]
10/1/2023	[redacted]
11/1/2023	[redacted]
12/1/2023	[redacted]
1/1/2024	[redacted]
2/1/2024	[redacted]
3/1/2024	[redacted]
4/1/2024	[redacted]
5/1/2024	[redacted]
6/1/2024	[redacted]
7/1/2024	[redacted]
8/1/2024	[redacted]
9/1/2024	[redacted]
10/1/2024	[redacted]
11/1/2024	[redacted]
12/1/2024	[redacted]
1/1/2025	[redacted]
2/1/2025	[redacted]
3/1/2025	[redacted]
4/1/2025	[redacted]
5/1/2025	[redacted]
6/1/2025	[redacted]
7/1/2025	[redacted]
8/1/2025	[redacted]

9/1/2025	[redacted]
10/1/2025	[redacted]
11/1/2025	[redacted]
12/1/2025	[redacted]
1/1/2026	[redacted]
2/1/2026	[redacted]
3/1/2026	[redacted]
4/1/2026	[redacted]
5/1/2026	[redacted]
6/1/2026	[redacted]
7/1/2026	[redacted]
8/1/2026	[redacted]
9/1/2026	[redacted]
10/1/2026	[redacted]
11/1/2026	[redacted]
12/1/2026	[redacted]
1/1/2027	[redacted]
2/1/2027	[redacted]
3/1/2027	[redacted]
4/1/2027	[redacted]
5/1/2027	[redacted]
6/1/2027	[redacted]
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9/1/2027	[redacted]
10/1/2027	[redacted]
11/1/2027	[redacted]
12/1/2027	[redacted]
1/1/2028	[redacted]
2/1/2028	[redacted]
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5/1/2039	[redacted]
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11/1/2041	
12/1/2041	

Table 7: Annual Non-Coincident Peak (MW) Forecast – Class Values Coincident to ENO NCP (Includes T&D Losses)

Date	Res	Com	Ind	Gov	Company Use	Total
2022	570	387	60	127	2	1,146
2023	570	400	60	129	2	1,161
2024	569	409	60	130	2	1,170

2025	567	416	60	130	2	1,175
2026	570	418	63	129	2	1,182
2027	573	421	63	129	2	1,188
2028	577	423	63	129	2	1,194
2029	577	427	64	128	2	1,199
2030	577	432	64	128	2	1,204
2031	578	436	65	128	2	1,209
2032	581	438	65	128	2	1,214
2033	583	441	66	128	2	1,220
2034	586	443	66	127	2	1,225
2035	587	447	67	127	2	1,230
2036	586	452	68	128	2	1,236
2037	589	454	68	128	2	1,241
2038	590	457	69	128	2	1,246
2039	593	459	69	128	2	1,251
2040	595	462	70	127	2	1,256
2041	594	465	71	128	2	1,260

Table 8: Annual Load Factor Forecast

Date	Res	Com	Ind	Gov	Total
2022	48%	64%	86%	73%	58%
2023	48%	65%	86%	73%	59%
2024	49%	65%	86%	73%	59%
2025	49%	65%	85%	72%	59%
2026	49%	66%	84%	72%	59%
2027	49%	66%	84%	72%	59%
2028	49%	66%	84%	72%	59%
2029	49%	66%	84%	72%	59%
2030	49%	66%	84%	72%	59%
2031	49%	66%	83%	71%	59%
2032	49%	66%	84%	71%	59%
2033	49%	67%	84%	71%	59%
2034	49%	67%	84%	71%	59%
2035	49%	67%	84%	71%	59%
2036	49%	67%	83%	70%	59%
2037	49%	67%	83%	70%	59%
2038	48%	67%	84%	70%	59%
2039	48%	67%	84%	70%	59%
2040	48%	67%	84%	70%	59%
2041	48%	67%	83%	70%	59%

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***EX PARTE: IN RE*: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX C

TOTAL RELEVANT SUPPLY COSTS

PUBLIC VERSION

MARCH 2022

Appendix C: Total Relevant Supply Costs – Detail

Scenario 1 – Present Value (2022$) of Total Relevant Supply Costs

Note: Fixed Costs are calculated on a levelized real basis for all futures

Portfolio titles denoted by red font were optimized in the above Scenario

Strategy 1 - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$1,125
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$324
DSM Levelized Fixed Costs	[$MM]	$202
Capacity Purchases / (Benefit)	[$MM]	($125)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$1,526

Strategy 2 - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$1,077
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$370
DSM Levelized Fixed Costs	[$MM]	$250
Capacity Purchases / (Benefit)	[$MM]	($138)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$1,560

Manual Portfolio 1a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$980
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$690
DSM Levelized Fixed Costs	[$MM]	$202
Capacity Purchases / (Benefit)	[$MM]	($115)
Avoided Levelized Union Costs (Benefit)	[$MM]	($106)
Total Relevant Supply Cost	[$MM]	$1,650

Manual Portfolio 3a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$1,226
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$530
DSM Levelized Fixed Costs	[$MM]	$250
Capacity Purchases / (Benefit)	[$MM]	($205)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$1,802

Manual Portfolio 4a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	($910)
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$2,165
DSM Levelized Fixed Costs	[$MM]	$598
Capacity Purchases / (Benefit)	[$MM]	($101)
Avoided Levelized Union Costs (Benefit)	[$MM]	($106)
Total Relevant Supply Cost	[$MM]	$1,645

Scenario 1 – Annual Total Relevant Supply Costs **[HSPM]**

[redacted]

Scenario 2 – Present Value (2022$) of Total Relevant Supply Costs

Note: Fixed Costs are calculated on a levelized real basis for all futures

Portfolio titles denoted by red font were optimized in the above Scenario

Strategy 1 - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$813
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$324
DSM Levelized Fixed Costs	[$MM]	$202
Capacity Purchases / (Benefit)	[$MM]	($125)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$1,214

Strategy 2 - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$772
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$370
DSM Levelized Fixed Costs	[$MM]	$250
Capacity Purchases / (Benefit)	[$MM]	($138)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$1,254

Manual Portfolio 1a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$701
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$690
DSM Levelized Fixed Costs	[$MM]	$202
Capacity Purchases / (Benefit)	[$MM]	($115)
Avoided Levelized Union Costs (Benefit)	[$MM]	($106)
Total Relevant Supply Cost	[$MM]	$1,372

Manual Portfolio 3a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$906
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$530
DSM Levelized Fixed Costs	[$MM]	$250
Capacity Purchases / (Benefit)	[$MM]	($205)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$1,481

Manual Portfolio 4a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	($888)
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$2,165
DSM Levelized Fixed Costs	[$MM]	$598
Capacity Purchases / (Benefit)	[$MM]	($101)
Avoided Levelized Union Costs (Benefit)	[$MM]	($106)
Total Relevant Supply Cost	[$MM]	$1,667

Scenario 2 – Annual Total Relevant Supply Costs **[HSPM]**

[redacted]

Scenario 3 – Present Value (2022$) of Total Relevant Supply Costs

Note: Fixed Costs are calculated on a levelized real basis for all futures

Portfolio titles denoted by red font were optimized in the above Scenario

Strategy 1 - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$1,596
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$324
DSM Levelized Fixed Costs	[$MM]	$202
Capacity Purchases / (Benefit)	[$MM]	($125)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$1,997

Strategy 2 - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$1,540
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$370
DSM Levelized Fixed Costs	[$MM]	$250
Capacity Purchases / (Benefit)	[$MM]	($138)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$2,023

Manual Portfolio 1a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$1,378
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$690
DSM Levelized Fixed Costs	[$MM]	$202
Capacity Purchases / (Benefit)	[$MM]	($115)
Avoided Levelized Union Costs (Benefit)	[$MM]	($106)
Total Relevant Supply Cost	[$MM]	$2,049

Manual Portfolio 3a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	$1,691
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$530
DSM Levelized Fixed Costs	[$MM]	$250
Capacity Purchases / (Benefit)	[$MM]	($205)
Avoided Levelized Union Costs (Benefit)	[$MM]	$0
Total Relevant Supply Cost	[$MM]	$2,266

Manual Portfolio 4a - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	($385)
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$2,165
DSM Levelized Fixed Costs	[$MM]	$598
Capacity Purchases / (Benefit)	[$MM]	($101)
Avoided Levelized Union Costs (Benefit)	[$MM]	($106)
Total Relevant Supply Cost	[$MM]	$2,170

Manual Portfolio 4b Sensitivity - Total Relevant Supply Cost		
		PV 2022$ [2022-2041]
Net Variable Supply Cost / (Benefit)	[$MM]	($385)
Resource Additions Levelized Fixed Costs - 6/1 COD	[$MM]	$1,841
DSM Levelized Fixed Costs	[$MM]	$598
Capacity Purchases / (Benefit)	[$MM]	($101)
Avoided Levelized Union Costs (Benefit)	[$MM]	($106)
Total Relevant Supply Cost	[$MM]	$1,847

Scenario 3 – Annual Total Relevant Supply Costs **[HSPM]**

[redacted]

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***EX PARTE: IN RE*: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX D

GUIDEHOUSE 2021 POTENTIAL STUDY

MARCH 2022

Entergy Services, LLC
639 Loyola Avenue
P. O. Box 61000
New Orleans, LA 70161-1000
Tel 504 576 6571
Fax 504 576 5579
tcragin@entergy.com

Timothy S. Cragin
Assistant General Counsel
Legal Department -- Regulatory

July 30, 2021

Via Electronic Delivery
Lora W. Johnson, CMC, LMMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

**Re: 2021 Triennial Integrated Resource Plan of Entergy New Orleans, LLC
Council Docket No. UD-20-02**

Dear Ms. Johnson:

Entergy New Orleans, LLC ("ENO") respectfully submits its 2021 Integrated Resource Plan Demand Side Management ("DSM") Potential Study in the above-referenced docket. 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.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Timothy S. Cragin

TSC/rdm
Enclosures

cc: Official Service List via email

Entergy New Orleans, LLC

2021 Integrated Resource Plan DSM Potential Study

FINAL REPORT

Prepared for:

Entergy New Orleans, LLC

Submitted by:

Guidehouse Inc.
1200 19th Street, NW
Suite 700
Washington, DC 20036
Telephone (202) 973-2400

Reference No.: 217146
July 27, 2021

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List of Acronyms

AC	Air Conditioning
ACEEE	American Council for an Energy-Efficient Economy
AMI	Advanced Metering Infrastructure
BAU	Business as Usual
BP20	Business Plan 2020 Update
BTMS	Behind-the-Meter Storage
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CBECS	Commercial Buildings Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CPP	Critical Peak Pricing
DI	Direct Install
DLC	Direct Load Control
DOE	Department of Energy (US)
DR	Demand Response
DRSim™	Demand Response Simulator
DSM	Demand Side Management
DSMSim™	Demand-Side Management Simulator
EE	Energy Efficiency
EIA	Energy Information Administration (US)
EMS	Energy Management Systems
ENO	Entergy New Orleans, LLC
EUI	End-Use Intensities
EUL	Effective Useful Life
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt-Hour
HVAC	Heating, Ventilation, and Air Conditioning
IRP	Integrated Resource Plan
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-Hour
LED	Light Emitting Diode
MISO	Midcontinent Independent System Operator
MW	Megawatt
NEW	New Construction
NPV	Net Present Value
NTG	Net-to-Gross
O&M	Operations and Maintenance
PAC	Program Administrator Cost
PCT	Programmable Communicating Thermostat
POU	Publicly Owned Utility
PV	Present Value
PY	Program Year
RBSA	Residential Building Stock Assessment
RET	Retrofit
RIM	Ratepayer Impact Measure
ROB	Replace-on-Burnout
RTO	Regional Transmission Operator
SEER	Seasonal Energy Efficiency Ratio
SF	Square Feet
SIC	Standard Industrial Classification
T&D	Transmission and Distribution
TMY	Typical Meteorological Year
TOU	Time-of-Use
TRC	Total Resource Cost
TRM	Technical Resource Manual
TSD	Technical Support Documents

Executive Summary

Introduction

In support of the 2021 Integrated Resource Plan's (IRP's) development, Entergy New Orleans, LLC (ENO) engaged Guidehouse Consulting, Inc. ("Guidehouse" or "the team") to prepare a demand side management (DSM) potential study.[1] The study assesses the long-term potential for reducing energy consumption in the residential and commercial and industrial (C&I) sectors by using energy efficiency and peak load reduction measures and improving end-user behaviors.

ENO previously engaged Navigant Consulting, Inc. (as Guidehouse was named at the time) to prepare a DSM potential study to be used in its 2018 IRP. The 2018 study included four cases, Base, Low, High, and 2%, and informed both the 2018 IRP analysis and the Implementation Plan for Energy Smart (ES) Program Years 10-12 that was later approved by the Council of the City of New Orleans (Council) in Docket UD-17-03.

The 2018 study projected certain levels of achievable energy savings and program costs based on business assumptions and historical results of Energy Smart at the time. The PY10-12 Implementation Plan developed with ENO's Third-Party Administrator, Aptim, and subsequent actual program results reflect more aggressive splits between incentive and administrative costs and greater utilization of behavioral efficiency programs than were identified in the 2018 study. This 2021 study highlights the long-term effects of such aggressive incentives.

For the 2021 study, the team approached the energy efficiency (EE) component of the potential study with a rigorous analysis of input data. This data was necessary for Guidehouse to run the DSM Simulator (DSMSim™) model, which calculates various levels of EE savings potential across the ENO service area. Guidehouse further delineated the achievable potential using a range of assumptions for alternative cases to estimate the effect on customer participation of funding for customer incentives, awareness, and other factors.

For the demand response (DR) potential component of this study, the team similarly began with a rigorous analysis of input data necessary for the DRSim™ model. Inputting a range of reasonable assumptions, the team used the DRSim™ model to estimate the DR potential for a range of cases.

ENO intends to inform the 2021 IRP with the results from the potential study. Although these results may also be used to further ENO's DSM planning and long-term conservation goals, EE program design efforts, long-term load forecasts, and long-term potential studies do not replace the need for detailed near-term implementation planning and program design. Accordingly, ENO should only use this study to inform those planning and design efforts in combination with ENO's Energy Smart program experience and the market intelligence and insights of the Council and its Advisors and stakeholders.

Study Objectives

ENO will use the results of the potential study as an input to its 2021 IRP, providing a long-range outlook on the cost-effective potential for delivering demand side resources such as EE and DR and the associated levels of investment required to implement such programs. Guidehouse

[1] The study period for the potential study is 2021-2040.

designed its project approach to ensure the study results adequately address ENO's objectives and the Council's IRP rules. Table 1 summarizes the study's objectives and how Guidehouse met those objectives.

Table 1. Study Objectives Overview

Objective		Guidehouse's Approach
1	Use consistent methodology and planning assumptions	Guidehouse has a variety of analytical tools and approaches to inform DSM planning and the establishment of long-term conservation targets and goals (details provided in the following sections). The team also worked closely with ENO to vet methodology, assumptions, and inputs at each stage of this study.
2	Reflect current information	Guidehouse leveraged its prior work with ENO to create a bottom-up analysis that includes inputs, such as the New Orleans TRM, and other up-to-date information (new codes and standards, saturation data from surveys and Energy Smart programs, avoided costs, etc.) in this study.
3	Quantify achievable potential	Guidehouse quantifies achievable potential for both EE and DR by first calculating the technical and economic (EE only) potential. The achievable potential base case is then calibrated to the historical Energy Smart program data and the current programs approved by the Council for Energy Smart PYs 10-12.
4	Provide input to the IRP	Guidehouse's approach provides the following for all modeled market cases: • Supply curve of conservation potential for input to ENO's IRP • Outputs available with 8,760 hourly impact load shapes

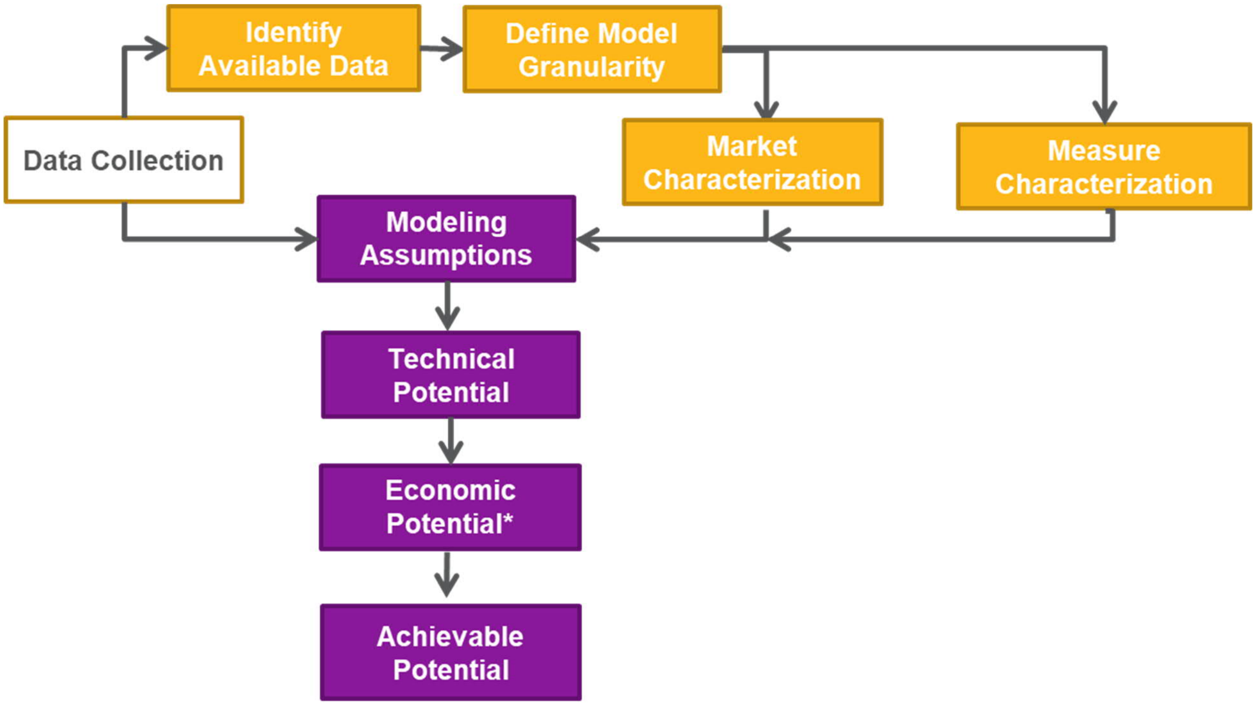
Source: Guidehouse

Energy Efficiency

Detailed Approach

Guidehouse analyzed potential in the ENO service area for 2021 through 2040. After gathering existing data sources, the team characterized the market and measures, and estimated potential using the DSMSim^{TM} tool, a bottom-up stock forecasting model. The third step involved three sequential stages—calculating technical, economic, and achievable potential. Figure 1 illustrates our EE analysis approach.

Figure 1. EE Analysis Approach Overview



*Not calculated for DR potential

Source: Guidehouse

Market Characterization

Characterizing the market involved identifying and understanding key factors defining the service area or market and codifying assumptions for the model to accurately represent the market. Specifically, the market characterization required defining the sales and stock[2] for 2019 (the study's base year consumption),[3] and then forecasting sales and stock out from 2021-2040 to create the study's base forecast consumption, or baseline. To complete this effort, Guidehouse collected multiple datasets including:

- 2019 ENO billing and customer account data
- ENO Business Plan 2020 (BP20) forecast sales and customer counts
- US Energy Information Administration (EIA) Commercial Buildings Energy Consumption Survey (CBECS)
- US Department of Labor SIC
- Guidehouse research

[2] Sales refers to the kWh consumption, typically by sector. Stock refers to the customer count, typically per household for the residential sector and per 1,000 square feet for the non-residential sector. For the potential analysis, Guidehouse prefers more disaggregated analysis at the segment level (or building types).

[3] The base year is typically the most recent full year of utility available data for sales and stock.

After defining sales and stock for the base year and base forecast consumption, the team determined energy use at the customer segment and end use levels. Guidehouse based the level of disaggregation for the segments and end uses on existing program definitions, data availability to accomplish disaggregation, and the level of granularity needed for stakeholders to draw meaningful conclusions from the study. The study details the selected customer segments and assumptions about the stock, electricity sales, end use breakdown, and energy use intensity (EUI) for each segment and end use.

The team also aggregated additional inputs from ENO for inclusion in the model, including various economic and financial parameters such as carbon pricing, avoided costs, inflation, and historic program costs.

Measure Characterization

Measure characterization consisted of defining enough data points for all measures included in the study to accurately model them. Key data points used to characterize measures included assumptions about energy and demand savings, codes and standards, measure life, and measure costs. We used data provided by ENO, data from regional efficiency programs offered by other utilities, and Technical Reference Manuals (TRMs) primarily from New Orleans v4,[4] and other state TRMs to fill the gaps.

The team used a measure list with sufficient characteristics to identify and focus our efforts on technologies likely to have the highest feasible, cost-effective contribution to savings potential over the study horizon. The study does not account for unknown or emerging but unproven technologies that may arise and increase savings opportunities over the forecast horizon. It also does not account for broader societal changes that may affect levels of energy use in unanticipated ways.

Estimation of Potential

After defining the market and measure characteristics, Guidehouse employed the DSMSim™ potential model to estimate the technical, economic, and achievable savings potential for electric energy and demand across ENO's service area from 2021 to 2040. Each type of potential is defined below:

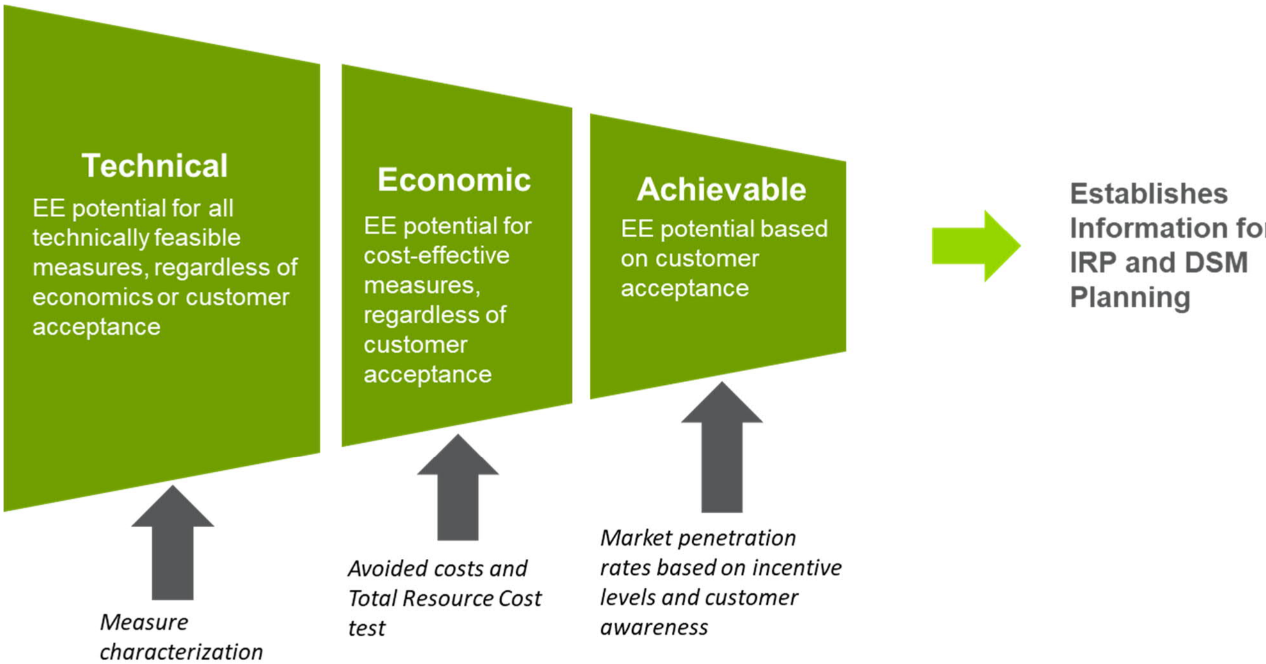
- **Technical potential** is the total energy savings available assuming all installed measures can immediately be replaced with the efficient measure/technology—wherever technically feasible—regardless of cost, market acceptance, or whether a measure has failed and must be replaced.
- **Economic potential** is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential, but including only those measures that have passed the benefit-cost test chosen for measure screening; in this study, that is the Total Resource Cost (TRC) test.

[4] New Orleans Energy Smart Technical Reference Manual: Version 4.0, September 2020, prepared by ADM Associates, Inc.

- **Achievable potential** is a subset of economic potential. The team determined achievable potential by modifying economic potential to account for measure adoption ramp rates and the diffusion of technology through the market.

Figure 2 depicts each potential types and their respective data inputs.

Figure 2. Energy Efficiency Potential Analysis Approach



Source: Guidehouse

With these definitions and data inputs, the DSMSim™ uses a bottom-up technology diffusion and stock tracking model implemented by means of a system dynamics framework to estimate the different potential types.[5] The model outputs technical, economic, and achievable savings potential for the service area, sector, customer segment, end use category, and highest impact measures.

Results

Given ENO's objective to quantify the achievable potential for use in the 2021 IRP and gain a better understanding as to the best path for planning ENO's Energy Smart programs, the project team modeled several possible future cases, including:

1. **2% Program case:** The 2% program case is defined by the approved Energy Smart PY10-12 implementation plan, Scenario 2.[6] Guidehouse set incentives at 86% and 32% of the full measure cost for residential and C&I measures, respectively. Guidehouse calibrated

[5] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000 for detail on System Dynamics modeling.

[6] https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_10-12/Correction_Revised_Implementation_Plan_%20PY_10-12_1-24-20.pdf?_ga=2.216502932.327611312.1611206281-15932630.1611206281 and https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_10-12/Revised_Implementation_Plan_PY_10-12_1-22-20.pdf?_ga=2.216502932.327611312.1611206281-15932630.1611206281

the model results by adjusting adoption parameters and behavior program rollout to align with the historical program achievements and planned savings as documented in the implementation plan.

2. **Low Program case:** The low case uses the same inputs as the 2% program case, (ENO implementation plan, Scenario 2) except for lower levels of behavior program participation rollout (50% of the 2% program case). Incentives are set to 50% of full measure cost for residential and 25% for C&I. Administrative costs on a dollar per kWh saved basis are the same as the 2% program case.

3. **High Program case:** The high case is based off the 2% program case but with higher incentives as a percent of full measure cost at 100% for residential and 50% for C&I. Additionally, there is a more aggressive plan for behavior program rollout. Behavioral program rollout for the residential sector increases slightly compared to the 2% case and reaches the maximum achievable level.[7] Administrative costs on a dollar per kWh saved basis are relatively equal to those in the 2% program case.

4. **Reference case:** In an effort to develop a case reflecting an industry-standard level of incentives, and because the actual program results for the approved PY10-12 plan are tracking to higher levels of administrative costs and kWh savings than are often seen in long term potential studies, it was useful to provide a Reference Case that tied back to the Base case from the 2018 study. This Reference case reflects the Base case from the 2018 study where the program administrative costs reflected current spend targets on a dollar per kWh saved basis and the incentives were set at 50% of incremental measure costs. In Guidehouse's experience in incentive level setting and potential study analysis, others have set incentives or cap incentives at 50% of incremental measure cost. Behavior program roll out matches the low program case levels as a conservative assessment of the potential roll out of the recommended programs for the ENO portfolio.

The study reports savings as gross versus net of free ridership impacts. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about net-to-gross ratios or changing EUI with natural occurring energy become available. Study results can then be used to define the portfolio energy savings goals, projected costs, and forecasts.

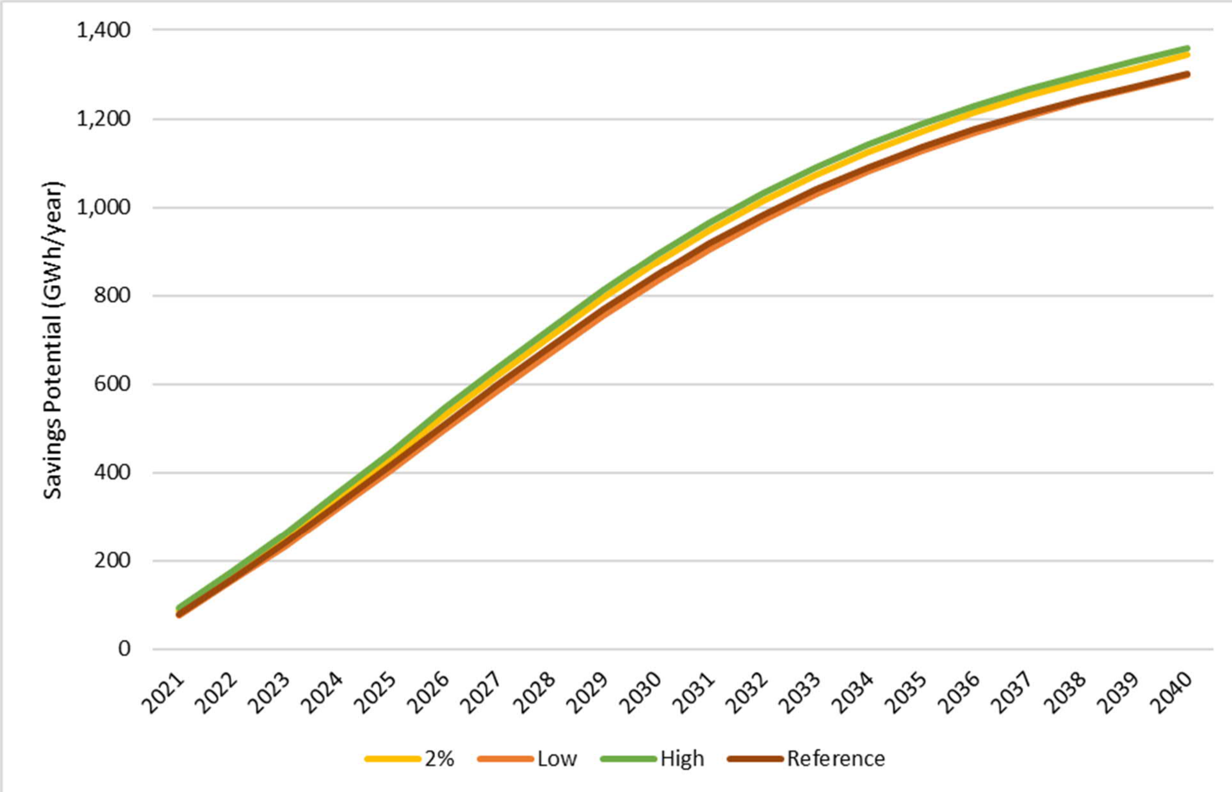
This study only includes known, market-ready, quantifiable measures. However, over the lifetime of EE programs, new technologies and innovative program interventions could result in additional cost-effective energy savings. ENO should periodically revisit and reanalyze the potential forecast to account for these technologies and programs.

Results

Figure 3 and Figure 4 show the cumulative annual energy and demand savings for each case.

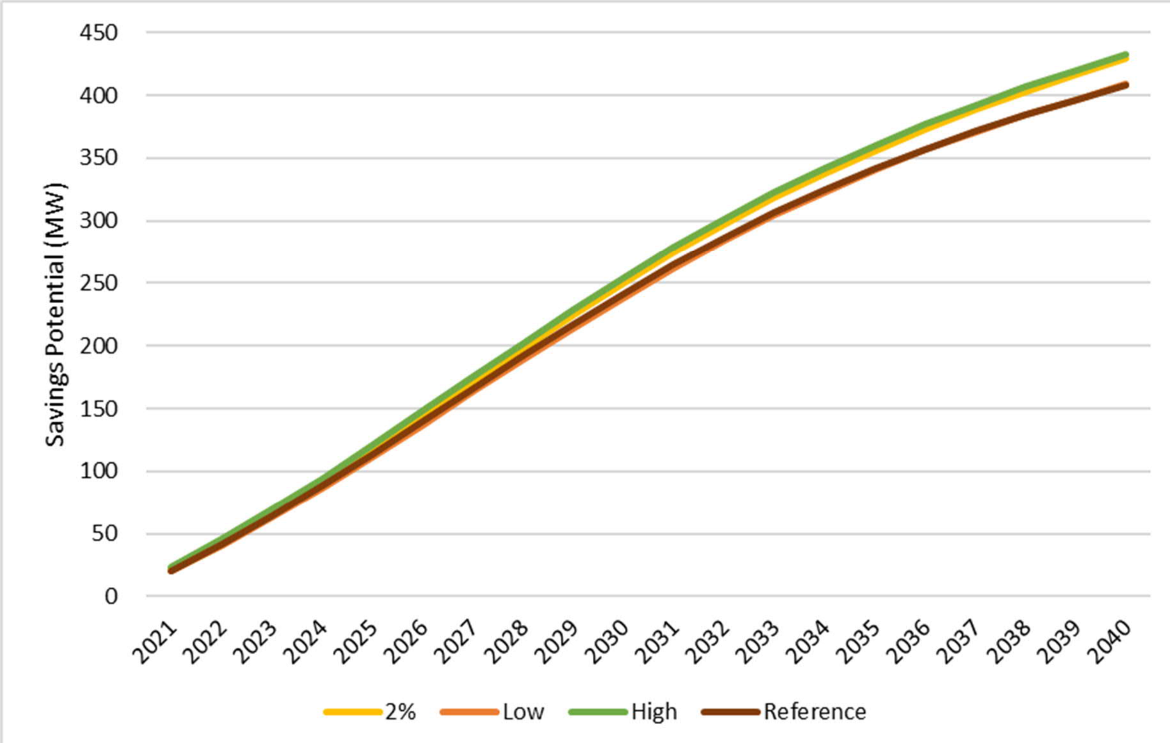
[7] Residential behavior programs using a control group to assess energy savings result in an ability to treat less than 100% of the suitable participant pool.

Figure 3. Cumulative Energy Achievable Savings EE Potential by Case



Source: Guidehouse analysis

Figure 4. Cumulative Peak Demand Achievable Savings EE Potential by Case



Source: Guidehouse analysis

The various cases do not show significant differences from each other; however, each case has marked differences in the program design, i.e., changes in ENO-influenced parameters including incentive level setting and behavioral program rollout.[8] Table 2 summarizes the EE potential study results, showing achievable annual incremental energy and peak demand savings by case in 5-year increments. Total cumulative EE potential energy and peak demand savings for the 2% program case are 1,344 GWh and 429 MW, respectively, between 2021 and 2040.

Table 2. Annual Incremental Achievable Energy Efficiency Savings by Case

Year	Electric Energy (GWh/Year)				Peak Demand (MW)			
	2%	Low	High	Reference	2%	Low	High	Reference
2021	89	77	93	79	22	20	23	21
2025	119	101	126	103	26	25	26	25
2030	115	96	123	96	25	25	26	24
2035	86	66	94	65	18	17	18	17
2040	73	51	81	50	13	12	13	12
Total	**1,344**	**1,299**	**1,359**	**1,302**	**429**	**409**	**432**	**408**

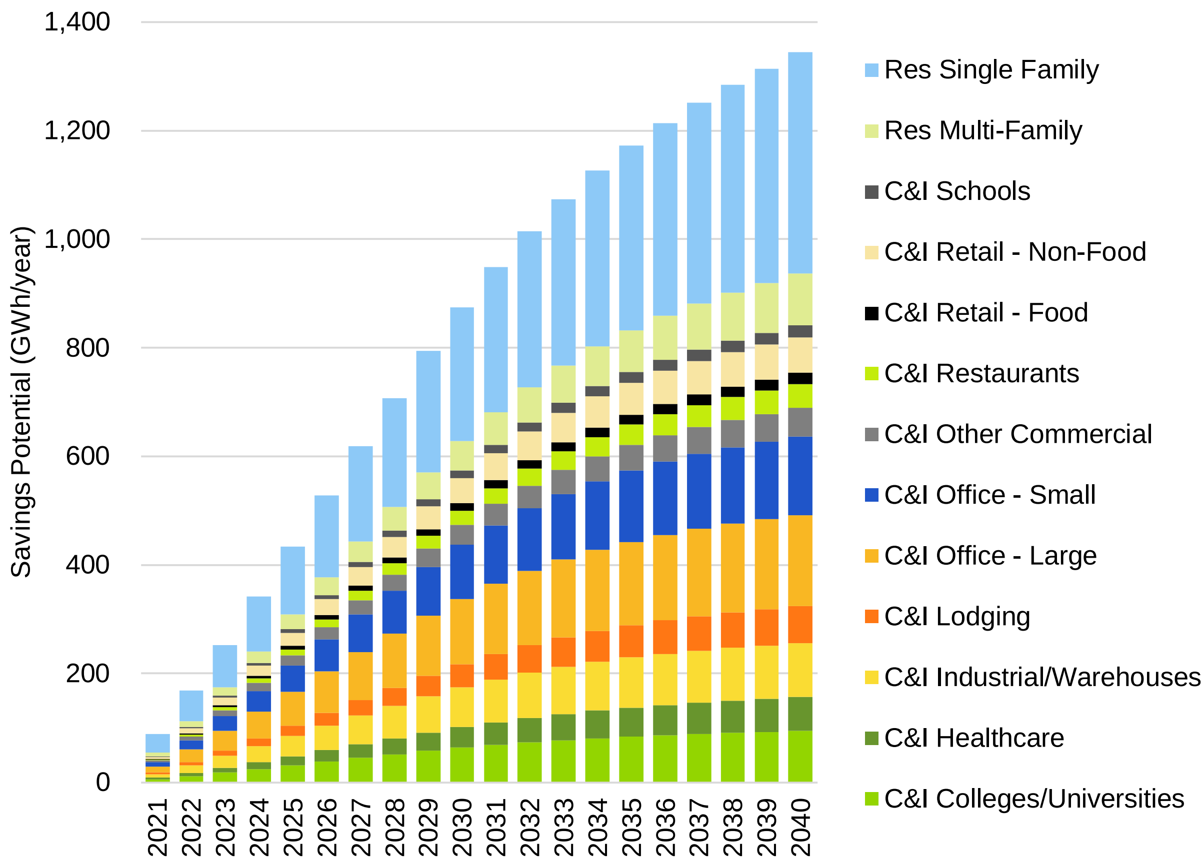
[8] Incentive levels change the customer payback period. Depending on amount of change will result in a change on the payback acceptance curve influencing the market share potential of the energy efficient option. The payback acceptance curve was developed as a result of customer surveys of hypothetical situations from a Midwest utility.

Source: Guidehouse analysis

In the subsequent data, the report highlights the 2% Program case, which most reflects the current ENO PY10-12 Implementation Plan.

Figure 5 shows the cumulative electric energy achievable potential by customer segment. Single-family homes make up the largest residential segment, while large and small offices contribute the most savings to the C&I sector.

Figure 5. 2% Program Case Cumulative Achievable Potential Savings Customer Segment Breakdown



Source: Guidehouse analysis

Table 3 shows the incremental electric energy achievable savings as a percentage of ENO's total sales for each case in 5-year increments. The 2% program case, which was calibrated to the current PY10-12 Implementation Plan, achieves at least 2% of sales savings from 2025 through 2029. The 2% program case and the high case fall below 2% in later years because most of the measures will have been adopted, depleting the available potential in the future years. Behavior program participation maintains the 2% program and high case at greater than 1% throughout the forecast period.

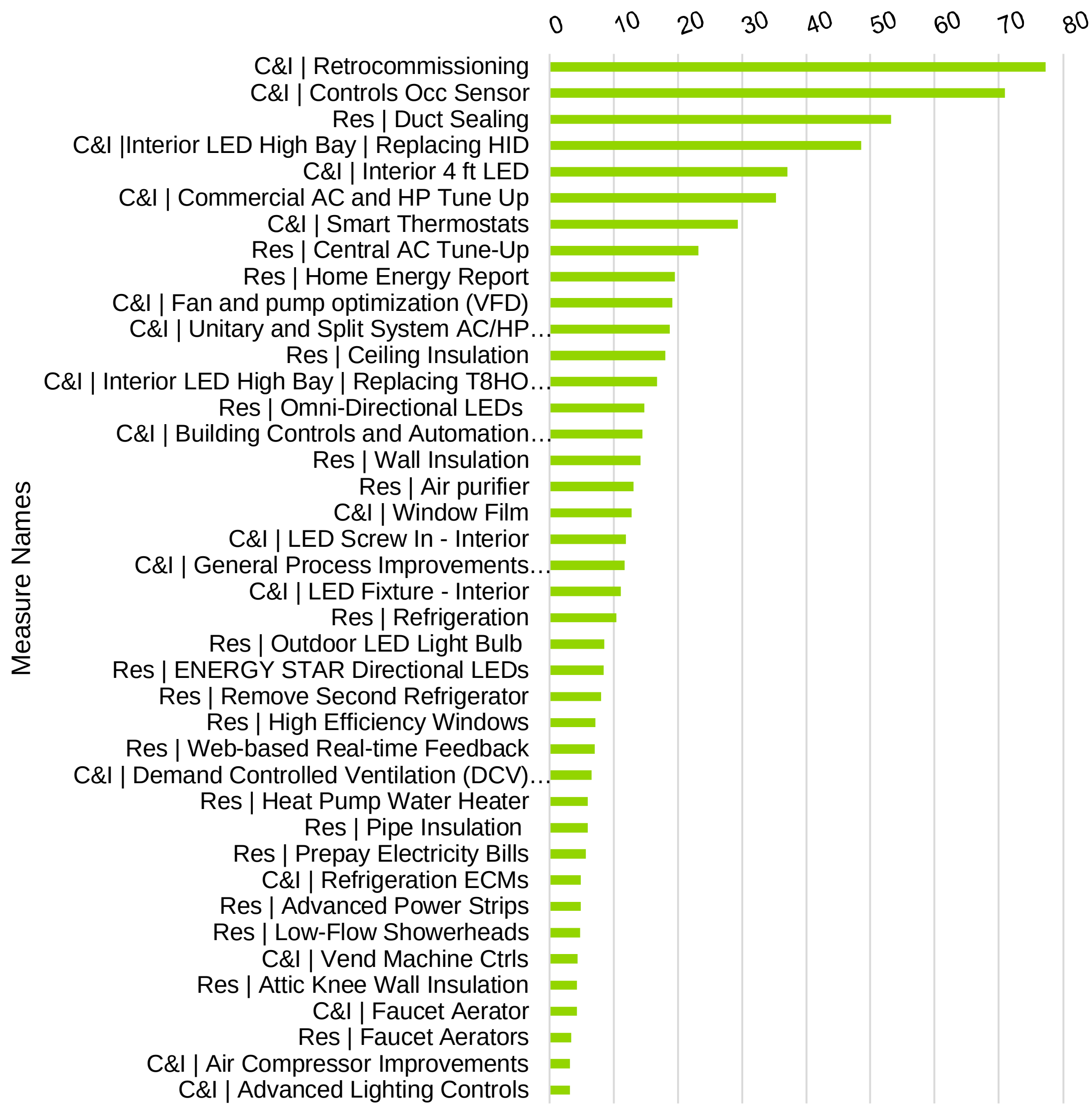
Table 3. Incremental Energy Achievable Savings Potential as a Percentage of Sales by Case (%, GWh)

Year	2%	Low	High	Reference
2021	1.54%	1.34%	1.62%	1.38%
2025	2.05%	1.75%	2.18%	1.78%
2030	1.97%	1.65%	2.10%	1.64%
2035	1.45%	1.12%	1.59%	1.09%
2040	1.22%	0.85%	1.36%	0.84%
Total	22.54%	21.78%	22.79%	21.83%

Source: Guidehouse analysis

Figure 6 shows the top 40 measures contributing to the electric energy achievable potential in 2028 (representative of the 20-year results). Retrocommissioning in the C&I sector provides the most savings, followed by occupancy sensor controls, interior high bay LEDs, 4-foot LEDs and smart thermostats. Residential duct sealing, central AC tune-up and home energy reports provide the highest three residential sector savings.

Figure 6. Top 40 Measures for Cumulative Electric Energy 2% Program Case Achievable Savings Potential: 2028 (GWh/year)



Source: Guidehouse analysis

The total, administrative, and incentive costs for each case are provided in Table 4 in 5-year increments for the study period. Administrative spending is relatively consistent between the cases, while the incentive spending varies significantly between the cases, with higher spending correlated to higher savings.

Table 4. Spending Breakdown for Achievable Potential ($ Millions/Year)[9]

Year	Total				Incentives				Admin			
	2%	Low	High	Reference	2%	Low	High	Reference	2%	Low	High	Reference
2021	$14	$12	$17	$15	$8	$6	$11	$9	$6	$6	$6	$6
2025	$20	$17	$23	$20	$12	$9	$15	$12	$8	$8	$8	$8
2030	$21	$18	$24	$19	$13	$10	$16	$11	$8	$8	$8	$8
2035	$15	$13	$16	$13	$10	$8	$12	$8	$5	$5	$5	$5
Total	$349	$293	$394	$321	$220	$166	$265	$194	$129	$127	$129	$127

Source: Guidehouse analysis

Table 5 shows the portfolio TRC to be cost-effective for all cases. One of the screening criteria in the potential analysis is for the measures to pass the TRC test. A handful of measures were allowed into the analysis that fell below 1.0. As a result, the portfolio is still cost-effective. Typically, the more aggressive the portfolio, the lower the TRC as less cost-effective measures are added and administrative efforts to address more services to the market are increased.

Table 5. Portfolio TRC Benefit-Cost Ratios for Achievable Potential (Ratio)

Year	2%	Low	High	Reference
2021-2040	1.85	1.88	1.84	1.86

Source: Guidehouse analysis

Demand Response

Detailed Approach

Guidehouse developed ENO's DR potential and cost estimates using a bottom-up modeling approach consisting of five steps:

1. Characterize the market
2. Develop baseline projections
3. Define and characterize DR options
4. Develop key assumptions for potential and costs
5. Estimate potential and costs

Guidehouse used primary data from ENO and relevant secondary sources for this analysis as documented in Section 2. Figure 7 summarizes the DR potential estimation approach.

[9] The values in this table are shown in nominal dollars and are rounded to the nearest million which may result in rounding errors.

Figure 7. DR Potential Assessment Steps

Step 1: Market Characterization	Characterize market for DR potential estimation (no. of customers and coincident peak load estimates by customer class- residential, small/large C&I) and by building type.
Step 2: Develop Baseline Projections	Develop baseline projections for customer count and peak demand over the study period (2021-2040).
Step 3: Define DR Options and Characterize	Define and characterize DR options and map applicable options to relevant customer classes.
Step 4: Develop Key Assumptions for Potential & Costs	Develop participation and unit load reduction assumptions under each DR option; develop itemized cost assumptions.
Step 5: Estimate Potential and Costs; Assess Cost-effectiveness of Programs	Present potential estimates by DR option and customer segments, annual and levelized costs, and cost-effectiveness results by scenarios.

Source: Guidehouse

Market Characterization

The team segmented the market appropriately for analysis in the market characterization process for the DR assessment. Guidehouse aggregated data on key characteristics including customer count and peak demand by customer class and segment and end use to input to the model. The customer segmentation for the DR analysis is based on an examination of ENO's rate schedules combined with the customer segments established in the EE potential study.

As part of characterizing the market, the team identified the demand response target period, defined as the peak period. For ENO, this peak period within the summer is defined as the top 40 hours of demand during the hours of 2:00 p.m. through 6:00 p.m., June through September.

ENO expressed a desire to align the peak period definition with times the Midcontinent Independent System Operator (MISO) is expected to see peak demand. This allows ENO to use the findings of the DR potential assessment should it seek to register any DR resources as load modifying resources with MISO. Per MISO's business practice manual, "…the expected peak occurs during the period (June through August) during the hours from 2:00 p.m. through 6:00 p.m."[10] Guidehouse added two additional constraints to this definition. First, the team only included weekdays in the peak period definition because it is not typical for utilities to call DR events on weekends. Second, Guidehouse only included the top 40 weekday hours within this window, which is the typical limit for calling summer DR events. This assumption is consistent with the 2018 study assumption which found that 95% or greater of ENO's system peak occurred within the top 40 hours based on an examination of historical system load data, which is what utilities typically target to call DR events.

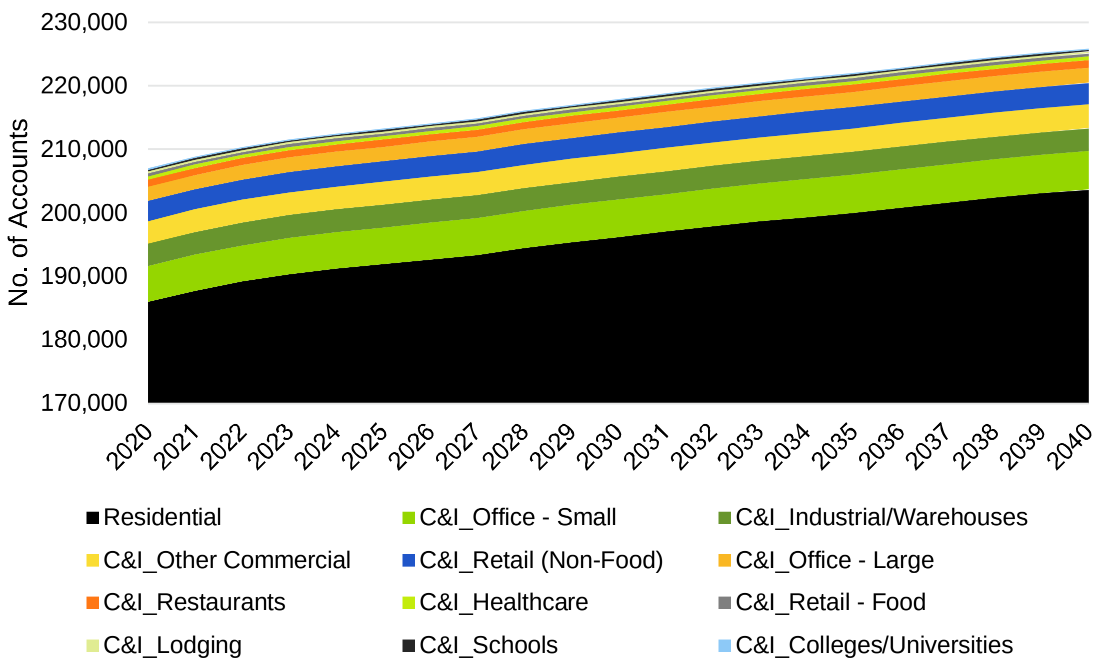
[10] MISO. *Business Practice Manual,* BPM 026, -Demand Response. Effective date: July 20, 2020, pg 20.

Baseline Projections

Baseline projections in the DR potential assessment are a forecast of customer demand over the study period based on existing trends and market characteristics, similar to the base forecast in the EE potential study. The project team used these projections as a basis for modeling savings. More specifically, Guidehouse applied the year-over-year change in the stock forecast of the 2019 customer count data broken out by customer class and segment for the projections. These projections are calibrated to the sector-level customer count forecast ENO provided.

Figure 8 shows the aggregate customer count forecast by segment, summed across all customer classes.

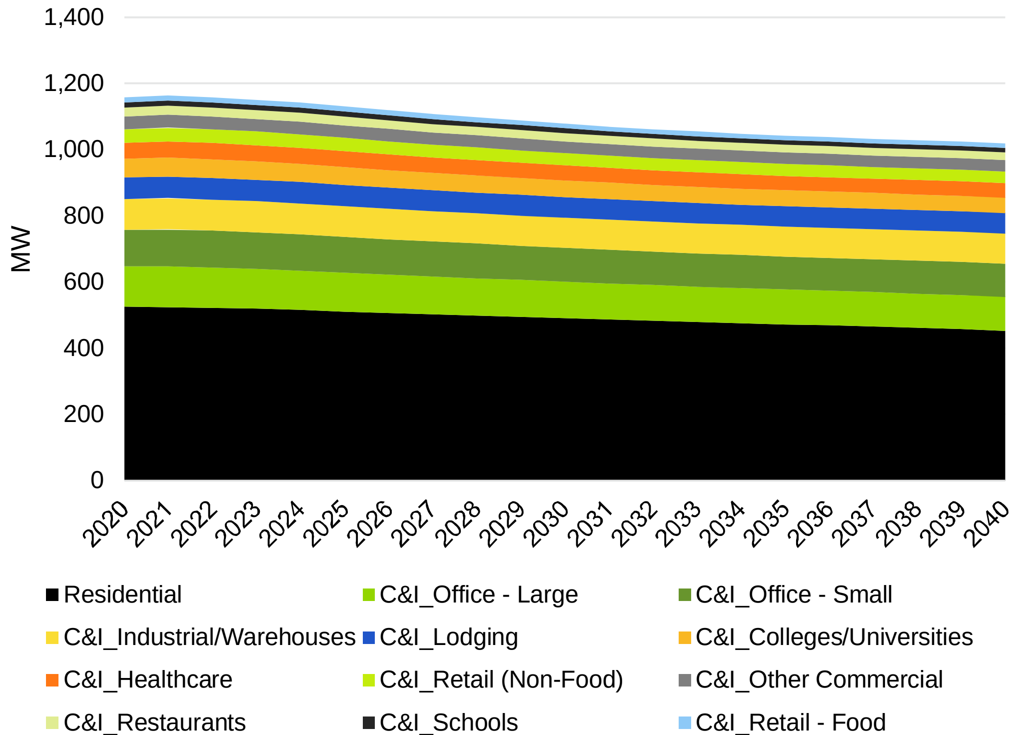
Figure 8. Customer Count Projections for DR Potential Assessment



Source: Guidehouse analysis

Figure 9 shows the summer peak demand projections Guidehouse developed by combining 2019 hourly system load data, 2019 customer count and sales data by NAICS code, load profiles by revenue class, and sales projections by revenue class. Section 2 describes the approach used by Guidehouse to develop disaggregate peak demand projections by customer class and segment. The peak demand projections are adjusted with EE potential estimated to derive the net load post EE, which serves as the baseline load for DR potential estimation. Guidehouse developed the baseline peak demand projections for all three cases (mid, low, and high) corresponding to the EE achievable potential estimates for these three cases. Figure 9 below shows the summer peak demand projections for the mid case. The baseline peak demand projections progressively decline over time due to higher penetration of EE.

Figure 9. Peak Load Forecast by Customer Segment (MW)



Source: Guidehouse analysis

DR Options

Once the baseline peak demand projections were developed, the team characterized different types of DR options that could be used to reduce peak demand.

Error! Reference source not found. summarizes the DR options included in the analysis. The DR options represent ENO's current DR program offers and those that are commonly deployed in the industry. These programs align with Council's IRP rules, which state that DR programs should include those "…enabled by the deployment of advanced meter infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer class." A study of a battery storage program was also included as required by the 2021 IRP Initiating Resolution.[11]

[11] Council Resolution No. R-20-257, p. 12

Table 6. Summary of DR Options

DR Option	Characteristics	Eligible Customer Classes	Targeted/ Controllable End Uses and/or Technologies
DLC[12] ✓ Load control switch ✓ Thermostat	Control of cooling load using either a load control switch or smart thermostat; control of water heating load using a load control switch.	Residential Small C&I	Cooling, water heating
C&I Curtailment[13] ✓ Manual ✓ Auto-DR enabled	Firm capacity reduction commitment with pay-for-performance ($/kW) based on nominated amount or actual performance.	Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads
Dynamic Pricing[14] ✓ Without enabling technology ✓ With enabling technology	Voluntary opt-in dynamic pricing offer, such as Critical Peak Pricing (CPP)	All customer classes	All
BTMS ✓ Standalone battery storage	Dispatch of BTM batteries for load reductions during peak demand periods.	All customer classes	Batteries

Source: Guidehouse

Estimation of Potential

With the market, baseline projections, and DR options characterized, Guidehouse estimated technical and achievable potential by inputting their parameters into its model. Guidehouse developed programmatic assumptions such as participation, unit impacts, and costs to estimate potential and assess cost-effectiveness. The team developed variations in assumptions across the three cases to assess variations in potential estimates with varying levels of incentives and participation projections. The achievable potential estimates presented in the results represent potential from cost-effective DR options that pass the benefit-cost threshold of 1.0 based on the TRC test.

12 This represents both the switch-based and smart thermostat based "Easy Cool" program offered by ENO to residential and small business customers (switch-based option offered only to residential customers and smart thermostat-based option offered to both residential and small business customers).

13 This represents the current Large Commercial Demand Response program offered by ENO to Large C&I customers with greater than 100 kW demand.

14 Guidehouse did not include time-of-use (TOU) rates in the DR options mix because this study only includes event-based dispatchable DR options. TOU rates lead to a permanent reduction in the baseline load and are not considered a DR option.

Guidehouse used the following key variables for potential and cost estimates:

1. Program participation/enrollment assumptions and the rates at which these ramp up
2. Technology market penetration (e.g., penetration of DR-enabling technologies such as smart thermostats and energy management system)
3. Realizable load reduction from different types of control mechanisms, referred to as unit impacts
4. Annual attrition and event opt-out rates
5. Itemized fixed and variable costs which are incurred upfront and on a recurring basis for running DR programs (program development, program administration, marketing and recruitment, incentives, O&M, etc.)

Guidehouse used the following definitions for calculating technical and achievable DR potential:

- **Technical potential** refers to load reduction that results from 100% of eligible customers/load enrolled in DR programs. This is a theoretical maximum.
- **Achievable potential** estimates are derived by applying participation assumptions to the technical potential estimates. The team calculated this by multiplying achievable participation assumptions (subject to program participation hierarchy) by the technical potential estimates.

Unlike EE, the DR analysis does not develop separate economic potential estimates for DR since the cost-effectiveness screening of DR options takes place at the program level under achievable participation assumptions. The achievable potential results presented later in the report only includes cost-effective DR options.

Results

Achievable peak demand reduction potential is estimated to grow from 12 MW in 2021 to 70 MW in 2040. Cost-effective achievable potential makes up approximately 7% of ENO's peak demand in 2040. Guidehouse observed the following:

- DLC has the largest achievable peak demand reduction potential: 39% share of total potential in 2040. DLC potential grows from 6.8 MW in 2021 to 27.4 MW in 2040.
- Dynamic pricing has a 36% share of the total potential in 2040. The dynamic pricing offer begins in 2023 because it is tied to ENO's advanced metering infrastructure implementation plan and readiness to implement the option. The program ramps up over a 5-year period (2023-2027) until it reaches a value of 24 MW. From then on, potential slowly increases until it reaches a value of 25.6 MW in 2040.
- C&I curtailment makes up the remainder of the cost-effective achievable potential with a 25% share of the total potential in 2040. C&I curtailment potential grows rapidly from 5 MW in 2021 to 17.5 MW in 2024. This growth follows the S-shaped ramp assumed for the program over a 3-5-year period. Beyond 2024, the program attains a steady participation

level and its potential slightly decreases (due to changing market and energy intensity forecasts over time) over the remainder of the forecast period, ending at 17.3 MW in 2040.

Table 7**Error! Reference source not found.** lists the DR potential results by option in 5-year increments. The calculated achievable potential for peak load reduction is 70.3 MW in 2040.

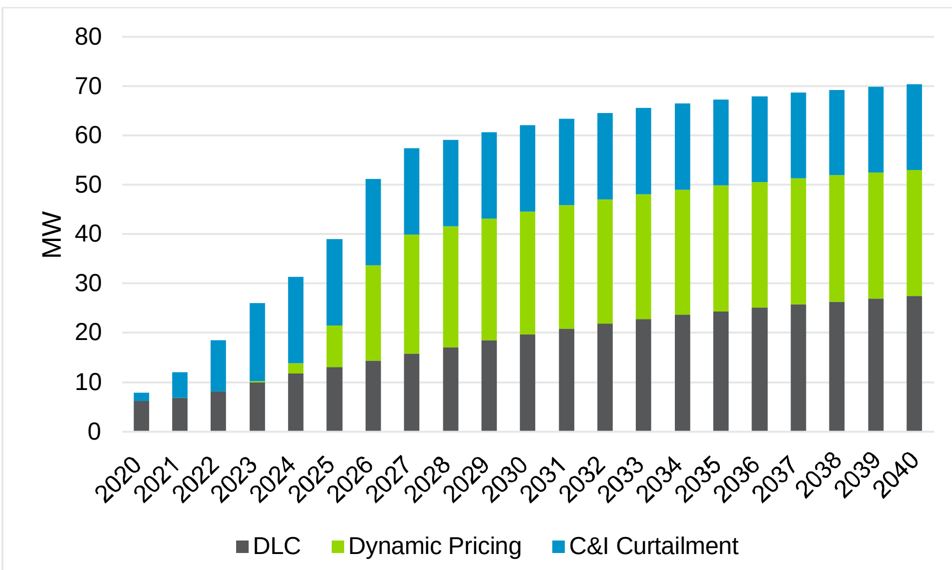
Table 7. Incremental Achievable Summer DR Potential by Option (MW)

Year	DLC	Dynamic Pricing	C&I Curtailment	Total
2021	6.8	0.0	5.2	12.0
2025	13.0	8.5	17.5	39.0
2030	19.7	24.9	17.5	62.1
2035	24.4	25.4	17.4	67.2
2040	27.4	25.6	17.3	70.3

Source: Guidehouse analysis

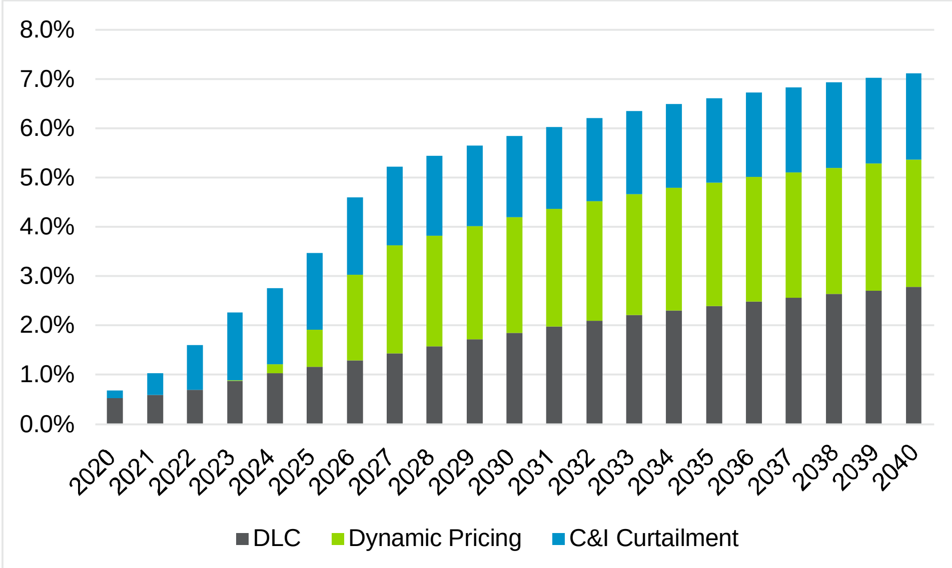
Figure 10 and Figure 11 summarize the cost-effective programs where the benefits exceed the costs (TRC ≥1.0) and achievable potential by DR option for the mid case in megawatts and as a percentage of ENO's peak demand.

Figure 10. Summer Peak Achievable Potential by DR Option (MW)



Source: Guidehouse analysis

Figure 11. Summer DR Achievable Potential by DR Option (% of Peak Demand)



Source: Guidehouse analysis

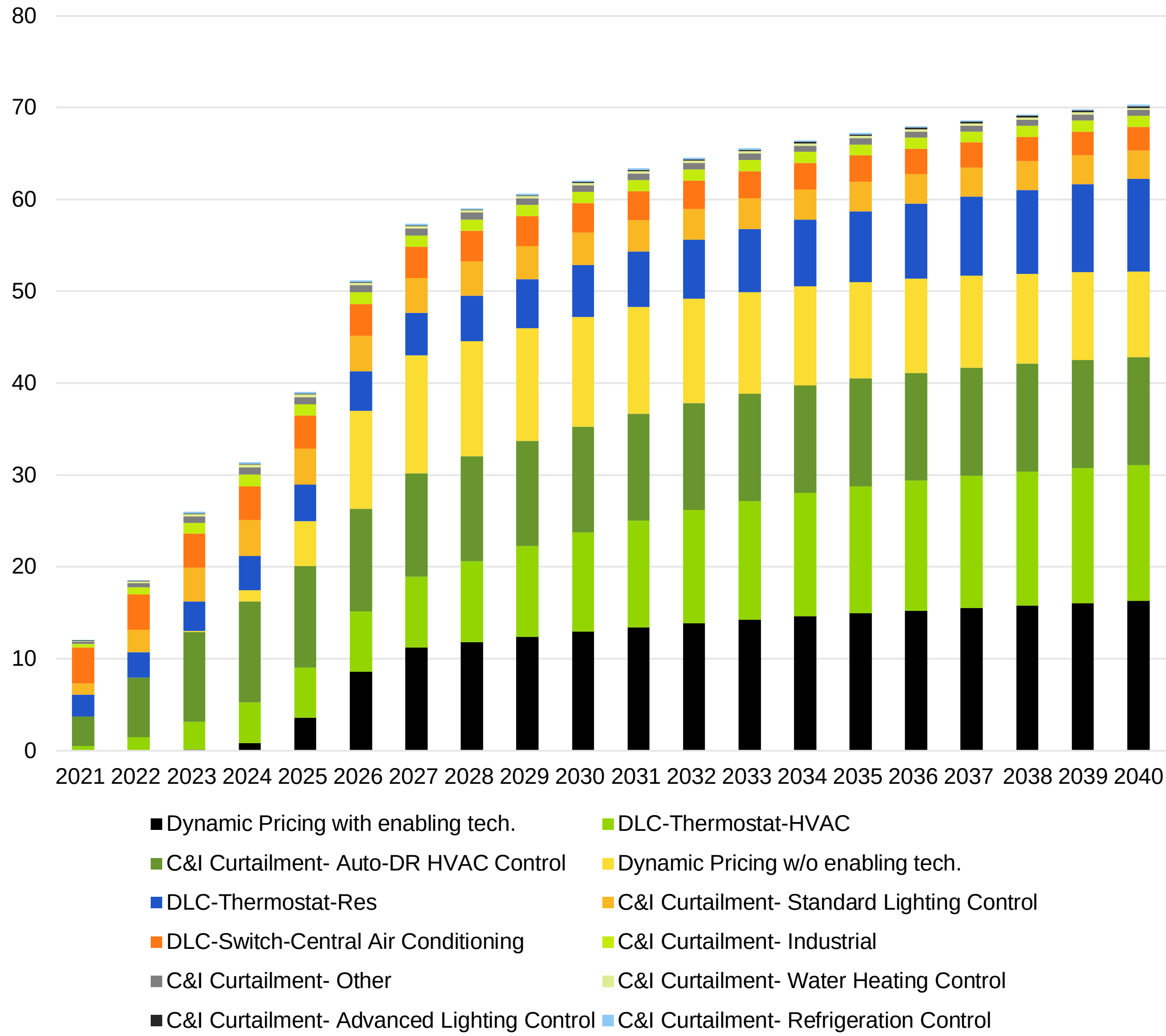
Figure 12 summarizes the cost-effective achievable potential by DR sub-option for the mid case. Analysis of the mid case results by sub-option yielded the following key observations:

- Only direct control of HVAC loads (DLC-Switch and DLC-Thermostat in Figure 12) is cost-effective (and not water heating). This sub-option makes up nearly 40% of the total cost-effective achievable potential in 2040 at 27 MW. Of this 27 MW, 24.9 MW is from thermostat-based control, while the remaining 2.6 MW is from switch-based control.

- Dynamic pricing makes up 36% of the total cost-effective achievable potential in 2040. Potential from customers with enabling technology in the form of thermostats/energy management systems is almost two times higher than that from customers without enabling technology—16 MW versus 9 MW in 2040.

- Under the C&I curtailment program, reductions associated with refrigeration control, advanced and standard lighting control, water heating control, industrial, and auto-DR HVAC control make up 25% of the total cost-effective potential in 2040.

Figure 12. Summer DR Achievable Potential by DR Sub-Option



Source: Guidehouse

Conclusions and Next Steps

The team benchmarked the study results against the 2018 study and similar utilities and identified how the results could be used in ENO's 2021 IRP.

2018 Potential Results

The 2018 and 2021 potential studies leveraged the same methodology, however, there are differences between the two studies.

Energy Efficiency
The 2018 and 2021 studied differed for the following areas:

1. Calibration targets differed for the two studies

   a. 2018 study relied on the historical programs and the 2018 immediate program goal, including delivery costs
   b. 2021 study relied on the existing program framework which has the program plans at or near 2% of consumption
2. Different assumptions on planned rollout for home energy reports
3. Updated data on residential saturation and density data using the Entergy residential appliance saturation study data
4. Updates to commercial saturation values based on year over year program data (for measures where data was available)
5. Changes in commercial lighting baseline and efficient assumptions
6. Updates in the TRM from version 1.0 to version 4.0
7. Addition of new measures
8. Assumptions on measures costs both from Guidehouse sources and the TRM were lower than the 2018 study

Demand response

The 2018 and 2021 demand response analysis differed in the following ways:

1. Guidehouse used actual data of implementation for C&I curtailment. There has been growth in program participation compared to the data from 3 years ago.
2. There is updated data on the penetration of smart thermostat data and updated AMI rollout plan.

These changes resulted in differences in program potential.

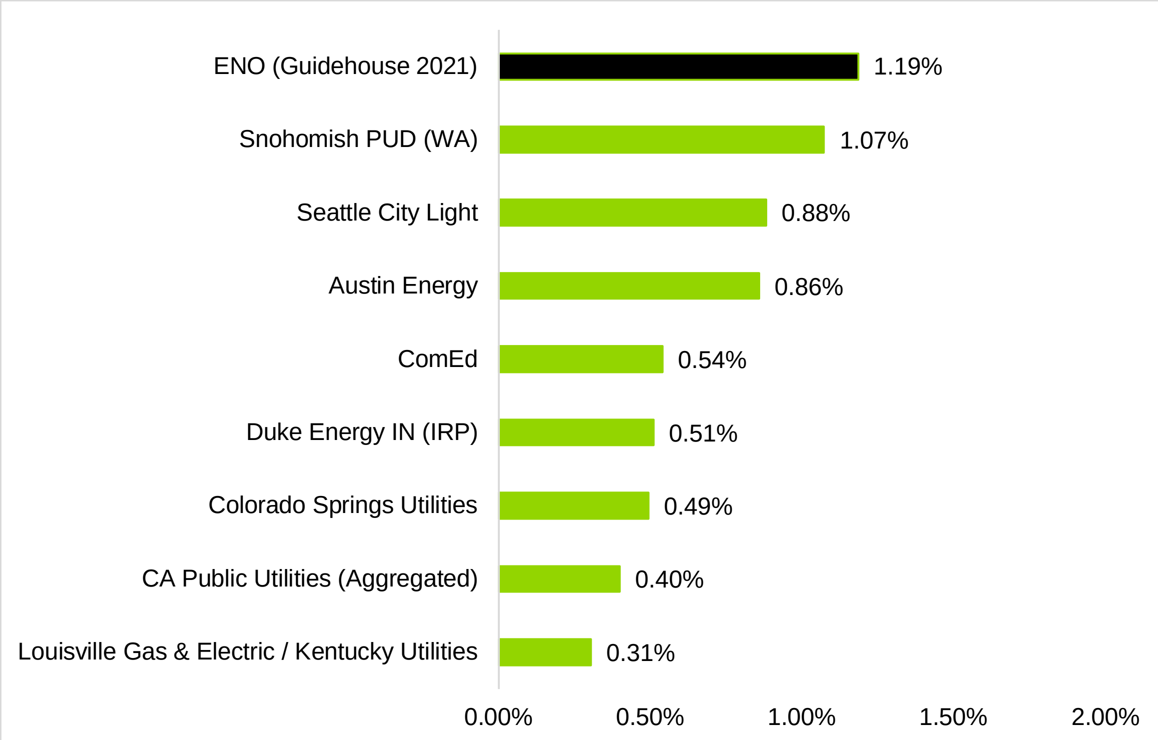
Benchmarking

Guidehouse benchmarked the EE and DR achievable potential results against the potential study findings of other utilities to provide context for our results and to understand how results may be influenced by various factors such as region or program spend.

Figure 13 illustrates how ENO's achievable EE savings potential compares with peer utilities as a percent of sales.[15] ENO is higher than other peer utilities.

[15] There have not been many updates to the peer utility data reports as of the 2018 ENO potential study.

Figure 13. Benchmarking Pool Average EE Achievable Potential Savings (% of Sales)[16]



Source: Guidehouse analysis

The team compared potential estimates and found that although the utilities included in the benchmarking pool may have some similar characteristics, no two utilities are the same; so the results may vary based on the inputs each utility provided to its respective potential study evaluator. Study methodologies may also differ based on the potential study evaluator, providing additional room for variances across studies.

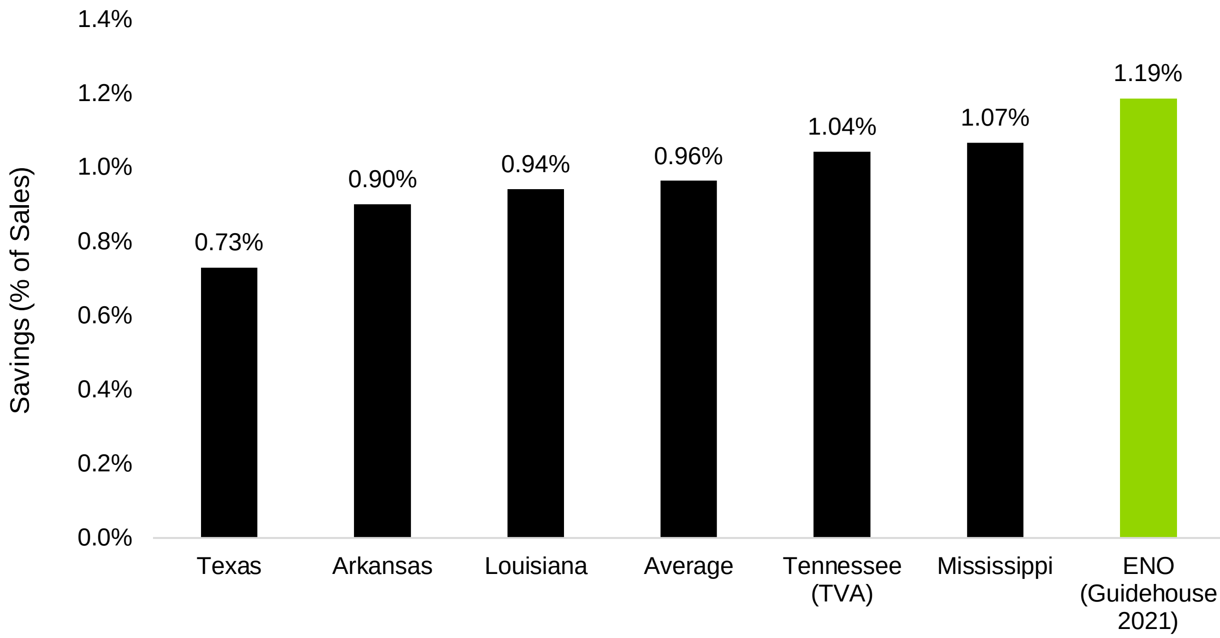
ENO's achievable potential is at the top of the range over the study period (2021-2040). This is similar to Snohomish PUD. Interestingly, both utilities operate in large metropolitan areas and have similar governance structures in that they are regulated by a city council.[17]

In addition to benchmarking the results at the utility level, Guidehouse created a peer pool at the state level. The team's goal was to understand ENO's potential savings within the broader context of the state of Louisiana and its neighbors. Given that the states are mostly clustered within the Southeast region of the US, they have the same general climate (hot-humid) and so may experience similar levels of achievable potential savings. Figure 14 shows how ENO's achievable potential is much higher than the broader state-level context.

[16] These savings are shown as an annual average, which Guidehouse derived by dividing the cumulative study averages by the number of years in the study. Guidehouse used this approach since study years tend to differ greatly.

[17] Unlike ENO, which is an IOU, Austin Energy and Seattle City Light are both POUs that function as departments within their respective municipalities. However, all three must comply with the mandates of the local regulatory body. No updates to Austin Energy and Seattle City Light data have been published since the 2018 DSM study.

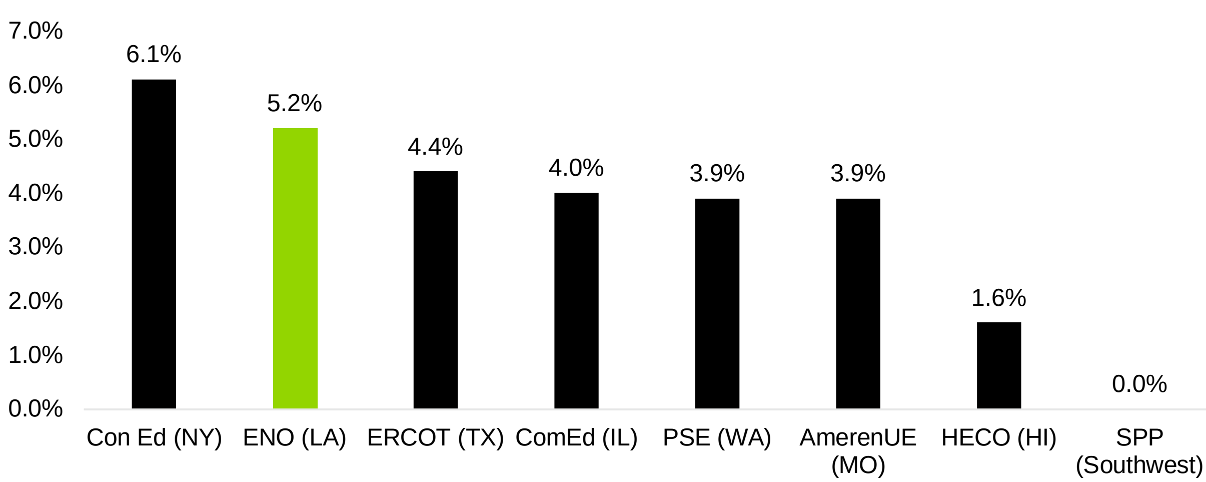
Figure 14. Benchmarking Pool State-Level EE Achievable Potential (% of Savings)



As Figure 14 shows, ENO's achievable potential savings is in the top of the range for the region at 1.19%. When reviewing the comparison, it is important to pay attention to the potential model framework differences, input assumptions, and other parameters for a complete picture of the benchmarking results

Guidehouse also benchmarked DR. Figure 15 displays the results.

Figure 15. Benchmarking Pool DR Potential (% of Savings)



As Figure 15 shows, ENO falls in the top of the benchmarking pool, only slightly higher than ERCOT and slightly below Con Edison in New York. Given that DR, like EE, varies based on program administration and geographic location, among other factors, ENO's DR potential aligns closely to its peers.

IRP

Guidehouse used the study's EE and DR potential savings findings to provide ENO with savings forecast inputs to include in the 2021 IRP modeling process. Guidehouse developed these inputs by sector, segment, and end use, as each combination of these classifications is mapped to a load shape within the IRP analysis (see **Error! Reference source not found.**).

Creating savings inputs for the IRP began with mapping each EE measure to one or more DSM programs. Guidehouse then developed a load shape representative of each DSM program as a whole based on its constituent measures. The resulting DSM program-level load shapes represent the aggregate hourly energy savings for the measures included in the program over the 20-year planning period spanning 2022 to 2041. These load shapes then define the hourly usage profiles for the DSM program portfolio within the IRP model.

Program Planning

This potential study provides ENO with a wealth of data to support and inform DSM program planning efforts. However, programmatic design considerations such as delivery methods and marketing strategies will impact savings goals and costs. **As a result, near-term savings potential, actual achievable goals, and program costs for measure-level implementation will differ from the savings potential and costs estimated in this long-term study.** The findings from this study can effectively be used along with historical program participation, current marketing conditions, and other relevant factors to aid in program design.

Key findings from this potential study may inform program planning, and include the following observations on high potential measures:

- Significant savings potential exists in promoting retro-commissioning, occupancy sensor controls and interior high bay and 4ft LEDs for the C&I sector.

- There is high potential in operations and maintenance (residential duct sealing and AC tune up) and behavior-type programs such as home energy reports in the residential sector.

- Significant demand response potential in the C&I sector for C&I curtailment and DLC; with the residential sector leading in peak demand reduction potential with the increased penetration of enabling technologies like smart thermostats.

As ENO proceeds to future program years, the Guidehouse team suggests research in the following areas:

- Review and update the TRM for high impact measures (for example ceiling insulation and duct sealing)

- Explore cost-effective opportunities, pricing structures, and research on additional benefits to behind the meter generation, including battery storage.

1. Introduction

1.1 Context and Study Goals

Entergy New Orleans, LLC (ENO) engaged Guidehouse to prepare a demand side management (DSM) potential study for electricity as an input to its 2021 Integrated Resource Plan (IRP) for the 2021-2040 period. The study assesses the long-term potential for reducing energy consumption in the residential and commercial and industrial (C&I) sectors by analyzing energy efficiency (EE) and peak load reduction measures and improving end-user behaviors. The EE potential analysis efforts provide input data to Guidehouse's DSM Simulator (DSMSim™) model, which calculates achievable savings potential across the service area. This study also includes demand response (DR) program potential analyzed within Guidehouse's DRSim™. While ENO primarily plans to use the results from the potential study to inform the IRP, these results may also be used as inputs to DSM planning, long-term conservation goals, and EE program design.

1.1.1 Study Objectives

Potential studies provide utilities with a long-range outlook on the cost-effective potential for delivering demand side resources such as EE and DR. A thorough review of achievable potential across ENO's service area helps predict the effects customer actions can have over the forecast period. The current study will allow ENO to incorporate DSM in its IRP modeling and analysis, inform the design of future customer efficiency programs, and understand the level of investment needed to pursue various demand side resource options.

Guidehouse designed its study approach to ensure the results adequately address ENO's objectives and the requirements of the Council's IRP rules. **Error! Reference source not found.** details these objectives and offers Guidehouse's approach to meeting each objective.

Table 1-1. Guidehouse's Approach to Addressing ENO's Objectives

	Objective	Guidehouse's Approach
1	Use consistent methodology and planning assumptions	Guidehouse developed a variety of analytical tools and approaches to inform DSM planning and the establishment of long-term conservation targets and goals (details provided in the following sections). The team worked closely with ENO to ensure transparency, vet methodology, assumptions, and inputs at each stage of this study.
2	Reflect current information	Guidehouse used its prior work with ENO to create a bottom-up analysis that includes inputs, such as the New Orleans TRM, and other up-to-date information (new codes and standards, saturation data from surveys and Energy Smart programs, avoided costs, etc.) are included in this study.
3	Quantify achievable potential	Guidehouse quantifies achievable potential for EE and DR by first calculating the technical and economic (EE only) potential. The achievable potential 2% program case is then calibrated to the historical Energy Smart program data and the current programs approved by the Council for Energy Smart PYs 10-12.

Objective		Guidehouse's Approach
4	Provide input to the IRP	Guidehouse's approach will provide the following for all modeled cases: • Supply curve of conservation potential for input to ENO's IRP • Output available with 8,760 hourly impact load shapes

Source: Guidehouse

1.2 Organization of the Study

Guidehouse organized this study into five sections that detail the study's approach, results, and conclusions. The following list describes each section.

- **Section 1** summarizes the study, including its background and purpose.
- **Section 2** describes the methodologies and approaches Guidehouse used to estimate energy efficiency and demand reduction potential, including discussions of base year calibration, base forecast, and measure characterization.
- **Section 3** details the EE achievable potential forecast, including the approach and results by case, segment, end use, and measure.
- **Section 44** describes the process for estimating DR potential and details the achievable potential savings forecast for ENO, including the modeling results by customer segment. This section also includes our analysis of energy storage potential.
- **Section 5** summarizes the next steps that result from this study's findings and benchmarks those findings against similar potential studies' findings and actual savings achieved by other utilities.

The appendices detail model results and additional context around modeling assumptions.

1.3 Caveats and Limitations

There are several caveats and limitations associated with the results of this study. Potential studies typically begin as a bottom-up effort and then are calibrated to system and sector base year and base forecast consumption. They are an exercise in data management and analysis requiring a careful balancing of abundant data for some inputs with scarce data for others. Accordingly, the team must understand what data gaps exist, and determine how to fill them, to provide reasonable and realistic savings potential estimates. This study documents Guidehouse's approach and the decisions made in cases where appropriate data was not available. Throughout this study, the team leveraged the work conducted for ENO's 2018 IRP Potential study to maximize value to ENO's customers and ensure consistency.

1.3.1 Forecasting Limitations

Guidehouse obtained historic and forecasted energy sales and customer counts from ENO by sector. Each rate class forecast (i.e., residential and C&I) contains its own set of assumptions based on ENO's expertise and models. The team leveraged these assumptions frequently as inputs to develop the base forecast stock and energy demand projections. Where sufficient information could not be extracted due to the limited granularity of the available data, Guidehouse developed independent projections based on better practices. These independent projections were based on secondary data resources and produced in collaboration with ENO. Secondary resources and any underlying assumptions used are referenced throughout this study. Guidehouse referenced the previous 2018 IRP potential study and the existing, approved Energy Smart implementation plans to calibrate the forecast.

1.3.2 Segmentation

Guidehouse obtained data from ENO to segment the residential and C&I sectors, including customer counts by premise type for residential and industry type for C&I. The team supplemented this data through its subject matter expertise and ENO's experience and judgment to ensure alignment of sales and stock data with segments. Government customers were included as part of the C&I sector. Savings potential analysis from city-owned street lighting is not included in this study as the majority of lamps have been converted to LEDs.

1.3.3 Measure Characterization

Efficiency potential studies may employ a variety of primary data collection techniques (e.g., customer surveys, onsite equipment saturation studies, and telephone interviews) that can enhance the accuracy of the results, though not without considerable cost and time considerations. Guidehouse deemed existing primary and secondary data sources as most appropriate to this study.

Energy efficiency measures: The study's scope did not include primary data collection. The EE potential analysis relied on the New Orleans TRM[18] and included data from ENO and other regional efficiency programs and utilities to inform inputs to DSMSim™. Guidehouse sourced density and saturation data for the residential section from an Entergy residential appliance saturation study. Guidehouse used historical program participation data for the C&I programs to provide evidence on saturation levels of efficient technologies.

Guidehouse developed the measure list in this study to focus on those technologies likely to contribute the highest level of savings over the study horizon. As the study excluded nascent technologies not yet marketed, emerging technologies may arise that could increase savings opportunities over the forecast horizon. There is also the potential for broader societal changes (which are not captured in this study) to affect levels of energy use in unforeseen ways. This study does not model these potentially disruptive and unforeseen changes.

DR programs: The scope of this study leveraged available ENO data from the direct load control (DLC) pilot and "EasyCool" program to characterize DR program participation and costs. Additional DR characterization is based on Guidehouse's research on programs nationwide and other potential studies. The team used ENO load and account data to size the market eligible for DR program participation.

1.3.4 Measure Interactive Effects

This study models EE measures independently. The total aggregated EE potential estimates may be higher or lower than the actual potential available if a customer installs multiple measures in

[18] New Orleans Energy Smart Technical Reference Manual: Version 4.0, September 2020, prepared by ADM Associates, Inc. https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/New_Orleans_TRM/New_Orleans_TRM_Version_4.pdf

their home or business. Multiple measure installations at a single site generate two types of interactive effects: within end-use interactive effects and cross end-use interactive effects. An example of a within end-use interactive effect is when a customer implements temperature control strategies but also installs a more efficient cooling unit. If the controls reduce cooling requirements at the cooling unit, the savings from the efficient cooling unit are reduced. An example of a cross end-use interactive effect is when a homeowner replaces heat-producing, less efficient light bulbs with efficient LEDs. This influences the cooling and heating load of the space—however slightly—by increasing the amount of heat and decreasing the amount of cooling generated by the HVAC system.

Guidehouse employed the following methods to account for measure interactive effects:

- Where measures compete for the same application (e.g., an air source heat pump being replaced by a more efficient air source heat pump or a ground source heat pump), the team created competition groups to eliminate the potential for double counting savings.

- For measures with significant interactive effects (e.g., HVAC control upgrades and building automation systems), the team adjusted applicability percentages to reflect varying degrees of interaction.

- Wherever cross end-use interactive effects were appreciable (e.g., lighting and HVAC), the team typically characterized those interactive effects for same fuel (e.g., lighting and electric heating) applications but not for cross fuel because no natural gas savings or consumptions were considered in this study.

The team did not always consider the stacking of savings. These instances included mostly measures from the TRM, the primary source for the measure characterization. For example, if an efficient cooling unit is installed at the same time as improved insulation, the overall effects will be lower than the sum of individual effects. Guidehouse did address stacking for residential behavior programs due to the planned rollout of the residential behavior program to a large percentage of ENO residential customers.

1.3.5 Measure-Level Results

This study includes a high level account of potential results across the ENO service area and focuses largely on aggregated forms of potential. Guidehouse mapped the measure-level data to the customer segments and end-use categories so a reviewer can easily create custom aggregations.

1.3.6 Gross Savings Study

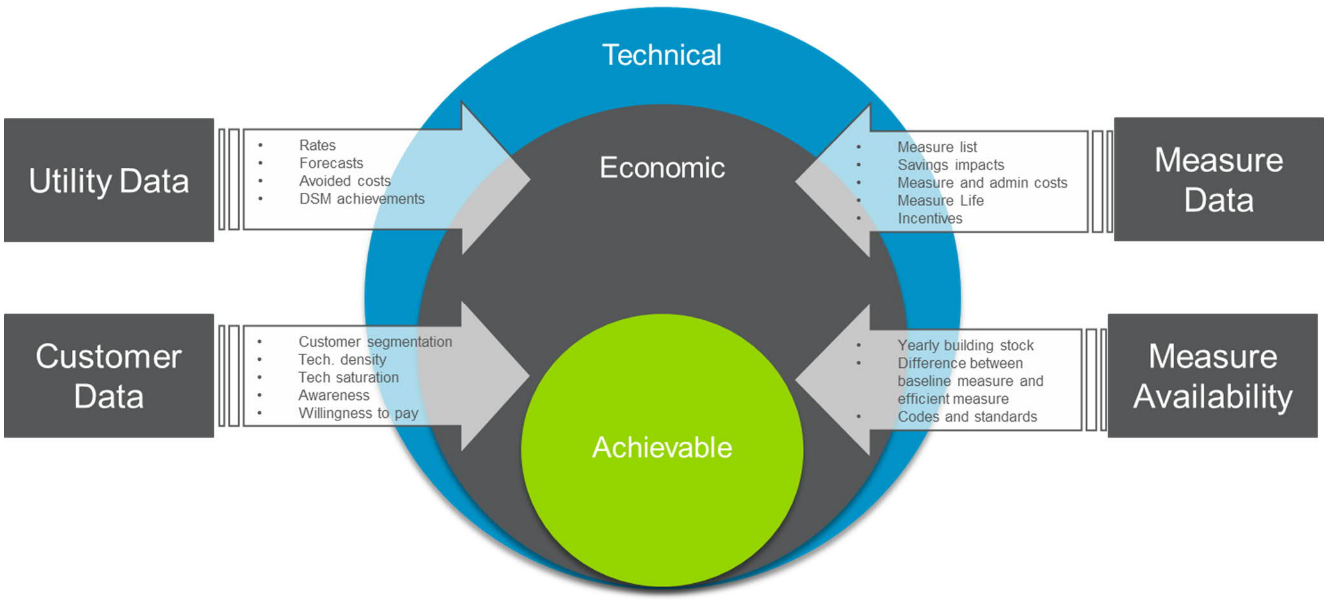
Savings in this study are shown at the gross level, meaning natural change (either natural conservation or natural growth in consumption) or, in other words, free-ridership, is not included in the savings estimates. Providing gross potential is advantageous because it permits a reviewer to easily calculate net potential when new information about changing energy use intensity (EUI) (natural changes in consumption), considerations of program design, or net-to-gross (NTG) ratios become available.

2. Study Approach and Data

2.1 Energy Efficiency

Guidehouse forecast technical, economic, and program achievable electric savings potential in the ENO service area from 2021 through 2040 using a bottom-up potential model. These efficiency forecasts relied on disaggregated estimates of building stock and electric energy sales before conservation and a set of detailed measure characteristics for a thorough list of energy efficiency measures relevant to ENO's service region. This section details the team's approach and methodology to develop the key inputs to the potential model, as Figure 2-1 illustrates.

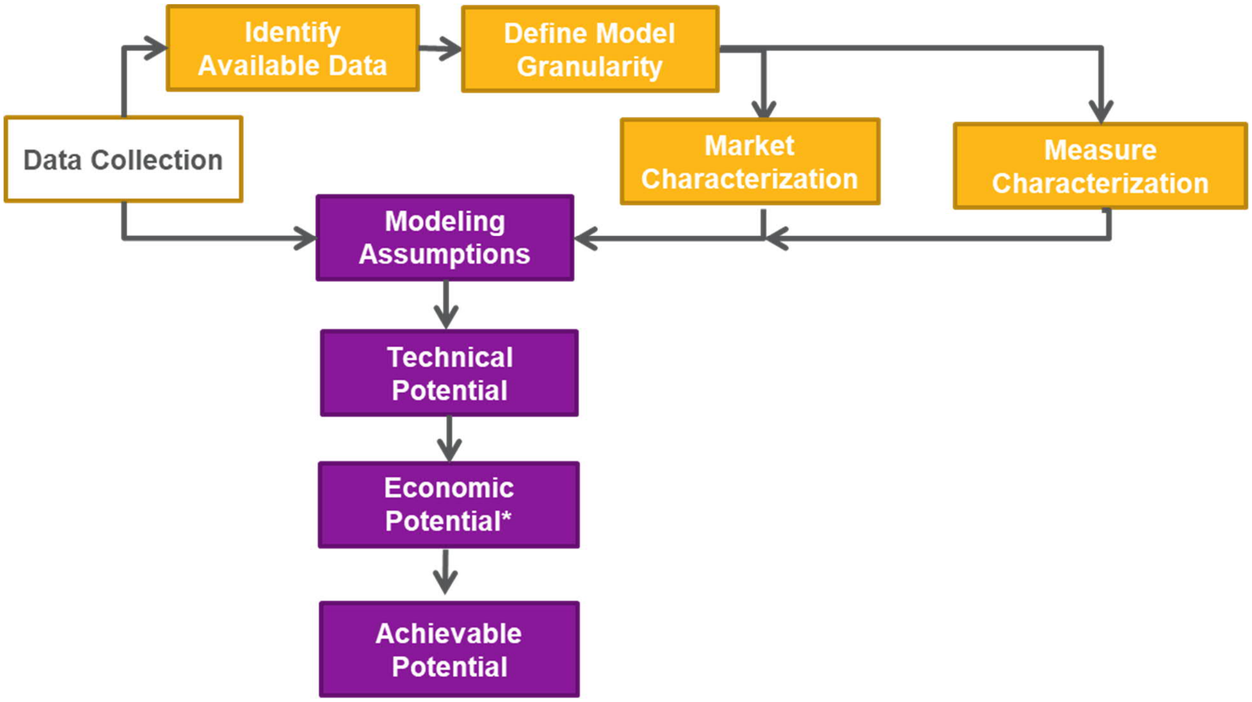
Figure 2-1. Potential Study Inputs



Source: Guidehouse

Calculating achievable potential includes several elements such as a base year calibration, a base forecast consumption, and full measure characterization. Figure 2-2 shows how these elements interact to result in the achievable savings potential.

Figure 2-2. High Level Overview of Potential Study Methodology



*Not calculated for DR Potential

Source: Guidehouse

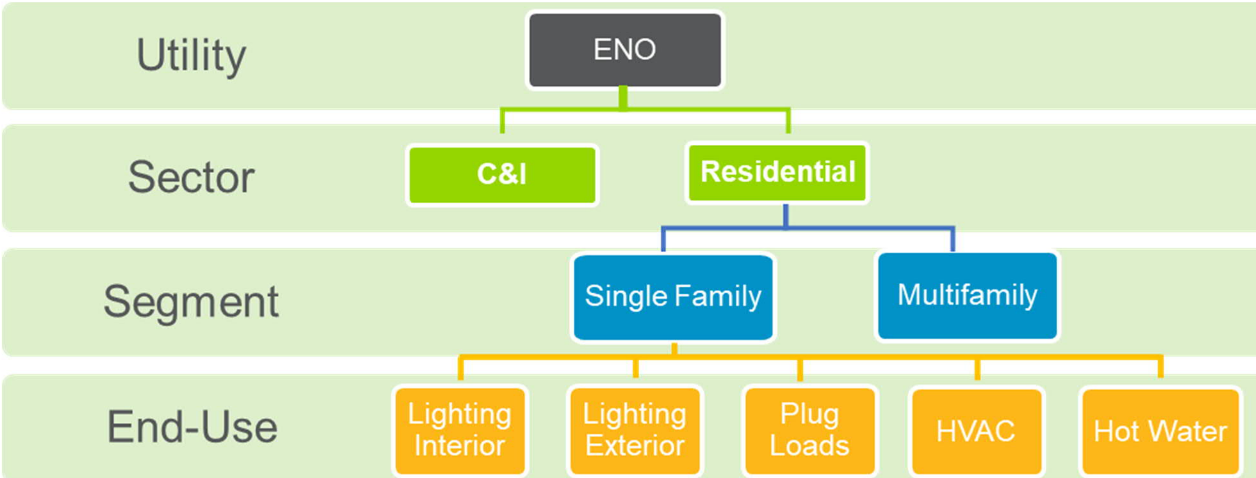
2.1.1 Market Characterization

Guidehouse's model uses inputs from two workflows: market characterization and measure characterization. This section describes the steps involved in the first workflow, market characterization. The market characterization workflow aims to define the base year profile and base forecast consumption used to calculate potential.

2.1.1.1 Base Year Profile

This section describes the approach used to develop the base year (2019) profile of electricity use in ENO's service area, a key input to the potential model. The objective of the base year is to define a detailed profile of electricity sales by customer sector and segment (Figure 2-3). The end use level data is not used in calculating potential. The selected year is the most recent year with actual (not forecasted) reported data. The model uses the base year as the foundation to develop the base forecast consumption of electricity demand from 2021 through 2040.

Figure 2-3. Base Year Electricity Profile – Residential Example



Source: Guidehouse

Guidehouse developed the base year profile based on ENO's 2019 billing and customer account data because it was the most recent year with a fully complete and verified dataset. Where ENO-specific information was unavailable, Guidehouse used data from publicly available sources such as the US Energy Information Administration (EIA) Commercial Buildings Energy Consumption Survey (CBECS) and the US Department of Labor Standard Industrial Classification (SIC) System, in addition to internal Guidehouse data sources. The team used these resources to support ENO's data sources and to ensure consistency.

2.1.1.2 Defining Customer Sectors and Segments

The first major task to develop the base year electricity calibration involved disaggregating the main sectors—residential and C&I—into specific customer segments. The team selected customer segments based on several factors including the 2018 study, TRM characterization, data availability, and level of detail. Table 2-1. Customer Segments by Sector shows the segmentation used for the residential and C&I sectors. The following subsections detail the segmentation used for these sectors.

Table 2-1. Customer Segments by Sector

Residential	Commercial & Industrial
Single-Family	Colleges/Universities
Multifamily	Healthcare
	Industrial/Warehouse
	Lodging
	Large Office
	Small Office
	Other
	Restaurants
	Retail – Food
	Retail – Non-Food
	Schools

Source: Guidehouse analysis

2.1.1.3 Residential Segments

After establishing the study sectors and segments, Guidehouse and ENO aligned ENO's data to the definitions established in Table 2-1 established. For residential, the team divided the sector into two segments based on consumption: single family and multifamily. ENO provided Guidehouse with a 2016 household split survey, which broke down residential customers by household segment: single-family detached, duplexes, townhouses, and the like. Guidehouse mapped the household segments to the appropriate customer segment (single-family or multifamily).

Table 2-2. provides the finalized descriptions for each of these residential segments.

Table 2-2. Residential Segment Descriptions

Segment	Description
Single-Family	Detached, duplex/triplex/fourplex, attached row and/or townhouses (condominium), and mobile homes residential dwellings
Multifamily	Apartment units located in low rise or high rise apartment buildings

Source: Guidehouse

2.1.1.4 C&I Segments

Guidehouse combined the commercial, industrial, and government sectors, noted as C&I. Working with ENO, the team divided the C&I sector into 11 customer segments. Table 2-3. C&I Segment Descriptions describes each segment.

The team selected these C&I segments to be representative of the population of C&I customers in ENO's service area by comparing similar building characteristics such as patterns of electricity use, operating and mechanical systems, and annual operating hours. Generally, the selection of these segments aligned with the New Orleans TRM v4[19] and the SIC code for the account and kilowatt-hour sales data from ENO. This study differs from those sources; it includes industrial/warehouses and other as standalone segments and aggregates fast food and full menu restaurant into a single segment.

Appendix A.3 details on the allocation of the sales and stock data into the C&I sector.

Table 2-3. C&I Segment Descriptions

Segment	Description
Large Office	Larger offices engaged in administration, clerical services, consulting, professional, or bureaucratic work; excludes retail sales.
Small Office	Smaller offices engaged in personal services (e.g., dry cleaning), insurance, real estate, auto repair, and miscellaneous work; excludes retail sales.
Retail – Food	Retail and distribution of food; excludes restaurants.

[19] There are different building types in the V4 of the TRM depending on the measure.

Segment	Description
Retail – Non-Food	Retailing services and distribution of merchandise; excludes retailers involved in food and beverage products services.
Healthcare	Health services, including diagnostic and medical treatment facilities, such as hospitals and clinics.
Lodging	Short-term lodging and related services, such as restaurants and recreational facilities; includes residential care, nursing, or other types of long-term care.
Restaurant	Establishments engaged in preparation of meals, snacks, and beverages for immediate consumption including restaurants, taverns, and bars.
School	Primary schools, secondary schools (K-12), and miscellaneous educational centers, like libraries and information centers.
College/University	Post-secondary education facilities such as colleges, universities, and related training centers.
Industrial/Warehouse	Establishments that engage in the production, manufacturing, or storing of goods, including warehouses, manufacturing facilities, and storage facilities for general merchandise, refrigerated goods, and other wholesale distribution.
Other	Establishments not categorized under any other sector including but not limited to recreational, entertainment, and other miscellaneous activities.

Source: Guidehouse

2.1.1.5 Defining End Uses

The next step in the base year analysis was to establish end uses for each customer sector. Guidehouse defined these uses based on past ENO potential studies and internal expertise.

The end uses in Table 2-4. End Uses by Sector, are important for reporting and defining savings, among other reasons. For instance, the team uses the categories to report achievable savings with more granularity than at the sector and segment levels. Guidehouse derives these reported end-use savings by rolling up individual EE measures that map to the broader end-use categories. For example, savings from ENERGY STAR refrigerators and freezers are reported under the plug load end use.

Table 2-4. End Uses by Sector

Residential	C&I
Lighting Interior	Lighting Interior
Lighting Exterior	Lighting Exterior
Plug Loads	Plug Loads
HVAC	HVAC
Hot Water	Hot Water
	Refrigeration

Source: Guidehouse

In addition to the end uses shown in Table 2-4. End Uses by Sector, Guidehouse reported savings for total facility. These savings represent the sum of all the individual end uses and any miscellaneous loads not captured. The previous study defined heating, cooling, heating and cooling (which was the sum of the heating and cooling), and ventilation separately.

2.1.1.6 Base Year Inputs

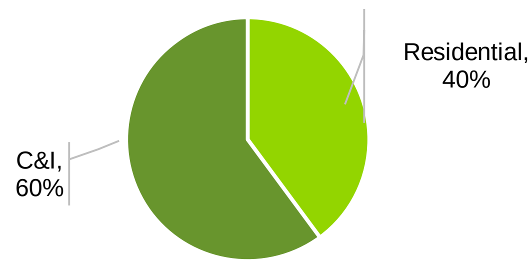
This section summarizes the breakdown of stock (households), electricity sales, and EUIs at the sector, segment, and end-use levels. The team used base year sales as direct inputs to the potential model. Appendix A describes the methodology used to develop these estimates. The DR portion of this study reconciles and derives the breakdown of demand across the sectors, segments, and end uses.[20]

Table 2-5. and Figure 2-4 show the high level breakdown of electricity sales by sector. Of total ENO reported 2019 electricity sales, 60% comes from the C&I[21] sector and 40% from the residential sector.

Table 2-5. 2019 Base Year Electricity Sector Sales (GWh)

Sector	GWh
Residential	2,353
C&I	3,468
Total	**5,821**

Figure 2-4. 2019 Base Year Electricity Sector Breakdown (%, GWh)



Source: Guidehouse analysis of ENO 2019 electricity sales

All other base year inputs are shown and detailed in the following sections.

Residential Sector

To define the base year residential sector inputs, Guidehouse began by determining the base year stock using ENO's number of households in the class breakdown, which was an estimated number of households in 2019 based off of an ENO survey conducted in 2016 and provided in Table 2-6.

Table 2-6. 2016 Survey Household Splits

Household Type	Percent of Total
Single-Family Detached House	63%
Duplex, Triplex, or Fourplex	13%
Condominium/Townhouse/Apartment	24%
Mobile Home or Manufactured Home	1%
Weekend or Vacation Home	1%

[20] Guidehouse developed the peak demand base year using the average peak demand factors from the 2019 sales data for the top 40 hours in each season.

[21] As noted in Section 2.1.1.4, C&I includes commercial, industrial and government sales.

Source: ENO data

Base year sales used the 2019 reported sales provided by ENO. Guidehouse used the 2016 household split survey results to calculate the segment-level base year sales by multiplying the household split by the total. From the 2018 study, Guidehouse had determined that multifamily households consume 67% of the electricity that a single-family household does based on data provided by ENO. Using this ratio, the single family and multifamily household splits were multiplied by the ratio of their energy use – 1 for single family, and 0.67 for multifamily – to calculate weighted household splits. Then to calculate the percentage of sales for each segment, the weighted household splits for each segment were divided by the summed weight of the single family and multifamily household splits. To calculate segment-level sales, Guidehouse multiplied the percentage of sales by the total reported 2019 sales.

Table 2-7. shows the base year residential stock, electricity sales, and average electricity usage per home by segment. The base year residential stock is approximately 186,000 homes and accounts for just over 2,350 GWh of sales.

Table 2-7. Base Year Residential Results

Segment	Stock (Accounts)	Electricity Use (GWh)	kWh per Account
Multifamily	46,100	425	9,219
Single-Family	140,143	1,928	13,759
Total	**186,243**	**2,353**	**12,635**[22]

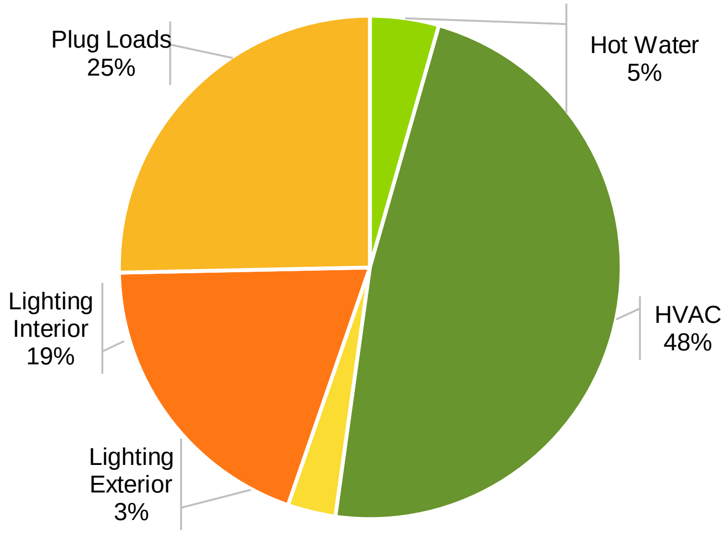
Source: Guidehouse analysis of ENO data

Figure 2-5 shows the breakdown of base year residential electricity sales by end use and segment. In terms of end uses, lighting, HVAC, and plug loads represent the largest residential end uses and account for 90% of residential electricity sales. HVAC represents the largest portion of the residential end uses at 48% of the total, and includes the sum of heating, cooling, and ventilation. This end use allocation was based on the 2018 study.[23]

[22] Note that this number represents the average annual kWh consumption for all households (total electricity use/ total accounts) and not the sum of the kWh per account for the two segments

[23] ENO provided Guidehouse end use breakdown analysis for its load forecast. The residential allocation was similar to Guidehouse's previous estimates.

Figure 2-5. Base Year Residential Electricity End-Use Breakdown (%, GWh)



Source: Guidehouse analysis

C&I Sector

Similar to the residential sector, Guidehouse needed to determine the base year stock (thousands square feet [SF]) by segment, sales (kWh) by segment, and EUIs (kWh/thousands SF) by end use. Guidehouse followed two steps to determine these values for the base year:

1. Define sales usage based on ENO's account and billing data
2. Determine the base year stock

This section outlines the general processes for each of these steps. Appendix A.3 details the calibrations, data, and calculations used to define the base year values.

For step 1, Guidehouse used a mapping of SIC codes to customer segment to aggregate ENO's account and billing data to the segment level for the base year 2019. Once the segment mapping was complete, Guidehouse used the segment-level intensities from EIA that were also used in the 2018 study for industrial. For commercial and government intensities, Guidehouse took the EIA segment-level intensities and adjusted them so the C&I sector-level intensity equaled the Itron intensity for 2019. Using the resulting intensities, Guidehouse calculated stock (square feet) for each segment by dividing sales by intensity.

Table 2-8 shows the base year C&I stock (SF of floor space), electricity sales, and average electricity usage per SF by segment. C&I floor space stock is estimated at 247 million SF and contributes approximately 3,468 GWh of sales.

Table 2-8. Base Year C&I Results

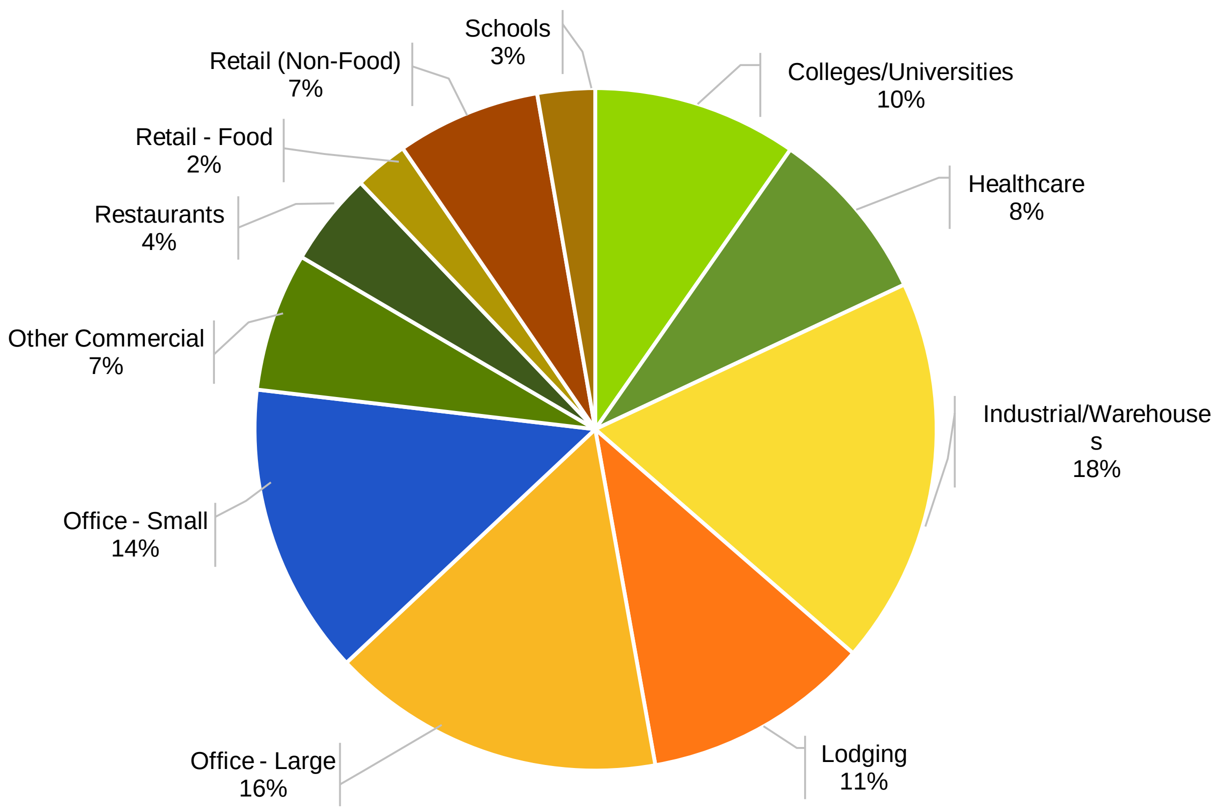
Segment	Stock (thousands SF)	Electricity Use (GWh)	kWh per SF
College/University	38,282	340	8.9
Healthcare	14,738	293	19.9

Segment	Stock (thousands SF)	Electricity Use (GWh)	kWh per SF
Industrial/Warehouse	22,602	642	28.4
Lodging	35,475	372	10.5
Office – Large	45,426	539	11.9
Office – Small	40,537	481	11.9
Other Commercial	15,243	229	15.0
Restaurant	4,754	153	32.2
Retail – Food	2,609	88	33.9
Retail – Non-Food	17,022	235	13.8
School	10,991	98	8.9
Total	**247,679**	**3,468**	-

Source: Guidehouse analysis

Figure 2-6 shows the breakdown of base year C&I electricity sales by segment. Offices and lodging consume the most electricity, accounting for almost half (40.5%) of C&I electricity sales.

Figure 2-6. Base Year C&I Electricity Segment Breakdown (%, GWh)

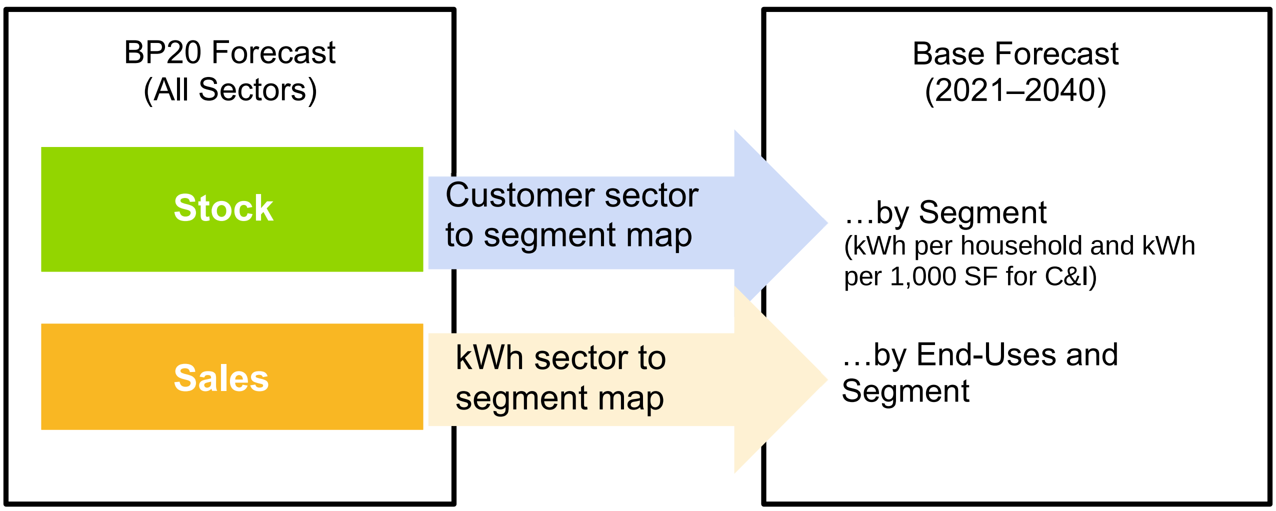


Source: Guidehouse analysis

2.1.2 Base Forecast Consumption

This section presents the base forecast consumption from 2021 to 2040. The base forecast consumption represents the expected level of electricity sales over the study period, absent incremental DSM activities or load impacts from rates. Electricity sales in the base forecast consumption are consistent with ENO's load forecast. The base forecast consumption is significant because it acts as the point of comparison (i.e., the baseline) for the calculation of achievable potential cases. Figure 2-7 illustrates the process Guidehouse used to develop the base forecast consumption. The base forecast consumption uses the Business Plan 2020 (BP20) forecast as its foundation and converts it to the required customer segments to develop the residential and C&I forecasts.

Figure 2-7. Schematic of Base Forecast Consumption



Source: Guidehouse

Guidehouse constructed the base forecast consumption by using the BP20 sales forecast and disaggregating from ENO sectors[24] to customer segments. The forecast applies growth rates from ENO's account and load forecasts directly to the base year stock, sales, and EUI values.

The following sections describe the approach and assumptions employed and present the results of the residential and C&I reference case forecasts. Appendix A provides the details.

2.1.2.1 Residential Base Forecast Consumption

Guidehouse used the BP20 residential customer count forecast to develop the base forecast consumption for stock. Using the same 2016 household split survey Section 2.1.1.5 describes, Guidehouse disaggregated the residential forecast to the segment level (single-family and multifamily) by multiplying the household segment percentages by the total residential forecast. Table 2-9. shows the growth in residential stock forecast from 2020 to 2040. Residential stock increases at an average annual growth rate of 0.5% from approximately 186,000 accounts in 2020 to around 205,000 accounts in 2040.

[24] ENO sectors were residential, commercial, industrial, and government.

Table 2-9. Residential Base Stock Forecast (Accounts)

Segment	2020	2040
Single-Family	140,143	154,780
Multifamily	46,100	50,914
Total	**186,243**	**205,694**

Source: Guidehouse analysis of ENOs residential load forecast

Guidehouse followed a similar methodology for sales, using ENO's forecasting. The team used the BP20 sales forecasts and disaggregated to the segment level using the class breakdowns adjusted for energy use, as Section 2.1.1.5 describes.

Guidehouse reviewed new ENO data sources (ENO load research data) with the 2018 study approach for defining the end-use proportion. Guidehouse determined that the 2018 method is suitable for use in the 2021 study since it aligned well with the ENO data sources.. Appendix A.2 details the end use energy intensity calculations.

2.1.2.2 C&I Base Forecast Consumption

Like the residential base forecast, Guidehouse built the C&I base forecast on the BP20 sales forecast from ENO. Appendix A.3 describes the process used to develop the C&I stock forecast.

To forecast the customer counts and sales, Guidehouse used the ENO forecast, which was at the ENO sector level (commercial, industrial, and government). Guidehouse converted the forecast to the segment level using a customer segment to sector map derived from the account and billing data.

To forecast the stock, Guidehouse developed escalators using the sales forecast and the Itron intensity forecast. For non-industrial segments, Guidehouse divided the sales forecast by the Itron intensity forecast and converted the resulting time series into an escalation factor. For industrial segments, Guidehouse escalated stock based on the forecasted number of customers. Then the escalation factors were applied to the base year stock to develop the base forecast through 2040.

Table 2-10. shows the results of the reference case analysis.

Table 2-10. C&I Base Stock Forecast (Thousands SF)

Segment	2019	2040
Colleges/Universities	37,477	46,548
Healthcare	14,443	17,939
Industrial/Warehouses	22,242	22,389
Lodging	35,396	43,962
Office – Large	45,886	54,077
Office – Small	40,150	49,867
Other Commercial	15,035	18,673
Restaurants	4,745	5,894
Retail – Food	2,604	3,234
Retail – Non-Food	16,981	21,090

Segment	2019	2040
Schools	10,663	13,244
Total	**245,623**	**296,917**

Source: Guidehouse analysis

Guidehouse used the 2018 end-use proportions to distribute energy use among end uses. Appendix A.3 details the 2018 process. The new ENO data from the load research analysis did not provide end use allocation by building segment. The building segment specific end use energy intensity is a more definitive data set for the potential analysis.

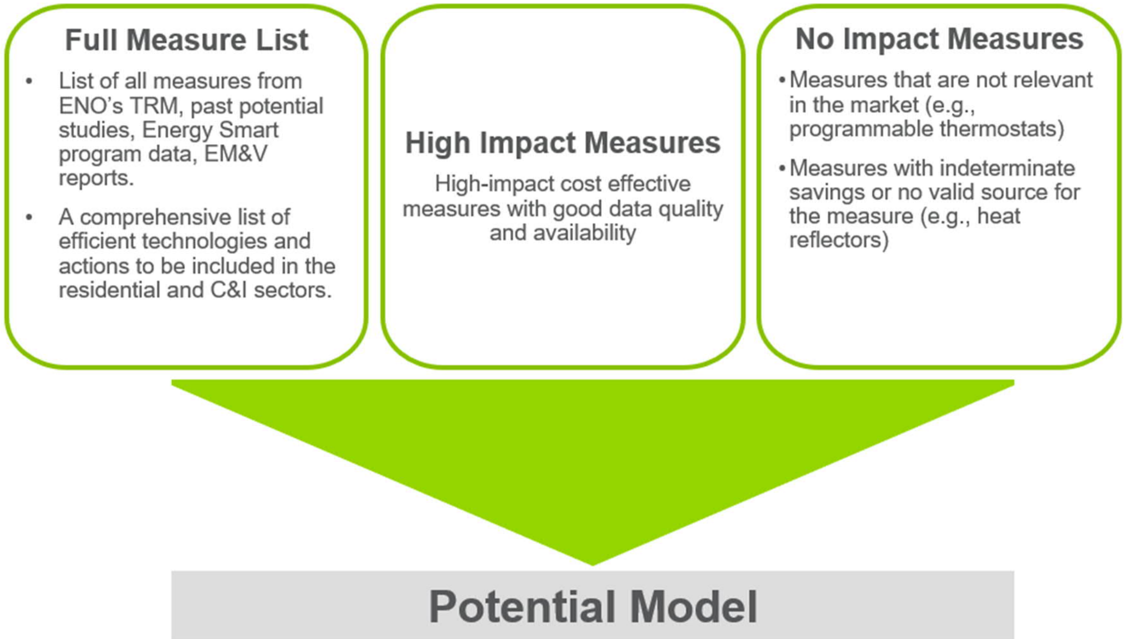
2.1.3 Energy Efficiency Measure Characterization

Guidehouse characterized 146 measures across ENO's residential and C&I sectors. While finalizing the measure list, the team prioritized high impact, cost-effective measures with good data quality and availability.

2.1.3.1 Measure List

Guidehouse developed a thorough list of EE measures likely to contribute to achievable potential. The team used the measure list from the 2018 ENO potential study as the basis and updated it with measures in the New Orleans Energy Smart TRM v4, current ENO Energy Smart program offerings, and potential model measure lists from other states to identify EE measures with the highest expected economic impact. The team supplemented the measure list using secondary data from publicly available sources such as TRMs from various US regions including California, Illinois, and the mid-Atlantic. Guidehouse prioritized measures in existing ENO Energy Smart programs based on data availability for appropriate characterization and measures most likely to be cost-effective. The team worked with ENO and ENO contractors, including program implementers, to finalize the measure list and ensure it contained technologies viable for future ENO program planning activities. Figure 2-8 shows the process Guidehouse implemented to finalize the measure list.

Figure 2-8. Measure Screening Process



Source: Guidehouse

There were measures included in the initial screen that did not make it into the study. Working sessions with ENO staff revealed the following measure information:

- **Residential thermostats:** Programmable thermostats control space temperatures according to a preset schedule, while smart thermostats are Wi-Fi-controlled and implement a learning algorithm to control temperature to a desired level while managing HVAC energy use. ENO recently conducted a pilot study in low income housing in anticipation of developing a future program offering. Programmable thermostats were not included in this study as they have limited potential with the advent of Wi-Fi thermostats.

- **Industrial measures:** ENO reported that its industrial energy use is relatively low compared to commercial and residential sectors. Guidehouse retained the industrial measures from the 2017 potential study and did not add any new industrial measures. The team aggregated the industrial sector potential with the commercial sector potential.

2.1.3.2 Measure Characterization Key Parameters

The measure characterization effort involved defining nearly 50 individual parameters for each measure included in this study. This section defines the top 14 parameters and how each influences the technical and economic (and also achievable) potential savings estimates.

Table 2-11. includes parameters used to qualitatively define each characterized measure.

Table 2-11. Measure Characterization Parameter Definitions

Parameter Name	Definition	Example
Baseline Measure	Existing inefficient equipment or process to be replaced.	Central Air Conditioner 15 SEER
Energy Efficiency Measure	Efficient equipment, process, or project to replace the baseline.	ENERGY STAR Central Air Conditioner 18 SEER
Measure Lifetime	The lifetime in years for the base and energy efficient technologies. The base and energy efficient lifetimes only differ in instances where the two cases represent inherently different technologies, such as solar water heaters compared to a baseline of regular storage water heaters	Storage Water Heater: 10 years Solar Water Heater: 15 years
Measure Costs	The incremental cost between the assumed baseline and efficient technology using the following variables: • Base Costs: The cost of the base equipment, including both material and labor costs. • Energy Efficient Costs: The cost of the energy efficient equipment, including both material and labor costs.	Baseline cost: $690 Efficient cost: $500
Replacement Type	Identifies when in the technology or building's life an efficiency measure is introduced. Replacement type affects when in the potential study period the savings are achieved as well as the duration of savings and is discussed in greater detail in Section 2.1.4.1	Retrofit (RET), replace-on-burnout (ROB) and new construction (NEW)
Annual Energy Consumption	The annual energy consumption in electricity (kWh), demand (kW) for each baseline and energy efficiency measure.	Baseline: 196 kWh/year Efficient: 163 kWh/year
Unit Basis	The normalising unit for energy, demand, cost, and density estimates.	Per bulb, per hp, per kWh consumption.
Scaling Basis	The unit used to scale the energy, demand, cost and density estimate for each measure according to the reference forecast.	Per home, per 1,000 SF of commercial area, etc.
Sector and End Use Mapping	The team mapped each measure to the appropriate end uses, customer segments, and sectors across ENO's service area. Section 2.1.1 describes the breakdown of customer segments within each sector.	ENERGY STAR room air conditioners are mapped to the HVAC end use in the single family and multi-family segments.
Measure Density	Used to characterise the occurrence or count of a baseline or energy efficiency measure, or stock, within a residential household or within 1,000 square feet of a commercial building. This parameter was not defined for industrial measures.[25]	35 bulbs per household.

[25] Guidehouse sourced density estimates from the Entergy 2016 Residential Appliance Saturation Survey (ENO RASS), Energy Smart program data and other related secondary sources. Additionally, the density value addressed any reference to fuel type splits for space and water heating.

Parameter Name	Definition	Example
Energy Efficiency Saturation	The fraction of the residential housing stock or commercial building space that has the efficiency measure installed each year. For the industrial sector, saturations are based on energy consumption.	40% of all residential bulbs are LEDs so saturation of LEDs is 40%.
Technical Suitability	The percentage of the base technology that can be reasonably and practically replaced with the specified efficient technology.	Occupancy sensors have a technical applicability of less than 1.0 because they are only practical for interior lighting fixtures that do not need to be on at all times.
Competition Group	Identifies measures competing to replace the same baseline density in order to avoid double counting of savings. Section 2.1.4.1 provides further explanation on competition groups.	Efficient storage tank water heater or a tankless water heater can replace an inefficient storage water heater, but not both.

2.1.3.3 Measure Characterization Approaches and Sources

This section provides approaches and sources for the main measure characterization variables.

Table 2-12. Measure Characterization Input Data Sources

Measure Input	Data Sources
Measure Costs, Measure Life, Energy Savings	• New Orleans Energy Smart Technical Reference Manual: Version 4.0 • Energy Smart program data • 2018 ENO potential study data • US DOE Appliance Standards and Rulemakings supporting documents • Engineering analyses • TRMs • Guidehouse measure database and previous potential studies
Fuel Type Applicability Splits, Density, Baseline Initial Saturation, Technical Suitability, End-Use Consumption Breakdown	• Entergy 2016 Residential Appliance Saturation Survey (ENO RASS) • Energy Smart program data • Guidehouse's previous potential studies
Codes and Standards	• US DOE engineering analyses • Local building code

Source: Guidehouse

2.1.3.4 Energy Savings

Guidehouse used three bottom-up approaches to analyze residential and C&I measure energy savings:

1. **New Orleans TRM calculations:** The New Orleans Energy Smart TRM v4 was the primary source for unit energy savings calculations. The TRM provided deemed (default) savings values for majority of the measures in the study.
2. **Standard algorithms:** Guidehouse used standard algorithms for unit energy savings calculations for most measures not contained in the New Orleans TRM. To supplement this, the team used ENO Energy Smart Program Evaluation Reports, other relevant TRMs such as the Illinois and Mid-Atlantic TRM, and DOE Appliance Standards and Rulemaking supporting documents.
3. **Engineering analysis and engineering studies:** Guidehouse used engineering algorithms to calculate energy savings for any measures not included in the New Orleans TRM or other available TRMs. The team also referenced established engineering studies with savings estimates in absence of engineering algorithms. The team used its internal expertise with potential studies to calculate energy savings for measures that were not a part of the New Orleans TRM v4.

2.1.3.5 Peak Demand Savings

Peak demand savings were either from the New Orleans Energy Smart TRM v4 or calculated by dividing the annual energy use by the annual hours of use and then multiplying by a coincidence factor. The coincidence factor is an expression of how much of the equipment's demand occurs during the system's peak period. According to the TRM, the defined peak period is the average peak demand savings, Monday-Friday, non-holidays from 4-6 p.m. in June, July, and August.

2.1.3.6 Incremental Costs

New Orleans Energy Smart TRM v4 was the primary source for incremental cost information. The team conducted secondary research and used other publicly available cost data sources such as the Illinois and the Mid-Atlantic TRMs, California TRM, ENERGY STAR, US DOE Appliance Standards and Rulemaking for measures where cost information was not available in the ENO TRM.

2.1.3.7 Densities

For the residential density values, we used the Entergy 2016 Residential Appliance Saturation Survey to extract square footage of home by housing type, space heating and cooling system splits, density and saturation values for measures such as dishwashers, clothes washers, dryers, refrigerators, thermostats, windows, attic insulation, central air conditioners and room air conditioners. Our team cross tabulated the data for each housing type to get these values for single-family and multifamily segments.

For commercial measures, the density values from the previous potential study were retained for most measures. Measure saturations were updated for measures available in the Energy Smart Program data. The Commercial Building Stock Assessment (CBSA) and previous potential studies in other jurisdictions were reviewed for any other overall updates to the saturation values. For water and space heating measures, the fuel type multipliers from the previous ENO potential study were incorporated directly into the measures. For commercial lighting, measure densities were updated based on recent lighting studies in other jurisdictions as the previous ENO potential study was using values from an older study conducted in 2015.

2.1.3.8 8,760 Load Profile

No updates were made to the 8,760 load profiles in the 2021 study. This study leverages the 2018 developed load profiles **Error! Reference source not found.** describes. There was no new data to leverage or to develop new load profiles. These load shapes should still be representative of customer usage patterns in ENO territory. These profiles are 8,760 (i.e., hourly annual) end-use load shapes. These profiles are by end use (e.g., heating, lighting), by sector (e.g., residential, commercial), and by commercial and industrial segments (e.g., retail, office).

2.1.3.9 Codes and Standards Adjustments

The US DOE publishes federal energy efficiency regulations for many types of residential appliances and commercial equipment. The US DOE Technical Support Documents (TSD)[26] contain information on energy and cost impacts of each appliance standard. In the TSD, Chapter 5 includes engineering analysis, Chapter 7 includes energy use analysis, and Chapter 8 includes cost impact. As these codes and standards take effect, the energy savings from existing measures impacted by these codes and standards decline and the reduction is transferred to the codes and standards savings potential. Guidehouse accounts for the effect of codes (including building code[27]) and standards through baseline energy and cost multipliers (sourced from the DOE's analysis), which reduce the baseline equipment consumption starting from the year a code or standard takes effect. The baseline cost of an efficient measure affected by codes and standards will often increase upon the code's implementation. Guidehouse incorporated the 2023 residential central ACs standard in this study, which results in the baseline for residential air conditioners changing from 14 Seasonal Energy Efficiency Ratio (SEER) to 14.3 SEER in 2023. Accordingly, the model accounts for a reduction in energy consumption and an increase in cost in 2023 for the baseline technology through the codes and standards multipliers. As such, computed measure-level potential is net of these adjustments from codes and standards implemented after the study's first year.[28]

These codes and standard adjustments were made to the following measures based on DOE standards:

- Omni-Directional LEDs
- Advanced Networked Lighting Controls with Omni-Directional LEDs
- Furnace Fan Motor Retrofit
- Energy Star Pool Pumps

[26] Appliance standards rulemaking notices and TSD can be found at: https://www.energy.gov/eere/buildings/appliance-and-equipment-standards-program

[27] Section 26-15 of the New Orleans Code of Ordinances

[28] It is important to note that the second tier of Energy Independence and Security Act of (EISA) 2007 regulations went into effect beginning January 2020 where the general service lamps must comply with a higher standard. Because the EUL of some lamps extend beyond this date, the baseline per guidance from the New Orleans TRM is adjusted to the second tier in years after 2022. For commercial lighting, these retrofits are considered as RET and baseline changes start in 2020.

- Energy Star Dehumidifiers
- Air Source Heat Pump
- Central AC
- Ground Source Heat Pump
- Ductless Heat Pump - ROB and NEW

2.1.3.10 Measure Quality Control

Guidehouse fully vetted and characterized each measure in terms of its energy savings, costs, and applicability. The characterization includes the following:

- Measure descriptions and baseline assumptions
- Energy savings and cost associated with the measure
- Cost of conserved energy, including operations and maintenance (O&M) costs
- Lifetime of the measure (Effective useful life and remaining useful life)
- Applicability factors including initial energy efficient market penetration and technical suitability
- Load shape of measure
- Replacement type of measure

2.1.4 Potential Estimation Approach

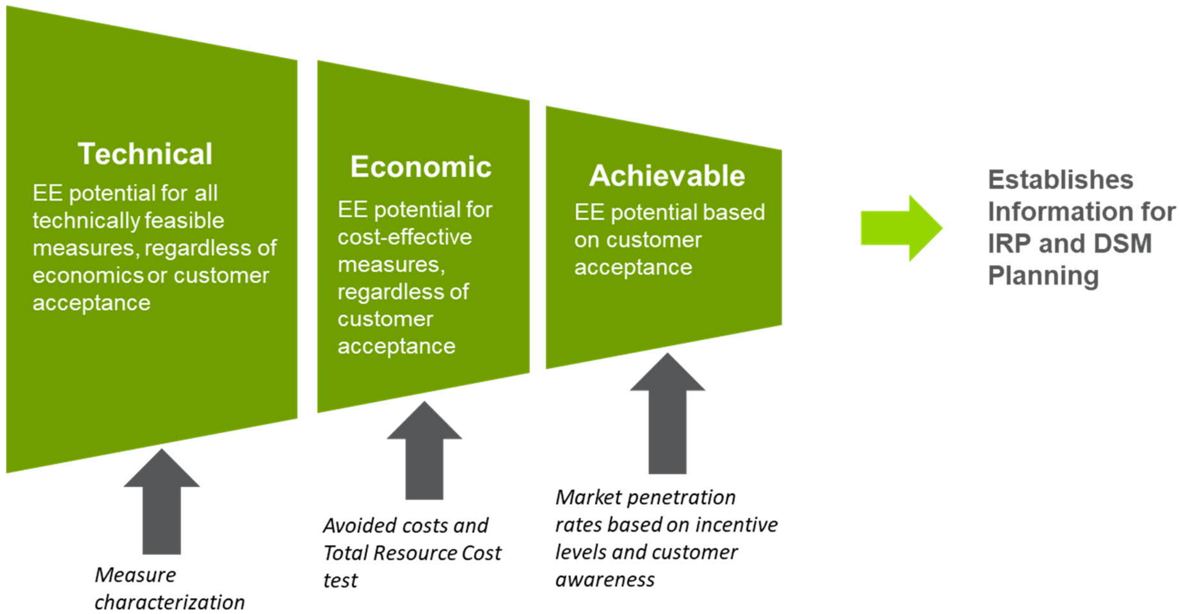
Guidehouse used its proprietary DSMSim™ potential model to estimate the technical, economic, and achievable savings potential for electric energy and demand across ENO's service area. DSMSim™ is a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics[29] framework. The DSMSim™ model accounts for different efficiency measures such as RET, ROB, and NEW and the effects these measures have on savings potential. The model then reports the technical, economic, and achievable potential savings in aggregate for the service area, sector, customer segment, end-use category, and highest impact measures.

This study defines technical potential as the total energy savings available assuming all installed measures can immediately be replaced with the efficient measure/technology—wherever technically feasible. This assumption is made regardless of the cost, market acceptance, or whether a measure has failed and must be replaced. Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential but including only those measures that have passed the benefit-cost test chosen for measure screening; in this case, that is the total resource cost (TRC) test. Finally, the achievable potential

[29] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000 for detail on System Dynamics modeling.

is analyzed based on the measure adoption ramp rates and the diffusion of technology through the market. Figure 2-9 details the methodology.

Figure 2-9. Potential Calculation Methodology



Source: Guidehouse

Savings reported in this study are gross rather than net, meaning they do not include the effects of natural change. Providing gross potential permits a reviewer to more easily calculate net potential when new information about NTG ratios or changing EUIs become available.

Once the potential results and cases are analyzed, the output can help define the portfolio energy savings goals, costs, and forecast for alignment into other utility planning landscapes like the IRP.

2.1.4.1 Technical Potential

Approach to Estimating Technical Potential

This study defines technical potential as the total energy savings available assuming all installed measures can immediately be replaced with the efficient measure or technology—wherever technically feasible. This assumption is made regardless of the cost, market acceptance, or whether a measure has failed and must be replaced.

Guidehouse's modeling approach considers an energy efficient measure to be any change made to a building, piece of equipment, process, or behavior that saves energy.[30] The savings can be defined in numerous ways depending on which method is most appropriate for a given measure. Measures that consist of a change to a single, discrete product, or piece of equipment (e.g., lighting fixture replacements) are best characterized as some fixed amount of savings per fixture. Measures related to products or equipment that vary by size (e.g., AC equipment) are best characterized on a basis that is normalized to a certain aspect of the equipment, such as per ton

[30] This study does not examine the impact of end-user electricity rates on sales or energy efficiency's impact on electricity rates.

of AC capacity. Other measures that could affect multiple pieces of equipment (e.g., behavior-based measures) are characterized as a percentage of customer segment sales saved.

The calculation of technical potential in this study differs depending on the assumed measure replacement type. Technical potential is calculated on a per-measure basis and includes estimates of savings per unit, measure density (e.g., quantity of measures per home for residential or per 1,000 SF of floor space for C&I), and total building stock in each service area. The study accounts for three replacement types, where potential from RET and ROB measures are calculated differently from potential for NEW measures. Equation 2-1 through Equation 2-3 show the formulae used to calculate technical potential by replacement type.

Retrofit and ROB Measures

Commonly referred to as advancement or early retirement measures, RET measures are replacements of existing equipment before the equipment fails. RET measures can also be efficient processes that are not in place and that are not required for operational purposes. These measures incur the full cost of implementation rather than incremental costs to some other baseline technology or process because the customer could choose not to replace the measure and thus would incur no costs. In contrast, ROB measures—sometimes referred to as lost opportunity measures—are replacements of existing equipment that failed and must be replaced or are existing processes that must be renewed. Because the failure of the existing measure requires a capital investment by the customer, the cost of implementing ROB measures is always incremental to the cost of a baseline (and less efficient) measure.

RET and ROB measures have a different meaning for technical potential compared to NEW measures. In any given year, the model uses the existing building stock to calculate technical potential.[31] This method does not limit the calculated technical potential to any pre-assumed adoption rate of RET measures. Existing building stock is reduced each year by the quantity of demolished building stock in that year and does not include new building stock added throughout the simulation. For RET and ROB measures, annual potential is equal to total potential, offering an instantaneous view of technical potential. Equation 2-1 calculates technical potential for RET and ROB measures.

Equation 2-1. Annual/Total RET/ROB Technical Savings Potential

$$\begin{aligned}&Total\ Potential\\&= Existing\ Stock\ x\ Measure\ Density\ x\ Savings\ x\ Technical\ Suitability\ \ x\ Baseline\ Initial\ Saturation\end{aligned}$$

Where:

- Total Potential: kWh
- Existing Stock:[32] C&I floor space per year or residential households per year
- Measure Density: Widgets per unit of stock
- Savings: kWh per widget per year

[31] In some cases, customer segment-level and end-use-level sales are used as proxies for building stock. These sales figures are treated like building stock in that they are subject to demolition rates and stock tracking dynamics.

[32] Units for building stock and measure densities may vary by measure and customer segment (e.g., 1,000 SF of building space, number of residential homes, customer segment sales, etc.).

- Technical Suitability: Percentage of applicable stock
- Baseline Initial Saturation: Percentage of energy efficient stock

New Construction Measures

The cost of implementing NEW measures is incremental to the cost of a baseline (and less efficient) measure. However, NEW technical potential is driven by equipment installations in new building stock rather than by equipment in existing building stock.[33] New building stock is added to keep up with forecast growth in total building stock and to replace existing stock that is demolished each year. Demolished (sometimes called replacement) stock is calculated as a percentage of existing stock in each year; this study uses a demolition rate of 0.5% per year for residential and C&I stock. New building stock determines the incremental annual addition to technical potential, which is then added to totals from previous years to calculate the total potential in any given year. Equation 2-2 and Equation 2-3 provide calculations of technical potential for new construction measures.

Equation 2-2. Annual Incremental NEW Technical Potential

$$\begin{gathered}Annual\ Incremental\ NEW\ Technical\ Potential\\ = New\ Stock\ x\ Measure\ Density\ x\ Savings\ x\ Technical\ Suitability\end{gathered}$$

Where:

- Annual Incremental NEW Technical Potential: kWh
- New Stock:[34] C&I floor space per year or residential households per year
- Measure Density: Widgets per unit of stock
- Savings: kWh per widget per year
- Technical Suitability: Percentage of the total baseline measures that could be replaced with the efficient measure. Occupancy sensors have a technical applicability of less than 1.0 because they are only practical for interior lighting fixtures that do not need to be on at all times.

Equation 2-3. Total NEW Technical Potential

$$\mathit{Total\ NEW\ Technical\ Potential} = \sum_{YEAR=2020}^{YEAR=2040} Annual\ Incremental\ Technical\ Potential_{YEAR}$$

Competition Groups

Guidehouse's modeling approach recognizes that some efficient technologies will compete against each other in the calculation of potential. The study defines competition as an efficient measure competing for the same installation as another efficient measure. For instance, a consumer has the choice to replace an air source heat pump with a more efficient air source heat

[33] In some cases, customer segment-level and end-use-level sales are used as proxies for building stock. These sales figures are treated like building stock in that they are subject to demolition rates and stock tracking dynamics.

[34] Units for new building stock and measure densities may vary by measure and customer segment (e.g., 1,000 SF of building space, number of residential homes, customer segment consumption, etc.)

pump or a ground source heat pump, but not both. These efficient technologies compete for the same installation.

Guidehouse used several competing technologies characteristics to define competition groups in this study:

- Competing efficient technologies share the same baseline technology characteristics, including baseline technology densities, costs, and consumption.
- The total (baseline plus efficient) measure densities of competing efficient technologies are the same.
- Installation of competing technologies is mutually exclusive (i.e., installing one precludes installation of the others for that application).
- Competing technologies share the same replacement type (RET, ROB, or NEW).

To address the overlapping nature of measures within a competition group, Guidehouse's analysis only selected one measure per competition group to include in the summation of technical potential across measures (e.g., at the end use, customer segment, sector, service area, or total level). The measure with the largest energy savings potential in each competition group was used to calculate total technical potential of that competition group. This approach ensures that the aggregated technical potential does not double count savings. The model does still, however, calculate the technical potential for each individual measure outside of the summations.

2.1.4.2 Economic Potential

This section describes the economic savings potential—potential that meets a prescribed level of cost-effectiveness—available in ENO's service area. The section explains Guidehouse's approach to calculating economic potential.

Approach to Estimating Economic Potential

Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential but including only those measures that have passed the benefit-cost test chosen for measure screening (in this study the TRC test, as per the Council's IRP rules). The TRC ratio for each measure is calculated each year and compared against the measure-level TRC ratio screening threshold of 1.0. A measure with a TRC ratio greater than or equal to 1.0 is a measure that provides monetary benefits greater than or equal to its costs. If a measure's TRC meets or exceeds the threshold, it is included in the economic potential.

The TRC test is a benefit-cost metric that measures the net benefits of energy efficiency measures from the combined stakeholder viewpoint of the utility (or program administrator) and the customers. The TRC benefit-cost ratio is calculated in the model using Equation 2-4.

Equation 2-4. Benefit-Cost Ratio for the TRC Test

$$TRC = \frac{PV(Avoided\ Costs)}{PV(Incremental\ Cost + Admin\ Costs)}$$

Where:

- PV is the present value calculation that discounts cost streams over time.

- Avoided Costs are the monetary benefits that result from electric energy and capacity savings—e.g., avoided or deferred costs of infrastructure investments and avoided long-run marginal cost (commodity costs) due to electric energy conserved by efficient measures.
- Incremental Cost is the measure cost as defined (see definition in Section 2.1.3.6).
- Admin Costs are the administrative costs incurred by the utility or program administrator (not including incentives).

Guidehouse calculated TRC ratios for each measure based on the present value of benefits and costs (as defined in the numerator and denominator, respectively) over each measure's life. 0 presents the avoided costs, discount rates, and other key data inputs used in the TRC calculation. The study's results did not include the effects of free ridership, so the team did not apply a NTG factor. Providing gross savings results will allow ENO to easily apply updated NTG assumptions in the future and allows for variations in NTG assumptions by reviewers. Although the TRC equation includes administrative costs, the study did not consider these costs during the economic screening process, except for behavioral programs, because the study is concerned with an individual measure's cost-effectiveness on the margin.

Like technical potential, only one economic measure from each competition group was included in the summation of economic potential across measures (e.g., at the end-use category, customer segment, sector, service area, or total level). If a competition group was composed of more than one measure that passes the TRC test, then the economic measure that provides the greatest electric savings potential was included in the summation of economic potential. This approach ensures that double counting is avoided in the reported economic potential, though economic potential for each individual measure is still calculated and reported outside of the summation.

2.1.4.3 Achievable Potential

Achievable potential is defined as the subset of economic potential considered achievable given assumptions about the realistic market adoption of a given measure. It is the product of the economic potential with two measure-specific factors: 1) the assumed maximum long-run achievability of each measure, and 2) a time-dependent factor called "ramp rate" that reflects barriers to market adoption. The adoption of measures can be broken down into calculation of the equilibrium market share and calculation of the dynamic approach to equilibrium market share.

The effects of program intervention result in applying ramp rates to the maximum achievable potential to model the changes in time-dependent barriers to market adoption. These ramp rates spread each measure's maximum achievable potential over the study horizon, accounting for assumptions about the timing of when this potential will be realized.

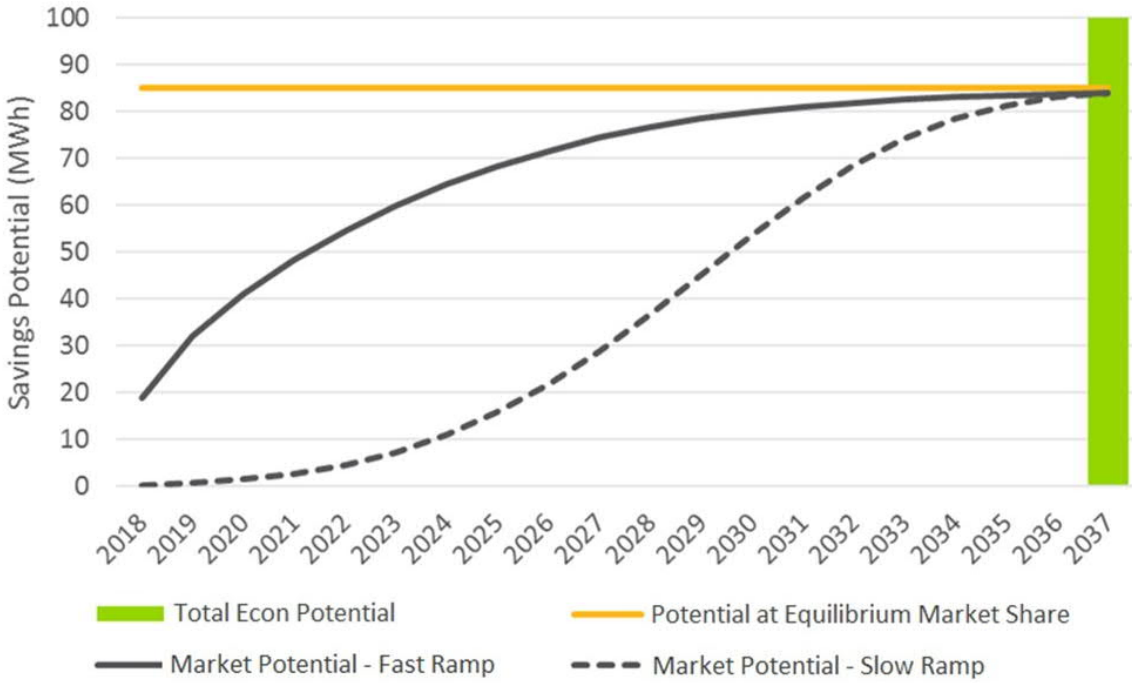
Using the definitions of cumulative total technical potential provided in Section 2.1.4.1, Equation 2-5 shows the calculation for achievable potential. Guidehouse calculated achievable potential by multiplying each measure's total economic potential by its maximum achievability factor and then applying a ramp rate for the adoption to the resulting maximum achievable potential.

Equation 2-5. Achievable Potential

$$Achievable\ Potential_{Year} = Total\ Economic\ Potential \times Max\ Achievability\ Factor \times Ramp\ Rate_{Year}$$

Figure 2-10 illustrates the relationship between total economic potential, maximum achievable potential, and final computed achievable potential in each year of the study as a function of ramp rate choice. The timing of achievable potential across the study horizon is driven by the choice of ramp rate. All values in the figure are for illustration purposes only.

Figure 2-10. Illustration of Achievable Potential Calculation



Source: Guidehouse

For measures involved in competition groups, an additional computational step is required to compute achievable potential to ensure no double counting of savings. While the technical and economic potential for a competition group reflects only the measure in that group with the greatest savings potential, all measures in a competition group may be allocated achievable potential based on their attractiveness (relative to one another).

Guidehouse allocated the economic potential proportionally across the various competing measures within the group based on their relative customer economics (payback). The team computed the relative customer economics ratio to reflect all costs and savings a customer would experience as a result of implementing the measure. The team multiplied the resulting market share splits by the maximum achievable potential for the group to get the achievable potential for each individual measure. This methodology ensured that final estimates of achievable potential reflected the relative economic attractiveness of measures in a competition group and that the sum of achievable potential from all measures in a competition group reflected the maximum achievable potential of the whole group.

2.2 Demand Response

Guidehouse prepared a DR potential assessment for ENO's electric service area from 2021 to 2040 as part of the DSM potential study. The objective of this assessment was to estimate the potential for using DR to reduce customer loads during peak summer periods.

Guidehouse identified and analyzed a suite of DR options for potential implementation in ENO's service area based on similar studies performed in other jurisdictions. These are:

1. **DLC:** This program controls water heating and cooling loads for residential and small business customers using either a DLC device (switch) or a PCT. For air conditioning control, this option represents the "EasyCool" program that ENO offers to residential and small business customers using load control switches and smart thermostats.[35]
2. **C&I Curtailment:** This represents the "Energy Smart Large Commercial Demand Response" program that ENO currently offers where large commercial customers agree to reduce load by a specific amount when called and get paid based on performance.
3. **Dynamic pricing:** This program encourages load reduction through a critical peak pricing (CPP) tariff, with a 6:1 critical peak to off-peak price ratio. All customer types are eligible to participate.
4. **Behind-the-meter storage (BTMS):** As required for study by the Council's initiating resolution, this program triggers power dispatch from behind-the-meter (BTM) battery storage systems that are grid-connected during peak load conditions. Battery dispatch helps reduce net system load during DR event periods.

Guidehouse developed programmatic assumptions (participation, unit impacts, and costs) for these DR options and estimated potential and cost-effectiveness under "achievable" participation assumptions. The team developed achievable potential estimates for each of these DR options at various levels of disaggregation, along with the costs associated with rolling out and implementing a DR program portfolio. The assessment considered both conventional and advanced control methods to curtail load at customer premises. Guidehouse assessed the cost-effectiveness of the DR program options and included only cost-effective DR options in the final achievable potential estimates.

2.2.1 General Approach and Methodology

Guidehouse developed ENO's DR potential and cost estimates using a bottom-up analysis, which used primary data from ENO and relevant secondary sources. The team configured its DRSim™ model, which uses this data as inputs, for this study. The following subsections detail Guidehouse's DR potential and cost estimation methodology:

- **Market Characterization:** Segment ENO's customer base into customer classes eligible to participate in DR programs.
- **Develop Baseline Projections:** Develop baseline projections for customer count and peak demand over the 20-year forecast period.
- **Characterize DR Options:** Define DR program options and map them to applicable customer classes.
- **Develop Model Inputs for Potential and Cost Estimates:** Develop participation, load reduction, and cost assumptions that feed the DRSim™ model.

[35] The switch based DLC program is only offered to residential customers and the smart thermostat-based program is offered to both residential and small business customers.

- **Case Analysis:** Estimate DR potential and associated implementation costs for low and high cases relative to the base (medium) case.

2.2.2 Market Characterization for DR Potential Assessment

Market characterization was the first step in the DR potential assessment process. Table 2-13. presents the different levels of market segmentation for the DR potential assessment. It is based on Guidehouse's examination of ENO's rate schedules and the customer segments established in the EE potential study. The team finalized the market segmentation for the DR potential assessment in consultation with ENO.

The methodology Guidehouse used to segment the market at these levels is briefly described below. Government customers are included as part of the C&I sector. Savings potential analysis from street lighting is not included in this study.

Table 2-13. Market Segmentation for DR Potential Assessment

Level	Description
Level 1: Sector	• Residential • C&I
Level 2: Customer Class	• Residential • C&I customers by size based on maximum demand values: o Small C&I: <= 100 kW maximum demand o Large C&I: >100 kW maximum demand
Level 3: Customer Segment	• Residential • C&I customer segments[36] o Colleges/Universities o Healthcare o Industrial/Warehouse o Lodging o Office – Large o Office – Small o Other o Restaurants o Retail – Food o Retail – Non-Food o Schools

Source: Guidehouse

[36] Descriptions of these customer segments can be found in Table 2-3. C&I Segment Descriptions.

Guidehouse first segmented customers into residential and C&I. The team combined single-family and multifamily customers into a single residential category because DR program and pricing offers are typically not distinguished by dwelling type. Next, Guidehouse segmented C&I customers into two sizes (small and large) and further segmented them into customer segments. To do this, the team requested 2019 account-level maximum billed demand data from ENO. As Section 2.1.1 notes, 2019 was chosen as the base year because it would have been the most recent year with a fully complete and verified dataset. However, the account level maximum demand data was not available for 2019 and therefore Guidehouse used the segment level small/large split from the 2018 Potential Study.[37]

The team mapped the SIC codes associated with individual accounts to customer segments in the analysis, similar to the approach used by the EE potential study team in its market characterization effort. Then, the team used the 2018 study split of customers into small and large C&I by customer segment, using a cutoff value of 100 kW maximum demand for the small vs. large classification.[38] This cutoff value was determined in consultation with ENO and is aligned to ENO's EE programs when there is a specific offer to the small business segment. These splits were then used to develop a customer count and sales forecast by customer class and segment for the DR study. This segmentation is necessary because the type of DR program offer varies by customer size.

2.2.3 Baseline Projections

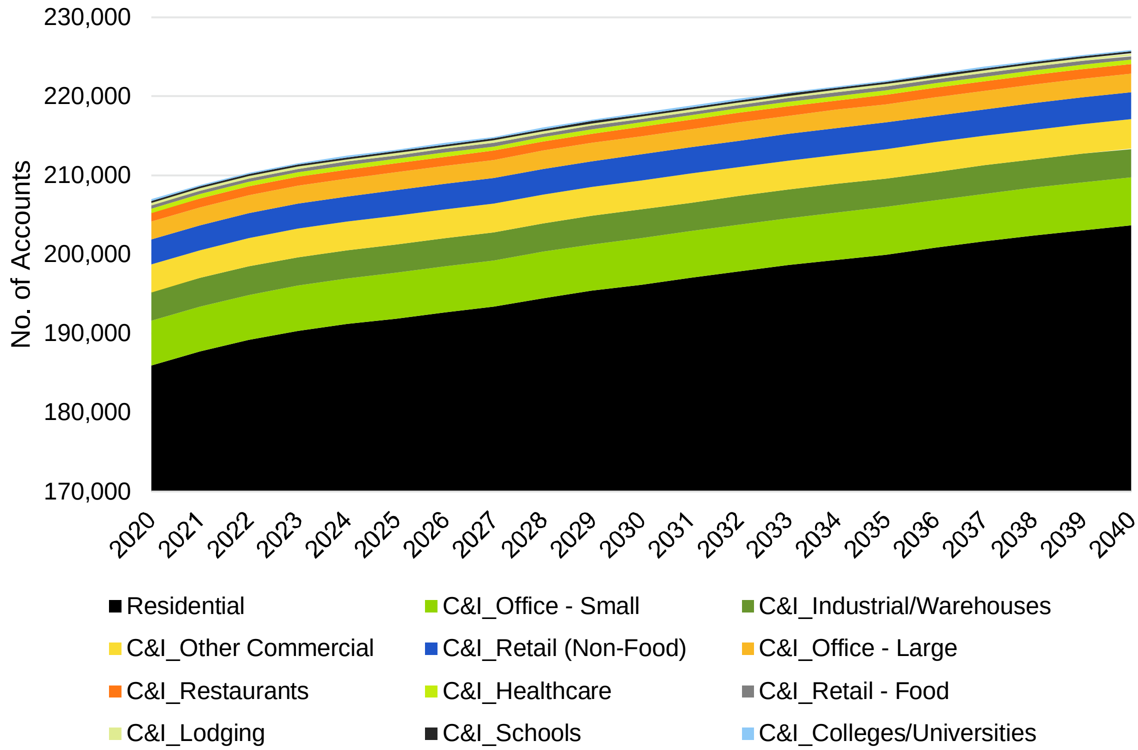
2.2.3.1 Customer Count Projections

Guidehouse applied year-over-year change in the stock forecast (described in Appendix A.2 and A.3) to the 2019 customer count data segmented by customer class and customer segment to produce a customer count forecast for the DR potential study. The team trued up this forecast to the sector-level customer count forecast provided by ENO. Figure 2-11 shows the aggregate customer count forecast by segment only, summed across all customer classes.

[37] "2018 Integrated Resource Plan DSM Potential Study"; prepared for Entergy, submitted by Navigant Consulting; August 31, 2018.

[38] Since specific SIC codes map to small and large offices, Guidehouse did not use the 100 kW cutoff to segment office customers into the small and large categories. The small versus large distinction for offices is solely based on the NAICS code mapping.

Figure 2-11. Customer Count Projections for DR Potential Assessment



Source: Guidehouse

2.2.3.2 Peak Demand Projections

The first step in developing peak demand projections is to define the peak period. This study only considered DR potential for summer peak reduction. Guidehouse kept the same summer peak definition as the 2018 potential study based on an examination of the 2019 hourly system load data. The system load shape for 2019 is similar to what the 2018 study used. Additionally, Guidehouse wanted to maintain consistency in the peak definition with the previous study. ENO expressed a desire to align the peak period definition with times MISO is expected to see peak demand. This allows ENO to use the findings of the DR potential assessment should it seek to register any DR resources as load modifying resources with MISO. Per MISO's business practice manual, "…the expected peak occurs during the period (June through August) during the hours from 2:00 p.m. through 6:00 p.m."[39] Guidehouse added two additional constraints to this definition. First, the team only included weekdays in the peak period definition because it is not typical for utilities to call DR events on weekends. Second, Guidehouse only included the top 40 weekday hours within this window, which is the typical limit for calling summer DR events. This assumption is consistent with the 2018 study assumption which found that 95% or greater of ENO's system peak occurred within the top 40 hours based on an examination of historical system load data, which is what utilities typically target to call DR events.

Once the team defined the peak period, Guidehouse developed a disaggregated bottom-up peak demand forecast by customer class and segment. The team also estimated the end-use breakdown of the peak demand for C&I customers, as reduction estimates are typically expressed

[39]MISO. *Business Practice Manual,* BPM 026, -Demand Response. Effective date: July 20, 2020, pg 20.

as a percentage of baseline load for these customers. The step-by-step methodology Guidehouse used to develop the baseline peak load projections follows:

1. **Disaggregate sales forecast by customer class and customer segment:** Guidehouse first projected the base year (2019) sales data, segmented by customer class and customer segment, over the study horizon using the year-over-year change in building stock. The team used the segment level sales projections developed for the EE potential assessment and applied the rate class split from the 2018 potential study, since the maximum demand data for differentiation into small and large categories was not available from ENO for the current study.
2. **Use 8760 load profiles by revenue class to calculate coincident peak load factors by revenue class:** Guidehouse received 8760 load profiles by revenue class from ENO for 2019. Based on the peak period definition, the team used the load profiles to estimate the average coincident peak load factor by revenue class. The team calculated the average hourly demand by revenue class, coincident with the top 40 system load hours, and used this in conjunction with the sales data by revenue class to calculate the coincident peak load factor by revenue class. Per industry-standard definition, coincident peak load factor is calculated as follows:

$$Coincident\ Peak\ Load\ Factor = \frac{Annual\ Sales}{Average\ Hourly\ Coincident\ Peak\ Demand * 8{,}760}$$

3. **Estimate weighted average coincident peak load factors by customer class and segment:** Guidehouse developed weighted average coincident peak load factors by customer class and segment by combining the coincident peak load factors by revenue class, developed in step 2 above, with the revenue class distribution data (distribution based on sales) within each customer class and segment to estimate the weighted average coincident peak load factor by customer class and segment. The peak load factor derived in this manner is shown in Table 2-14.

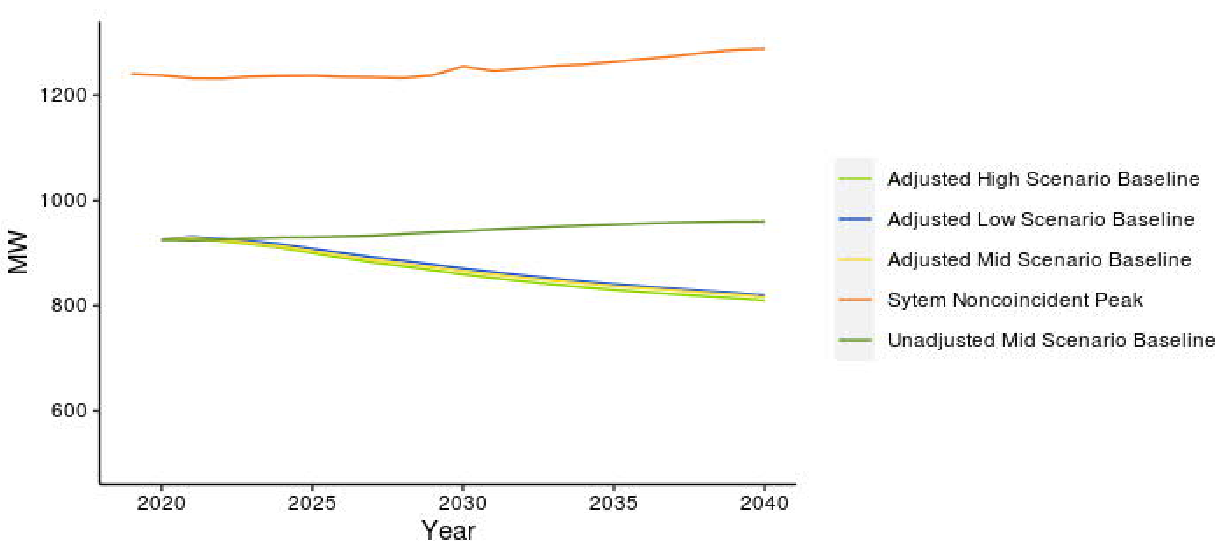
Table 2-14. Peak Load Factor by Segment

Customer Segment	Peak Load Factor
C&I_Colleges/Universities	0.68
C&I_Healthcare	0.68
C&I_Industrial/Warehouses	0.80
C&I_Lodging	0.66
C&I_Office - Large	0.50
C&I_Office - Small	0.50
C&I_Other Commercial	0.67
C&I_Restaurants	0.65
C&I_Retail - Food	0.65
C&I_Retail (Non-Food)	0.66
C&I_Schools	0.70
Residential	0.50

Source: Guidehouse

4. Apply weighted average coincident peak load factors to sales projections to estimate average coincident peak demand by customer class and segment: Guidehouse applied the average coincident peak load factors by customer class and segment, developed in step #3 above, to the disaggregate sales projections by customer class and segment (described earlier in step#1) to develop average coincident summer peak demand projections by customer class and segment. The team retained the end-use shares in peak demand from the 2018 study since there were no updates to building simulation runs from the 2018 study in the current study. Therefore, the end-use load profiles by segment from the 2018 study served as the best available information source for end-use shares in peak demand.
5. **Adjust baseline load for DR potential estimation with EE achievable potential estimates**: Since EE leads to permanent load reductions in the baseline load, the baseline load for DR needs to be adjusted with EE potential estimates. Figure 2-12 below shows the disaggregate peak demand projections before and after EE adjustments. The top line in the figure below represents ENO's noncoincident peak demand projections at the system level.[40] This is used as a reference to compare the disaggregated bottom-up peak demand projections by customer class and segment. The "unadjusted mid case baseline" represents the bottom up disaggregate peak demand projections by customer class and segment, described in steps #1 through #4 above. This projection is adjusted with the EE achievable potential estimates for all three cases (low, mid, and high) to derive the downward sloping "adjusted baseline" projections for all three cases. This graph indicates that the baseline peak demand projections progressively decline over time with higher penetration of EE.

Figure 2-12. Peak Demand Forecast Comparisons



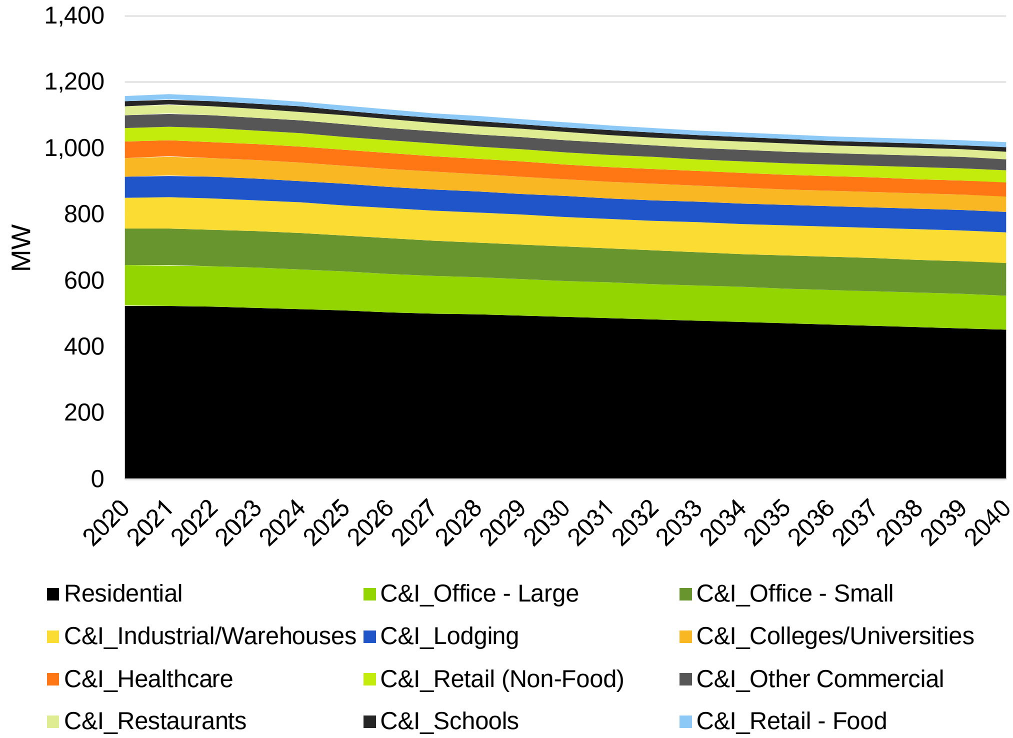
Source: Guidehouse

Figure 2-13 shows the disaggregate peak demand projections by customer segment and Figure 2-14 shows the disaggregate C&I peak demand by end-use for the mid case, derived from all five

[40] The noncoincident system peak is the sum of the sectoral peak demands provided by ENO.

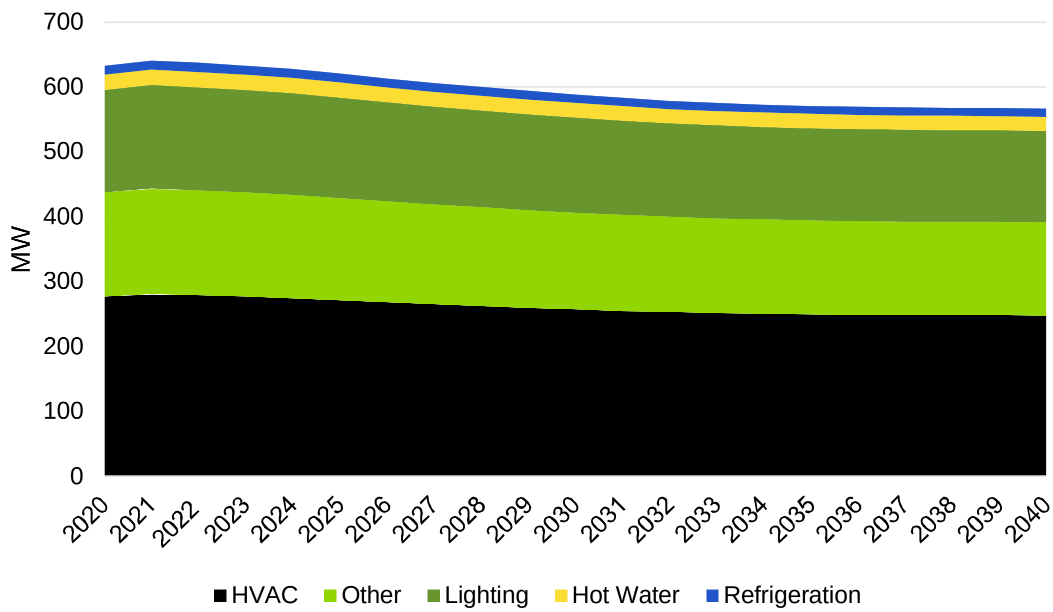
steps described above. The disaggregated peak demand projections establish the foundation for DR potential estimates.

Figure 2-13. Peak Load Forecast by Customer Segment (MW)



Source: Guidehouse

Figure 2-14. Peak Load Forecast by End Use for C&I Customers (MW)



Source: Guidehouse

2.2.4 Descriptions of DR Options

Once the baseline peak demand projections were developed, the team characterized different types of DR options that could be used to reduce peak demand. Table 2-15 summarizes the DR options included in the analysis. The DR options represent ENO's current DR program offers and those that are commonly deployed in the industry. These programs also align with Council's IRP rules, which state that DR programs should include those "…enabled by the deployment of advanced meter infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer class." The different types of DR options are detailed below.

Additionally, the Council requested a specific analysis of battery storage potential in the 2021 IRP Initiating Resolution, R-20-257:

"Whereas, further, the Council is specifically interested in evaluating the feasibility of a customer DER program whereby customers would receive an incentive to install energy storage facilities on their property controlled by the utility, such that the utility could direct when the storage units dispatch stored electricity onto the distribution grid. The Council directs ENO to include such a measure as one of the measures evaluated in the DSM potential…"

Guidehouse analyzed battery storage potential with details provided in 5.4Appendix D documenting the approach and analysis results. This analysis addressed the feasibility of a customer DER program for receiving an incentive to install dispatchable storage units.

Table 2-15. Summary of DR Options

DR Option	Characteristics	Eligible Customer Classes	Targeted/ Controllable End Uses and/or Technologies
DLC[41] ✓ Load control switch ✓ Thermostat	Control of cooling load using either a load control switch or smart thermostat; control of water heating load using a load control switch.	Residential Small C&I	Cooling, water heating
C&I Curtailment ✓ Manual ✓ Auto-DR enabled	Firm capacity reduction commitment with pay-for-performance ($/kW) based on nominated amount or actual performance.	Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads

[41] This represents both the switch-based and smart thermostat based "Easy Cool" program offered by ENO to residential and small business customers (switch-based option offered only to residential customers and smart thermostat-based option offered to both residential and small business customers).

DR Option	Characteristics	Eligible Customer Classes	Targeted/ Controllable End Uses and/or Technologies
Dynamic Pricing[42] ✓ Without enabling technology ✓ With enabling technology	Voluntary opt-in dynamic pricing offer, such as Critical Peak Pricing (CPP)	All customer classes	All
BTMS ✓ Standalone battery storage	Dispatch of BTM batteries for load reductions during peak demand periods.	All customer classes	Batteries

Source: Guidehouse

Each DR option was segmented into several DR sub-options, each of which was tied to a specific end use and/or control strategy. Table 2-16 summarizes this segmentation. The different types of DR options are described in detail below.

Table 2-16. Segmentation of DR Options into DR Sub-Options

DR Option	DR Sub-Option	Eligible Customer Classes
DLC	Switch-Water Heating	Residential, Small C&I
	Thermostat-CAC/Heat Pump (BYOT)	Residential
	Switch-CAC/Heat Pump	Residential
	Thermostat-HVAC (BYOT)	Small C&I
C&I Curtailment	Curtailment-Manual HVAC Control	Large C&I
	Curtailment-Auto-DR HVAC Control	
	Curtailment-Standard Lighting Control	
	Curtailment-Advanced Lighting Control	
	Curtailment-Water Heating Control	
	Curtailment-Refrigeration Control	
	Curtailment-Compressed Air	
	Curtailment-Fans/Ventilation	
	Curtailment-Industrial Process	
	Curtailment-Pumps	
	Curtailment-Other	
Dynamic Pricing	Dynamic pricing with enabling tech	Residential, Small C&I, Large C&I
	Dynamic pricing without enabling tech	

[42] Guidehouse did not include time-of-use (TOU) rates in the DR options mix because this study only includes event-based dispatchable DR options. TOU rates lead to a permanent reduction in the baseline load and are not considered a DR option.

DR Option	DR Sub-Option	Eligible Customer Classes
BTMS	BTMS-Battery Storage	Residential, Small C&I, Large C&I

Source: Guidehouse

2.2.4.1 Direct Load Control

DLC involves ENO directly controlling electric water heating and cooling load using a load control switch or a smart thermostat. ENO currently offers the “EasyCool” program that uses a load control switch for cycling Central Air Conditioning (CAC) or heat pump system. In addition, ENO offers the Bring Your Own Thermostat (BYOT) option to residential and small business customers under the same programs. The DLC option modeled in this potential study represents both the switch-based and the smart thermostat-based program offers. In the switch-based option, ENO is responsible for installing the switch to control the CAC/heat pump unit. The smart thermostat-based option represents a BYOT approach where the residential and small business customers are responsible for smart thermostat purchase and installation and ENO does not bear any responsibility for that. In addition, the DLC option includes electric water heating control for residential and small C&I customers using a load control switch where ENO is responsible for purchase and installation of the switches for controlling water heaters.

Table 2-17 summarizes the DLC program characteristics considered in this study.

Table 2-17. DLC Program Characteristics

Item	Description
Program Name	Direct Load Control (DLC)
Program Description	• This program controls electric water heating and cooling (including central air conditioning and heat pumps) loads for residential and small C&I customers using either a DLC device (switch) or a smart thermostat. PCT, where and when applicable. • Both switch-based and smart thermostat-based (BYOT) offers apply to residential customers, while only the smart thermostat-based offer (BYOT) applies to small C&I customers.[43] • Switch-based electric water heating load control apply to both residential and small C&I customers.
Purpose/Trigger	DLC events will be called primarily to meet capacity shortfalls during summer, triggered primarily by a high day-ahead temperature forecast.

[43] These assumptions are consistent with ENO’s current program offers.

Item	Description
Key Program Design Parameters	• Events will be called during peak demand periods in summer (June 1 through September 30), only on non-holiday weekdays. • Switch-based option for CAC/heat pump control[44]: o CAC or heat pump cycled for 2-4 hours during events o Event window: 12 p.m. to 8 p.m. o Enrolled customers receive upfront $25 incentive payment at the time of enrollment, plus $40 each season they participate. o No advanced notification provided to customers. o Customers can opt-out of an event by calling ENO • Smart thermostat-based option[45] o Maximum 15 events called during summer o Enrolled customers receive upfront $25 incentive payment at the time of enrollment, plus $40 each season they participate. o Eligible thermostats listed in the EasyCool program site. o Event notification varies by thermostat provider o Load reduction achieved through a max. 4-degree temp. offset o Event window: 12 p.m. to 8 p.m. o Max. event duration: 4 hours o Customers can opt-out any time at the thermostat, mobile device or web app • Customers may be precooled prior to an event taking place.
Participation Eligibility	• Residential and small C&I customers with CAC and heat pumps • Residential and small C&I customers with electric water heaters
Dependent Technology and Metering	**Technology:** Switches control water heating, central air conditioning, or heat pumps. Smart thermostats control central air conditioning or heat pumps. **Metering:** Standard meter (no interval meter required). The program can use data loggers on a sample of participants to record interval usage for measurement and verification.

Source: Guidehouse

2.2.4.2 C&I Curtailment

The C&I curtailment program modeled in the potential assessment represents the "Energy Smart Large Commercial Demand Response" program that ENO currently offers.[46] Under this program, ENO contracts with a DR service provider to deliver a fixed amount of load reduction. Enrolled participants nominate a certain amount of load reduction. In return, they receive a fixed incentive

[44] https://www.energysmartnola.info/wp-content/uploads/2020/07/2020-EasyCool-Switch-FAQs.pdf

[45] https://enrollmythermostat.com/faqs/entergyno/

[46] https://energysmartadr.com/wp-content/uploads/2020/06/Energy-Smart-Large-Commercial-DR-Trifold-Brochure-V4.pdf

payment in the form of reservation payments (expressed as $/kW-year) for being on call. Participants are paid based on performance when DR events are called. Only customers with greater than 100 kW demand qualify for enrollment. The program requires a minimum 20kW curtailment per metered site for enrollment[47]. Once enrolled, customers are required to fulfill the nominated amount of load reduction when DR events are called. A specific site could curtail a variety of end-use loads depending on the types of business processes. All load reductions are Auto-DR enabled.

Table 2-18 describes the C&I curtailment program characteristics considered in this study.

Table 2-18. C&I Curtailment Program Characteristics

Item	Description
Program Name	C&I Curtailment[48]
Program Description	This is a voluntary program offer to large C&I customers with greater than 100 kW demand The Large Commercial Demand Response Program ("DR Program") is a voluntary program that pays incentives to commercial and industrial customers for reducing a specified level of load reduction through on-site load reduction equipment. Customers receive fixed $/kW-yr. payment for being on call to deliver load reductions when DR events take place. When DR events are called, customers are paid based on the actual kW reduced during an event against their baseline load. This program is currently being administered by a third-party. Participating sites enrolled in the program curtail a variety of end uses (e.g., HVAC, water heating, lighting, refrigeration, process loads), depending on the business type. The entire load curtailment in this program is Auto-DR (ADR) enabled.
Purpose/Trigger	DR events could be triggered by operating, reliability, and/or economic purposes.[49]
Key Program Design Parameters	• Sites require to fulfill minimum 20 kW load reduction for participation. However, ENO may allow 10 kW reduction per site in cases where two or more sites in aggregate curtail at least 30 kW. • Event window: May 1 to September 30 during summer • Maximum event hours: 40 hours during summer; 30 hours during winter. • Event notification: Day-of (via email and/or text) • Incentive: $23/kW for summer[50]
Participation Eligibility	Large C&I customers with greater than 100 kW demand.

[47] Entergy may lower this requirement if a customer with two or more sites can curtail at least 30 kW.

[48] Represents the Energy Smart Large Commercial DR program currently offered by ENO.

[49] This study estimates summer peak reduction potential only from this program.

[50] A reduction in credit applies for underperformance. If Customer fails to meet at least 75% contracted reduction performance, corresponding Incentive Payment will be pro-rated based on actual performance. If Customer's seasonal average exceeds 150% of contracted reduction performance, corresponding Incentive Payment will be reduced by 50% of kW reduced past 150% *(Source: Entergy Commercial DR Agreement).*

Item	Description
Dependent Technology and Metering	**Dependent technology:** Auto-DR requires a building automation system, a load control device, or breakers on specific circuits. All control mechanisms must be able to receive an electronic signal from the program administrator and initiate the curtailment procedure without manual intervention. Auto-DR dispatches are called using an open communication protocol known as Open-ADR. For Auto-DR customers, the vendor installs an Open-ADR-compliant gateway at the participating site, which is then able to notify the energy management systems (EMS) or other control systems at the facility to run their preprogramed curtailment scripts. The vendor monitors energy reduction in real time and provides visual access to this demand data to the participant through a web-based software platform. This platform may be integrated for overall energy optimization, which may help realize energy efficiency benefits along with DR benefits. **Metering:** Interval meters or smart meters.

Source: Guidehouse

2.2.4.3 Dynamic Pricing

Dynamic pricing refers to a Critical Peak Pricing (CPP) rate offer across all customer classes. This is the most commonly deployed dynamic rate in the industry. Customers who opt to participate in the program are placed on a CPP rate with a significantly higher rate during certain critical peak periods in the year and a lower off-peak rate than the standard offer rate. Customers enrolled in the CPP rate pay the higher critical peak rate for electricity consumption during the critical peak periods, which incentivizes them to reduce consumption during those periods. Customers enrolled in the CPP rate receive either day-of or day-ahead notification of the critical peak period.

The unit impacts or per-customer load reductions depend on the critical peak to off-peak price ratio. This study assumes a 6:1 critical peak to on-peak price ratio. The off-peak rate is lower than the customer’s Otherwise Applicable Tariff (OAT) and therefore customers have an incentive to enroll in the CPP rate vis-à-vis their existing tariff. It is best practice in the industry to provide bill protection during the first year of enrollment in the tariff so that customer bills do not exceed what they would have paid under their existing tariff. Industry experience suggests that enabling technology such as smart thermostats and Auto-DR can substantially enhance load reductions when customers on CPP rates are equipped with these technologies. ENO could offer CPP either as an opt-in rate or as a default rate with opt out. This study assumes an opt-in offer type for CPP.

The CPP offer requires advanced metering infrastructure (AMI) meters for settlement purposes. Hence, the rate offer is tied to AMI deployment. This study assumes that ENO offers the CPP rate from 2023 onward to account for lead time for rate design and approval before launching the program. Table 2-19 describes the dynamic pricing program characteristics considered in this study.

Table 2-19. Dynamic Pricing Program Characteristics

Item	Description
Program Name	Dynamic Pricing

Item	Description
Program Description	Opt-in CPP offer to all customers with a 6:1 critical peak to off-peak price ratio.
Purpose/Trigger	• Events are primarily called for economic purposes (high market prices). • Events can be called during summer months. • Current study estimates potential for summer peak reduction.
Key Program Design Parameters	• Event window: May 1 to September 30 during summer. • Event notification is typically day-ahead. • Average event duration assumed to be 4 hours. No more than one event is called in a day. Calling events for more than 2 consecutive days may lead to customer dissatisfaction and disenrollment. • Annual maximum event hours set at 80-100 hours.
Participation Eligibility	All customers.
Dependent Technology and Metering	All customers need smart meters for settlement purposes.

Source: Guidehouse

2.2.4.4 Behind-the-Meter Storage

BTMS refers to a program through which ENO would offer an incentive to customers to install battery storage behind the meter in their homes or businesses in exchange for the customers' allowing ENO to control their battery systems to discharge power to the grid during peak load conditions. ENO does not have data on the number or capacity of non-grid interconnected backup generators at customer sites in its service area, so the technology was not considered for this program in this study. Guidehouse assumed the market adoption and size for battery storage systems using internal analysis, described in 5.4Appendix D. Customer adoption of batteries is driven by customer economics (payback period). Guidehouse assumed that ENO shares a portion of the installed battery costs and additionally provides performance incentives (on a $/kW basis) for dispatching batteries. Both the upfront cost sharing and the pay for performance incentives are built in the customer economics calculation to estimate likelihood of battery adoption by customers.

Table 2-20 describes the BTMS program characteristics.

Table 2-20. BTMS Program Characteristics

Item	Description
Program Name	Behind-the-Meter Storage (BTMS)

Item	Description
Program Description	• Program assumes an arrangement between ENO and the end-use customer where customers receive incentives for purchase and battery installation with a commitment to ENO to have the battery capacity available for dispatch by ENO during system needs. • Customers install battery storage systems that are interconnected with the grid. When there are peak load conditions, the utility sends signals to the battery system, which would trigger power dispatch to the grid. • ENO shares a portion of the upfront battery capital plus installation cost. Program assumes that ENO shares 50% of the upfront battery capital plus installation cost for residential customers and 20% of the upfront battery capital plus installation for C&I customers in order to incentivize battery adoption. In addition, ENO pays customers on a $/kW basis for the dispatched capacity (kW) when called.
Purpose/Trigger	Events are called any time of the year to meet grid needs. Events could be triggered by emergency/reliability needs, economic purposes and to fulfill operating reserve requirements (spin, non-spin, regulation).
Key Program Design Parameters	• Batteries can be dispatched any time of the year based on grid needs. • Average event duration: 2-3 hours per event. • Event notification is typically day-ahead and/or 1-2 hours ahead[51]. • No. of annual events: can go considerably higher than other programs/technologies since batteries are highly dispatchable. Maximum number of annual events can be set at 60.[52]
Participation Eligibility	• Residential – customers with solar • Commercial – customers with solar and/or demand charges
Dependent Technology and Metering	All customers need PV-tied or standalone batteries with grid interconnection.

Source: Guidehouse

2.2.5 Key Assumptions for DR Potential and Cost Estimation

This study includes two key variables that feed the DR potential calculation:

- Customer participation rates
- Amount of load reduction that could be realized from different types of control mechanisms, referred to as unit impacts

[51] The notification time will vary based on the on the type of trigger. If ENO were to use batteries for meeting operating reserve requirements (spin, non-spin, regulation), the notification time could be considerably shorter as these services require fast response.

[52] National Grid's Connected Solutions sets maximum number of events at 60. https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-madailydispatchflyer.pdf

Other variables that impact DR potential calculation include participation opt-out rates, technology market penetration, and enrollment attrition rates. Guidehouse calculated both the technical and achievable potential associated with implementing DR programs for this study. Technical potential refers to load reduction that results from 100% customer participation. This is a theoretical maximum. The team calculated technical potential by multiplying the eligible load/customers by the unit impact for each DR sub-option. The technical potential calculation does not account for participation overlaps between the DR sub-options. Technical potential across the various sub-options is not additive and should not be added together to obtain a total technical potential. In other words, the technical potential estimates for each DR sub-option should be considered independently. Equation 2-6 summarizes the technical potential calculation.

Equation 2-6. DR Technical Potential

$$\begin{aligned} &Technical\ Potential_{DR\ Sub\ Option, End\ Use, Year} \\ &\quad = Eligible\ Load_{DR\ Sub\ Option, Segment, End\ Use, Year} \\ &\quad * Unit\ Impact_{DR\ Sub\ Option, Segment, Year} \end{aligned}$$

Guidehouse calculated the achievable potential by multiplying achievable participation assumptions (subject to the program participation hierarchy) by the technical potential estimates. Market potential also accounts for customers opting out during DR events. Equation 2-7 shows the calculation for achievable potential.

Equation 2-7. DR Achievable Potential

$$\begin{aligned} &Achievable\ Potential \\ &\quad = Technical\ Potential_{DR\ Sub\ Option, Segment, End\ Use, Year} \\ &\quad * Achievable\ Participation\ Rate_{DR\ Sub\ Option, Segment, Year} \\ &\quad * (1 - Event\ Opt\ Out\ Rate)_{DR\ Sub\ Option, Year} \end{aligned}$$

In addition to the potential estimates, the team developed annual and levelized costs by DR option and sub-option. Guidehouse subsequently assessed the cost-effectiveness of each sub-option and DR option in aggregate. Developing annual and levelized costs involves itemizing various cost components such as program development costs, equipment costs, participant marketing and recruitment costs, annual program administration costs, technology lifetimes, and a discount rate. Table 2-21 summarizes the variables Guidehouse used to calculate DR potential and its associated costs in this analysis. These variables are discussed further in the following subsections.

Table 2-21. Key Variables for DR Potential and Cost Estimates

Key Variables	Description
Participation Rates	Percentage of eligible customers by program type and customer class.
Unit Impacts	• kW reduction per device for DLC • Percentage of enrolled load by end use for C&I curtailment • Percentage of total facility load for dynamic pricing • Percentage of battery load for BTMS
Costs	• One-time fixed costs related to program development • One-time variable costs for customer recruitment, program marketing, and equipment installation and enablement • Recurring fixed and variable costs such as annual program admin. costs, customer incentives, O&M, etc.
Global Parameters	Program lifetime, discount rate, inflation rate, line losses, avoided costs

Source: Guidehouse

2.2.5.1 Participation Assumptions and Hierarchy

Participation assumptions differ by customer class and segment. Participation assumptions are informed by ENO's current program enrollment data and projections from program implementers, and benchmarking with similar programs offered by other utilities.

Participation assumptions are developed as "% of eligible customers". For the EasyCool program, eligible customers are those with CAC/heat pump and electric water heating. For the Bring Your Own Thermostat (BYOT) option within DLC, the DR team obtained smart thermostat penetration from the EE study and used that data to inform total number of eligible customers for the BYOT program. The team applied participation assumptions to these eligible customers. For the C&I Curtailment program, only automated DR (ADR) is considered based on ENO's current Large Commercial Demand Response program offer. Therefore, customers with Energy Management System that can be pre-programmed to execute curtailment strategies in response to DR event signals are eligible to participate. In this case, the DR team obtained EMS saturation projections from the EE analysis and used that information to establish eligibility in C&I Curtailment DR program participation. For dynamic pricing, Guidehouse assumed that the Critical Peak Pricing (CPP) rate is offered to customers once AMI is deployed. For the BTMS program, only customers with BTM batteries can participate and therefore participation in the DR program is tied to battery adoption projections.

Guidehouse also accounted for participation overlaps among the different DR programs in estimating potential. Table 2-22 presents the participation hierarchy for this study, whereby achievable participation estimates are applied to eligible customers only. The participation hierarchy presented here is a well-tested approach, initially established in the *National Assessment of DR Potential Study* conducted by the Federal Energy Regulatory Commission (FERC)[53] and adopted in other DR potential studies. The participation hierarchy helps avoid

[53] https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdfelow

double counting of potential through common load participation across multiple programs and is necessary to arrive at an aggregate potential estimate for the entire portfolio of DR programs.

Table 2-22. Program Hierarchy to Account for Participation Overlaps

Customer Class	DR Options	Eligible Customers
Residential	DLC - Thermostat	Customers with central AC or heat pumps controlled using smart thermostats
	DLC - Switch	• For CAC/Heat Pump control: customers with CAC/heat pump • For water heating control: customers with electric water heating
	Dynamic Pricing	Customers not enrolled in DLC
	BTMS	Customers with batteries
Small C&I	DLC - Thermostat	Customers with central AC or heat pumps controlled using smart thermostats
	DLC - Switch	For water heating control: customers with electric water heating
	Dynamic Pricing	Customers not enrolled in DLC
	BTMS	Customers with batteries
Large C&I	C&I Curtailment	Customers with Energy Management System (EMS) to enable Auto-DR
	Dynamic Pricing	Customers not enrolled in C&I Curtailment
	BTMS	Customers with batteries

Source: Guidehouse

2.2.5.2 Unit Impact Assumptions

The unit impacts specify the amount of load that could be reduced during a DR event by customers enrolled in a DR program. Unit impacts differ by sub-option because they are tied to specific end uses and control strategies. For example, the load reductions associated with manual HVAC control and auto-DR HVAC control differ and are specified accordingly. Unit impacts can be specified either directly as kilowatt reduction per participant or as percentage of enrolled load[54]:

- DLC sub-options use kilowatt reduction per participant for residential and percentage of the end-use load for small C&I
- C&I curtailment sub-options use percentage of the end-use load
- Dynamic pricing uses a percentage of the total facility load

[54] The unit impact values assume a 4-hour event duration, and the values represent the average load reduction over the 4-hour event duration.

- BTMS uses a percentage of the battery load

This study used ENO's DLC pilot program accomplishments and the latest available secondary sources of information for other programs for the unit impact assumptions.

2.2.5.3 Cost Assumptions

Guidehouse developed itemized cost assumptions for each DR option to calculate annual program costs and levelized costs for each option. These assumptions also feed the cost-effectiveness calculations in this study. The cost assumptions fall into the following broad categories:

- **One-time fixed costs**, specified in terms of $/DR option, including the program startup costs—for example, the software and IT infrastructure-related costs and associated labor time/costs (in terms of full-time equivalents) incurred to set up the program.

- **One-time variable costs**, which include marketing/recruitment costs for new participants, metering costs, and all other costs associated with control and communications technologies that enable load reduction at participating sites. The enabling technology cost is specified either in terms of $/new participant on a per-site basis or as $/kW of enabled load reduction on a participating load basis.

- **Annual fixed costs,** specified in terms of $/year, which primarily includes full time equivalent costs for annual program administration.

- **Annual variable costs,** which primarily includes customer incentives, specified either as a fixed monthly/annual incentive amount per participant ($/participant) or in terms of load and/or energy reduction ($/kW and $/kWh reduction) depending on the program type. It also includes additional O&M costs that may be associated with servicing technology installed at customer premises.

- **Program delivery costs,** which is a fixed contracted payment for third-party delivery of DR programs and is specified as $/kW-yr.

In addition to these itemized program costs, the following variables feed the cost-effectiveness calculations in this study:

- **Nominal discount rate** of 7.09% used for net present value (NPV) calculations.

- **Inflation rate** of 2% used to inflate the costs over the forecast period (2021-2040).

- Transmission and distribution (T&D) line loss of 4.4%.

- **Program life**, assumed to be 10 years for DLC, C&I curtailment, and BTMS and 20 years for dynamic pricing.

- **Derating factor,** used to derate the benefits from DR to bring it to par with generation and account for program design constraints. These design constraints include limitations on how often events can be called, annual maximum hours for which events can be called, window of hours during the day during which events can be called, and sometimes even the number of days in a row that events may be called. The derating factor lowers the benefits from DR so that a megawatt from DR is not considered the same as a megawatt from a dispatchable generator, which does not have similar availability constraints and could be available round the clock.[55]

To assess the benefits associated with DR programs, Guidehouse used the avoided generation capacity projections provided by ENO. Guidehouse calculated benefit-cost ratios for the TRC, program administrator cost (PAC), ratepayer impact measure (RIM), and PCT for this study, consistent with the Council's IRP rules. The TRC Benefit-Cost ratios are used for screening for cost-effectiveness using a 1.0 B/C ratio threshold.

[55] "Valuing Demand Response: International Best Practices, Case Studies, and Applications." Prepared by the Brattle Group. January 2015. Page 10 of this report explains why the derating factor is important, though its inclusion varies across utilities and jurisdictions: http://files.brattle.com/files/5766_valuing_demand_response_-_international_best_practices__case_studies__and_applications.pdf
"2016 Demand Response Cost-Effectiveness Protocols", July 2016, California Public Utilities Commission
"2019-2021 ADR BCR Model" for National Grid, which shows no derating for batteries.

3. Energy Efficiency Achievable Potential Forecast

This section provides the results of the energy efficiency achievable potential analysis.

3.1 Model Calibration

Calibrating a predictive model is challenging, as future data is not available to compare against model predictions. While engineering models can often be calibrated to a high degree of accuracy because simulated performance can be compared directly with performance of actual hardware, predictive models do not have this luxury. DSM models must rely on other techniques to provide the developer and the recipient with a level of comfort that simulated results are reasonable. For this study, Guidehouse took several steps to ensure that the forecast model results are reasonable and consider historic adoption:

- Comparing forecast values by sector and end use, typically against historic achieved savings (e.g., program savings from 2019) and planned savings for Energy Smart PY10-12. Although in some studies DSM potential models are calibrated to ensure first-year simulated savings precisely equal prior-year reported savings, Guidehouse notes that forcing such precise agreement may introduce errors into the modeling process by effectively masking the explanation for differences—particularly when the measures included may vary significantly. Additionally, there may be sound reasons for first-year simulated savings to differ from prior-year reported savings (e.g., a program is rapidly ramping up or savings estimates have changed). Although the team endeavored to achieve reasonable agreement between past results and forecasted first-year results, the team's approach did not force the model to do so, providing confidence that the model is internally consistent.

- Identifying and ensuring an explanation existed for significant discrepancies between forecast savings and prior-year savings, recognizing that some ramp up is expected, especially for new measures or archetype programs.

- Calculating $/first-year kilowatt-hour costs and comparing them to past results.

- Calculating the split (percentage) in spending between incentives and variable administrative costs predicted by the model to historic values.

- Calculating total spending and comparing the resulting values to historical spending.

3.1.1 Achievable Potential Case Studies and Incentive Levels

A key component of any potential study is determining the appropriate level at which to set measure incentives for each case.

For ENO, the incentive-level strategy characterized is the percent of full measure cost approach. This approach calculates measure-level incentives based on a specified percentage of full measure costs. ENO provided Guidehouse data regarding the average incentives as a percent of the installation invoice (in other words, the full measure cost) by sector. For example, if the specified incentive percentage was 50% and a measure's cost was $100, then the calculated incentive for that measure would be $50. Guidehouse used the full measure cost strategy since ENO provided its historical program incentives based on full measure costs.[56]

3.1.2 Achievable Cases Analysis

For the 2021 IRP Potential Study, Guidehouse ran four cases for achievable EE potential. Three of the cases were derived from Scenario 2 of the approved Energy Smart PY10-12 implementation plan and set incentives for potential measures based on a percentage of the Full Measure Cost (FMC). One case was derived from the base case used in the 2018 IRP Potential Study and set incentives for potential measures based on a percentage of the Incremental Measure Cost (IMC) in order to offer a case showing an industry standard level of incentives.

FMC takes into account the full cost of installing a measure, while IMC represents the additional cost of installing a higher energy efficiency measure as compared to installing a base level energy efficiency measure. Guidehouse set incentive levels at 86% and 32% of FMC for residential and commercial programs in the 2% Program case, respectively. These percentages are consistent with what is currently being seen in Energy Smart program implementation when looking at incentive level compared with the full invoice cost of the measure. Guidehouse then varied the percentages for the Low and High Program cases. The Reference case used IMCs because it was based on the Base case from the 2018 IRP Potential Study performed by Navigant, in which IMCs were also used. Either IMCs or FMCs can be used to tie back to historical performance without significant variance in model results.

2% Program Case

The 2% program case is defined by the approved Energy Smart PY10-12 implementation plan, Scenario 2.[57] Guidehouse set incentives at 86% and 32% of the full measure cost for residential and C&I measures, respectively. Guidehouse calibrated the model results by adjusting adoption parameters and behavior program rollout to align with the historical program achievements and planned savings as documented in the implementation plan.

Low Program Case

The low case uses the same inputs as the 2% program case, (ENO implementation plan, Scenario 2) except for lower levels of behavior program participation rollout (50% of the 2% program case). Incentives are set to 50% of full measure cost for residential and 25% for C&I. Administrative costs on a dollar per kWh saved basis are the same as the 2% program case.

High Program Case

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[56] In all cases, incentives are capped at a levelized cost to prevent paying more incentives than the equivalent avoided cost benefit.

[57] https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_10-12/Correction_Revised_Implementation_Plan_%20PY_10-12_1-24-20.pdf?_ga=2.216502932.327611312.1611206281-15932630.1611206281 and https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_10-12/Revised_Implementation_Plan_PY_10-12_1-22-20.pdf?_ga=2.216502932.327611312.1611206281-15932630.1611206281

The high case is based off the 2% program case but with higher incentives as a percent of full measure cost at 100% for residential and 50% for C&I. Additionally, there is a more aggressive plan for behavior program rollout. Behavioral program rollout for the residential sector increases slightly compared to the 2% case and reaches the maximum achievable level.[58] Administrative costs on a dollar per kWh saved basis are relatively equal to those in the 2% program case.

Reference Case

In an effort to develop a case reflecting an industry-standard level of incentives, and because the actual program results for the approved PY10-12 plan are tracking to higher levels of administrative costs and kWh savings than are often seen in long term potential studies, it was useful to provide a Reference Case that tied back to the Base case from the 2018 study. This Reference case reflects the Base case from the 2018 study where the program administrative costs reflected current spend targets on a dollar per kWh saved basis and the incentives were set at 50% of incremental measure costs. In Guidehouse's experience in incentive level setting and potential study analysis, others have set incentives or cap incentives at 50% of incremental measure cost. Behavior program roll out matches the low program case levels as a conservative assessment of the potential roll out of the recommended programs for the ENO portfolio.

3.2 Energy Efficiency Achievable Potential Results

Achievable potential values are termed annual incremental potential—they represent the incremental new potential available in each year. The total cumulative potential over the time period is the sum of each year's annual incremental achievable potential. Economic potential can be thought of as a reservoir of cost-effective potential[59] from which programs can draw over time. Achievable potential represents the draining of that reservoir, the rate of which is governed by several factors including the lifetime of measures (for ROB technologies), market effectiveness, incentive levels, and customer willingness to adopt, among others. If the cumulative achievable potential ultimately reaches the economic potential, it would signify that all economic potential in the reservoir had been drawn down or harvested. However, achievable potential levels rarely

[58] Residential behavior programs using a control group to assess energy savings result in an ability to treat less than 100% of the suitable participant pool.

[59] Cost-effectiveness threshold is a TRC = 1.0. There were measures that were passed through with a TRC ratio <1.0 where it was reasonable to assume that the measure is important to program implementation. These measures include: C&I lighting occupancy sensor controls, interior LED high bay, and retrocommissioning. The following highlights the major differences from the last study and this study for the C&I lighting measures:

1. Incremental costs – For a subset of measures, the 2020 study has lower incremental costs as compared to the 2018 study
2. Density – For a subset of measures in 2020, the densities were updated to more recent data sources versus the last study used a 2015 source.
3. EE saturation – Actual program data was used to update lighting saturation for a subset of measures.

For retrocommissioning, the measure exists in the program portfolio currently and becomes cost-effective in later years.

reach the full economic potential level due to a variety of market and customer constraints that inhibit full economic adoption.[60]

All tables and figures (except for Section 3.2.1) have the potential savings for the 2% program case only.

3.2.1 Case-Level Results

As explained in Section 2.1.4.3, the achievable potential analysis was modeled with four different case studies. The case studies are based on the incremental and full measure cost capping and shown in Table 3-1.

Table 3-1. Incentive Setting and Behavioral Program Participation by Case

	2%	Low	High	Reference
Res Incentives	86% Full	50% Full	100% Full	50% IMC
C&I Incentives	32% Full	25% Full	50% Full	50% IMC
Behavioral Participation	Medium forecast	Low forecast	High forecast	Low forecast

Table 3-2 shows the incremental energy and demand savings per year for each case. Figure 3-1 and Figure 3-2 show the cumulative annual energy and demand savings for each case. The different cases do not show significant difference from each other; however, each case has marked differences in the program design, i.e., changes in ENO-influenced parameters including incentive level setting and behavioral program rollout.[61]

[60] Constraints on achievable potential that inhibit realization of the full economic potential include the rate at which homes and businesses will adopt efficient technologies, as well as the word of mouth and marketing effectiveness for the technology. If a technology already has high saturation at the beginning of the study, it may theoretically be possible to fully saturate the market and achieve 100% of the economic potential for that technology.

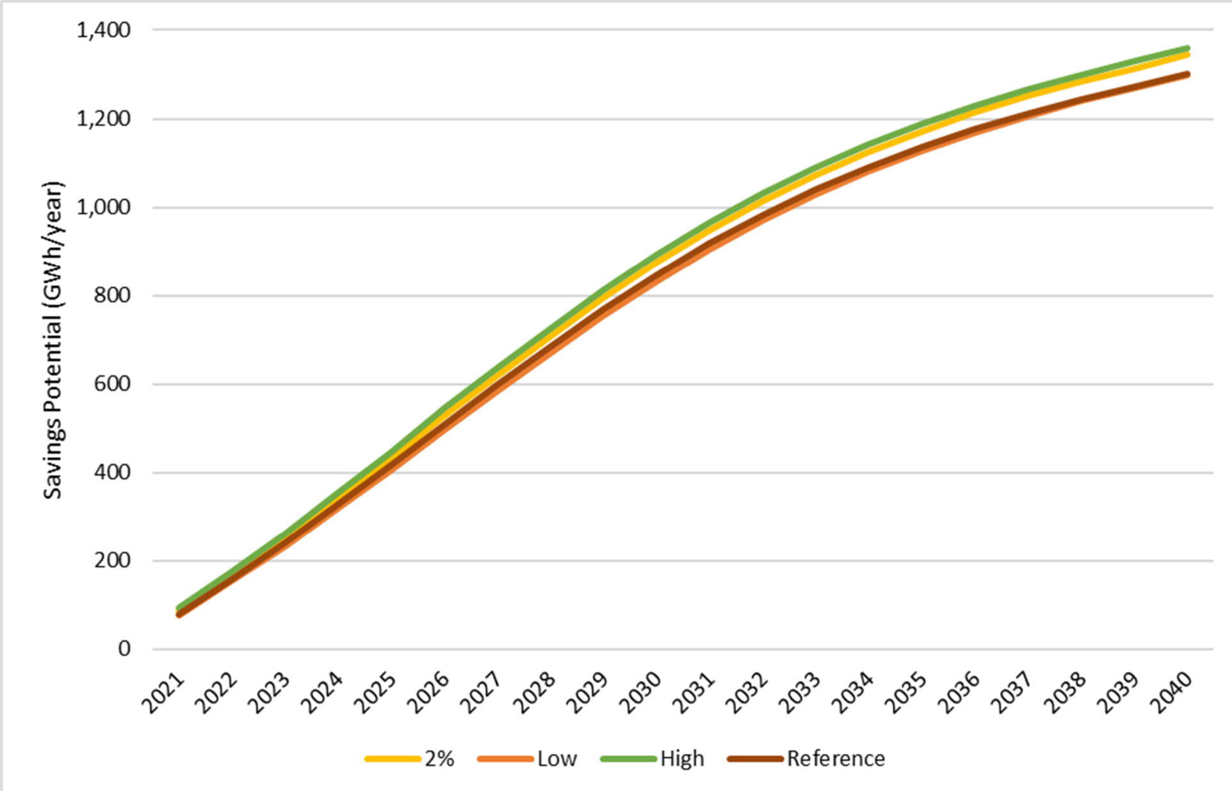
[61] Incentive levels change the customer payback period. Depending on amount of change will result in a change on the payback acceptance curve influencing the market share potential of the energy efficient option. The payback acceptance curve was developed as a result of customer surveys of hypothetical situations.

Table 3-2. Annual Incremental Achievable Energy Efficiency Savings by Case

Year	Electric Energy (GWh/Year)				Peak Demand (MW)			
	2%	Low	High	Reference	2%	Low	High	Reference
2021	89	77	93	79	22	20	23	21
2022	98	86	104	88	22	21	22	21
2023	105	91	111	93	23	22	24	23
2024	112	96	119	99	25	24	25	24
2025	119	101	126	103	26	25	26	25
2026	124	105	132	106	27	26	27	26
2027	122	104	130	104	27	26	27	26
2028	121	102	128	102	27	26	27	26
2029	120	101	128	102	26	25	26	25
2030	115	96	123	96	25	25	26	24
2031	109	90	117	89	24	23	24	23
2032	103	84	110	83	23	22	23	22
2033	97	77	104	76	21	20	21	20
2034	91	71	99	70	20	19	20	18
2035	86	66	94	65	18	17	18	17
2036	83	62	91	61	17	16	17	16
2037	79	58	87	57	16	15	15	14
2038	76	54	84	53	15	13	14	13
2039	72	51	81	50	13	12	13	12
2040	73	51	81	50	13	12	13	12
Total	**1,344**	**1,299**	**1,359**	**1,302**	**429**	**409**	**432**	**408**

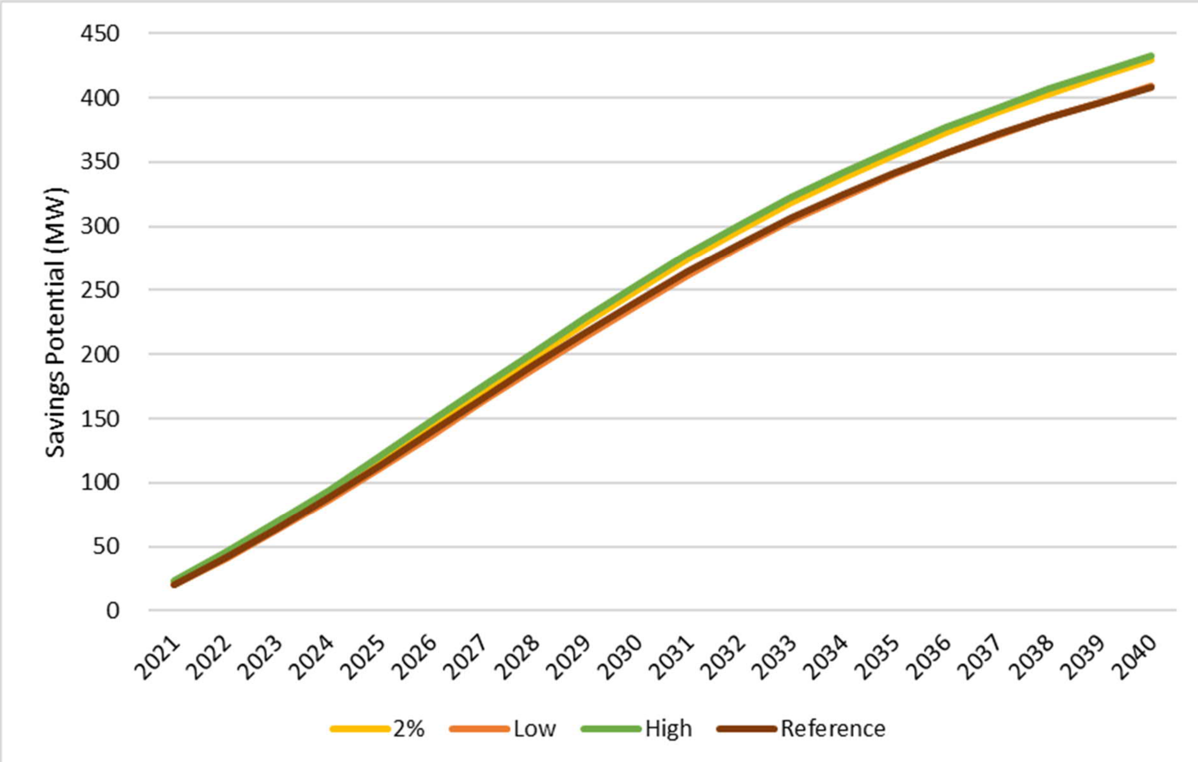
Source: Guidehouse analysis

Figure 3-1. Electric Energy Cumulative Achievable Savings Potential by Case (GWh/year)



Source: Guidehouse analysis

Figure 3-2. Peak Demand Cumulative Achievable Savings Potential by Case (MW)



Source: Guidehouse analysis

Table 3-3. shows the incremental electric energy achievable savings as a percentage of ENO's total sales for each case. The 2% program case, which was calibrated to the current approved implementation plan, achieves at least 2% of sales savings from 2025 through 2029. The 2% program case, as well as the high program case, falls below 2% in later years because most of the measures will have been adopted, depleting the available potential in the future years. What keeps the 2% program and high program case at greater than 1% throughout the forecast period are the behavior programs.

This study only includes known, market-ready, quantifiable measures without introducing new measures in later years. However, over the lifetime of energy efficiency programs, new technologies and innovative program interventions could result in additional cost-effective energy savings. Therefore, the need to periodically revisit and reanalyze the potential forecast is necessary.

Table 3-3. Incremental Electric Energy Achievable Savings Potential as a Percentage of Sales, by Case (%, GWh)

Year	2%	Low	High	Reference
2021	1.54%	1.34%	1.62%	1.38%
2022	1.71%	1.49%	1.80%	1.53%
2023	1.82%	1.57%	1.93%	1.62%
2024	1.94%	1.67%	2.06%	1.71%

2025	2.05%	1.75%	2.18%	1.78%
2026	2.14%	1.81%	2.28%	1.84%
2027	2.11%	1.79%	2.24%	1.80%
2028	2.07%	1.75%	2.20%	1.76%
2029	2.06%	1.74%	2.20%	1.75%
2030	1.97%	1.65%	2.10%	1.64%
2031	1.86%	1.54%	1.99%	1.52%
2032	1.75%	1.43%	1.88%	1.41%
2033	1.64%	1.31%	1.77%	1.29%
2034	1.54%	1.21%	1.67%	1.19%
2035	1.45%	1.12%	1.59%	1.09%
2036	1.40%	1.05%	1.54%	1.03%
2037	1.33%	0.97%	1.47%	0.95%
2038	1.27%	0.91%	1.42%	0.89%
2039	1.21%	0.85%	1.36%	0.84%
2040	1.22%	0.85%	1.36%	0.84%
Total	**22.54%**	**21.78%**	**22.79%**	**21.83%**

Source: Guidehouse analysis

The total, administrative and incentive costs for each case are provided in Table 3-4. for each year of the study period. It is important to note the differences in these cases as compared to the savings achieved. Administrative spending is relatively consistent between the cases, while incentive spending varies between the cases, with higher spending correlated to higher savings.

Table 3-4. Spending Breakdown for Achievable Potential ($ millions/year)[62]

	Total				**Incentives**				**Non-Incentives**			
Year	2%	Low	High	Reference	2%	Low	High	Reference	2%	Low	High	Reference
2021	$14	$12	$17	$15	$8	$6	$11	$9	$6	$6	$6	$6
2022	$16	$13	$19	$17	$9	$7	$12	$10	$7	$7	$7	$7
2023	$17	$14	$20	$18	$10	$7	$13	$11	$7	$7	$7	$7
2024	$19	$16	$22	$19	$11	$8	$14	$11	$8	$8	$8	$8
2025	$20	$17	$23	$20	$12	$9	$15	$12	$8	$8	$8	$8
2026	$21	$18	$25	$21	$13	$9	$16	$12	$9	$8	$9	$9
2027	$22	$18	$25	$21	$13	$10	$16	$12	$9	$8	$9	$9
2028	$22	$18	$25	$20	$13	$10	$16	$12	$9	$8	$9	$8
2029	$22	$18	$25	$20	$13	$10	$16	$12	$9	$8	$9	$8
2030	$21	$18	$24	$19	$13	$10	$16	$11	$8	$8	$8	$8
2031	$20	$17	$23	$18	$13	$10	$15	$11	$7	$7	$7	$7
2032	$19	$16	$21	$17	$12	$9	$14	$10	$7	$7	$7	$7
2033	$18	$15	$19	$15	$11	$9	$13	$9	$6	$6	$6	$6

62 The values in this table are rounded to the nearest million and may result in rounding errors.

	Total				Incentives				Non-Incentives			
Year	2%	Low	High	Reference	2%	Low	High	Reference	2%	Low	High	Reference
2034	$16	$14	$18	$14	$11	$8	$12	$9	$6	$6	$5	$5
2035	$15	$13	$16	$13	$10	$8	$12	$8	$5	$5	$5	$5
2036	$15	$12	$16	$12	$10	$8	$11	$8	$5	$5	$4	$4
2037	$14	$12	$15	$11	$10	$7	$11	$7	$4	$4	$4	$4
2038	$13	$11	$14	$10	$10	$7	$11	$7	$4	$4	$4	$4
2039	$13	$10	$14	$9	$9	$7	$10	$6	$3	$3	$3	$3
2040	$13	$11	$14	$10	$10	$7	$11	$6	$4	$3	$3	$3
Total	**$349**	**$293**	**$394**	**$321**	**$220**	**$166**	**$265**	**$194**	**$129**	**$127**	**$129**	**$127**

Source: Guidehouse analysis

The TRC test is a benefit-cost metric that measures the net benefits of energy efficiency measures from the combined stakeholder viewpoint of the program administrator (utility) and program participants. The TRC benefit-cost ratio is calculated in the model using Equation 3-1.

Equation 3-1. Benefit-Cost Ratio for the TRC Test

$$TRC = \frac{PV(Avoided\ Costs + Externalties)}{PV(Technology\ Cost + Admin\ Costs)}$$

Where:

- *PV( )* is the present value calculation that discounts cost streams over time.
- *Avoided Costs* are the monetary benefits that result from electric energy and capacity savings—e.g., avoided costs of infrastructure investments and avoided fuel (commodity costs) due to electric energy conserved by efficient measures.
- *Externalities* are the monetary or quantifiable benefits associated to greenhouse gas (GHG) gas reductions (i.e., the market cost of carbon).
- *Technology Cost* is the incremental equipment cost to the customer to purchase and install a measure.
- *Admin* are the costs incurred by the program administrator to deliver services (excluding incentive costs paid to participants).

Guidehouse calculated TRC ratios for each measure based on the present value of benefits and costs (as defined by the numerator and denominator, respectively) over each measure's life. Avoided costs, discount rates, and other key data inputs used in the TRC calculation are presented in **Error! Reference source not found.**A. Effects of free ridership are not present in the results from this study, so the team did not apply a NTG factor. Providing gross savings results will allow the utility to easily apply updated NTG assumptions in the future and allow for variations in NTG assumptions by reviewers.

The TRC ratios for these cases are provided by year in Table 3-5.. Even with the large increases in incentives for the high case, all cases are cost-effective. Increasing incentives does not necessarily translate to a lower TRC because incentives are considered a transfer cost and are excluded from the TRC benefit-cost calculation. However, higher incentives may make higher cost measures more attractive to end users and spur their adoption. Thus, where incentives increase as a percentage of measure cost, TRC scores can be lower even though incentives are not part of the TRC calculation.

One of the screening criteria in the potential analysis is for the measures to pass the TRC test. A handful of measures were allowed into the analysis that fell below 1.0. As a result, the portfolio is still cost-effective. Typically, the more aggressive the portfolio, the lower the TRC as more non-cost-effective measures are added and increase administrative efforts to address more services to the market.

Table 3-5. Portfolio TRC Benefit-Cost Ratios for Achievable Potential (Ratio)

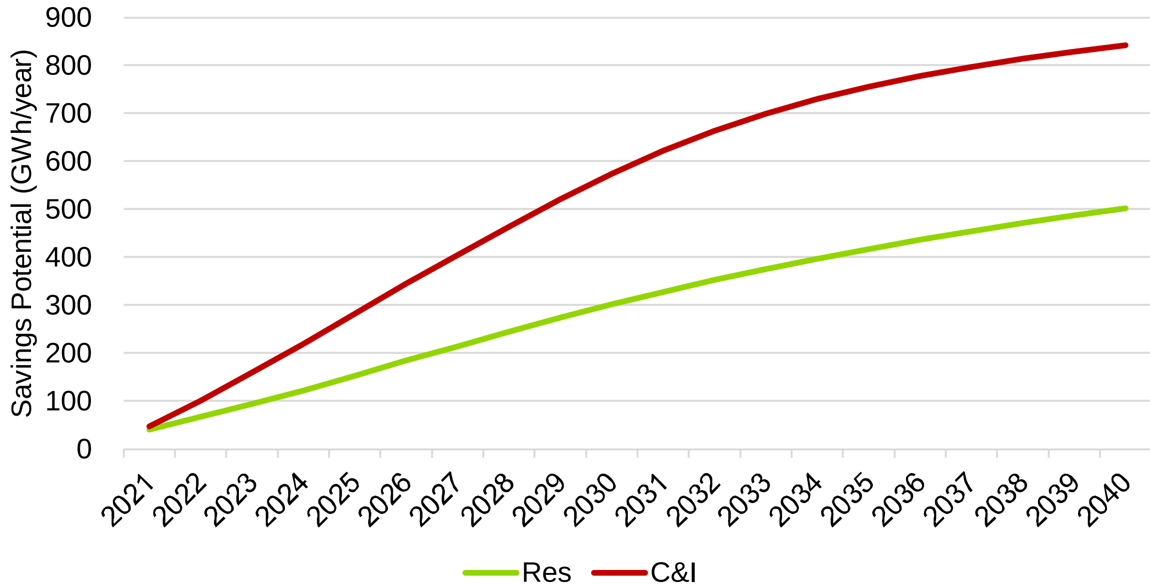
Year	2%	Low	High	Reference
2021	1.45	1.48	1.44	1.46
2022	1.52	1.55	1.50	1.53
2023	1.63	1.66	1.61	1.64
2024	1.69	1.72	1.67	1.70
2025	1.72	1.76	1.71	1.73
2026	1.77	1.81	1.76	1.79
2027	1.81	1.85	1.80	1.83
2028	1.87	1.91	1.86	1.90
2029	1.92	1.96	1.91	1.95
2030	1.97	2.01	1.96	2.00
2031	2.03	2.06	2.02	2.05
2032	2.08	2.11	2.07	2.10
2033	2.13	2.16	2.13	2.16
2034	2.18	2.21	2.19	2.21
2035	2.24	2.26	2.25	2.27
2036	2.27	2.29	2.28	2.31
2037	2.32	2.34	2.33	2.36
2038	2.37	2.38	2.38	2.40
2039	2.40	2.42	2.42	2.45
2040	2.28	2.30	2.30	2.32
2021-2040	1.85	1.88	1.84	1.86

Source: Guidehouse analysis

3.2.2 Achievable Potential Results by Sector

Figure 3-3 shows the cumulative electric achievable savings potential for all analysis years by sector for the 2% program case. The 2% program case is calibrated based on the existing ENO PY10-12 implementation plan.

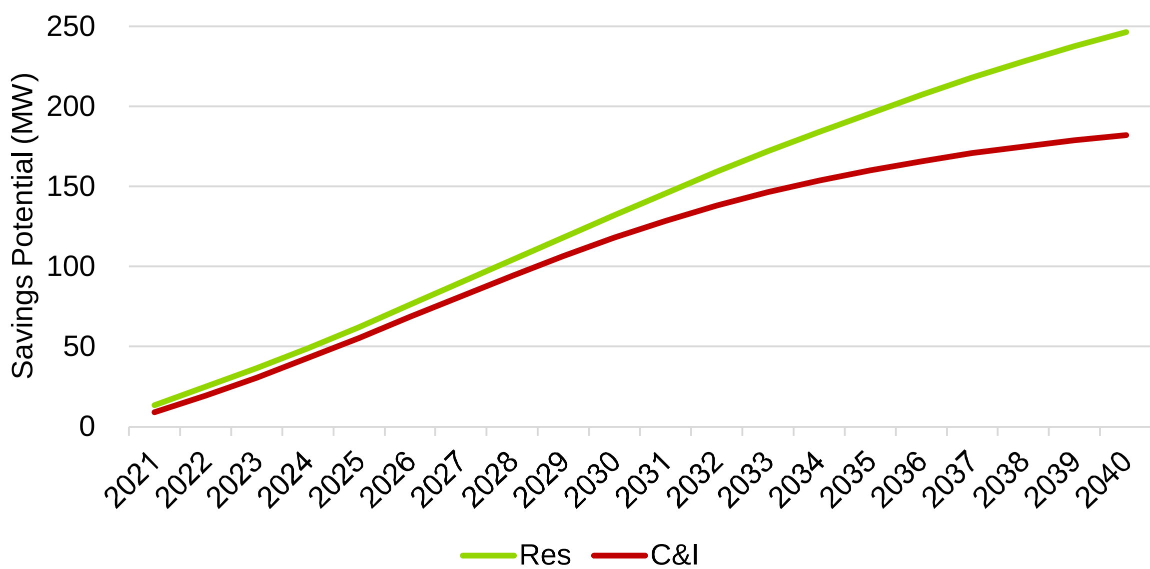
Figure 3-3. Electric Energy Cumulative 2% Program Case Achievable Savings Potential by Sector (GWh/year)



Source: Guidehouse analysis

Figure 3-4 shows the cumulative achievable demand savings potential for all analysis years by sector for the 2% program case.

Figure 3-4. Electric Demand Cumulative 2% Program Case Achievable Savings by Sector (MW)



Source: Guidehouse analysis

Table 3-6. shows the cumulative electric energy achievable savings as a percentage of ENO's total sales for each sector. The residential sector accounts for a larger percentage than the C&I sector.

Table 3-6. Cumulative Electric Energy Achievable Savings Potential by Sector as a Percentage of Sales (%, GWh), 2% Program Case

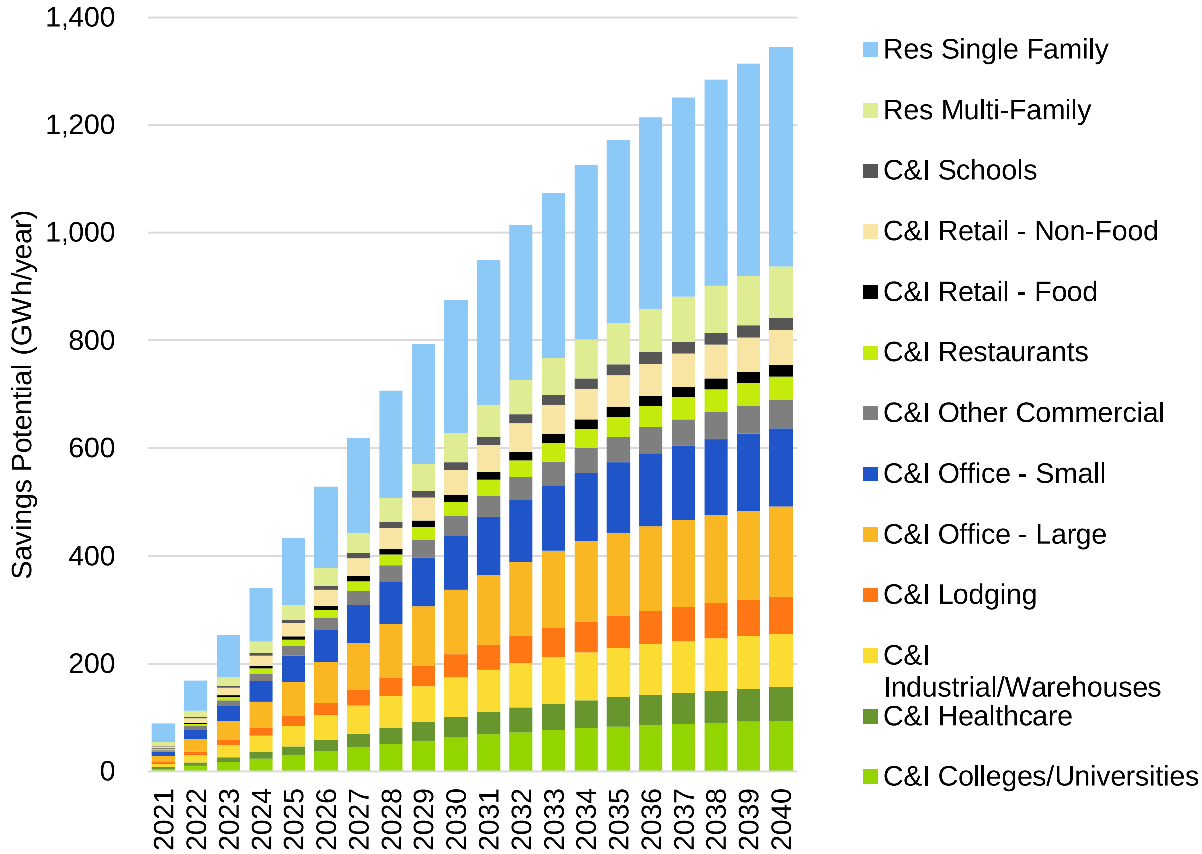
Year	All	Res	C&I
2021	1.5%	1.8%	1.4%
2022	2.9%	3.0%	2.9%
2023	4.4%	4.1%	4.6%
2024	5.9%	5.3%	6.3%
2025	7.5%	6.6%	8.1%
2026	9.1%	8.0%	9.9%
2027	10.7%	9.3%	11.6%
2028	12.2%	10.5%	13.2%
2029	13.6%	11.8%	14.9%
2030	15.0%	12.9%	16.3%
2031	16.2%	14.0%	17.6%
2032	17.3%	15.0%	18.8%
2033	18.2%	16.0%	19.7%
2034	19.1%	16.9%	20.5%
2035	19.8%	17.7%	21.2%
2036	20.5%	18.5%	21.8%
2037	21.1%	19.3%	22.2%
2038	21.6%	20.0%	22.6%
2039	22.1%	20.7%	23.0%
2040	22.5%	21.4%	23.3%

Source: Guidehouse analysis

3.2.3 Results by Customer Segment

Figure 3-5 shows the cumulative electric energy achievable potential by customer segment. Single-family homes make up the largest residential segment, while large and small office contribute the most savings to the C&I sector.

Figure 3-5. 2% Program Case Cumulative Achievable Potential Savings Customer Segment Breakdown



Source: Guidehouse analysis

3.2.4 Results by End Use

Figure 3-6 and Figure 3-7 show the percentage of each end use for each sector. The lighting interior and HVAC end use have the largest potential. The HVAC end uses are high relative to others because this end use includes the sales associated with envelope and systems that affect both heating and cooling. ENO has a relatively high penetration of electric heating, which contributes to this factor even though New Orleans experiences rather low heating degree days and high cooling degree days.

The total facility end use refers to holistic measures, such as the behavior program.

Figure 3-6. Residential 2021 Electric Energy Achievable Potential End-Use Breakdown (%, GWh)

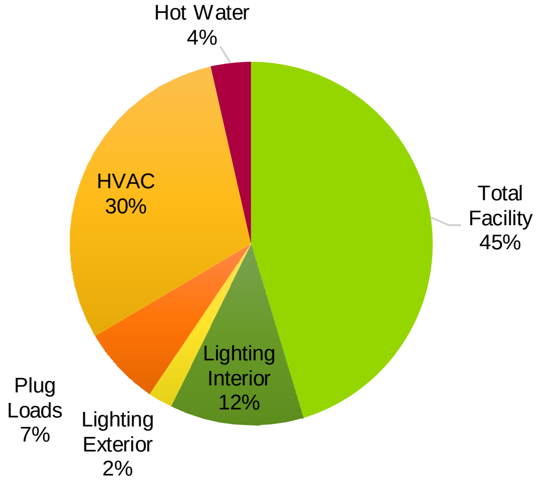
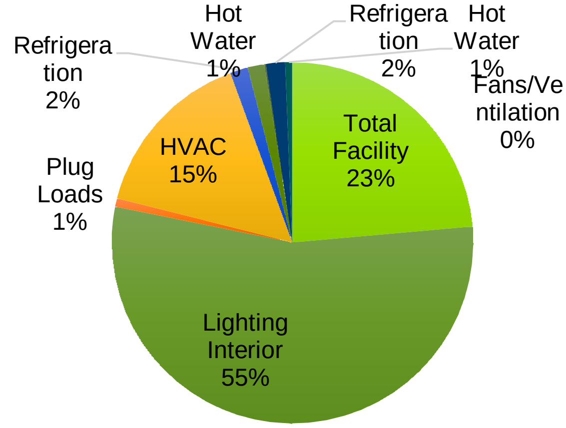


Figure 3-7. C&I 2021 Electric Energy Achievable Potential End-Use Breakdown (%, GWh)

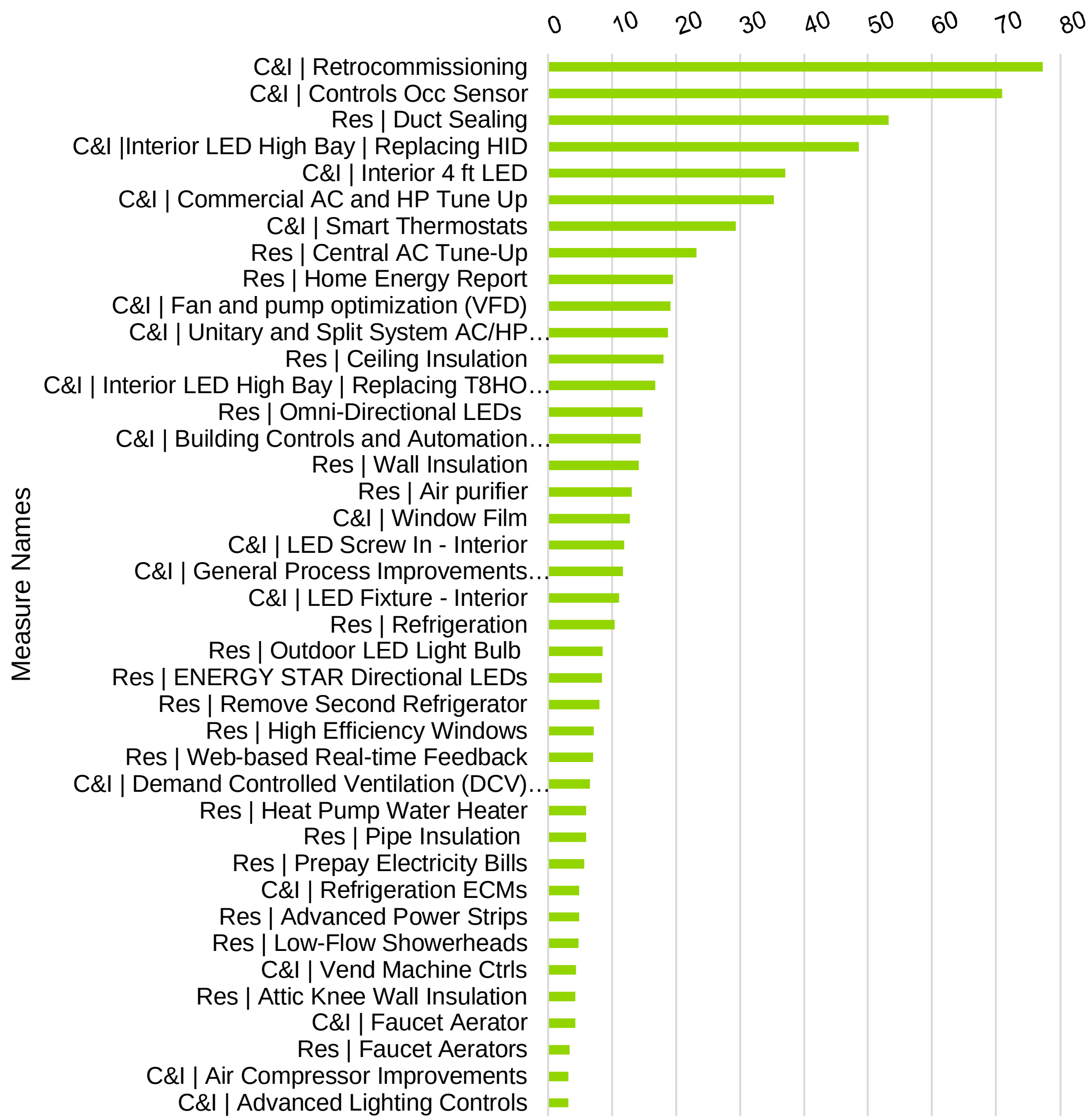


Source: Guidehouse analysis

3.2.5 Achievable Potential Results by Measure

Figure 3-8 shows the top 40 measures contributing to the electric energy achievable potential in 2028 (representative of the 20-year results). Retrocommissioning in the C&I sector provides the most savings, followed by occupancy sensor controls, interior high bay LEDs, 4-foot LEDs and smart thermostats. Residential duct sealing, central AC tune-up and home energy reports provide the highest three residential sector savings.

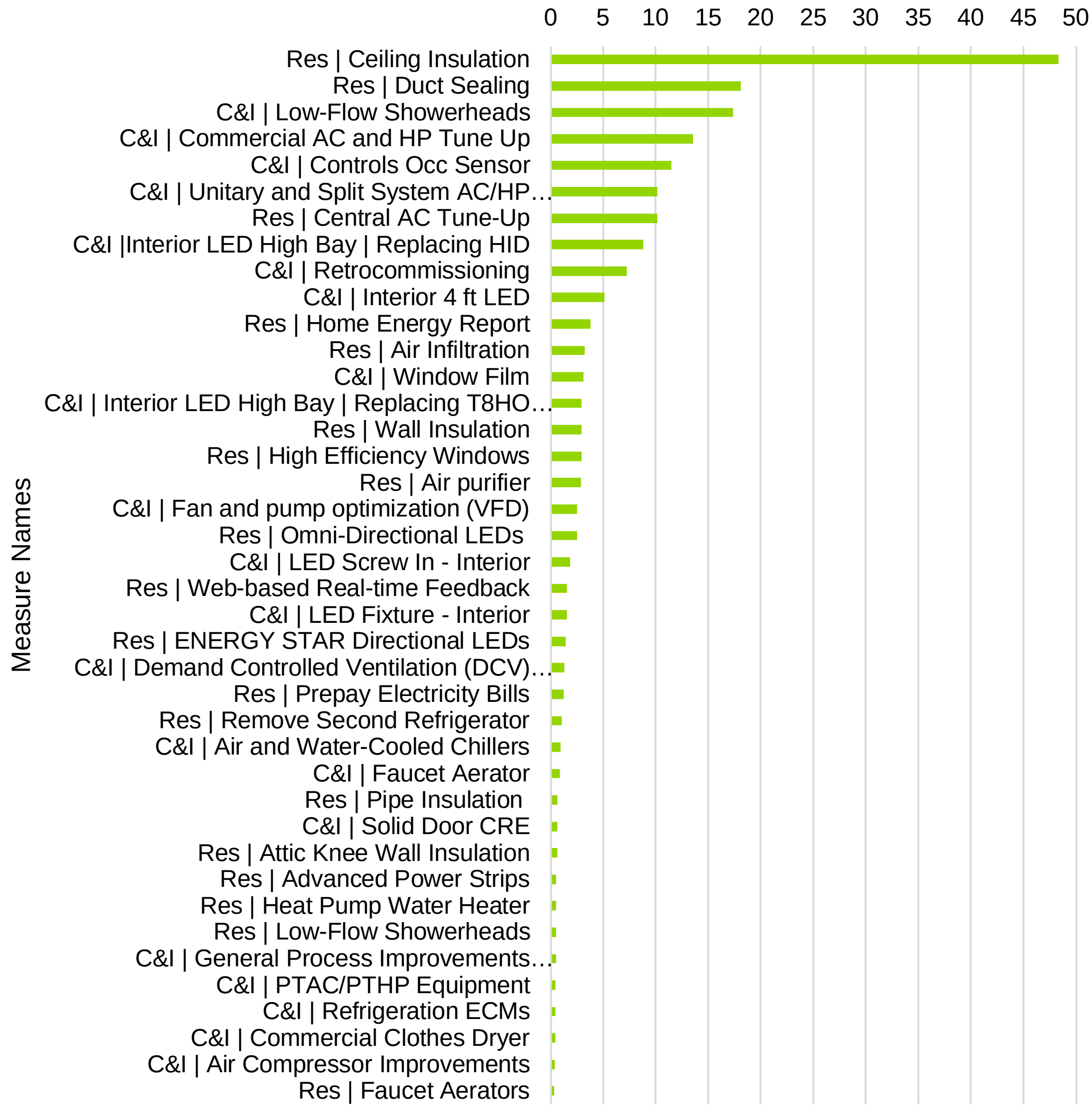
Figure 3-8. Top 40 Measures for Cumulative Electric Energy 2% Program Case Achievable Savings Potential: 2028 (GWh/year)



Source: Guidehouse analysis

Figure 3-9 shows the top 40 measures contributing to the demand achievable potential in 2028. The top measures are different than those listed for electric energy. For the Residential sector, ceiling insulation and duct sealing are the highest demand savings. For the C&I sector, the highest savings come from low flow showerheads, tune-ups, and occupancy sensors. These measures' unit energy and peak demand savings are sourced from the TRM v4.0.

Figure 3-9. Top 40 Measures for Cumulative Electric Demand 2% Program Case Savings Potential: 2028 (MW)



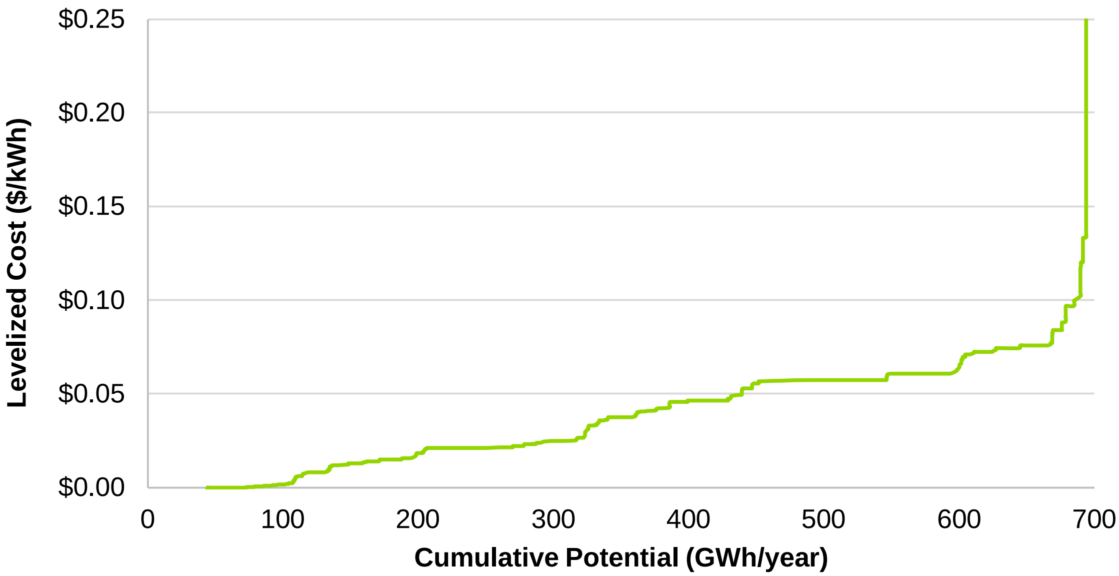
Source: Guidehouse analysis

Figure 3-10 provides a supply curve of savings potential versus the levelized cost of savings in $/kWh for all measures considered in the study. The X-axis shows *cumulative* achievable potential through 2028, which means the cumulated annual savings from 2021-2028. In Figure 3-3 that the cumulative savings in 2028 is about 700 GWh/year, which matches the X-axis in the supply curve. To develop the supply curve, the Guidehouse model calculates the following:

1. Levelized cost which is the net present value of the TRC costs (program non-incentive costs + measure costs) divided by the net present value of the lifetime savings over the measure life.
2. Cumulative potential which is the cumulated annual savings up until the year-of-interest per measure at the specific levelized cost.

The supply curve allows for the comparison of the cost of obtaining demand side energy reductions against the cost of supply side resources. The curve shows that additional units of savings come at an increased cost, eventually resulting in savings that are quite expensive. In other words, certain measures are the "lowest hanging fruit", and once those measures are expended, we move to the next measure along the curve. By the time we get to 2028, most of the savings from 2021-2028 were obtained below a $0.08/kWh levelized cost.

Figure 3-10. Supply Curve of Electric Energy Achievable Potential (GWh/year) vs. Levelized Cost ($/kWh): 2028

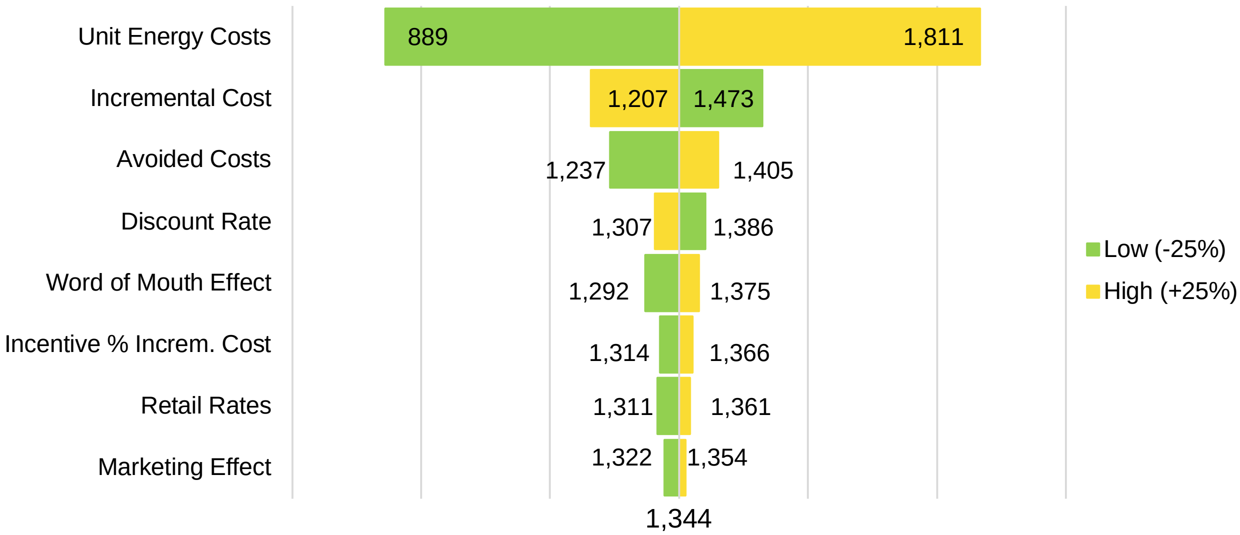


Source: Guidehouse analysis

3.2.6 Sensitivity Analysis

Figure 3-11 shows a sensitivity analysis of the effect on energy savings potential that results from varying the most influential factors by +/- 25%. Table 3-7. shows the percent change to the cumulative energy savings potential for each sensitivity parameter in 2040. Unit energy savings (energy savings of each measure, for example, quantified as a kWh/unit or kWh/ton for HVAC) have the largest impact, followed by incremental costs, avoided costs, and word of mouth effect. Such understandings are critical to evaluating related policy decisions and informing effective program design.

Figure 3-11. Cumulative Achievable GWh Savings in 2040 Sensitivity to Key Variables



Source: Guidehouse analysis

Table 3-7. Percent Change to Cumulative Potential in 2040 with 25% Parameter Change

Parameter	Low (-25%)	High (+25%)
Unit Energy Costs	-34%	35%
Incremental Cost	10%	-10%
Avoided Costs	-8%	5%
Discount Rate	3%	-3%
Word of Mouth Effect	-4%	2%
Incentive % Incremental Cost	-2%	2%
Retail Rates	-2%	1%
Marketing Effect	-2%	1%

Source: Guidehouse analysis

4. Demand Response Achievable Potential and Cost Results

This chapter presents the DR achievable potential and cost results based on the approach described in Section 2.2.

4.1 Cost-Effectiveness Results

This section presents cost-effectiveness results by DR option and sub-option based on the TRC test. Guidehouse also calculated the cost-effectiveness results based on three additional tests: the utility cost test (UCT), RIM test, and the Participant Cost Test (PCT).

4.1.1 Cost-Effectiveness Assessment Results

Table 4-1. shows benefit-cost ratios calculated for each DR sub-option based on the TRC test over the forecast period. Only the following programs are not cost-effective:

- **Direct Load Control:** Switch water heating sub-options for residential and small C&I
- **Behind the Meter Storage:** Battery storage for all customer classes

The only benefit stream captured by the TRC test is the avoided cost of generation capacity. ENO does not currently have a way to value avoided T&D capacity. These cost-effectiveness results would improve if avoided T&D capacity benefits were also included in the assessment. Only cost-effective sub-options are shown in the achievable potential results in subsequent sections.

Table 4-1. Mid Case Benefit-Cost Ratios by DR Options and Sub-Options

Customer Class	DR Option	DR SubOption	TRC
Residential	Dynamic Pricing	Without enabling tech.	2.27
		With enabling tech.	3.01
	DLC	Switch-Central Air Conditioning	3.06
		Thermostat-Res	1.89
		Switch-Water Heating	0.35
	BTMS	Battery Storage	0.08
Small C&I	Dynamic Pricing	Without enabling tech.	4.91
		With enabling tech.	2.50
	DLC	Thermostat-HVAC	3.74
		Switch-Water Heating	0.10
	BTMS	With enabling tech.	0.13
Large C&I	Dynamic Pricing	Without enabling tech.	3.10
		With enabling tech.	4.03
	C&I Curtailment	Other	5.24
		Advanced Lighting Control	5.35
		Auto-DR HVAC Control	5.28
		Refrigeration Control	5.26
		Water Heating Control	5.25

Customer Class	DR Option	DR SubOption	TRC
		Standard Lighting Control	5.23
		Industrial	5.18
	BTMS	Battery Storage	0.15

Source: Guidehouse

As described in Section 2.2.5, in addition to the mid case, Guidehouse modeled potential results for low and high cases. For these cases, the team adjusted assumed participation levels and incentive amounts to determine the impacts on the DR achievable potential. The cost-effective results across the three cases for the DR sub-options match the mid case as shown above. All suboptions pass except for the behind the meter storage and switch – water heating. All other mid case cost-effective measures remain cost-effective under the low and high cases.

4.2 Achievable Potential Results

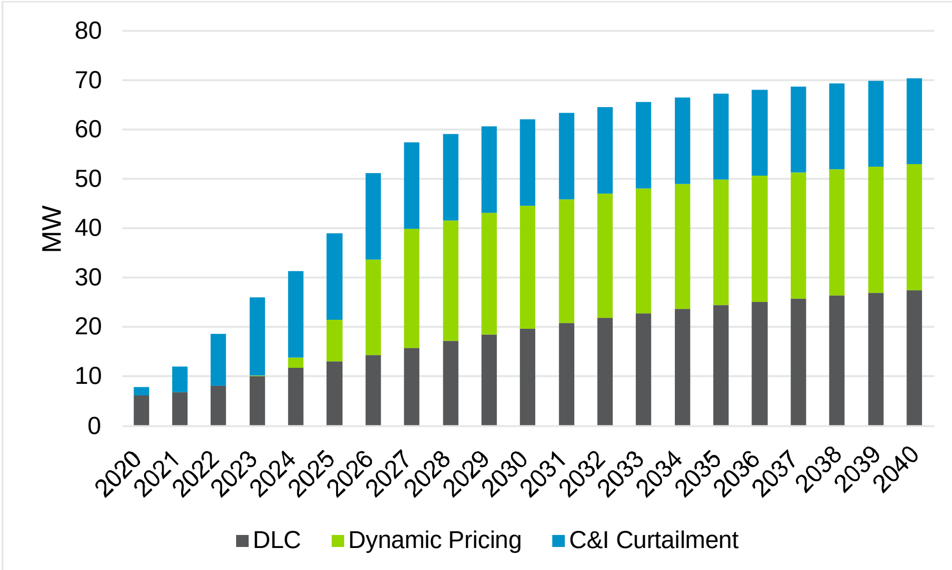
This section presents cost-effective achievable potential results by DR option, sub-option, customer class and segment.

4.2.1 Achievable Potential by DR Option

Figure 4-1 summarizes the cost-effective achievable potential by DR option for the mid case. Figure 4-2 shows the cost-effective achievable potential as a percentage of ENO's peak demand. Achievable peak demand reduction potential is estimated to grow from 12 MW in 2021 to 70 MW in 2040. Cost-effective achievable potential makes up approximately 7% of ENO's peak demand in 2040. The team made several key observations:

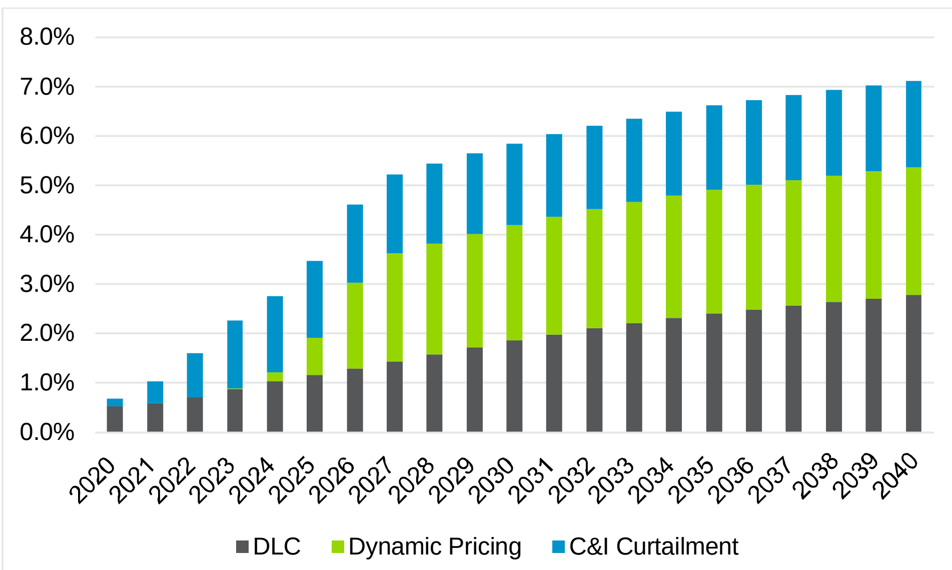
- DLC has the largest achievable potential: 39% share of total potential in 2040. DLC potential grows from 6.8 MW in 2021 to 27.4 MW in 2040.
- Dynamic pricing has a 36% share of the total potential in 2040. The dynamic pricing offer begins in 2023 because it is tied to ENO's advanced metering infrastructure implementation plan and readiness to implement the option. The program ramps up over a 5-year period (2023-2027) until it reaches a value of 24 MW. From then on, potential slowly increases until it reaches a value of 25.6 MW in 2040.
- C&I curtailment makes up the remainder of the cost-effective achievable potential with a 25% share of the total potential in 2040. C&I curtailment potential grows rapidly from 5 MW in 2021 to 17.5 MW in 2024. This growth follows the S-shaped ramp assumed for the program over a 3-5-year period. Beyond 2024, the program attains a steady participation level and its potential slightly decreases (due to changing market and energy intensity forecasts over time) over the remainder of the forecast period, ending at 17.3 MW in 2040.
- BTMS, as described in this report, is not cost-effective; thus, it contributes 0 MW to the DR achievable potential.

Figure 4-1. Summer Peak Achievable Potential by DR Option (MW)



Source: Guidehouse analysis

Figure 4-2. Summer DR Achievable Potential by DR Option (% of Peak Demand)



Source: Guidehouse analysis

4.2.2 Case Analysis Results

Guidehouse developed DR potential estimates for three different cases. These cases are based on the DR program incentive levels:

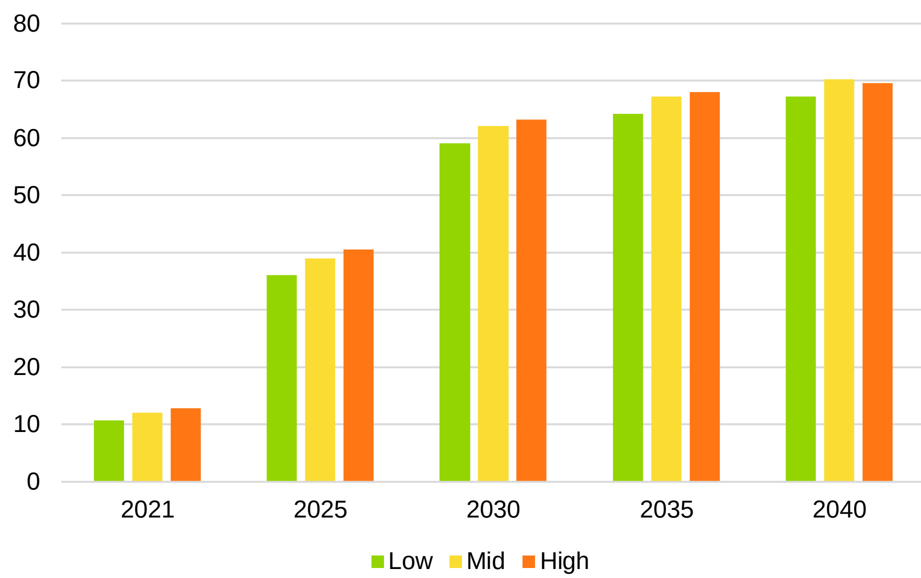
- **Mid case:** Reflects DR program participation based on incentives at levels that match current programs (e.g., ENO's Smart Easy Cool program) and industry best practice.

- **Low case:** Assumes incentives are 50% lower than in the mid case. This drives program participation down and results in lower implementation costs.
- **High case:** Assumes incentives are 50% higher than in the mid case. This drives program participation up and results in higher implementation costs.

The low and high cases do not apply to the dynamic pricing program, as participation is strictly based on customer response to real-time price signals. The change in participation levels due to changes in incentives is based on price response curves developed by the Lawrence Berkeley National Laboratory (Berkeley Lab) for the *2025 California Demand Response Potential Study*.[63, 64]

Figure 4-3 and Figure 4-4 show the achievable potential results in terms of MW and percentage of peak demand, respectively. Under the mid case, the achievable potential makes up approximately 7% of ENO's peak load in 2040. Under the low and high cases, the achievable potential represents approximately 6.6% and 7.0% of ENO's peak demand in 2040, respectively.

Figure 4-3. Summer DR Achievable Potential by Case (MW)

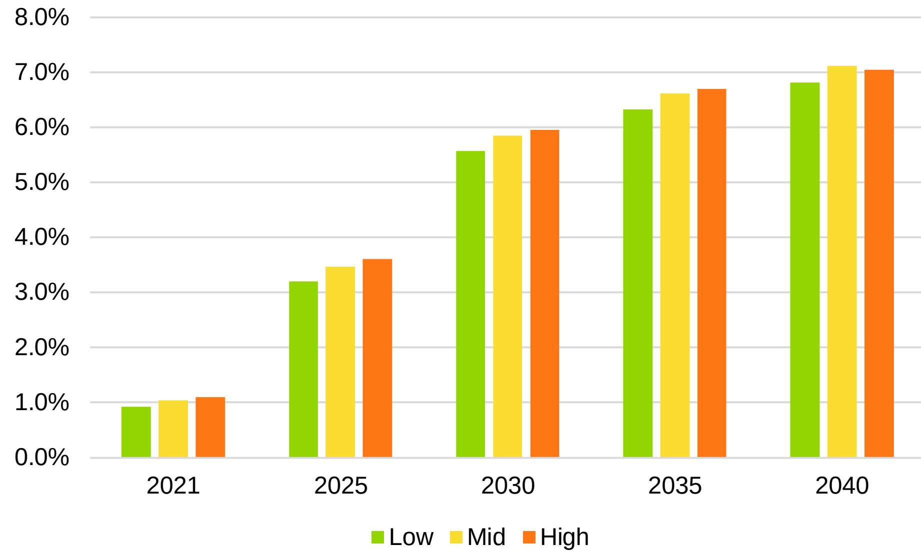


Source: Guidehouse

[63] Lawrence Berkeley National Laboratory. 2025 California Demand Response Potential Study: Charting California's Demand Response Future. Appendix F. March 1, 2017.

[64] Guidehouse assumed medium marketing spending levels for DR programs across cases.

Figure 4-4. Summer DR Achievable Potential by Case (% of Peak Demand)



Source: Guidehouse analysis

4.2.3 Achievable Potential by DR Sub-Option

This section presents the breakdown of cost-effective potential by DR sub-option. Each sub-option is tied to a specific control technology and/or end use. Any sub-option that is tied to a control technology is tied to the penetration of that technology in the market. This penetration trajectory is informed by saturation values from the energy efficiency potential study.

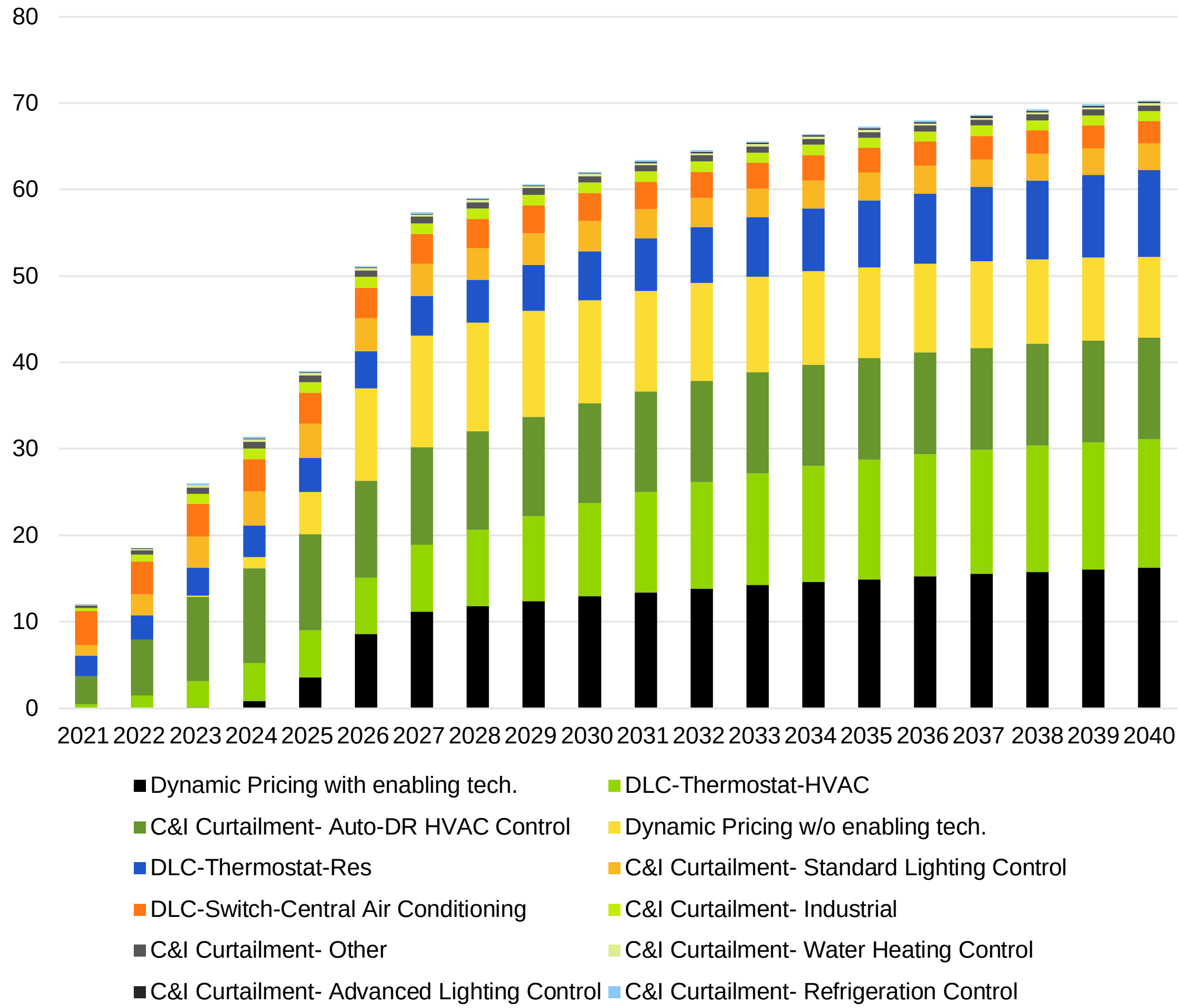
Figure 4-5 summarizes the cost-effective achievable potential by DR option for the mid case. Guidehouse had the following key observations:

- Only direct control of HVAC loads (DLC-Switch and DLC-Thermostat in Figure 12) is cost-effective (and not water heating). This sub-option makes up nearly 40% of the total cost-effective achievable potential in 2040 at 27 MW. Of this 27 MW, 24.9 MW is from thermostat-based control, while the remaining 2.6 MW is from switch-based control.

- Dynamic pricing makes up 36% of the total cost-effective achievable potential in 2040. Potential from customers with enabling technology in the form of thermostats/energy management systems is almost two times higher than that from customers without enabling technology—16 MW versus 9 MW in 2040.

- Under the C&I curtailment program, reductions associated with refrigeration control, advanced and standard lighting control, water heating control, industrial, and auto-DR HVAC control make up 25% of the total cost-effective potential in 2040.

Figure 4-5. Summer DR Achievable Potential by DR Sub-Option



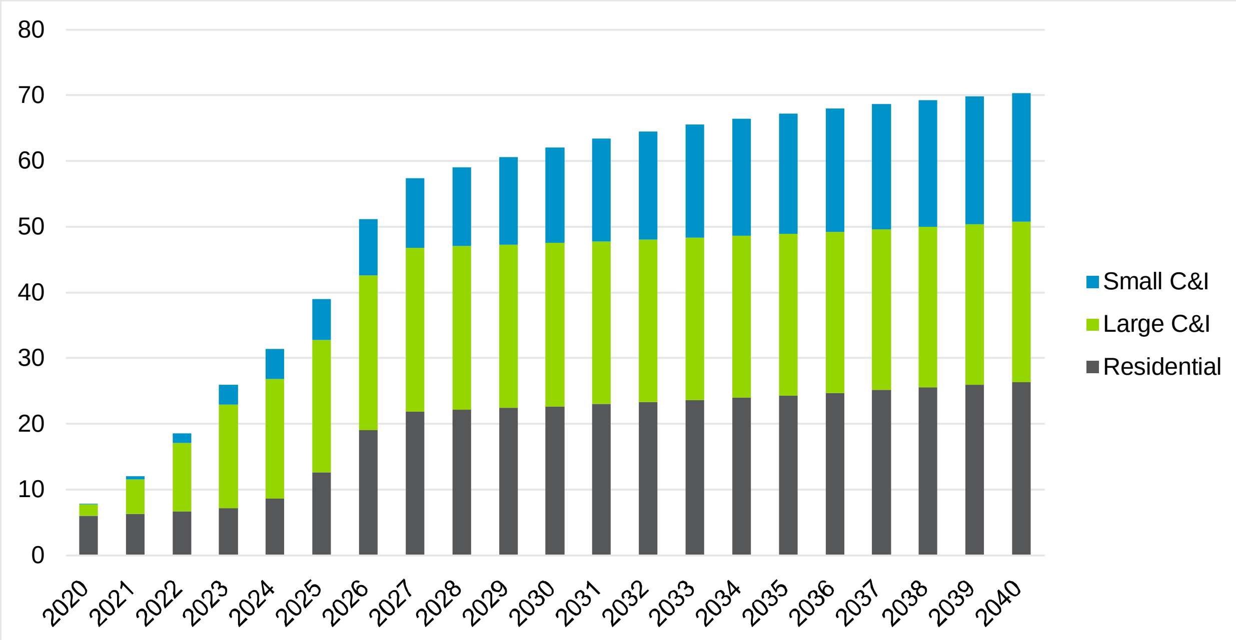
Source: Guidehouse analysis

4.2.4 Achievable Potential by Customer Class

This section presents the breakdown of cost-effective potential by customer class. The three customer classes included in the study are residential, small C&I, and large C&I.
Figure 4-6 summarizes the cost-effective achievable potential by customer class for the mid case. The team had the following key observations:

- Potential from residential customers makes up 37% (26 MW) of the total cost-effective achievable potential in 2040. C&I customers make up the remaining 63%.
- Potential from small C&I customers makes up 28% (19.6 MW) of the total cost-effective achievable potential in 2040. DLC of HVAC loads makes up 76% of this 19.6 MW, while dynamic pricing with enabling technology in the form of thermostats makes up the remaining 24%.
- Potential from large C&I customers makes up 35% (24.4 MW) of the total cost-effective achievable potential in 2040. C&I curtailment with auto-DR HVAC control makes up 48% at 11.75 MW.

Figure 4-6. Summer DR Achievable Potential by Customer Class (MW)



Source: Guidehouse analysis

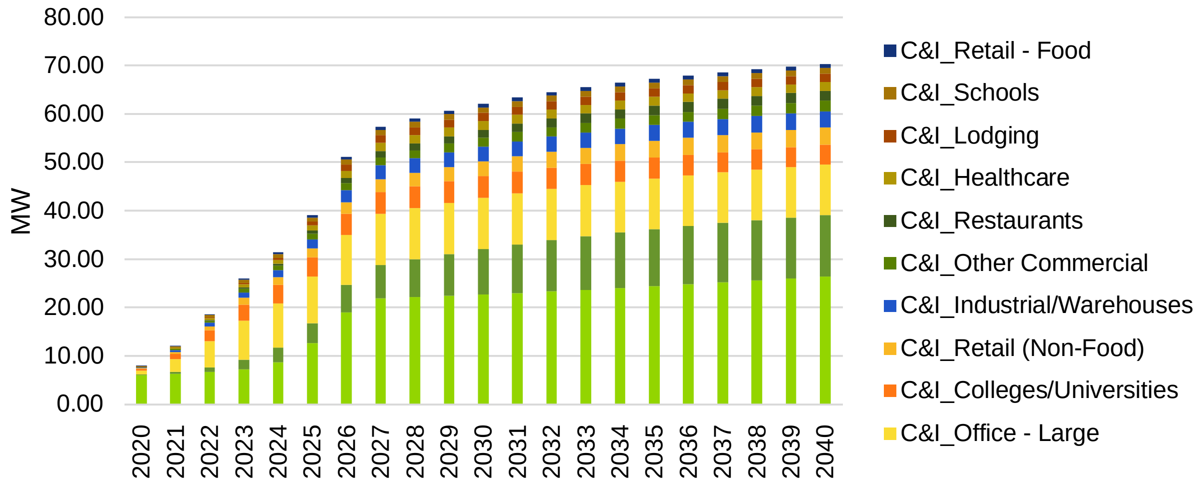
4.2.5 Achievable Potential by Customer Segment

This section presents the breakdown of cost-effective potential by customer segment. As previously discussed in the DR methodology section, these segments align with those included in the energy efficiency potential study. Guidehouse combined single family and multifamily customers into a single residential category because DR program and pricing offers are typically not distinguished by dwelling type. Government customers are included as part of the C&I sector. Savings potential analysis from street lighting is not included in this study.

Figure 4-5 summarizes the cost-effective achievable potential by customer segment for the mid case. Guidehouse had the following key observations:

- Potential from C&I customers primarily comes from small offices, which make up 18% (12.7 MW) of the total cost-effective achievable potential in 2040. This is followed by large office, colleges/universities, and retail building category, which each make up between 5% and 15% of the total cost-effective achievable DR potential in 2040—10.4 MW, 4.14 MW, and 3.6 MW, respectively.
- All other C&I segments make up less than 19% of the cost-effective achievable potential in 2040, which is 13.1 MW.

Figure 4-7. Summer DR Achievable Potential by Customer Segment



Source: Guidehouse analysis

4.3 Program Costs Results

This section presents annual program costs by case and DR option.

4.3.1 Annual Program Costs

4.3.1.1 Annual Costs by Case

Table 4-2. shows annual implementation costs for the entire cost-effective DR portfolio by case. These costs represent the estimated total annual costs that ENO is likely to incur to realize the potential values discussed in Section 4.2. Relative to the mid case, costs are lower and higher in the low and high cases, respectively, due to varied incentive levels paid to customers. This affects the level of participation from customers, which varies technology enablement costs, marketing costs, and O&M costs.

Table 4-2. Annual DR Portfolio Costs by Case

Year	Low	Mid	High
2021	$519,519	$702,868	$895,217
2022	$608,747	$883,274	$1,171,919
2023	$1,166,774	$1,542,201	$1,915,297
2024	$1,207,783	$1,638,822	$2,058,366
2025	$1,391,927	$1,848,971	$2,291,861
2026	$1,471,008	$1,960,225	$2,452,973
2027	$1,292,252	$1,819,751	$2,363,080
2028	$1,243,718	$1,810,222	$2,390,361
2029	$1,314,143	$1,917,893	$2,533,508
2030	$2,359,273	$3,067,340	$3,786,826
2031	$1,444,780	$2,128,367	$2,844,754
2032	$1,527,387	$2,250,516	$2,999,916

Year	Low	Mid	High
2033	$1,608,377	$2,371,351	$3,152,043
2034	$1,677,587	$2,478,447	$3,288,266
2035	$1,736,852	$2,575,017	$3,412,241
2036	$1,813,175	$2,690,041	$3,554,488
2037	$1,887,553	$2,803,818	$3,693,295
2038	$1,963,479	$2,920,126	$3,833,182
2039	$2,038,249	$3,036,197	$3,969,900
2040	$3,362,236	$4,482,182	$5,479,758

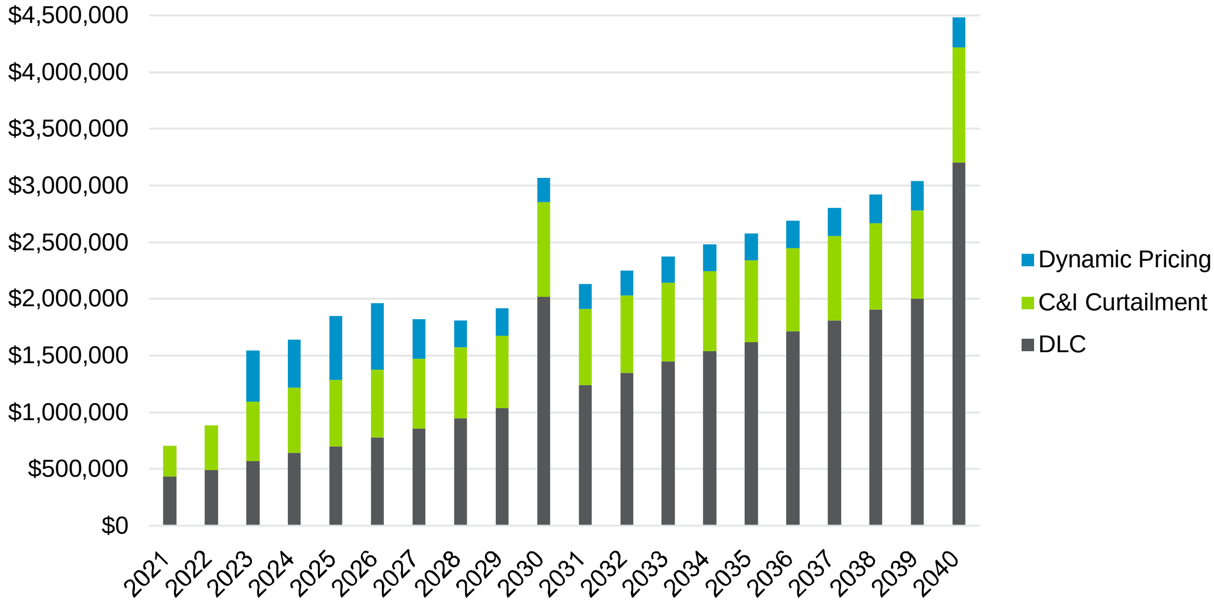
Source: Guidehouse analysis

4.3.1.2 Annual Costs by DR Option

Figure 4-8 summarizes the annual program costs by DR option. The team observed the following:

- The program costs for DLC increase steadily from 2021 to 2040. The costs spike in 2020 (not shown in graph since that is the start year of the program implementation), 2030 and 2040 because the DLC program has a program life of 10 years, so technology enablement and program development costs are re-incurred at this time. From then on, costs fluctuate in accordance with program participation, which is tied in part to thermostat market penetration, until it reaches its final value of $3.2 million in 2040.
- The program costs for C&I curtailment increase steadily from 2021 to 2022 until the program is fully ramped up. There is a spike in costs in 2030 and 2040 because, like DLC, the C&I curtailment program has a program life of 10 years, so program development costs are re-incurred at this time. In between investments, costs steadily climb with program participation until it reaches its final value of $1.0 million in 2040.
- Dynamic pricing program costs are relatively high during its initial ramp up between 2023 and 2026, and then drop in 2027 when the program is fully ramped up. By 2027, 90% of the program is ramped up, so the incremental cost to recruit new customers is lower in 2027. Beyond 2027, costs remain low and relatively steady.
- Annual BTMS program costs are zero as the program is not cost-effective.

Figure 4-8. Annual Program Costs by DR Option

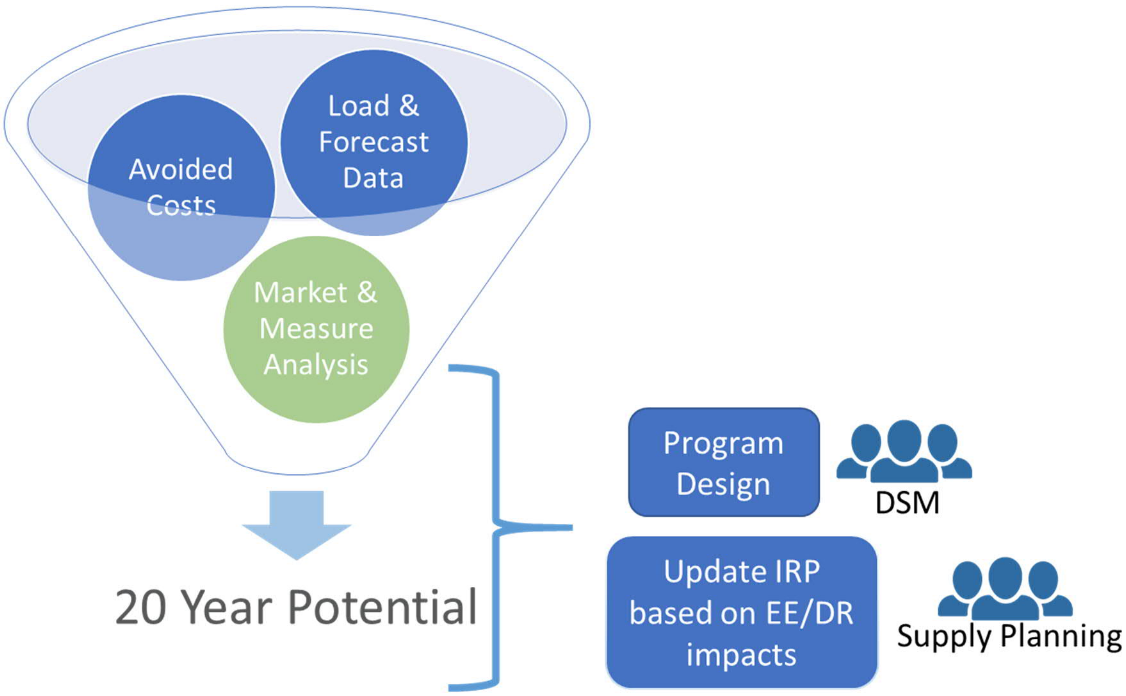


Source: Guidehouse analysis

5. Conclusions and Next Steps

Figure 5-1 illustrates the data inputs and outputs of the potential study, most notably for IRP and program planning.

Figure 5-1. Integrating Potential Study Outputs to IRP and DSM Planning



Source: Guidehouse

5.1 Benchmarking the Results

The team benchmarked the study results against the 2018 study and similar utilities and identified how the results could be used in ENO’s 2021 IRP.

Energy Efficiency
The 2018 and 2021 potential studies leveraged the same methodology, however, there are differences between the two studies:

1. Calibration targets differed for the two studies
    a. 2018 study relied on the historical programs and the 2018 immediate program goal
    b. 2021 study relied on the existing program framework which has the program plans at or near 2% of consumption
2. Different assumptions on planned rollout for home energy reports
3. Updated data on residential saturation and density data using the Entergy residential appliance saturation study data
4. Updates to commercial saturation values based on year over year program data (for measures where data was available)
5. Changes in commercial lighting baseline and efficient assumptions

6. Updates in the TRM from version 1.0 to version 4.0
7. Addition of new measures
8. Assumptions on measures costs both from Guidehouse sources and the TRM were lower than the 2018 study

After completing the potential study analysis, Guidehouse benchmarked EE achievable potential results against similar studies by other utilities. This exercise provided context for Guidehouse's results and understanding of how various factors such as region or program spend may affect the results.

For this exercise, Guidehouse conducted a literature review on recent potential studies and aggregated the results. The team aimed to include a mixture of utilities that had comparable electric customer counts, climate regions, regulatory requirements (e.g., publicly owned utilities), or locales (e.g., metropolitan centers). Based on this literature review, Guidehouse conducted three comparisons:

- Average annual achievable potential savings at the utility level
- Average annual potential savings at the state level
- Energy savings per dollar of program spend

The sources and points of comparison differ due to data availability.

In review of the benchmarking data sets, it is important to assess that there are many differences in reporting across jurisdictions. For example, each jurisdiction may have differences in the following areas, but not limited to:

- What is included in the program filing and reporting for costs
- Unit energy savings data source
- Level of evaluation for both realization rates and net-to-gross
- Existing baseline conditions
- Mix of building stock

The following tables list the final benchmarking pool for these comparisons and their respective data sources.

Table 5-1. EE Achievable Potential Benchmarking Pool and Sources

Utility	Data Source
Austin Energy	Austin Energy Resource Plan to 2027, 2019
Louisville Gas & Electric/ Kentucky Utilities	Louisville Gas & Electric Company and Kentucky Utilities Company, Demand-Side Management Potential Study, 2017[65]

[65] CADMUS, Louisville Gas & Electric Company and Kentucky Utilities Company, *Demand-Side Management Potential Study 2019-2038*, 2017, https://lge-ku.com/sites/default/files/2017-10/LGE-KU-DSM-Potential-Study.pdf

Utility	Data Source
Commonwealth Edison (ComEd)	ComEd Energy Efficiency Potential Study, 2019[66]
Duke Energy (Indiana)	The Duke Energy Indiana 2018 Integrated Resource Plan, 2018[67]
California Public Utilities[68]	California Public Utilities Commission, 2019 Potentials & Goals Report[69]
Colorado Springs Utilities	Colorado Springs Utilities 2015 Demand Side Management Potential Study, 2019[70]
Seattle City Light	Seattle City Light Conservation Potential Assessment, 2019[71]

Table 5-2. EE Achievable Potential Savings by State Benchmarking Pool and Sources

State	Data Source
Arkansas	Arkansas Energy Efficiency Potential Study[72]
Mississippi	A Guide to Growing an Energy-Efficient Economy in Mississippi[73]
Louisiana	Louisiana's 2030 Energy Efficiency Roadmap[74]
Tennessee	Tennessee Valley Authority Potential Study[75]
Texas	Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs[76]

Table 5-3. EE Actual Spending and Saving Benchmarking Pool and Sources

Utility	Data Source
Anaheim Public Utilities	Energy Efficiency in California's Public Power Sector 14th Edition[77]
Pasadena Water & Power	
Los Angeles Department of Water & Power	

[66] ICF, *ComEd Energy Efficiency Potential Study*, 2017-2030, May 2019, http://ilsagfiles.org/SAG_files/Potential_Studies/ComEd/ComEd_2017-2030_EE_Potential_Final_Report_5-2019.pdf

[67] Duke Energy Indiana, *The Duke Energy Indiana 2018 Integrated Resource Plan*, 2018, https://www.duke-energy.com/_/media/pdfs/for-your-home/indiana-irp/duke-energy-indiana-public-2018-irp.pdf?la=en

[68] CA Public Utilities are grouped together due to data availability and the study results referenced.

[69] Guidehouse, *California Public Utilities Commission 2019 Potentials & Goals (PG) Study Results Viewer*, 2019, https://www.cpuc.ca.gov/General.aspx?id=6442461220

[70] CADMUS, *Colorado Springs Utilities 2015 Demand Side Management Potential Study*, 2019, https://www.csu.org/CSUDocuments/dsmpotentialstudyvolume1.pdf

[71] Seattle City Light 2019 IRP "Appendix 6, Conservation Potential Assessment," https://www.seattle.gov/light/IRP/docs/2019App-6-Conservation%20Potential%20Assessment.pdf

[72] Guidehouse, *Arkansas Energy Efficiency Potential Study*, 2015, www.apscservices.info/pdf/13/13-002-U_212_2.pdf

[73] ACEEE, *A Guide to Growing an Energy-Efficient Economy in Mississippi*, 2013, http://aceee.org/research-report/e13m

[74] ACEEE, *Louisiana's 2030 Energy Efficiency Roadmap*, 2013, http://aceee.org/research-report/e13b

[75] Global Energy Partners, *Tennessee Valley Authority Potential Study*, 2011, http://152.87.4.98/news/releases/energy_efficiency/GEP_Potential.pdf

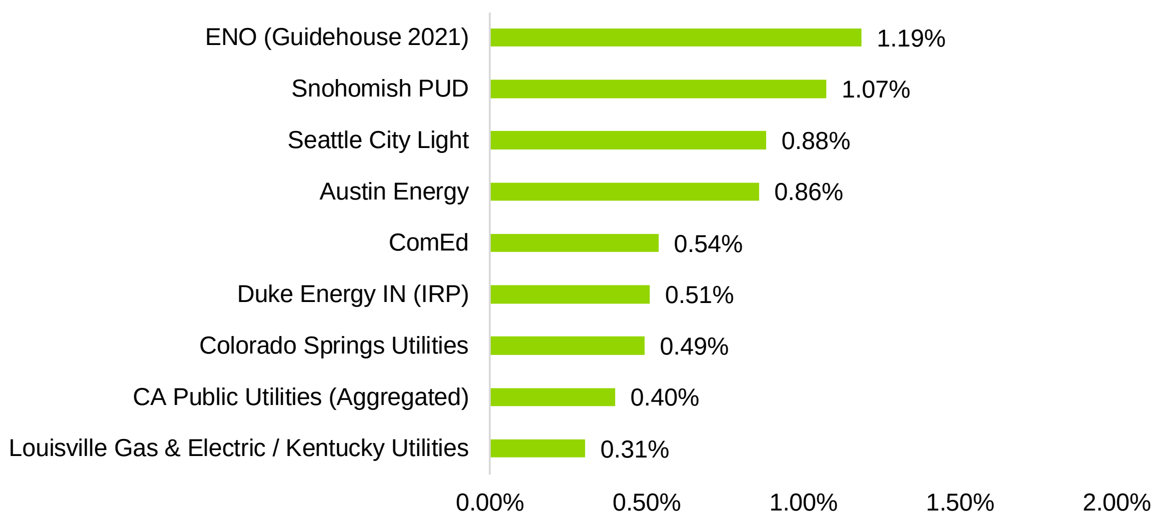
[76] ACEEE, Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs, 2007, https://aceee.org/research-report/e073

[77] California Municipal Utilities Association, Northern California Power Agency, Southern California Agency, *Energy Efficiency in California's Public Power Sector,* 14th Edition, 2020, http://ncpasharepointservice20161117100057.azurewebsites.net/api/document?uri=https://ncpapwr.sharepoint.com/sites/publicdocs/Compliance/2020%20CMUA%20Energy%20Efficiency%20Report%20Final.pdf.

Utility	Data Source
Sacramento Municipal Utility District	
SWEPCO	Texas Efficiency, Energy Efficiency Accomplishments of Texas Investor-Owned Utilities 2019[78]
Entergy Texas, Inc.	
El Paso Electric	
CPS Energy (City of San Antonio)	Evaluation, Measurement & Verification of CPS Energy's DSM Programs FY 2019[79]
Louisville Gas & Electric/Kentucky Utilities	LG&E/KU DSM Advisory Group Meeting, 2017[80]

Based on the sources above, Guidehouse aggregated the results into the following figures.[81] ENO is higher than other peer utilities.

Figure 5-2. Benchmarking Pool Average Achievable Potential Savings (% of Sales)[82]



Source: Guidehouse analysis

When comparing potential estimates, although the utilities included in the benchmarking pool may have some similar characteristics, no two utilities are the same. The results may vary based on the inputs each utility provided to its respective potential study evaluator. Study methodologies may also differ based on the potential study evaluator, providing additional room for variances across studies.

[78] Frontier Associates, *Energy Efficiency Accomplishments of Texas Investor-Owned Utilities 2018*, 2017, http://www.texasefficiency.com/images/documents/Publications/Reports/EnergyEfficiencyAccomplishments/EEPR2019.pdf

[79] Frontier Associates, *Evaluation Measurement & Verification of CPS Energy's FY 2019 DSM Programs*, https://www.sanantonio.gov/portals/0/files/sustainability/Environment/CPSFY2019.pdf

[80] LG&E and KU, "DSM Advisory Group Meeting," 2017, https://lge-ku.com/sites/default/files/2017-10/9-26-2017-EE-Advisory-Group-Presentation.pdf

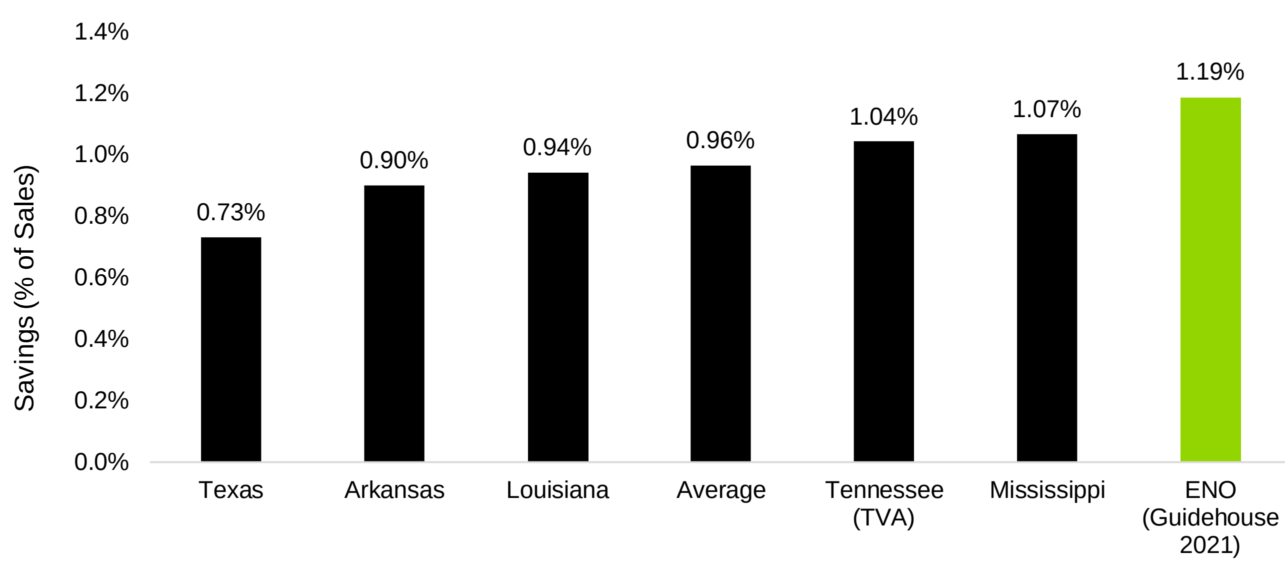
[81] There has not been many updates to the peer utility data reports as of the 2018 ENO potential study.

[82] These savings are shown as an annual average, which Guidehouse derived by dividing the cumulative study averages by the number of years in the study. The team used this approach because study years tend to differ greatly.

Achievable potential savings range from 0.31% to 1.19% of sales. Besides ENO, Snohomish Public Utility District in Washington has the highest potential and Louisville Gas & Electric/Kentucky Utilities has the lowest. Many factors may drive these differences, including measures studied, cost inputs, study years, and study methodology. ENO's achievable potential falls within the range of the benchmarking pool at an average of 1.19% savings per year over the study period (2021-2040). This is similar to Snohomish PUD. Both utilities operate in large metropolitan areas and have similar governance structures in that they are regulated by a city council.[83]

In addition to benchmarking the results at the utility level, Guidehouse created a peer pool at the state level. The goal was to understand ENO's potential savings within the broader context of the state of Louisiana and its neighbors. Given that the states are mostly clustered within the Southeast region of the US, they have the same climate (hot-humid) and may experience similar levels of achievable potential savings. Figure 5-3 shows how ENO's achievable potential fits into the broader state-level context.

Figure 5-3. Benchmarking Pool State Level Achievable Potential (% of Savings)



Source: Guidehouse analysis

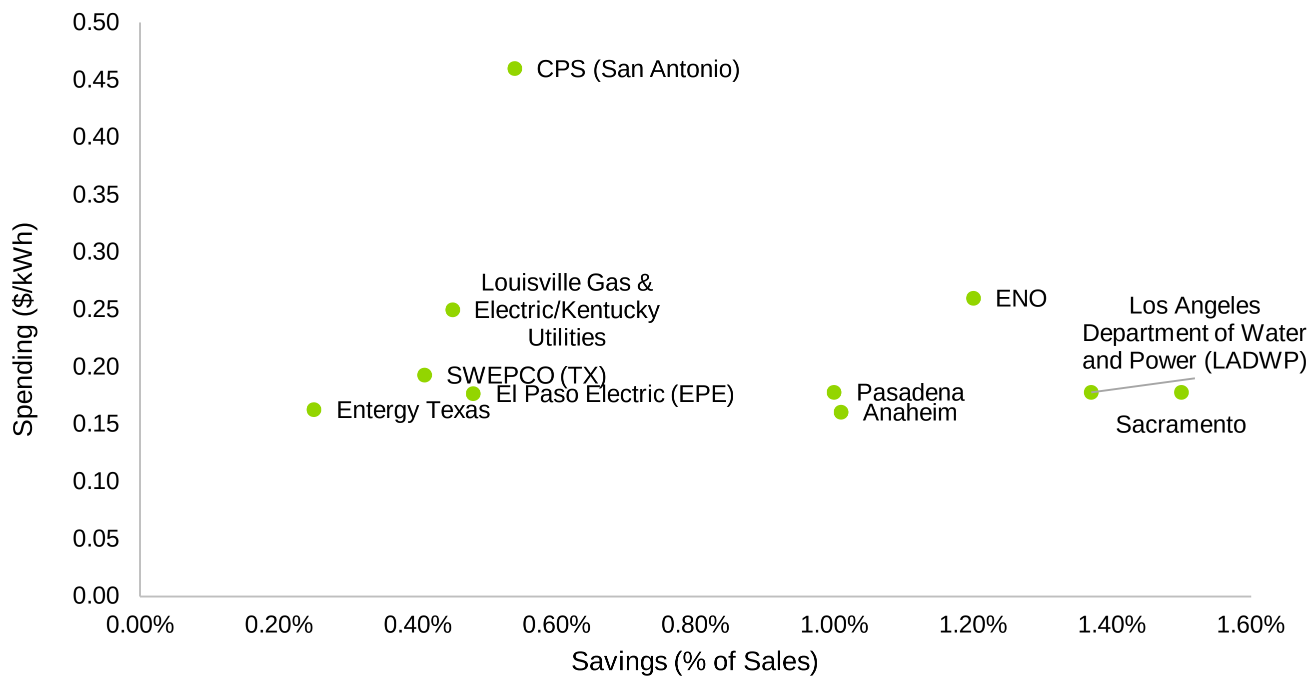
As Figure 5-3 shows, ENO's achievable potential savings are at the top of the range for the similar states. The slight difference in savings of this potential study and the state may be caused by several factors, including:

- Updated data inputs – including measure level unit energy savings

83 It should be noted that, unlike ENO, which is an IOU, Austin Energy and Seattle City Light are both POUs that function as departments within their respective municipalities. However, all three must comply with the mandates of the local regulatory body.

- Utilities outside New Orleans had not begun implementing EE programs at the time ACEEE conducted the Louisiana study in 2013
- Broader region covered (some areas may have more or less potential savings based on stock type and other utilities' energy efficiency spending)

Figure 5-4. Benchmarking Pool Actual Savings (% of Sales) vs. Spending ($/kWh)



Source: Guidehouse analysis

Like achievable potential estimations, actual savings and spending may vary greatly among utilities based on inputs. In this case, inputs may include how the study is administered, what measures are offered, how the program is designed, and the number of years the program has been in place. Figure 5-4 shows that CPS Energy in San Antonio spends the most ($0.46/kWh) for less savings (0.54%), while the larger California public utilities (Sacramento Municipal Utilities District, Los Angeles Department of Water & Power, and Pasadena Water & Power) spend the least ($0.16/kWh-$0.18/kWh) but achieve the most (1.0%+). ENO falls between these, spending $0.23/kWh and saving ~1.0% in 2020. ENO's most recent spending and savings align closely with California, suggesting strong program administration and design variances.

Demand Response

In addition to EE potential, the team also benchmarked DR potential, following a similar process.

The 2018 and 2021 demand response analysis differed in the following ways:

1. Guidehouse used actual data of implementation for C&I curtailment. There has been growth in program participation compared to the data from 3 years ago.
2. There is updated data on the penetration of smart thermostat data and updated AMI rollout plan.

For the process on benchmarking to different jurisdictions, the Guidehouse team included creating a peer pool based on ENO's characteristics and data availability. This particular effort included both individual utilities and two nearby Independent System Operators (ISOs) or Regional Transmission Authorities (RTOs). Table 5-4. includes the sources used for this analysis.

Table 5-4. Demand Response Potential Benchmarking Pool and Sources

Utility or ISO/RTO	Data Source
Ameren Union Electric (AmerenUE)	AmerenUE DSM Market Potential Study[84]
Con Edison (Con Ed)	DER Potential Study[85]
Commonwealth Edison (ComEd)	Comprehensive Assessment of Demand-Side Resource Potentials[86]
Electric Reliability Council of Texas (ERCOT)	Assessment of Demand Response and Advanced Metering[87]
Hawaii Electric Company (HECO)	Fast DR Pilot Program Evaluation[88]
Puget Sound Energy (PSE)	2017 IRP Demand-Side Resource Conservation Potential Assessment Report[89]
Southwest Power Pool (SPP)	Assessment of Demand Response and Advanced Metering[90]

Figure 5-5 shows the results of this analysis.

[84] Global Energy Partners, AmerenUE Demand Side Management (DSM) Market Potential Study Volume 1: Executive Summary, January 2010, https://www.ameren.com/-/media/missouri-site/Files/Environment/Renewables/AmerenUEVolume1ExecutiveSummary.pdf.

[85] Guidehouse, DER Potential Study, 2019.

[86] Cadmus Group, Comprehensive Assessment of Demand-Side Resource Potentials, February 2009, https://www.illinois.gov/sites/ipa/Documents/Appendix%20C-1%20-%20ComEd%20Potential%20Study.pdf

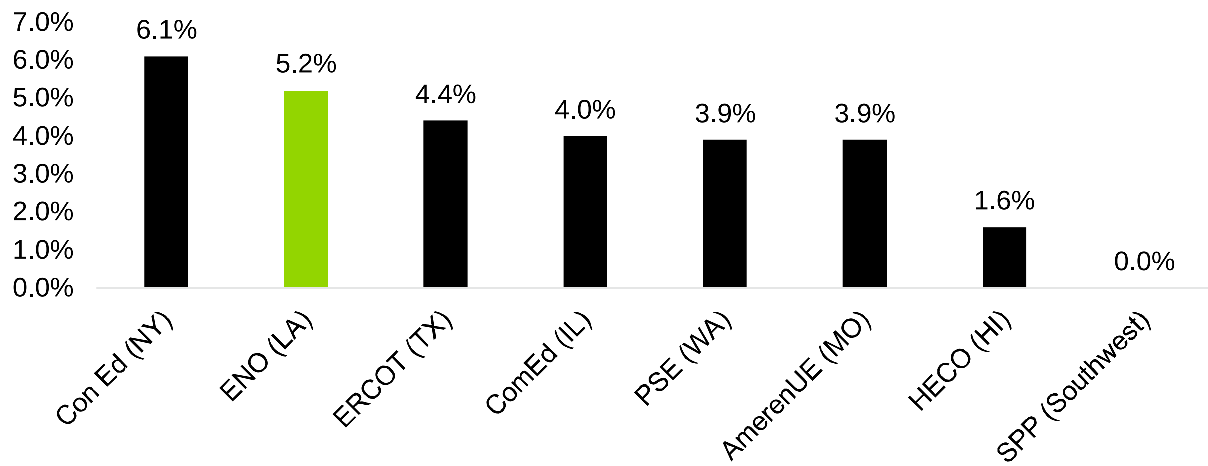
[87] Federal Energy Regulatory Commission (FERC) Assessment of Demand Response and Advanced Metering, 2019, https://www.ferc.gov/sites/default/files/2020-04/DR-AM-Report2019_2.pdf

[88] Guidehouse, Fast DR Pilot Program Evaluation, May 2015, http://media.Guidehouseconsulting.com/emarketing/Documents/Energy/HawaiianElectricFastDREvaluationReport_Sept302014GuidehouseRevisedMay192015v2.pdf

[89] Guidehouse, 2017 IRP Demand-Side Resource Conservation Potential Assessment Report, June 2017, https://pse.com/aboutpse/EnergySupply/Documents/DSR-Conservation-Potential-Assessment.pdf

[90] FERC, Assessment of Demand Response and Metering.

Figure 5-5. Benchmarking Pool DR Potential (% of Savings)



Source: Guidehouse analysis

As Figure 5-5 shows, ENO falls in the top of the benchmarking pool, only slightly higher than ERCOT and slightly below Con Edison in New York. Given that DR, like EE, varies based on program administration and geographic location, among other factors, ENO's DR potential aligns closely to its peers.

5.2 IRP

The ENO IRP is an iterative process to produce possible resource portfolios under different assumptions that optimize the mix of supply- and demand-side resources to meet the utility's demand. The mix of supply-side resources dictates the costs to be used as avoided costs, but if EE programs can vary the supply-side mix (i.e., reduce the need of costlier resources), the avoided costs will vary. The IRP outputs feed into the projected cost and goals used to inform the near-term DSM program implementation portfolio.

The potential study provides forecasted savings inputs for use in the IRP modeling. These inputs are provided by sector, segment, and end use because each combination of these items is mapped to a load shape (see **Error! Reference source not found.**). Each measure is mapped to one or more DSM programs. Guidehouse then develops a load shape representative of each DSM program. The DSM program load shape represents the aggregate hourly energy savings for the group of measures included in the program over the 20-year planning period. These load shapes are what define the hourly usage profiles for the DSM program portfolio. The data is aligned with the Council's IRP Rules, which require that the data supplied include a description of each demand side resource considered, including a description of resource expected penetration levels by year; hourly load reduction profiles for each DSM program; and results of all four standard cost-effectiveness tests.

5.3 Program Planning

DSM potential studies are inherently different from DSM program portfolio designs. The long-term achievable potential identified for a 20-year period through this study is different from the short-term savings potential that would be identified though a DSM program portfolio design effort targeting a 3-year period. However, programmatic design (such as delivery methods and marketing strategies) will have implications for the overall savings goals and projected cost.

As mentioned, near-term savings potential, actual achievable goals, and program costs for a measure-level implementation will vary from the savings potential and costs estimated in this long-term study. This potential study is one element to consider in program design, along with historical program participation and current market conditions (with the team members on the ground).

- Significant savings potential exists in promoting retro-commissioning, occupancy sensor controls and interior high bay and 4ft LEDs for the C&I sector.
- There is high potential in operations and maintenance (residential duct sealing and AC tune up) and behavior-type programs such as home energy reports in the residential sector.
- Significant demand response potential in the C&I sector for C&I curtailment and DLC; with the residential sector leading in peak demand reduction potential with the increased penetration of enabling technologies like smart thermostats.

5.4 Further Research

Finally, the potential study identified data gaps in characterizing ENO's market and measures. This is common for most utilities; however, for ENO to have more accurate potential estimates and information to support DSM planning, there is ENO-specific data that could support this end goal:

- Baseline and saturation studies for each sector
- Updated residential end-use survey
- C&I end-use survey
- Customer payback acceptance analysis or other market adoption study specific to the ENO service area either via customer survey, Delphi panel of regional stakeholders, or other method
- Exploration of behavior program opportunities in the ENO service territory

Appendix A. Energy Efficiency Detailed Methodology

A.1 End-Use Definitions

Table A-1. Description of End Uses

Segment	End Use	Definition
Residential	Total Facility	Consumption of all electric end uses in aggregate
	Lighting Interior	Overhead lights, lamps, etc.
	Lighting Exterior	Spotlighting, security lights, holiday/seasonal lighting, etc.
	Plug Loads	Large/small appliances including ovens, refrigerators, freezers, clothes washers, etc. Televisions, computers and related peripherals, and other electronic systems
	HVAC	All cooling, including both central air conditioning and room or portable air conditioning; All heating, including both primary heating and supplementary heating; Motor drives associated with heating and cooling
	Water Heating	Heating of water for domestic hot water use
	Other	Miscellaneous loads
C&I	Total Facility	Consumption of all electric end uses in aggregate
	Lighting Interior	Overhead lights, lamps, etc. (main building and secondary buildings)
	Lighting Exterior	Spotlighting, security lights, holiday/seasonal lighting, etc. (main building and secondary buildings)
	Plug Loads	Computers, monitors, servers, printers, copiers, and related peripherals
	HVAC	All cooling equipment, including chillers and direct expansion cooling; All heating equipment, including boilers, furnaces, unit heaters, and baseboard units; Motor drives associated with heating and cooling
	Refrigeration	Refrigeration equipment including fridges, coolers, and display cases
	Water Heating	Hot water boilers, tank heaters, and others
	Other	Miscellaneous loads including elevators, gym equipment, and other plug loads

Source: Guidehouse

A.2 Residential Sector

The following sections detail the approach used to determine electricity consumption by segment, the approach used to estimate end-use proportions, and the resulting residential household stock. To do this, Guidehouse needed to determine three pieces of information:

1. Base year and forecasted stock

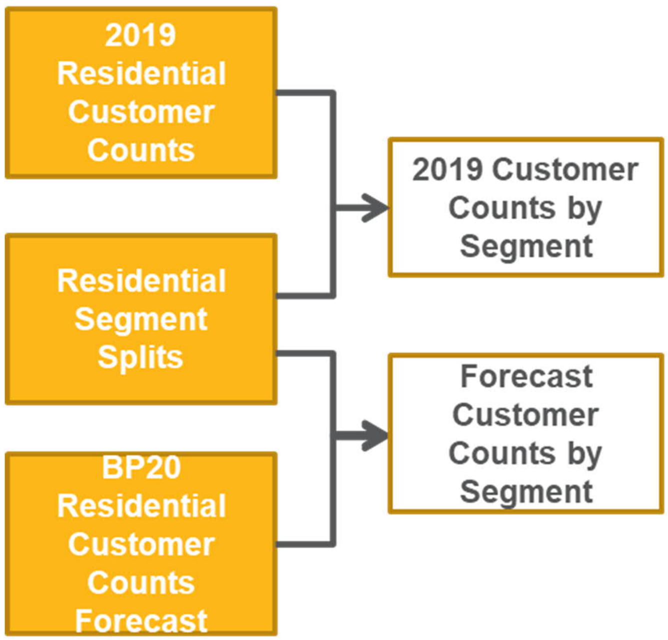
2. Base year and forecasted total consumption

3. Base year and forecasted consumption by end use

1. Base Year and Forecasted Residential Stock

Figure A-1 outlines Guidehouse's approach to determining the base year and forecasted residential stock.

Figure A-1. Residential Stock Base Year and Base Forecast Approach



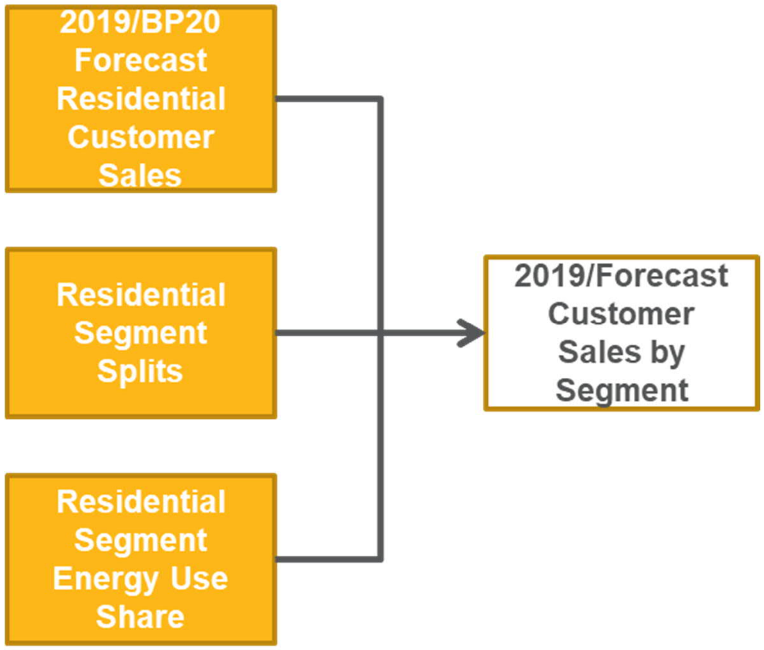
To define the base year residential sector inputs, Guidehouse determined the total base year stock using ENO's number of households in the class breakdown. Guidehouse needed to divide this total into single-family and multifamily segments. To do this, Guidehouse used the class breakdown from the 2016 household split survey and multiplied these splits by the total base year stock.

To define the forecasted residential sector inputs, Guidehouse used the same class breakdown from the 2016 household split survey and multiplied these splits by the total residential customer counts in the BP20 sales forecast.

2. Base Year and Forecasted Total Consumption

Figure A-2 outlines Guidehouse's approach to determining the base year and forecasted residential sales.

Figure A-2. Base Year and Forecasted Residential Sales Approach



Base year sales used the 2019 reported sales provided by ENO. Guidehouse used the 2016 household split survey results to calculate the segment-level base year sales by multiplying the household split by the total. From the 2018 study, Guidehouse determined that multifamily households consume 67% of the electricity that a single-family household does. The team determined this number by dividing the multifamily average annual consumption by the single family average annual consumption shown in Table A-2. The 2018 study used data provided by ENO to determine the average annual consumption by segment.

Table A-2. 2018 Average Annual Consumption (kWh/Account)

Building Segment	Average Annual Consumption	Consumption Ratio[91]
Single-Family	11,903	1
Multifamily	7,975	0.67

Source: Guidehouse analysis

The single family and multifamily household splits were multiplied by their consumption ratios (1 for single family, and 0.67 for multifamily) to calculate consumption-weighted household splits. Guidehouse calculated the new total of the consumption-weighted household splits and divided each weighted split by the total, producing new consumption splits that sum to one for the residential sector. These new consumption splits represent the proportion of the total residential energy used by each of the single family and multifamily segments. Guidehouse multiplied the consumption splits by the total reported 2019 sales to calculate segment-level sales.

3. Base Year and Forecasted Consumption by End Use

[91] Consumption ratio for a given segment is equal to that segment's average annual consumption divided by the average annual consumption of the single-family segment.

To disaggregate the total residential consumption for single-family and multifamily customers to the end-use level, Guidehouse relied on end-use proportions calculated in the 2018 study. In 2018, Guidehouse calculated the proportion of energy used by each end use (e.g., this proportion of the consumption is a percent of the total segment level consumption). Guidehouse derived these proportions using Guidehouse DOE's EnergyPLUS prototypical models with some adjustments to reflect ENO building stock and other Guidehouse adjustments based on lessons learned across utility jurisdictions. Guidehouse assumed the end-use proportions were constant across the forecast period. This assumption has minimal impact to the overall potential since all of the residential sector savings calculations are not dependent on end-use consumption proportions except for behavioral measures.

Table A-3 shows the resulting end use proportions by residential end use, which is an overall percentage of each household.

Table A-3. Residential End Use Proportion (% of whole building kWh)

End Use	Percent
Hot Water	4.4%
HVAC	47.8%
Lighting Exterior	3.1%
Lighting Interior	19.4%
Plug Loads	25.3%
Total	**100.0%**

Source: Guidehouse analysis

A.3 C&I Sector

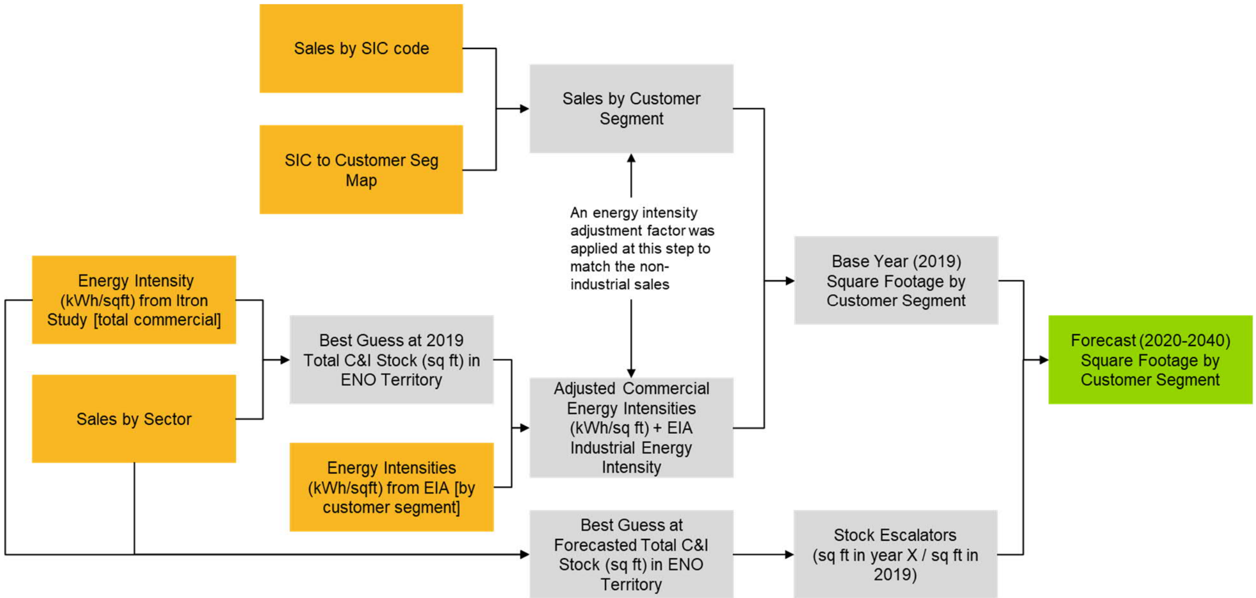
The following sections describe the detailed approach used to determine electricity consumption by segment, the approach used to estimate end-use proportions, and the resulting C&I stock. Guidehouse needed to determine two pieces of information:

1. Base year and forecasted stock and total consumption
2. Base year and forecasted consumption by end use

1. Base Year and Forecasted C&I Stock and Total Consumption

Figure A-3 outlines Guidehouse's approach to determining the base year and forecasted C&I stock.

Figure A-3. C&I Base Year and Forecast Approach



To define the base year C&I sector stock inputs, Guidehouse began with customer level billing data, which included customers' SIC codes and 2019 annual consumption. This data came in three datasets: commercial, industrial, and governmental. Guidehouse used a mapping of SIC codes to customer segments derived as part of the 2018 study. By joining the mapping file to each of the three billing datasets, Guidehouse aggregated the 2019 consumption to the customer segment level for each of the commercial, industrial, and governmental subsectors. ENO also provided 2019 total consumption for each of the commercial, industrial, and governmental subsectors in the class breakdown dataset. Guidehouse adjusted the segment-level usage to equal the sector totals for 2019.

To estimate square footage from segment level energy usage, Guidehouse developed segment-level energy intensities (kWh/square foot). Guidehouse began with segment-level intensities from US EIA. Table A-4. shows the mapping of segments in the EIA intensity data to the segments of this study.

Table A-4. C&I EUI Segments to Study Segment Mappings

EIA Principal Building Activity	Study Segment
Education	Colleges/Universities and Schools
Health Care	Healthcare
Buildings with Manufacturing	Industrial/Warehouses
Lodging	Lodging
Office	Office – Large and Office – Small
Public Assembly	Other Commercial
Food Service	Restaurants
Food Sales	Retail – Food
Mercantile	Retail – Non-Food

For the non-industrial segments, Guidehouse used overall commercial sector intensities from Itron to adjust the segment-level intensities from EIA. To do so, Guidehouse calculated the best estimate of overall square footage in the commercial sector by dividing total 2019 sales by the Itron intensity. Guidehouse then calculated an adjustment factor by dividing the best estimate of total stock by the sum of the segment-level stock derived from EIA intensities. Guidehouse multiplied the adjustment factor by the segment-level EIA intensities to produce final segment-level EIA intensities that average out to the Itron overall intensity. For industrial, Guidehouse used the EIA intensity directly as the final intensity for the industrial segment. Finally, Guidehouse divided the segment level base year sales (kWh) by the adjusted segment-level intensities (kWh/square feet) to calculate segment-level stock (square feet) in the base year.

Guidehouse used the base year segment level stock as the foundation for the stock forecast (2021-2040). For the non-industrial segments, Guidehouse used the BP20 sales forecast divided by the Itron sector level intensity forecasts to calculate forecasted stock (sqft) for the C&I sector as a whole. Guidehouse used this stock forecast to establish escalation factors (sqft in year X/sqft in 2019) for the C&I stock forecast. In doing so, the escalators account for assumed DSM over time for both the sales and intensity. For the industrial segment, Guidehouse used the BP20 sales forecast to calculate escalation factors. Once derived, Guidehouse multiplied the escalation factors by the base year segment level stock to calculate the segment-level stock forecast.

2. Base Year and Forecasted Consumption by End Use

To disaggregate the total C&I consumption for each segment to the end-use level, Guidehouse relied on end-use proportions calculated in the 2018 study. In 2018, Guidehouse calculated the proportion of energy used by each end use (e.g., this proportion of the consumption is X% of the total consumption). Guidehouse derived these proportions using Guidehouse's DOE EnergyPLUS prototypical models with some adjustments to reflect ENO building stock and other Guidehouse adjustments based on lessons learned across utility jurisdictions. Guidehouse assumed the end-use proportions were constant across the forecast period. This assumption has minimal impact to the overall potential since most of the commercial sector savings calculations (except for behavioral) are independent from end use consumption proportions.

Table A-5. shows the resulting end use proportions by C&I end use, which is an overall percentage of each building type segment consumption.

Table A-5. C&I Base Forecast End Use Proportions (% of kWh)

Segment	End Use	2019-2040
Colleges/Universities	Hot Water	1.5%
	HVAC	55.0%
	Lighting Exterior	2.7%
	Lighting Interior	25.4%
	Plug Loads	14.2%
	Refrigeration	1.2%
	Total Facility	**100.0%**
Healthcare	Hot Water	1.2%
	HVAC	52.0%
	Lighting Exterior	0.8%

Segment	End Use	2019-2040
	Lighting Interior	21.0%
	Plug Loads	24.5%
	Refrigeration	0.5%
	Total Facility	**100.0%**
Industrial/Warehouses	Hot Water	12.6%
	HVAC	44.2%
	Lighting Exterior	1.6%
	Lighting Interior	33.2%
	Plug Loads	5.4%
	Refrigeration	3.1%
	Total Facility	**100.0%**
Lodging	Hot Water	25.3%
	HVAC	32.3%
	Lighting Exterior	1.2%
	Lighting Interior	15.9%
	Plug Loads	24.5%
	Refrigeration	0.8%
	Total Facility	**100.0%**
Office - Large	Hot Water	0.4%
	HVAC	49.3%
	Lighting Exterior	0.2%
	Lighting Interior	31.1%
	Plug Loads	19.1%
	Total Facility	**100.0%**
Office - Small	Hot Water	0.4%
	HVAC	50.5%
	Lighting Exterior	0.2%
	Lighting Interior	30.3%
	Plug Loads	18.6%
	Total Facility	**100.0%**
Other Commercial	Hot Water	6.8%
	HVAC	30.5%
	Lighting Exterior	0.9%
	Lighting Interior	13.7%
	Plug Loads	44.5%
	Refrigeration	3.6%
	Total Facility	**100.0%**
Restaurants	Hot Water	5.2%
	HVAC	37.0%
	Lighting Exterior	4.5%

Segment	End Use	2019-2040
	Lighting Interior	7.4%
	Plug Loads	42.7%
	Refrigeration	3.2%
	Total Facility	**100.0%**
Retail - Food	Hot Water	0.1%
	HVAC	24.8%
	Lighting Exterior	1.2%
	Lighting Interior	22.4%
	Plug Loads	11.5%
	Refrigeration	40.1%
	Total Facility	**100.0%**
Retail (Non-Food)	Hot Water	11.0%
	HVAC	33.5%
	Lighting Exterior	3.0%
	Lighting Interior	44.3%
	Plug Loads	5.0%
	Refrigeration	3.2%
	Total Facility	**100.0%**
Schools	Hot Water	2.0%
	HVAC	57.1%
	Lighting Exterior	2.6%
	Lighting Interior	23.9%
	Plug Loads	13.3%
	Refrigeration	1.1%
	Total Facility	**100.0%**

Source: Guidehouse analysis

A.4 Measure List and Characterization Assumptions

Guidehouse developed the measure list and characterizations based on internal expertise, ENO-specific data, the New Orleans TRM, and secondary sources where necessary. This work is provided in a separate workbook.

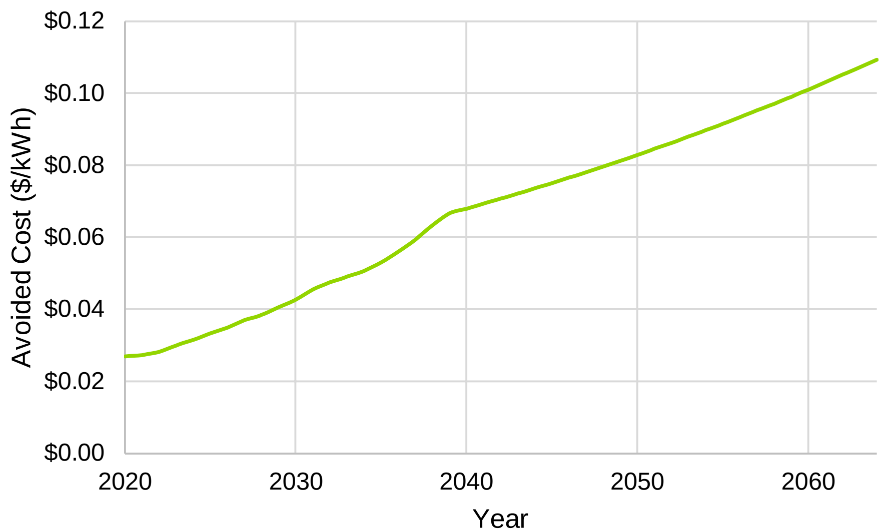
A.5 Avoided Costs and Cost-Effectiveness

Guidehouse input several cost-related inputs to determine the cost-effectiveness of measures over the study period. This section details those inputs.

A.5.1 Avoided Energy Costs

ENO provided the BP20[92] avoided costs through 2039 in nominal dollars. Guidehouse projected these costs over the remainder of the study period plus the longest measure life (25 years) using a 2% inflation rate starting in 2040 to input into the model. Figure A-4 shows the avoided energy cost projections or forecasted locational marginal prices in nominal dollars.

Figure A-4. ENO BP20 Avoided Cost Projections



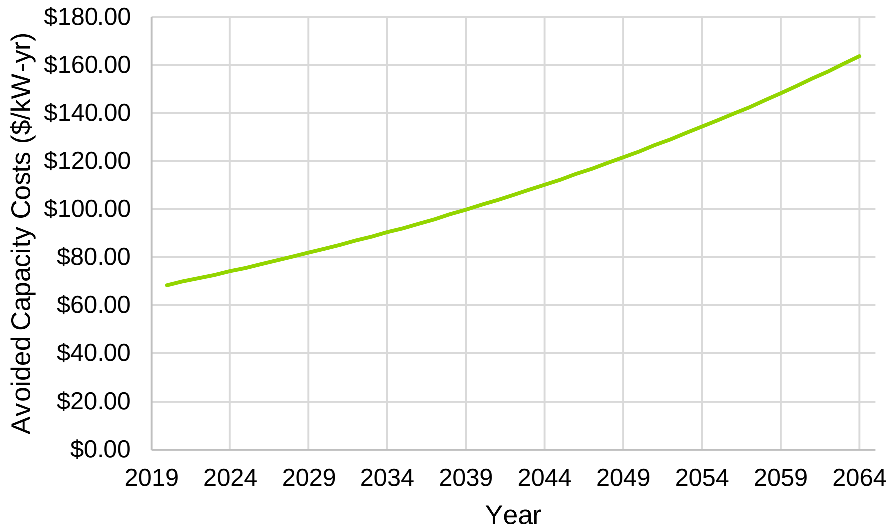
A.5.2 Avoided Capacity Cost

ENO provided the BP20[93] avoided capacity costs through 2049 in nominal dollars. Guidehouse projected these costs over the remainder of the study period plus the longest measure life (15 years) using a 2% inflation rate starting in 2050 to input into the model. Like the avoided energy costs, the capacity costs align with ENO's BP20 and its internal planning. Figure A-5 shows these costs over the study period in nominal dollars.

[92] BP20 refers to the vintage of a set of planning and modeling assumptions. At the time of this study, BP20 was the latest assumption set available.

[93] BP20 refers to the vintage of a set of planning and modeling assumptions. At the time of this study, BP20 was the latest assumption set available.

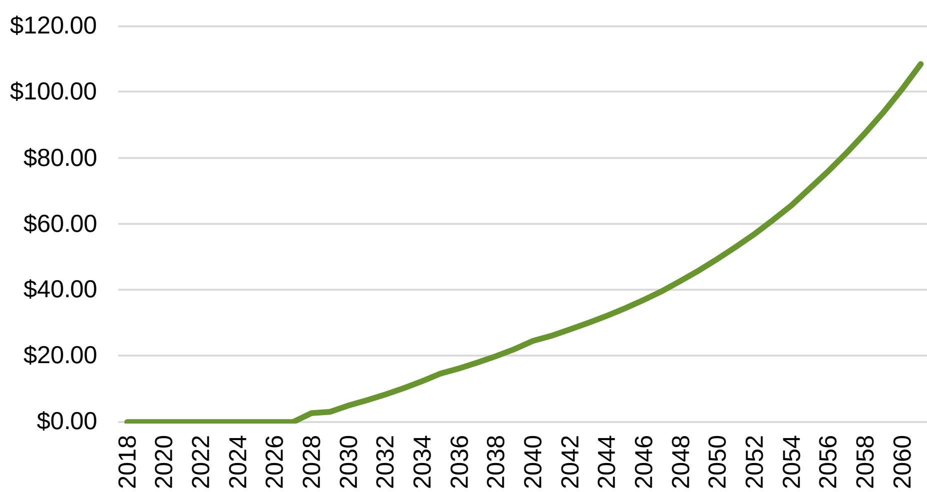
Figure A-5. ENO BP20 Avoided Capacity Projections



A.5.3 Carbon Pricing

In addition to avoided costs, ENO provided carbon pricing estimates through 2050 for the potential model. However, the carbon pricing inputs needed to extend further out than the study period to accurately model measure costs over their lifetime. More specifically, Guidehouse needed to model carbon prices up until the end of the study period plus the longest measure life (25 years). The team extrapolated these last years by taking the average growth (8%) for the last 5 years of the forecast (2045-2050) and applying it to the remaining 11 years.[94] Figure A-6 shows the carbon pricing estimates provided and extrapolated.

Figure A-6. ENO Carbon Pricing Projections[95]



[94] Note that the growth rate was flat for the remaining 5 years provided.

[95] Note that the forecast extends until 2061, although the label for year 2061 is not visible. This is because the chart shows years in increments of two for aesthetic purposes.

A.6 Cost-Effectiveness Calculations

The potential analysis uses two forms of cost-effectiveness calculations. The TRC test is for utility cost-effectiveness. There is also the PCT, which is mostly addressed by calculating the participant payback period instead of the benefit-cost ratio for the PCT. This section describes these tests, the inputs, and how they are used for the potential study.

A.6.1 TRC Test

The TRC test is a benefit-cost metric that measures the net benefits of EE measures from the combined stakeholder viewpoint of the utility (or program administrator) and the customers. The TRC benefit-cost ratio is calculated in the model using Equation A-1.

Equation A-1. Benefit-Cost Ratio for TRC Test

$$TRC = \frac{PV(Avoided\ Costs)}{PV(Technology\ Cost + Admin\ Costs)}$$

Where:

- PV( ) is the present value calculation that discounts cost streams over time.
- Avoided Costs are the monetary benefits resulting from electric energy and capacity savings—e.g., avoided costs of infrastructure investments and avoided fuel (commodity costs) due to electric energy conserved by efficient measures.
- Technology Cost is the incremental equipment cost to the customer.
- Admin Costs are the administrative costs incurred by the utility or program administrator.

Guidehouse calculated TRC ratios for each measure based on the present value of benefits and costs over each measure's life. Free ridership's effects are not present in the results from this study, so the team did not apply a NTG factor. Providing gross savings results will allow ENO to easily apply updated NTG assumptions in the future and allow for variations in NTG assumptions.

The administrative costs are included when reporting sector-specific or portfolio-wide cost-effectiveness. However, they are not included at the measure level for economic potential screening. For this screening, the focus is to identify measures that are cost-effective on the margin prior to assessing effects for the achievable potential where administrative costs are considered depending on the amount and level of programmatic spend.

A.6.2 Participant Payback Period

Guidehouse calculates the customer payback period to assess customer potential to implement the energy-saving action. The payback period is used to assess customer acceptance and adoption of the measure. Additional details are described in Section 2.1.4.3. The payback period is calculated after the incentive is applied to the measure cost. Equation A-2 demonstrates the calculation.

Equation A-2. Participant Payback Period

$$Payback = \frac{Annual\ kWh\ Saved\ \times Annualized\ Retail\ Rate\ \left(\$/_{kWh}\right)}{Incremental\ Measure\ Cost - Incentive}$$

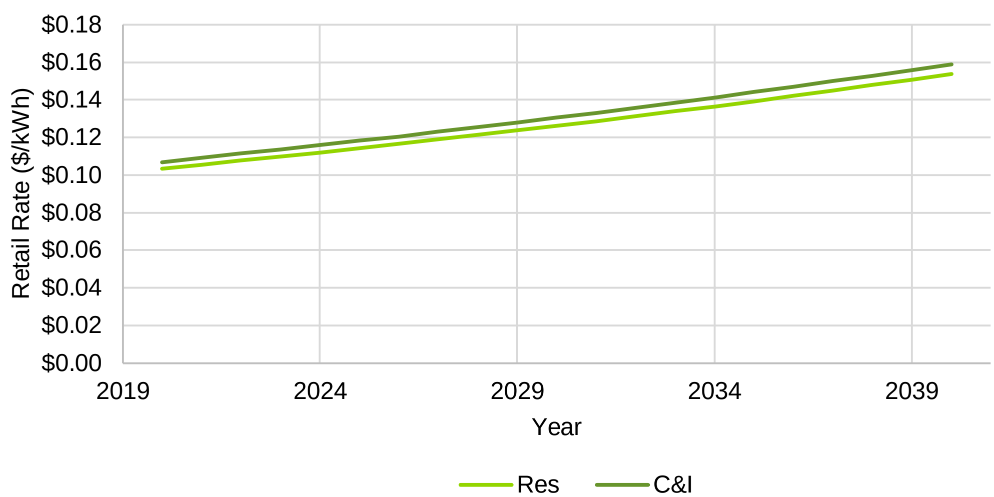
Where:

- Annual kWh Saved is calculated for each measure and segment (as appropriate).
- Annualized Retail Rate is the overall cost a customer pays per kWh consumed (see Appendix A.7).
- Incremental Measure Costs are the costs the participant would pay (without an incentive) to implement the measure. In replace-on-burnout (ROB) and new construction (NEW), depending on the measure, the difference in the cost of the efficiency and standard equipment is used instead of the full cost of installation (material and labor costs).
- Incentives are the incentive costs paid for a customer's out of pocket costs to be reduced.

A.7 Retail Rates

Customer economics is a primary driver of energy efficiency measure adoption, so Guidehouse used a forecast of electric retail rates for each sector to estimate achievable energy and demand potential. Because ENO did not have a forecast of retail rates readily available, the team calculated the retail rates based on historic sales. ENO provided 2019 revenue ($) and sales (kWh) by rate class and rate schedule, as well as customer counts by rate class and rate schedule. For each rate schedule, Guidehouse divided revenue by sales to calculate an average rate ($/kWh). Then, for each sector (residential and non-residential), Guidehouse calculated an average rate ($/kWh) weighted by the number of customers on each rate schedule. Guidehouse then assumed the rates would increase with inflation, or 2% per year.

Figure A-7. Electricity Retail Rate Forecast: 2021-2040



Source: Guidehouse analysis

A.8 Other Key Input Assumptions

As Table A-6 shows, Guidehouse used the discount rate provided by ENO and an inflation rate consistent with the utility's planning.

Table A-6. Potential Study Assumptions

Variable Name	Percentage
Discount Rate	7.09%
Inflation Rate	2.00%

Source: ENO

Appendix B. IRP Model Inputs Developments

The Guidehouse team used the 8,760 loadshapes developed using the approach described in the 2018 report Appendix B to convert the annual potential estimates into hourly potential estimates. In doing so, Guidehouse created program categories (Table B-1) to aggregate these hourly potential estimates to the program level and develop the input files necessary to support the IRP modeling. Guidehouse performed this aggregation using the mapping in Table B-2, below. The table shows a many-to-one mapping between measures and programs because some measures belong to more than one program. Guidehouse used the savings breakdown by program in each case to weight the savings allocation of these measures to programs.

Table B-1. Program Categories

Sector	Program Name	Program Abbreviation
C&I	Commercial Behavior	Com Behavior
	Large Commercial & Industrial	Large C&I
	Small Commercial & Industrial and Publicly Funded	Small C&I
Res	Retail Lighting & Appliances	Retail
	Home Performance with Energy Star	HPwES
	A/C Solutions	HVAC
	Multi Family Solutions and Income Qualified Weatherization	LI_MF
	Residential Behavior	Res Behavior
	School Kits and Education	School Kits

Table B-2. Measure and Program Mapping for IRP Modeling Inputs

Sector	Program	Measure
C&I	Com Behavior	C&I | Building Benchmarking
C&I	Com Behavior	C&I | Building Energy Information Management System
C&I	Com Behavior	C&I | Building Operator Certificate
C&I	Com Behavior	C&I | Business Energy Reports
C&I	Com Behavior	C&I | Refrigeration Retrocommissioning
C&I	Com Behavior	C&I | Retrocommissioning
C&I	Com Behavior	C&I | Strategic Energy Management
C&I	Large C&I	C&I | Advanced Lighting Controls
C&I	Large C&I	C&I | Advanced RTU Controls
C&I	Large C&I	C&I | Air and Water-Cooled Chillers
C&I	Large C&I	C&I | Air Compressor Improvements
C&I	Large C&I	C&I | Bi-Level Garage Lighting
C&I	Large C&I	C&I | Building Automation System
C&I	Large C&I	C&I | Chiller Plant Optimization
C&I	Large C&I	C&I | Combination Ovens
C&I	Large C&I	C&I | Commercial Air Conditioner and Heat Pump Tune-Up
C&I	Large C&I	C&I | Commercial Clothes Dryer
C&I	Large C&I	C&I | Commercial Clothes Washer

Sector	Program	Measure
C&I	Large C&I	C&I | Commercial Fryers
C&I	Large C&I	C&I | Commercial Griddles
C&I	Large C&I	C&I | Commercial HVAC Tune-up
C&I	Large C&I	C&I | Commercial Steam Cookers
C&I	Large C&I	C&I | Commercial Water Heater Pipe Insulation
C&I	Large C&I	C&I | Common area clothes washer (Lodging, university)
C&I	Large C&I	C&I | Computer Power Management
C&I	Large C&I	C&I | Control Hotel Room Occ
C&I	Large C&I	C&I | Controls Cont Dimming
C&I	Large C&I	C&I | Controls Occ Sensor
C&I	Large C&I	C&I | Controls Photocells
C&I	Large C&I	C&I | Convection Ovens
C&I	Large C&I	C&I | Cool Roof
C&I	Large C&I	C&I | Demand Control Ventilation
C&I	Large C&I	C&I | Door LEDs
C&I	Large C&I	C&I | Ductless Mini-Split Heat Pump
C&I	Large C&I	C&I | Electric Exhaust Hood
C&I	Large C&I	C&I | Electric tankless water heater replacing small (<12 kW) water heater
C&I	Large C&I	C&I | Energy Recovery Ventilator
C&I	Large C&I	C&I | ENERGY STAR Residential-size Refrigerator
C&I	Large C&I	C&I | Evap Fan Ctrls
C&I	Large C&I	C&I | Fan and Pump Optimization
C&I	Large C&I	C&I | Guest Room Energy Management (GREM) Controls
C&I	Large C&I	C&I | Heat Pump Water Heater Replacing Standard Water Heater
C&I	Large C&I	C&I | Electric Storage Water Heater
C&I	Large C&I	C&I | High Efficiency Fans and energy management
C&I	Large C&I	C&I | Ice Maker
C&I	Large C&I	C&I | Industrial Motors
C&I	Large C&I	C&I | Interior 4 ft LED
C&I	Large C&I	C&I | Interior LED High Bay | Replacing T8HO HB
C&I	Large C&I	C&I | LED Fixture - Interior
C&I	Large C&I	C&I | LED Screw In - Interior
C&I	Large C&I	C&I | LED Traffic Signals
C&I	Large C&I	C&I | Low Flow Pre-Rinse Spray Valves
C&I	Large C&I	C&I | Night Covers
C&I	Large C&I	C&I | Packaged Terminal AC/HP (PTAC/PTHP) Equipment
C&I	Large C&I	C&I | Plug Load Occupancy Sensors
C&I	Large C&I	C&I | Premium Efficiency Motors
C&I	Large C&I	C&I | Pump Equipment Upgrade
C&I	Large C&I	C&I | Solid Door CRE
C&I	Large C&I	C&I | Unitary and Split System AC/HP Equipment
C&I	Large C&I	C&I | Variable Air Volume HVAC
C&I	Large C&I	C&I | Window Film

Sector	Program	Measure
C&I	Large C&I	C&I | Zero Energy Doors
C&I	Large C&I	C&I |Interior LED High Bay | Replacing HID
C&I	Small C&I	C&I | Advanced Lighting Controls
C&I	Small C&I	C&I | Advanced Power Strips
C&I	Small C&I	C&I | Advanced RTU Controls
C&I	Small C&I	C&I | Bi-Level Garage Lighting
C&I	Small C&I	C&I | Building Automation System
C&I	Small C&I	C&I | Combination Ovens
C&I	Small C&I	C&I | Commercial Air Conditioner and Heat Pump Tune-Up
C&I	Small C&I	C&I | Commercial Clothes Dryer
C&I	Small C&I	C&I | Commercial Clothes Washer
C&I	Small C&I	C&I | Commercial Faucet Aerator
C&I	Small C&I	C&I | Commercial Fryers
C&I	Small C&I	C&I | Commercial Griddles
C&I	Small C&I	C&I | Commercial HVAC Tune-up
C&I	Small C&I	C&I | Commercial Low-Flow Showerheads
C&I	Small C&I	C&I | Commercial Steam Cookers
C&I	Small C&I	C&I | Commercial Water Heater Pipe Insulation
C&I	Small C&I	C&I | Commercial Weatherization
C&I	Small C&I	C&I | Common area clothes washer (Lodging, university)
C&I	Small C&I	C&I | Computer Power Management
C&I	Small C&I	C&I | Control Hotel Room Occ
C&I	Small C&I	C&I | Controls Cont Dimming
C&I	Small C&I	C&I | Controls Occ Sensor
C&I	Small C&I	C&I | Controls Photocells
C&I	Small C&I	C&I | Convection Ovens
C&I	Small C&I	C&I | Cool Roof
C&I	Small C&I	C&I | Demand Control Ventilation
C&I	Small C&I	C&I | Door Heater Controls
C&I	Small C&I	C&I | Door LEDs
C&I	Small C&I	C&I | Ductless Mini-Split Heat Pump
C&I	Small C&I	C&I | Electric Exhaust Hood
C&I	Small C&I	C&I | Electric tankless water heater replacing small (<12 kW) water heater
C&I	Small C&I	C&I | Electronically Commutated Motors (ECMs) for Refrigeration & HVAC
C&I	Small C&I	C&I | Energy Recovery Ventilator
C&I	Small C&I	C&I | ENERGY STAR Residential-size Refrigerator
C&I	Small C&I	C&I | Evap Fan Ctrls
C&I	Small C&I	C&I | Fan and Pump Optimization
C&I	Small C&I	C&I | Heat Pump Water Heater Replacing Standard Water Heater
C&I	Small C&I	C&I | Electric Storage Water Heater
C&I	Small C&I	C&I | Ice Maker
C&I	Small C&I	C&I | Interior 4 ft LED
C&I	Small C&I	C&I | Interior LED High Bay | Replacing T8HO HB

Sector	Program	Measure
C&I	Small C&I	C&I | LED Fixture - Interior
C&I	Small C&I	C&I | LED Screw In - Interior
C&I	Small C&I	C&I | LED Traffic Signals
C&I	Small C&I	C&I | Low Flow Pre-Rinse Spray Valves
C&I	Small C&I	C&I | Night Covers
C&I	Small C&I	C&I | Packaged Terminal AC/HP (PTAC/PTHP) Equipment
C&I	Small C&I	C&I | Plug Load Occupancy Sensors
C&I	Small C&I	C&I | Refrigeration ECMs
C&I	Small C&I	C&I | Smart Thermostats (Applicable to Packaged Systems)
C&I	Small C&I	C&I | Solid Door CRE
C&I	Small C&I	C&I | Strip Curtain
C&I	Small C&I	C&I | Unitary and Split System AC/HP Equipment
C&I	Small C&I	C&I | Vend Machine Ctrls
C&I	Small C&I	C&I | Window Film
C&I	Small C&I	C&I | Zero Energy Doors
C&I	Small C&I	C&I |Interior LED High Bay | Replacing HID
Res	HPwES	Res | Advanced Networked Lighting Controls with Directional LEDs
Res	HPwES	Res | Advanced Networked Lighting Controls with Omni-Directional LEDs
Res	HPwES	Res | Advanced Power Strips
Res	HPwES	Res | Air Infiltration
Res	HPwES	Res | Attic Knee Wall Insulation
Res	HPwES	Res | Ceiling Insulation
Res	HPwES	Res | Central AC Tune-Up
Res	HPwES	Res | Duct Sealing
Res	HPwES	Res | ECM circ pump | Elec
Res	HPwES	Res | ENERGY STAR Directional LEDs
Res	HPwES	Res | Faucet Aerators
Res	HPwES	Res | Floor Insulation
Res	HPwES	Res | Furnace fan motor retrofit
Res	HPwES	Res | Furnace Filter Whistle
Res	HPwES	Res | Heat Pump Water Heater
Res	HPwES	Res | High Efficiency Windows
Res	HPwES	Res | Low-Flow Showerheads
Res	HPwES	Res | Omni-Directional LEDs
Res	HPwES	Res | On demand tankless water heater
Res	HPwES	Res | Outdoor Dusk-Til-Dawn LED Light Bulb
Res	HPwES	Res | Outdoor LED Light Bulb
Res	HPwES	Res | Smart Thermostats - RET
Res	HPwES	Res | Solar Screens
Res	HPwES	Res | Solar Water Heater
Res	HPwES	Res | Thermostatic shower valve
Res	HPwES	Res | Tub spout diverters & Thermostatic shower valve

Sector	Program	Measure
Res	HPwES	Res | Wall Insulation
Res	HPwES	Res | Water Heater Pipe Insulation
Res	HPwES	Res | Window Film
Res	HVAC	Res | Air Source Heat Pump
Res	HVAC	Res | Central AC Tune-Up
Res	HVAC	Res | Central Air Conditioner
Res	HVAC	Res | Duct Sealing
Res	HVAC	Res | Ductless Heat Pump - Early Replacement
Res	HVAC	Res | Ductless Heat Pump- ROB & NEW
Res	HVAC	Res | Ground Source Heat Pump
Res	LI_MF	Res | Advanced Power Strips
Res	LI_MF	Res | Air Infiltration
Res	LI_MF	Res | Attic Knee Wall Insulation
Res	LI_MF	Res | Ceiling Insulation
Res	LI_MF	Res | Central AC Tune-Up
Res	LI_MF	Res | Duct Sealing
Res	LI_MF	Res | ENERGY STAR Directional LEDs
Res	LI_MF	Res | Faucet Aerators
Res	LI_MF	Res | Floor Insulation
Res	LI_MF	Res | Furnace fan motor retrofit
Res	LI_MF	Res | Furnace Filter Whistle
Res	LI_MF	Res | High Efficiency Windows
Res	LI_MF	Res | Low-Flow Showerheads
Res	LI_MF	Res | Omni-Directional LEDs
Res	LI_MF	Res | Outdoor Dusk-Til-Dawn LED Light Bulb
Res	LI_MF	Res | Outdoor LED Light Bulb
Res	LI_MF	Res | Smart Thermostats
Res	LI_MF	Res | Solar Screens
Res	LI_MF	Res | Solar Water Heater
Res	LI_MF	Res | Thermostatic shower valve
Res	LI_MF	Res | Tub spout diverters & Thermostatic shower valve
Res	LI_MF	Res | Wall Insulation
Res	LI_MF	Res | Water Heater Pipe Insulation
Res	LI_MF	Res | Window Film
Res	Res Behavior	Res | Home Energy Report
Res	Res Behavior	Res | Inhome display real-time Feedback
Res	Res Behavior	Res | Large Residential Competitions
Res	Res Behavior	Res | Online Audit tool
Res	Res Behavior	Res | Prepay Electricity Bills
Res	Res Behavior	Res | Web-based Real-time Feedback

Sector	Program	Measure
Res	Retail	Res | Energy Star air purifier
Res	Retail	Res | Energy Star Ceiling Fans
Res	Retail	Res | Energy Star Clothes Washers
Res	Retail	Res | Energy Star Dehumidifiers
Res	Retail	Res | ENERGY STAR Directional LEDs
Res	Retail	Res | Energy Star Dishwashers
Res	Retail	Res | Energy Star Dryers
Res	Retail	Res | Energy Star Freezers
Res	Retail	Res | Energy Star Heat pump dryers
Res	Retail	Res | Energy Star Pool Pumps
Res	Retail	Res | Energy Star Refrigerator/Freezer
Res	Retail	Res | Energy Star Refrigerator/Freezer - Early Retirement
Res	Retail	Res | Heat Pump Water Heater
Res	Retail	Res | Omni-Directional LEDs
Res	Retail	Res | On demand tankless water heater
Res	Retail	Res | Outdoor LED Light Bulb
Res	Retail	Res | Smart Plugs
Res	Retail	Res | Window AC
Res	School Kits	Res | ENERGY STAR Directional LEDs
Res	School Kits	Res | Faucet Aerators
Res	School Kits	Res | Low-Flow Showerheads
Res	School Kits	Res | Outdoor LED Light Bulb

Appendix C. Achievable Potential Modeling Methodology Details

C.1 Calculating Achievable Potential

This section demonstrates Guidehouse's approach to calculating achievable potential, which is fundamentally more complex than calculating technical or economic potential.

The critical first step in the process to accurately estimate achievable potential is to simulate market adoption of energy efficient measures. The team's approach to simulating the adoption of energy efficient technologies for purposes of calculating achievable potential can be broken down into the following two strata:

1. Calculation of the dynamic approach to equilibrium market share
2. Calculation of the equilibrium market share

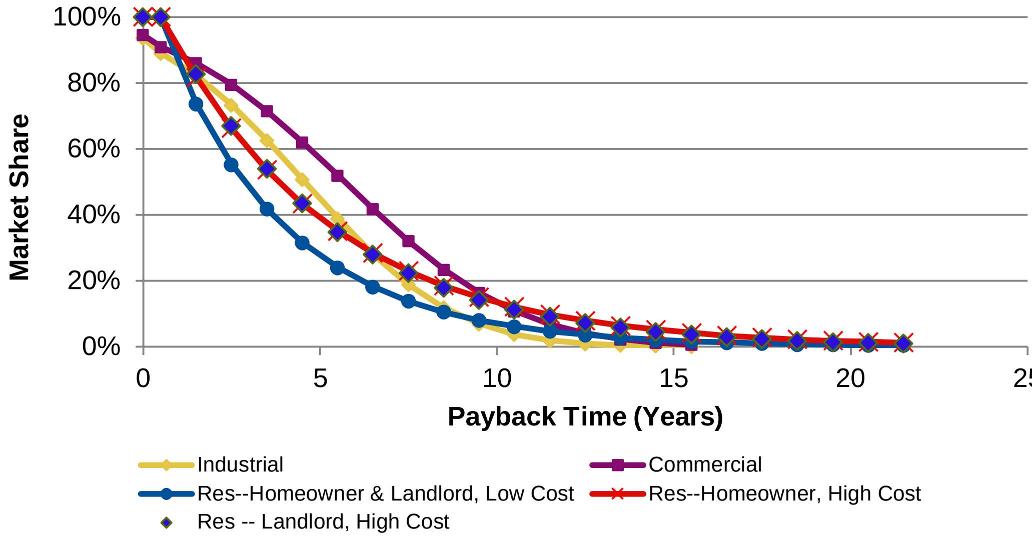
C.2 Calculation of Dynamic Equilibrium Market Share

The equilibrium market share can be thought of as the percentage of individuals choosing to purchase a technology, provided those individuals are fully aware of the technology and its relative merits (e.g., the energy- and cost-saving features of the technology). For energy efficient technologies, a key differentiating factor between the base technology and the efficient technology includes the energy and cost savings associated with the efficient technology. That additional efficiency often comes at a premium in initial cost. In efficiency potential studies, equilibrium market share is often calculated as a function of the payback time of the efficient technology relative to the inefficient technology. While such approaches have limitations, they are nonetheless directionally reasonable and simple enough to permit estimation of market share for the dozens or even hundreds of technologies that are often considered in potential studies.

Guidehouse uses equilibrium payback acceptance curves that were developed using primary research it conducted in the Midwestern US in 2012.[96] To develop these curves, the team surveyed 400 residential, 400 commercial, and 150 industrial customers. These surveys presented decision makers with numerous choices between technologies with low upfront costs but high annual energy costs and measures with higher upfront costs but lower annual energy costs. Guidehouse conducted statistical analysis to develop the set of curves shown in Figure C-1, which were leveraged in the 2021 ENO study. Though ENO-specific data is not currently available to estimate these curves, Guidehouse considers that the nature of the decision-making process is such that the data developed using these surveyed customers represents the best data available for this study at this time.

[96] A detailed discussion of the methodology and findings of this research is contained in the *Demand Side Resource Potential Study*, prepared for Kansas City Power and Light, August 2013.

Figure C-1. Payback Acceptance Curves



Source: Guidehouse, 2015

Because the payback time of a technology can change over time, as do technology costs or energy costs, the equilibrium market share can also evolve. The equilibrium market share is recalculated for every time-step within the market simulation to ensure the dynamics of technology adoption considers this effect. The term equilibrium market share is a bit of an oversimplification and a misnomer, as it can itself change over time and is never truly in equilibrium. It is used nonetheless to facilitate understanding of the approach.

C.3 Calculation of the Approach to Equilibrium Market Share

The team used two approaches to calculate the approach to equilibrium market share (i.e., how quickly a technology reaches final market saturation): one for new technologies or those being modeled as a retrofit (a.k.a. discretionary) measures, and one for technologies simulated as ROB (a.k.a. lost opportunity) measures.[97] The following sections summarize each approach at a high level.

C.3.1 Retrofit/New Technology Adoption Approach

Retrofit and new technologies employ an enhanced version of the classic Bass diffusion model[98,99] to simulate the S-shaped approach to equilibrium commonly observed for technology adoption. Figure C-2 illustrates the causal influences underlying the Bass model. In this model, achievable potential flows to adopters through two primary mechanisms: adoption from external influences such as program marketing/advertising, and adoption from internal influences including word of mouth. Figure C-1 illustrates the fraction of the population willing to adopt is estimated using the payback acceptance curves.

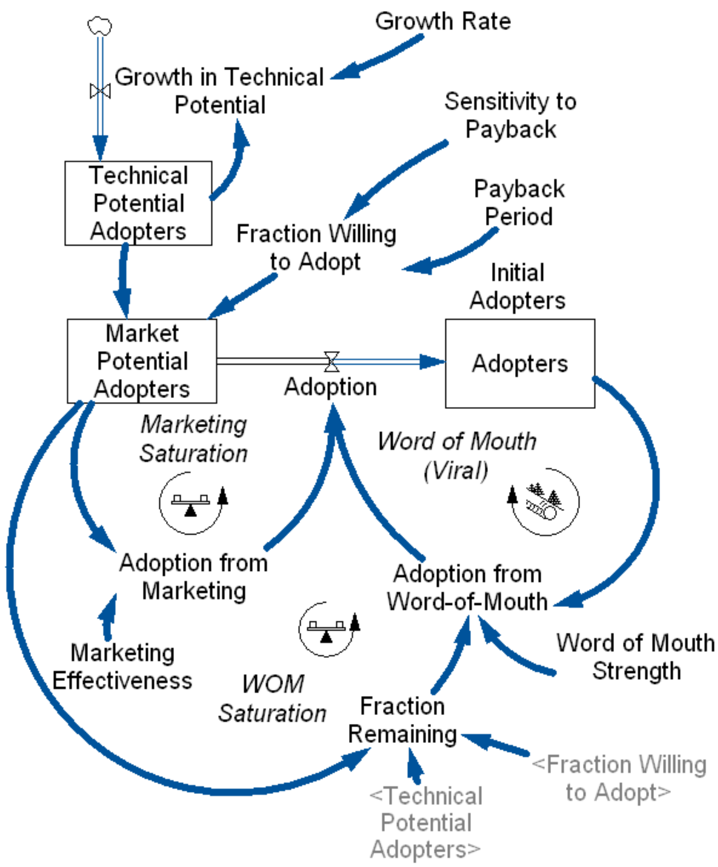
[97] Each of these approaches can be better understood by visiting Guidehouse's technology diffusion simulator, available at: http://forio.com/simulate/Guidehousesimulations/technology-diffusion-simulation.

[98] Bass, Frank (1969). "A new product growth model for consumer durables." *Management Science* 15 (5): p215–227.

[99] See Sterman, John D. Business Dynamics: Systems Thinking and Modeling for a Complex World. Irwin McGraw-Hill. 2000. p. 332.

The marketing effectiveness and external influence parameters for this diffusion model are typically estimated upon the results of case studies where these parameters were estimated for dozens of technologies.[100] Additionally, the calibration process permits adjusting these parameters as warranted (e.g., to better align with historic adoption patterns within the ENO market). Recognition of the positive or self-reinforcing feedback generated by the word of mouth mechanism is evidenced by increasing discussion of concepts like social marketing and the term "viral," which has been popularized and strengthened by social networking sites such as Facebook and YouTube. However, the underlying positive feedback associated with this mechanism has been part of the Bass diffusion model of product adoption since its inception in 1969.

Figure C-2. Stock/Flow Diagram of Diffusion Model for New Products and Retrofits



Source: Guidehouse, 2015

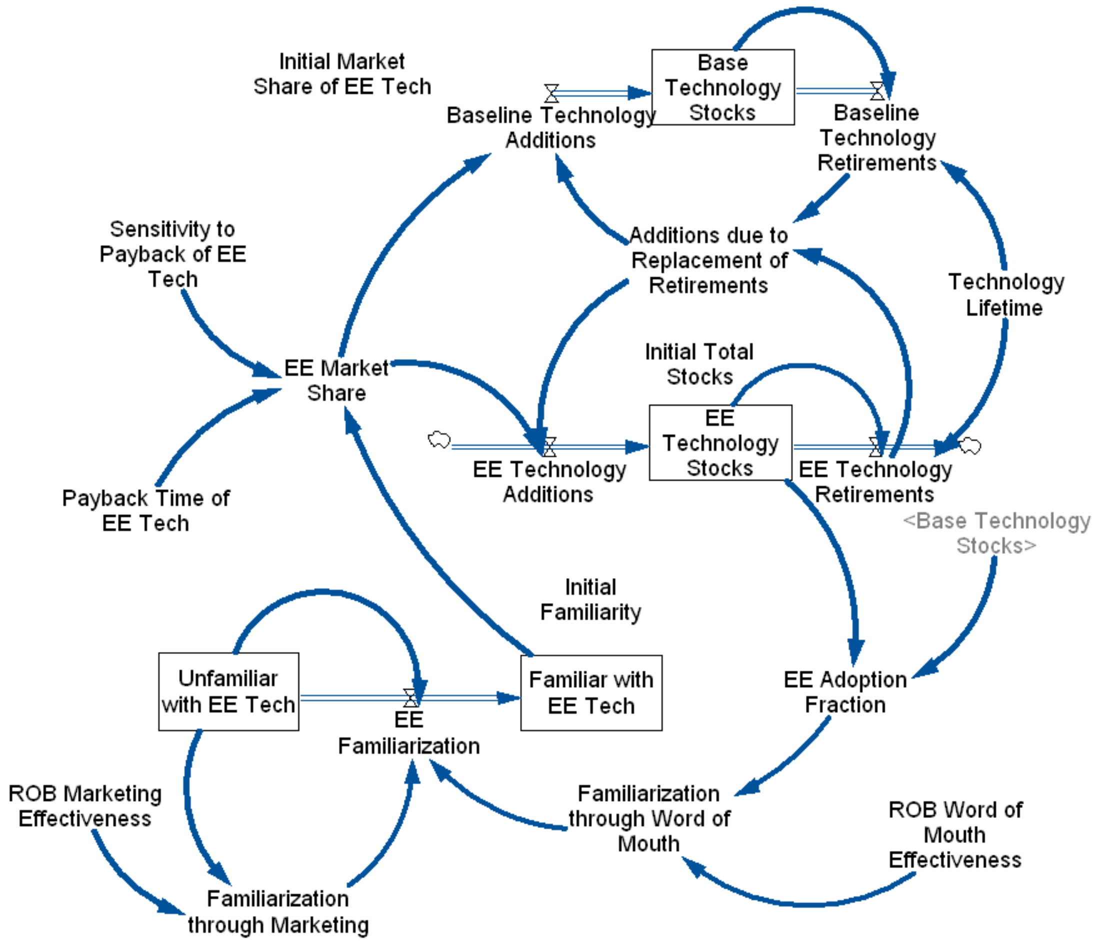
C.3.2 ROB Technology Adoption Approach

The dynamics of adoption for ROB technologies are more complicated than for new/retrofit technologies because it requires simulating the turnover of long-lived technology stocks. To account for this, the DSMSim model tracks the stock of all technologies, both base and efficient,

[100] See Mahajan, V., Muller, E., and Wind, Y. (2000). *New Product Diffusion Models.* Springer. Chapter 12 for estimation of the Bass diffusion parameters for dozens of technologies. This model uses the median value of 0.365 for the word of mouth strength in the base case. The Marketing Effectiveness parameter was assumed to be 0.04, representing a somewhat aggressive value that exceeds the most likely value of 0.021 (75th percentile value is 0.055) per Mahajan 2000.

and explicitly calculates technology retirements and additions consistent with the lifetime of the technologies. Such an approach ensures that technology churn is considered in the estimation of achievable potential, as only a fraction of the total stock of technologies are replaced each year, which affects how quickly technologies can be replaced. A model that endogenously generates growth in the familiarity of a technology, analogous to the Bass approach, is overlaid on the stock tracking model to capture the dynamics associated with the diffusion of technology familiarity. Figure C-3 illustrates a simplified version of the model employed in DSMSim.

Figure C-3. Stock/Flow Diagram of Diffusion Model for ROB Measures



Source: Guidehouse, 2015

Appendix D. Behind the Meter Battery Storage Forecast

D.1 Forecast Methodology

Battery system parameters, customer benefits, and customer costs were developed for each customer segment and inputted into a payback-adoption model to estimate long-run battery adoption. Bass diffusion curves were then applied to estimate the rate of growth in adoption out to 2040.

D.1.1 Battery Parameters

Battery system parameters such as battery capacity, efficiency, and duration were developed for the analysis. A rigorous derivation for the peak output for battery sizing requires a detailed analysis of historical data and weather data, and each customer has unique needs. In Guidehouse's experience, a storage system is typically sized at 15% to 20% of a customer's peak load. In the absence of detailed load data for every single customer, Guidehouse sized the batteries to 15% of the customers' coincident customer peak load for this analysis. Batteries were also assumed to have a 1.9-hour duration, which was the average duration found in an NREL survey of Li-ion projects[101].

D.1.2 Customer Benefits

Guidehouse modeled demand charge reduction, bill savings from evening discharge, and DR-related incentives when considering customer-side economic benefits. Small Electric Service and Large Electric Service rates were applied to customers in the corresponding rate class to calculate bill savings from demand charge reduction and evening discharge. Batteries are assumed to be available to the customer for days where ENO is not dispatching the battery. Similar to the demand response program definition, ENO would dispatch batteries no more than 40 days per year. The analysis also considers bill savings from customers with solar systems who charge the battery with excess solar power during the day to offset energy use in the evening. For C&I customers, bill savings from evening discharge is minor compared to savings from demand charge reduction, but for residential customers, this evening discharge is the primary economic benefit (aside from incentives). Incentives were modeled as an adjustable input. Incentive analysis includes the option to apply upfront incentives, recurring incentives for DR program participation, or both.

D.1.3 Customer Costs

Guidehouse used the battery size and per kW upfront capital costs and ongoing O&M costs from Guidehouse Insights and PNNL[102] to calculate total costs incurred by the customer. Capital costs range from $1800-2200/kW, with larger batteries having a lower per kW cost.

[101] Commercial Scale, Lithium-ion Projects in the U.S, NREL, October 2016. https://www.nrel.gov/docs/fy17osti/67235.pdf

[102] Energy Storage Technology and Cost Characterization Report, PNNL, July 2019. https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

D.1.4 Adoption Modeling

The inputs discussed above were fed into a simple payback calculation (shown below), and the resulting payback period was used, in conjunction with internally developed payback acceptance curves, to estimate long-run economic adoption. Customers who adopt for reasons other than utility bill savings economics (e.g. resiliency) will not be captured in the analysis.

Equation for Storage Payback Period Analysis

$$Payback\ Period = \frac{Installed\ Cost - Upfront\ Incentive}{Demand\ Charge\ Savings + Bill\ Savings\ from\ Discharge + Recurring\ Incentives - Ongoing\ Costs}$$

The model applied Bass diffusion curves to account for the gradual increase in adoptions up to the long-run market share.

D.1.5 Cases for DR Modeling

To develop different adoption forecasts for each of the DR cases, incentive levels and technology suitability parameters were varied according to the table below.

Table D–1. Battery Parameters for DR Adoption Cases

DR Case	Upfront Incentive	DR Participation Incentive	Technology Suitability
No Incentives	$0	$0	Only customers with solar
Base	C&I: 20% of upfront cost Res: 50% of upfront cost	$70/kW	Only customers with solar
Max Achievable	C&I: 20% of upfront cost Res: 50% of upfront cost	$275/kW	All customers

Source: Guidehouse

The demand response achievable potential analysis for the BTMS program used storage as a measure and examined battery program designs for all three cases shown in the table above. The analysis of all cases demonstrated that none of the battery program designs listed were cost-effective. Additional discussion on DR results can be found in Section 4.

D.2 Findings

This analysis shows that high incentives (as compared to the utility avoided costs) are required to drive sufficient adoption to enable meaningful DR savings from batteries. The table below shows the incentive levels at which customers begin to adopt batteries based on economic benefits. Large C&I customers have a more compelling value proposition to adopt storage systems due to their higher demand charges that can be mitigated by discharging storage during their facility peak. Thus, C&I customers will begin adopting battery storage at lower incentive levels compared to residential customers, whose primary benefits from batteries are recurring incentives and bill savings from evening discharge.

Table D–2. Incentive Levels at the Threshold of Adoption

Sector	Upfront Incentives ($)	Recurring Incentives ($/kW-year)
C&I	$0	$70
Res	$0	$120
C&I	40% of upfront cost	$0
Res	Little to no adoption even at 100% of upfront costs*	$0

*This behavior occurs when using a payback-based approach and when recurring O&M costs are greater than recurring benefits from bill savings, which is the case for residential customers.
Source: Guidehouse

While different combinations of upfront and recurring incentive levels could be used to model similar levels of long-run storage adoption, the DR cost-effectiveness results indicate that factors beyond battery program design, such as avoided capacity costs, battery costs, and platform fees, are driving the low cost-effectiveness of the battery program. If battery costs decline or if avoided capacity costs increase, it will be more feasible to create a cost-effective battery program.

CERTIFICATE OF SERVICE
DOCKET NO. UD-20-02

I hereby certify that I have served the required number of copies of the foregoing report upon all other known parties of this proceeding, by the following: electronic mail, facsimile, overnight mail, hand delivery, and/or United States Postal Service, postage prepaid.

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New Orleans, Louisiana, this 30th day of July 2021.

Timothy S. Cragin

Timothy S. Cragin

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX E

GDS 2021 POTENTIAL STUDY

MARCH 2022

CITY COUNCIL OF NEW ORLEANS

2021 DSM Market Potential Study

FINAL REPORT

July 2021

prepared by

GDS Associates, Inc. *with*

MSMM Engineering, LLC

The Villavaso Group, LLC

Casey DeMoss

Executive Summary

BACKGROUND & STUDY SCOPE

This study provides an estimate of energy efficiency and demand response potential for the Entergy New Orleans (Entergy) service territory. This study was commissioned by the Council of the City of New Orleans (Council) as part of their retail regulatory oversite of electric utility services in Orleans Parish. Energy efficiency and demand response can often provide a cost-effective means of meeting customer energy or demand needs compared to traditional supply-side investments. These resources can benefit both participants and non-participants by providing lower electric bills, improving building stock, and reducing environmental emissions from power plants, such as carbon dioxide.

This study is meant to help inform Entergy's future Energy Smart programs and to provide input into Entergy's Integrated Resource Plan (IRP) efforts. The outcome of this study forecasts the 20-year potential for Energy Smart programs to deliver energy and demand savings under several achievable cases, in addition to estimating the total technical and economic (cost-effective) potential.

To develop these estimates of potential, the GDS Team builds off of the two prior 2018 estimates of potential, provided by Entergy's consultant, Navigant (now Guidehouse), and Optimal Energy, the Council's prior consultant. Since that time, Entergy's Energy Smart programs have made efforts at energy efficiency and demand response, technologies and market acceptance have changed, and Entergy has developed new forecasts for energy consumption and associated supply costs. The GDS Team's modeling takes all these factors into account in developing new estimates for achievable program potential cases for the 2021-2040 timeframe.

TYPES OF POTENTIAL ANALYZED

This potential study provides a roadmap for the Council, Entergy, and other stakeholders as they engage on the Entergy IRP. In addition to technical and economic potential estimates, the development of achievable and program potential estimates for a range of feasible measures and program conditions is useful for program planning and modification purposes. Unlike achievable and program potential estimates, technical and economic potential estimates do not include customer acceptance considerations for measures, which are often among the most important factors when estimating the likely customer response to new programs. For this study, the GDS Team produced the following estimates of demand side management potential:

- Technical potential
- Economic potential
- Achievable potential
  - High Case Achievable Potential
  - 2% Council Policy Case
  - Reference Achievable Potential

For each level of potential, this detailed report presents the energy savings, peak demand savings, benefits and costs for the Entergy New Orleans service area for the period of 2021-2040, a 20-year time frame.

APPROACH SUMMARY

The purpose of this DSM potential study is to provide a foundation for the continuation of utility-administered energy efficiency and demand response programs in the Entergy New Orleans service territory, to determine the remaining opportunities for cost-effective energy and demand in the service territory. This study has examined a full array of technologies, programs, and energy efficient practices that are technically achievable, as a starting point for examining the economic opportunities, along with achievable program opportunities.

The GDS Team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use levels. In the commercial and industrial sector (C&I), the GDS team utilized a top-down modeling approach - first estimating measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of electric energy load. A bottom-up approaches was also used in the demand response analyses for all sectors.

Section 2.1 includes a wide-ranging discussion of numerous methodological considerations addressed in the energy efficiency potential analysis. Section 3.1 includes a similar discussion of the analysis approach specifically related to demand response.

STUDY LIMITATIONS AND CAVEATS

As with any assessment of potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs (total measure costs, incremental costs, and incentive costs)
- Projected penetration rates for energy efficiency measures
- Projections of energy avoided costs
- End-use saturations and fuel shares

While the GDS Team has sought to use the best and most current available data (including the use of new primary market research to understand New Orleans-specific adoption potential) there are often reasonable alternative assumptions which would yield slightly different results. For instance, the analysis assumes that many existing measures, regardless of their current efficiency levels, can be eligible for future installation and savings opportunities. Other studies may select a narrower viewpoint, limiting the amount of potential from equipment that is already considered to be energy efficient. Additionally, the models used in this analysis must make several assumptions regarding program delivery and the timing of equipment replacement that may ultimately occur more rapidly (or more slowly) than may be reflected in current plans or similar studies.

POTENTIAL SAVINGS RESULTS SUMMARIES

Below we provide summary results for the study, presenting results for energy efficiency and demand response for each of the residential and C&I sectors. For energy efficiency, the three achievable cases reflect the following:

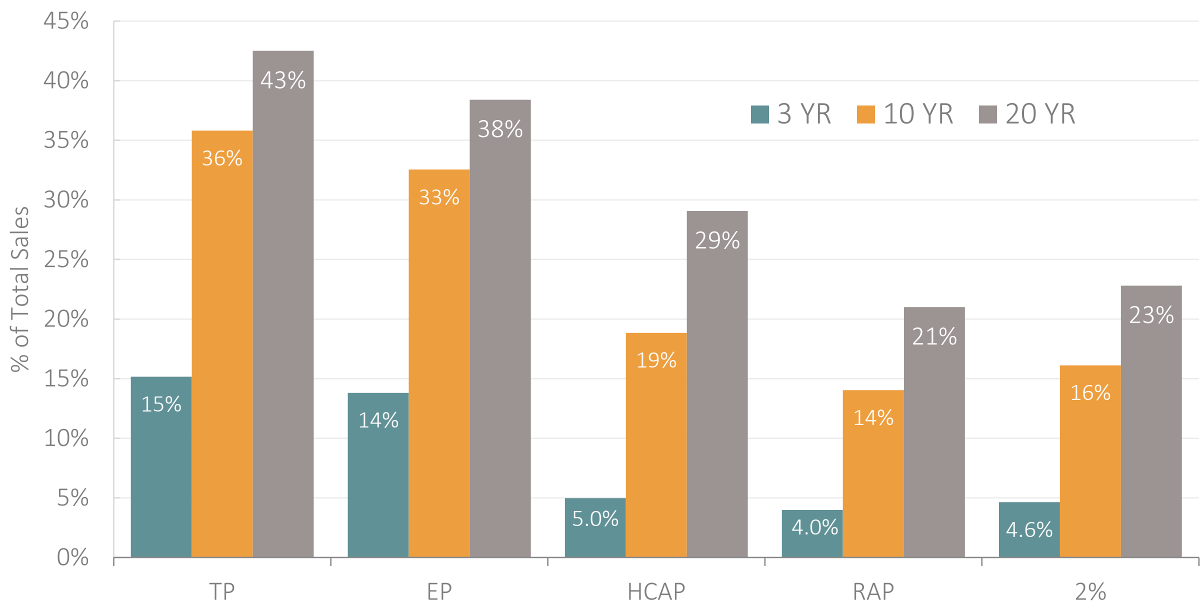
- ***High Case Achievable Potential* (HCAP)** estimates achievable potential from aggressive adoption rates based on paying incentives equal to 100% of measure incremental costs and increased program awareness.
- ***2% Council Policy Case* (2% Case)** estimates achievable potential in-line with Council policy, reflecting a 0.2% increase in savings as a percent of sales until savings as a percent of sales achieves 2%.
- ***Reference Achievable Potential* (RAP)** estimates achievable potential with Entergy paying incentive levels (as a percent of incremental measure costs) and program awareness closely calibrated to historical levels but is not constrained by any previously determined spending levels.

Demand response program potential was framed with two cases – a high case achievable case and a reference achievable case.

Energy Efficiency Potential Summary

Figure ES-1 provides the cumulative annual technical, economic, HCAP, RAP, and 2% policy case results for the 3-year, 10-year, and 20-year timeframes[1]. Over the duration of the study timeframe the technical and economic potential reach 43% and 38% of forecasted sales, respectively. This relatively close alignment of technical and economic potential suggests that a large portion of the technical potential is cost-effective. The HCAP case reaches 29% of forecasted ENO 2041 sales (or 76% of the economic potential). The RAP and 2% policy case achieve respectively to 21% and 23% of forecasted sales over the study timeframe. The gap between economic potential and the achievable policy cases represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential. Figure ES-2 shows the cumulative annual achievable potential by case over the entire 20-year timeframe.

FIGURE ES-1. OVERVIEW OF ENERGY EFFICIENCY POTENTIAL BY CASE



[1] Cumulative annual refers to savings in Year X that represent both the incremental annual (new) savings achieved in that year, as well as any sustained savings from measures installed in prior years that have not yet reached the end of their effective useful life (EUL).

FIGURE ES-2. CUMULATIVE ANNUAL ACHIEVABLE ELECTRIC ENERGY SAVINGS POTENTIAL BY CASE

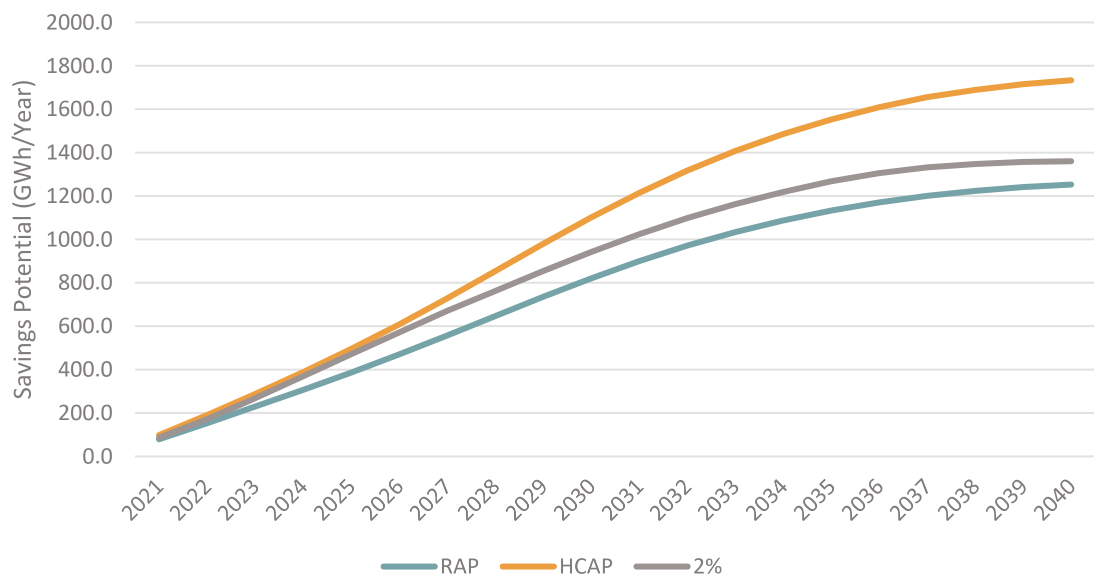


Table ES-1 provides incremental energy and demand savings for the RAP, HCAP, and 2% achievable cases in 5-year increments. The cumulative annual energy and demand savings in 2041 for the 2% policy case is 1360 GWh and 422 MW respectively.

TABLE ES-1. ANNUAL INCREMENTAL ACHIEVABLE ENERGY EFFICIENCY SAVINGS BY CASE

Year	Energy (GWh/Year)			Peak Demand (MW)		
	RAP	HCAP	2%	RAP	HCAP	2%
2021	79	98	86	17	19	19
2025	94	121	116	24	27	30
2030	105	143	109	36	38	35
2035	71	96	76	23	24	23
2040	53	71	58	11	13	12
Cum. Ann. (2041)	1253	1733	1360	403	480	422

Table ES-2 provides incremental energy potential savings as a percentage of ENO's total sales in 5-year increments. For the 2% case, savings increase by 0.2% a year in 2021-2023, and 2% savings per year from 2024-2027. Savings decrease over time as energy efficiency potential becomes more limited in the second decade on an incremental annual basis. The 2% policy case is slightly higher than the RAP case because of higher incentives and increased marketing awareness. The HCAP, which assumes incentives that are equal to the incremental measure cost, can sustain 2% savings over a longer period, though again, savings decrease during the second decade as remaining efficiency potential from measures included in this analysis are depleted.

TABLE ES-2. INCREMENTAL ACHIEVABLE ENERGY EFFICIENCY SAVINGS POTENTIAL BY CASE (AS A % OF SALES)

Year	RAP	HCAP	2%
2021	1.4%	1.7%	1.5%
2025	1.6%	2.1%	2.0%
2030	1.8%	2.4%	1.9%
2035	1.2%	1.6%	1.3%
2040	0.9%	1.2%	1.0%

Total costs by each associated with each achievable potential case are shown in Figure ES-2. Total costs are comparable between the RAP and 2% policy case, with differences aligned with the savings achieved in both cases. However, the HCAP case demonstrates significantly higher costs because of the corresponding modeling assumption that incentives are equivalent to 100% of the modeled incremental measure cost. Overall, incentives average between 50%-55% in the RAP and 2% policy cases. In the HCAP case, incentives are roughly 70% of the overall costs.

Table ES-3 shows the portfolio TRC to be cost-effective for all cases.

FIGURE ES-3. BUDGETS BY ACHIEVABLE POTENTIAL CASE ($ MILLIONS/YEAR)

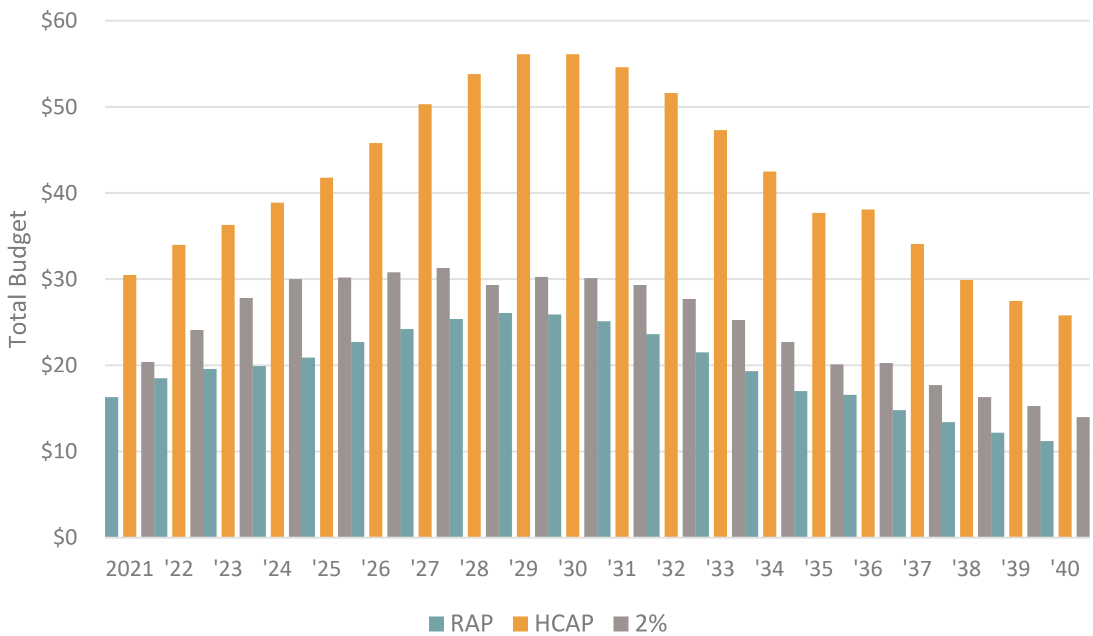


TABLE ES-3. PORTFOLIO TRC BENEFT-COST RATIOS BY ACHIEVABLE POTENTIAL CASE

Year	RAP	HCAP	2%
2021-2040	2.6	1.8	2.5

Demand Response Potential for All Customers

Figure ES-3 provides the cumulative opportunity for demand response, illustrating the residential and C&I (Non-Residential) reference achievable potential (RAP). We estimate that a total of 130 MW of avoided summer capacity could be met across the two sectors by 2040. This represents a growth of 108 MW over time.

FIGURE ES-3. TOTAL ANNUAL SUMMER PEAK MW RAP POTENTIAL BY SECTOR

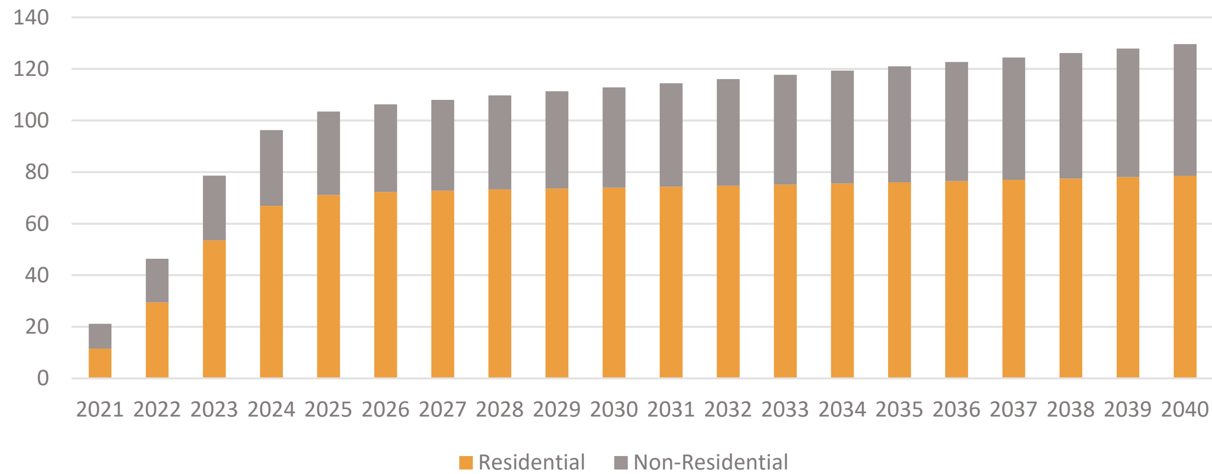
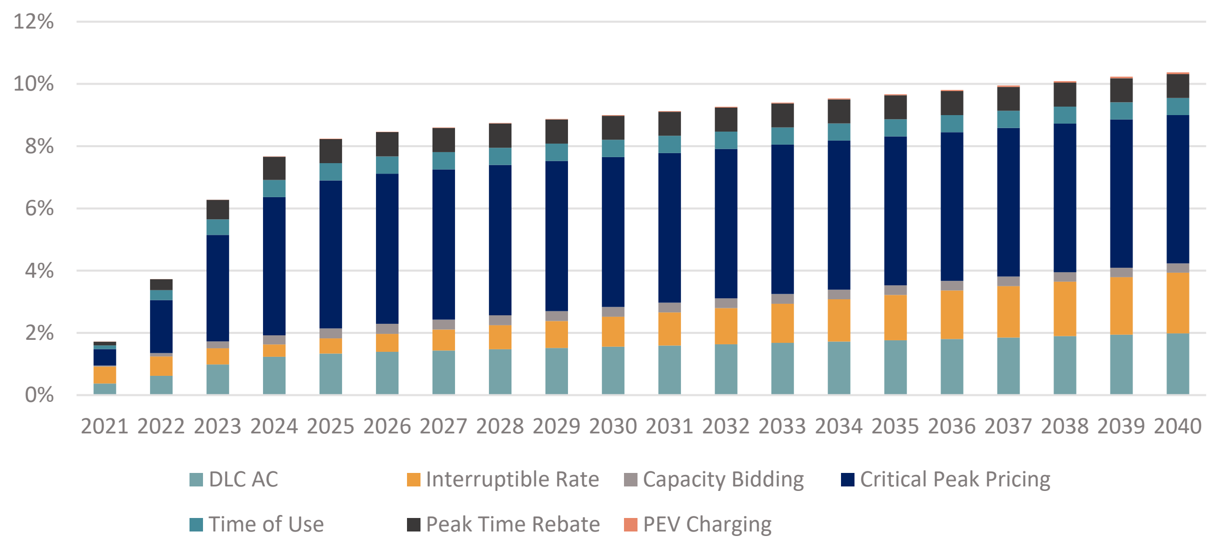


Figure ES-4 describes the nature of programs driving the demand response RAP and their contribution to meeting summer peak load over time. The share of summer peak load provided by demand response grows from just under two percent in 2021 to just over 10% in 2040. Major contributors to meeting summer peak load include critical peak pricing (5%), air conditioner direct load control (2%), and interruptible rates for large customers (2%).

FIGURE ES-4. TOTAL ANNUAL SUMMER PEAK RAP BY PROGRAM AS A PERCENTAGE OF PEAK LOAD



MOVING FORWARDS WITH PROGRAMS

Overall, GDS identified substantial cost-effective savings for energy efficiency and demand response exist and will continue to exist through 2040. Going forward, decisions regarding the level of effort will be based on the remaining potential for savings and the cost of developing those savings. Future technologies should continue to be researched and tested, which may identify still further savings. For example, battery storage systems (discussed in Section 3 – Demand Response) may become a future opportunity. Other examples include ongoing improvements in the efficiency of heat pumps and related technologies. GDS recommends that Entergy continue to refine its understanding of its energy efficiency markets and their associated opportunities and challenges for delivering energy savings, updating measure assumptions, or otherwise identifying the assets that its customers bring to help reduce or manage loads over time.

1 Introduction

The Council of the City of New Orleans (the Council) engaged GDS Associates and its team of subcontractors (the GDS Team) to provide an estimate of demand side management (DSM) energy efficiency and demand response potential for Entergy New Orleans (Entergy). The analysis of DSM potential is intended to provide input to Entergy's Integrated Resource Plan (IRP), covering the 2021 through 2040 timeframe. Beyond the potential for DSM savings over the 20-year period, the study also analyzed possible program spending levels required to achieve the outcomes from several possible achievable cases.

The GDS Team worked with the Council's representatives to develop several achievable energy efficiency cases. Along with technical and economic potential, these include:

- ***High Case Achievable Potential*** **(HCAP)** estimates achievable potential from aggressive adoption rates based on paying incentives equal to 100% of measure incremental costs and increased program awareness.
- ***2% Council Policy Case*** **(2% Case)** estimates achievable potential in-line with Council policy, reflecting a 0.2% increase in savings as a percent of sales until savings as a percent of sales achieves 2%.
- ***Reference Achievable Potential*** **(RAP)** estimates achievable potential with Entergy paying incentive levels (as a percent of incremental measure costs) and program awareness closely calibrated to historical levels but is not constrained by any previously determined spending levels.

For demand response, the GDS Team focused on providing a High Case Achievable Potential (HCAP) and Reference Achievable Potential case (RAP). Both energy efficiency and demand response cases are presented in more detail in subsequent report sections.

An additional energy efficiency stakeholder case was developed in collaboration with other stakeholders and will be provided in a separate report.

1.1 STUDY APPROACH

The purpose of this DSM potential study is to provide a foundation for the continuation of utility-administered energy efficiency and demand response programs in the Entergy New Orleans service territory, to determine the remaining opportunities for cost-effective energy and demand in the service territory. This study has examined a full array of technologies, programs, and energy efficient practices that are technically achievable, as a starting point for examining the economic opportunities, along with achievable program opportunities.

The GDS Team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use levels. In the commercial and industrial sector (C&I), the GDS team utilized a top-down modeling approach - first estimating measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of electric energy load. A bottom-up approaches was also used in the demand response analyses for all sectors.

1.2 REPORT ORGANIZATION

This report is organized into several sections. These include:

Section 1: An introduction to the study and background

Section 2: Describes the methods and results for the energy efficiency analysis

Section 3: Describes the methods and results for the demand response analysis

Appendices: Descriptions and details and key study elements or assumptions, including a benchmarking analysis to compare results from this study to other recent potential studies, along with a description of the Delphi Panel approach and results.

1.3 STUDY LIMITATIONS AND CAVEATS

As with any assessment of potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs (total measure costs, incremental costs, and incentive costs)
- Projected potential adoption rates for energy efficiency measures
- Projections of energy consumption and avoided costs
- End-use saturations and energy consumption shares

While the GDS Team has sought to use the best and most current available data, including the use of new primary market research to understand New Orleans-specific adoption potential, and recent data from Entergy, there are often reasonable alternative assumptions which would yield slightly different results. For instance, the analysis assumes that many existing measures, regardless of their current efficiency levels, can be eligible for future installation and savings opportunities. Other studies may select a narrower viewpoint, limiting the amount of potential from equipment that is already considered to be energy efficient. Additionally, the models used in this analysis must make several assumptions regarding program delivery and the timing of equipment replacement that may ultimately occur more rapidly (or more slowly) than may be reflected in current plans or similar studies.

In the next sections of the report, we present the details of the DSM potential analysis.

2 Energy Efficiency Potential Analysis

2.1 ANALYSIS APPROACH

This section describes the overall methodology proposed to assess the electric energy efficiency potential for residential and nonresidential customers in the Entergy New Orleans service territory. The main objectives of this Demand Side Management (DSM) Potential Study were to estimate the energy efficiency potential in terms of technical and economic potential, along with three achievable energy efficiency adoption cases in the Entergy New Orleans service territory:

- High Case Achievable Potential ("HCAP")
- Reference Achievable Potential ("RAP"), and
- Council (2%) Policy case (2% Council Policy Case)

These estimates were quantified in terms of MWh and MW savings, expected incremental and cumulative program participants, and associated costs, for each level of achievable energy efficiency potential. The energy efficiency potential results are presented in Section 2.2. Detailed appendices also provide a catalog of assumptions and annual outputs associated with this analysis.

2.1.1 Overview of Approach

For the residential sector, GDS utilized a bottom-up approach to the modeling of energy efficiency potential, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, taking into consideration incentives and estimates of annual adoption rates.

For the C&I sector, GDS employed a bottom-up modeling approach to first estimate measure-level savings, costs, and cost-effectiveness, and then applied measure savings to all applicable shares of energy load.

2.1.2 Market Characterization

The initial step in the analysis was to gather a clear understanding of the current market segments in the Entergy New Orleans (Entergy) service territory. The GDS team issued a data request to Entergy and received data regarding utility sales, sales forecasts, customer data, and related materials. These data define the market sectors and market segments from which energy efficiency can be derived and inform the types of measures that can drive energy efficiency savings.

In addition to Entergy data, the GDS compiled information related to:

- Energy efficiency saturation data
- End uses and relative shares of energy load

2.1.2.1 Forecast Disaggregation

GDS began with a forecast of Entergy's forecasted energy sales and demand, covering 2019 through 2040.[2] The forecast presented data for the residential sector and nonresidential sectors, including commercial customers, industrial customers, and government customers. For the C&I sector, GDS utilized SIC codes for each customer to further refine the forecast into building types. GDS refined both the residential and nonresidential building-types energy consumption into end uses using EIA data and, for the nonresidential

[2] This data is considered Highly Sensitive Protected Material and not included in this report.

sector, calibrating future end-use energy intensities using a forecast provided by Entergy. These refinements and general sources of information are summarized below.

For each major segment, GDS used the following data, with government customer loads combined with commercial customer loads to define an overall commercial sector:

- Residential. Utilized Entergy's description of customer types and share of load to define single family and multifamily homes. EIA's Residential Energy Consumption Survey (RECS) data were used to segment these loads into end-uses.
- Commercial. GDS utilized the following building types, based on the prior potential studies for consistency: college/university, healthcare, warehouse, lodging, small office, large office, grocery, other commercial, restaurants, retail (non-grocery), and schools. EIA's Commercial Building Energy Consumption Survey (CBECS) data and forecasted changes in intensity were used to define end-use shares of energy loads.
- Industrial. Entergy's SIC data was used to segment the industrial loads into major categories that align with EIA's Manufacturing Energy Consumption Survey (MECS). Based on the MECS data, the share of electricity loads associated with major end uses for each industry type were then weighted by the share of load from each industry to arrive at overall industrial end-use energy consumption estimates.[3]

2.1.2.1.1 Residential Sector

In the residential sector, disaggregated forecast data is useful for fine tuning measure baseline consumption and savings estimates, as well as calculating interactive effects to account for measures which save energy in the same end use (e.g. insulation and heat pumps both save on heating use). Entergy provided GDS with a sector-level sales forecast and end-use intensity forecast. This data was leveraged in the interactive effect calculations and annual savings adjustments.

The GDS team researched the breakdown of the number of customers by housing type (single-family vs. multifamily) and income type. The study assumes 76% of homes are single-family and 24% are multifamily and that 24% of homes are income-qualified.

2.1.2.1.2 C&I Sector

In the C&I sector, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. Entergy provided GDS with energy consumption data for its C&I accounts (segmented by rate category) and the account's SIC code. GDS utilized the SIC code data to classify nonresidential customers into either commercial or industrial categories, associating their energy loads with either commercial or industrial building functions. For commercial customers identified as Transportation, Communications, or Utilities, GDS shifted 75 percent of this load to the industrial sector load. Figure 2-1 provides a breakdown of commercial electricity sales shares by building type.

[3] Industrial sector potential was ultimately aggregated into an additional building type in the overall C&I (nonresidential) sector analysis.

FIGURE 2-1. C&I ELECTRIC SALES BREAKDOWN BY BUILDING/INDUSTRY TYPE[4]

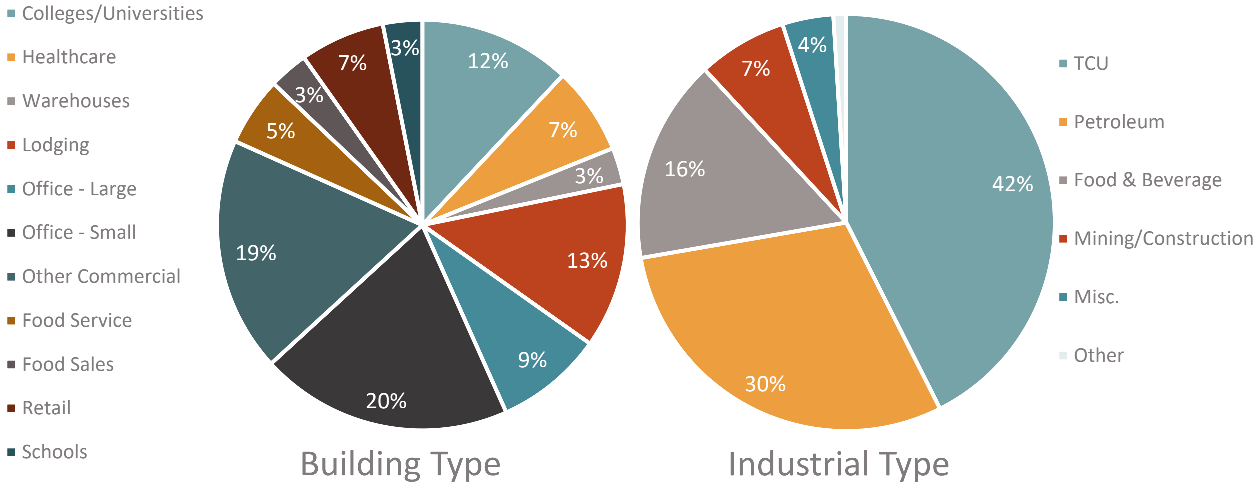
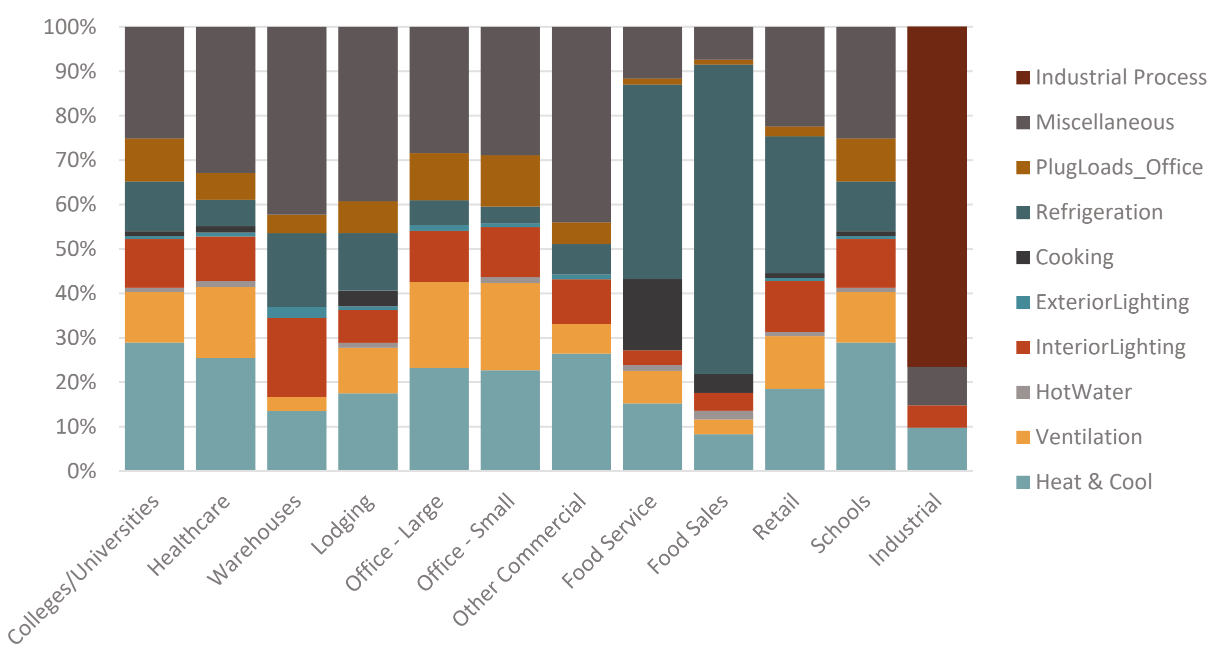


Figure 2-2 provides an illustration of the major end-uses across all building types in the commercial sector. Lighting represents 11% of the commercial business sector load across buildings, with HVAC (heating, cooling, ventilation) representing 35% or more across building types. Shares of refrigeration and office/computing are often dependent on the type of building, with refrigeration loads greatest in food sales and food service while office/computing loads are greatest in offices and education. Miscellaneous end-use load represents 30% of commercial sales with the overall contribution varying by building type.

FIGURE 2-2. COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE



[4] TCU (Transportation, Communications, and Utilities) load is reflected in ENO's commercial sales but the majority was moved to Industrial for purpose of the potential analysis. Other represents specific industry types (i.e. fabricated metals, electronics, etc.) with <1% of industrial load.

2.1.2.2 Building Stock/Equipment Saturation

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary. These are described for the Residential and C&I sectors, below.

2.1.2.2.1 Residential Sector

For the residential sector, GDS relied on the 2016 Entergy Residential Appliance Saturation Survey. This data allowed for GDS Team to characterize the baseline and efficiency saturations of the residential sector using housing-type specific data. Other data sources included ENERGY STAR unit shipment data, and the EIA Residential Energy Consumption Survey data from 2015. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

2.1.2.2.2 C&I Sector

For the C&I sector, building stock and equipment saturation data was informed by available regional or national data. Energy Star sales data helped inform shipments and shares of Energy Star rated equipment, which served as a proxy for efficient equipment sales shares over time for similar equipment. EIA data was used to describe the relative share of electricity consumption for a variety of end-uses, while USDOE Energy Scout[5] data provided breakdowns of load associated with specific equipment types to further refine EIA end-use data. GDS also leveraged its library of prior potential studies that leveraged a variety of equipment saturation surveys from around the U.S.

For the industrial sector, the analysis employed a top-down analysis at the end-use level. Accordingly, it was not critical to disaggregate the industrial sales at a measure-level. Instead, measures were developed to estimate savings at a total end-use level. Based on EIA MECS data, each industry type has characteristics of end-use equipment shares, with those shared weighted by their relative presence in Entergy's New Orleans service territory.

2.1.2.3 Remaining Factor

The remaining factor is the proportion of a given market segment and technology that is not yet efficient and can still be converted to an efficient alternative. It is the inverse of the saturation of an energy efficient measure, prior to any adjustments. For this study we made two key adjustments to recognize that the energy efficient saturation does not necessarily always fully represent the state of market transformation. In other words, while a percentage of installed measures may already be efficient, this does not preclude customers from backsliding, or reverting to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost and availability and customer preferences. For example, some customers have disliked CFL light quality, and have reverted to incandescent and halogen bulbs after the CFLs burn out. Similarly, high efficiency air conditioning equipment could be replaced with less efficient equipment in the future.

For measures categorized as market opportunity (i.e. replace-on-burnout), we assumed that 60% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. Essentially this adjustment implies that we are assuming that 40% of the market is transformed, and no future savings potential exists, whereas the remaining 60% of the market is not transformed and could backslide without the intervention of an I&M program and an incentive. Similarly, for retrofit measures, we assumed that only 25% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This recognizes the more proactive nature of retrofit measures, as the

[5] https://scout.energy.gov/

implementation of these measures are more likely to be elective in nature, compared to market opportunity measures, which are more likely to be needs-based. We recognize the uncertainty in these assumptions, but we believe these are appropriate assumptions, as they recognize a key component of the nature of customer decision making.

2.1.3 Measure Characterization

2.1.3.1 Measure Lists

The study's sector-level energy efficiency measure lists were informed by a range of sources. Entergy provided a list of measures expected to be used by Guidehouse, a consultant of Entergy. GDS utilized this measure list and added to that list using experience from other market potential studies. To develop measure-level characterizations, GDS primarily used the Entergy New Orleans Technical Reference Manual v4.0. In addition to this resource, additional measures were considered for inclusion by referencing current Entergy New Orleans program measure assumptions, publicly available research, and technical reference manuals (TRMs) from a variety of jurisdictions. The chief purpose in utilizing program offerings and alternate TRMs was to inform measure assumptions to align with potential study data requirements or to inform specific calculation approaches requiring a formulation or generalization not present in the Entergy TRM.

In total, GDS analyzed 104 residential and 83 C&I unique measure types. GDS developed a total of 1,349 measure permutations for this study. Each permutation was screened for cost-effectiveness according to the Total Resource Cost (TRC) Test. The parameters for cost-effectiveness under the TRC are discussed in detail later in Section 2.1.3.5

For each measure, key factors associated with energy efficiency performance included:

- Baseline energy and demand consumption, along with associated energy and demand savings
- Measure lifetime
- Measure cost (incremental or full)
- Status as retrofit or replace on burnout

2.1.3.2 Measure Baseline and Savings

GDS estimated the energy consumption of the baseline and energy efficient alternative using engineering analyses. For some measures, if savings percentages were known and the primary driver, an estimate of baseline and efficient energy consumption was derived from the savings percentage. As noted above, the TRM was the primary resource to inform savings. However, not all TRM measure characterization had sufficient detail to derive baseline and efficient consumption, necessitating the use of calculations from other TRMs or other industry literature. In all cases, current federal standards were used to inform baselines or derived baselines.

2.1.3.3 Measure Lifetime

Measure lifetimes describe how long a measure can be expected to provide savings over time and is a key factor in estimating measure cost-effectiveness. GDS relied primarily on the New Orleans TRM to inform measure lifetimes, though utilized other TRMs and GDS's library of measure characterizations as necessary.

2.1.3.4 Measure Costs

Measure costs are a key consideration in cost-effectiveness testing and incentive setting. GDS relied primarily on the New Orleans TRM as the source of incremental costs. In some cases, GDS relied on other recent TRMs, online product research, or GDS's library of measure characterizations. Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.[6]

Costs and savings for new construction and replace on burnout measures were calculated as the incremental difference between the code minimum equipment and the energy efficiency measure. This approach was utilized because the consumer must select an efficiency level that is at least the code minimum equipment when purchasing new equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard efficiency (code compliant) equipment. However, for retrofit or direct install measures, the measure cost was the "full" cost of the measure, as the baseline scenario assumes the consumer would not make energy efficiency improvements in the absence of a program. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life).

2.1.3.5 Measure Cost-Effectiveness

GDS screened each measure and sector portfolio for cost-effectiveness using the Total Resource Cost Test (TRC). The Total Resource Cost (TRC) test measures benefits and costs from the perspective of the utility and utility customers as a whole. The benefits include the present value of the energy and capacity saved by the measures but exclude any natural gas or other fossil fuel benefits. The forecast of electric avoided costs of energy and capacity were obtained from Entergy and represent their most recent forecast of avoided electric benefits.7 The costs are the present value of all costs to implement those measures. These costs include measure full or incremental costs (depending on the type of measure), but exclude incentive payments that offset measure costs to customers. Utility lost revenues are also excluded. For measure level screening, non-incentive program costs were excluded. Non-incentive program costs were included in the analysis of portfolio cost-effectiveness, which included the potential for measures that passed the cost-effectiveness screening. Measures were treated as passing the cost-effectiveness screening with a benefit-cost ratio of 0.85. Sector portfolios were all found to have cost-effectiveness greater than 1.0, detailed below in the results section.

To develop the present value of benefits and costs, GDS applied Entergy's weighted average cost of capital[8] as the discount rate. Additionally, GDS utilized an inflation rate of 2%, applying the inflation rate to future program non-incentive costs, while not inflating future measure costs. Inflating the program non-incentive costs reflects general cost factors associated with increasing personnel salaries, marketing, or other program operational expenses.

2.1.3.6 Retail Rates

Retail rates do not influence the TRC results. However, for analyzing C&I sector adoption rates, the simple payback period was used to estimate the impact of customer measure costs net of incentives. This data aligns with the Delphi panel approach for the C&I sector adoption curves, which are based on measure adoption levels and timing due to simple customer payback periods. The rate used to estimate simple payback was based on Entergy's current rate schedule.

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[6] GDS has noted that measure costs in TRMs do not show significant changes over time. For example, the deemed measure cost assumptions included in the Illinois TRM from 2012 (v1) through 2018 (v7) found no changes to measure costs across 80% of residential and business measures.

[7] These avoided costs are treated as Highly Sensitive Protected Materials and not disclosed in this report.

[8] Entergy's weighted average cost of capital is Highly Sensitive Protected Material and not disclosed.

2.1.4 Types of Potential

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, and various forms of achievable potential. The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100 percent of the technical or economic potential. Therefore, achievable potentials attempt to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. In this analysis, achievable potentials included an assessment of a high case achievable potential (HCAP), a reference achievable potential case (RAP), and a 2% of energy sales case (the 2% Council Policy Case). For the achievable cases, various assumption regarding the level of incentives and program effectiveness at moving a market were made to drive the outcomes. The RAP reflects the current level of incentives and level of savings as a percent of sales currently achieved by Entergy. The other two cases reflect higher incentives and program effectiveness.

Figure 4-2 illustrates the types of energy efficiency potential considered in this analysis.

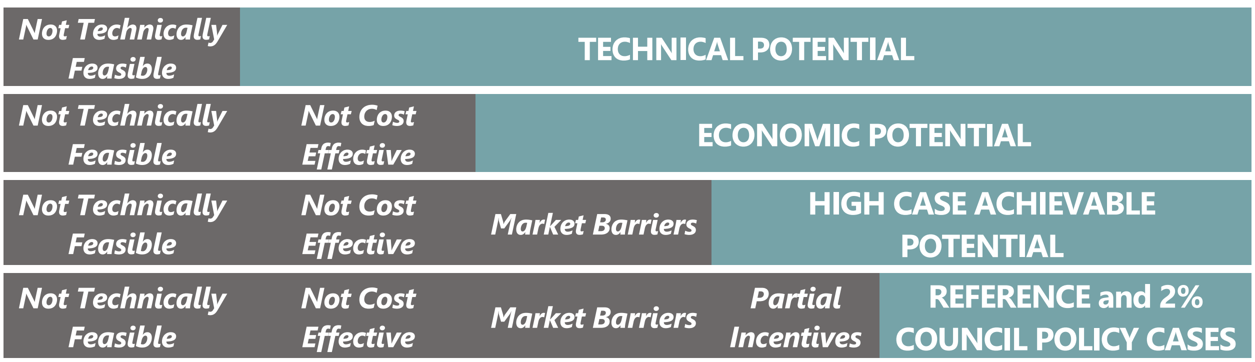


FIGURE 2-3. TYPE OF ENERGY EFFICIENCY POTENTIAL[9]

Each type of potential is described in more detail, below.

2.1.5 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential only constrained by factors such as technical feasibility of measures. Under technical potential, GDS assumes that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation will be assumed to be resource constrained and that it is not possible to install all retrofit measures all at once. Rather, retrofit opportunities will be assumed to be replaced incrementally until 100% of stock will be converted to the efficient measure over a period of no more than 19 years.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 4-1 below. The C&I sector employs a similar analytical approach, but with the top-down approach utilizes the building-type energy load share in place of the count of households.

[9] Reproduced from "Guide to Resource Planning with Energy Efficiency." November 2007. US Environmental Protection Agency (EPA). Modified to depict the levels of achievable and program potential cases included in this study.

EQUATION 2-1. CORE EQUATION FOR RESIDENTIAL SECTOR TECHNICAL POTENTIAL

TECHNICAL POTENTIAL OF EFFICIENT MEASURES = *Total Number of Households* X *Base Case End Use Intensity (kWh/unit)* X *Saturation Share* X *Remaining Factor* X *Feasibility Factor* X *Savings Factor*

Where…

Base Case Equipment End-Use Intensity = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment end-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

Feasibility Factor = (also functions as the applicability factor) the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install heat pump water heaters in all homes because of space limitations).[10]

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

2.1.5.1 Competing Measures & Interactive Effects Adjustments

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares may be factored into the baseline saturation estimates. For example, nearly all homes can receive insulation, but the analysis will create multiple measure permutations to account for varying impacts of different heating/cooling combinations and will apply baseline saturations to reflect proportions of households with each heating/cooling combination.

Feasibility Factor Adjustment. GDS combines measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat, connected thermostat, and smart thermostat. In general, the models assign the measure with the most savings the greatest feasibility factor in the measure group, with competing measures picking up any remaining share.

In instances where there are two (or more) competing technologies for the same electrical end use, such as heat pump water heaters with different tiers of efficiency, an applicability factor aids in determining the proportion of the available population assigned to each measure. In estimating the technical potential, measures with the most savings are given priority for installation. The applicability factors for Economic Potential and the achievable cases are adjusted to account for cost-effectiveness screening results.

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a smart thermostat are adjusted down to reflect the efficiency gains of installing an efficient air conditioner. The analysis also prioritizes efficiency measures relative to conservation (behavioral) measures. These impacts are accounted for in all phases of estimated potential savings.

2.1.6 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the TRC Test) as compared to conventional supply-side energy resources. Both technical and economic potential ignore market barriers to ensuring actual implementation of energy efficiency. Finally, they typically only consider the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration, program evaluation, etc.) that would be necessary to capture them.

The TRC test calculations in this study follow the prescribed methodology detailed in the latest version of the California Standard Practice Manual (CA SPM). The California Standard Practice Manual establishes standard procedures for cost-effectiveness evaluations for utility-sponsored or public benefits programs and is generally considered to be an authoritative source for defining cost-effectiveness criteria and methodology. This manual is often referenced by many other states and utilities.

The TRC Test was used as the screening test for measure, program, and portfolio cost-effectiveness for inclusion in economic potential and achievable cases. In each year of the analysis, the benefits of each measure are calculated as the cumulative energy and demand impact multiplied by all applicable avoided costs; the net present value of annual lifetime benefits are then compared against the cost of each measure.

All measures that are not found to be cost-effective with a ratio of at least 0.85 based on the results of the measure-level cost effectiveness screening were excluded from the economic potential and achievable cases. Feasibility factors were then re-adjusted and applied to the remaining measures that are cost effective, where appropriate.

2.1.7 Achievable Potential

Achievable potential is the amount of energy (and associated demand) that can realistically be saved given various market barriers and program interventions. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the “program intervention” is modeled to overcome. Additional considerations include political and/or regulatory constraints. GDS developed three achievable potential cases:

- ***High Case Achievable Potential*** estimates achievable potential from aggressive adoption rates based on paying incentives equal to 100% of measure incremental costs and increased program awareness.
- ***2% Council Policy Case*** estimates achievable potential in-line with Council policy, reflecting a 0.2% increase in savings as a percent of sales until savings as a percent of sales achieves 2%.
- ***Reference Achievable Potential*** estimates achievable potential with Entergy paying incentive levels (as a percent of incremental measure costs) and program awareness closely calibrated to historical levels but is not constrained by any previously determined spending levels.

2.1.7.1 Achievable Adoption Rates

The assumed level of customer participation for each energy efficiency measure is a key driver of market potential estimates. To inform estimates of future market adoption, the GDS team relied on both the historical PY9 Entergy programs, Entergy's PY10 through PY12 plan, as well as end-use long-term adoption rate estimates. The use of historical performance and near-term plans as references provides a point-estimate to serve as an initial "ground floor" market adoption rate while the final adoption rates reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

Initial Year Measure Adoption. First year adoption levels were informed by Entergy's PY9's historical adoption rates and PY10 through PY12 planned adoption rates. These guided the starting 2021 adoptions, from which the several achievable adoption scenarios then reflected the various program assumptions in subsequent years.

Long-Term Market Adoption Rates. Long-term market adoption rate estimates were derived from several sources. The Delphi panel provided expert local input to inform both residential and C&I maximum adoption rates under varying incentive levels or simple payback periods. These long-term adoption rates were then adjusted for the 2% Council Policy Case and High Case Achievable Potential, reflecting adjustments in incentives and program effectiveness. The details of the Delphi Panel approach and results are presented in Appendix B. The results of the long-term market adoption rates informed by the Delphi Panels are presented below.

In all technology cases, one can see that measures with lower incentive levels or longer simple payback periods are expected to achieve lower maximum adoption levels than those with higher incentive levels or shorter simple payback periods, indicating the importance of incentives to drive market adoption.

TABLE 2-1. RESIDENTIAL SECTOR MAXIMUM ADOPTION RATES

Generic Measure Description/Category	100% Incentive	75% Incentive	50% Incentive	25% Incentive	0% Incentive
LED/Appliance (ROB)	75.2%	66.5%	56.5%	41.0%	29.0%
HVAC/WH Equip (ROB)	79.0%	66.5%	52.5%	35.8%	22.5%
Early Replacement	46.0%	34.1%	23.0%	11.0%	4.2%
Retrofit ($)	67.5%	62.5%	46.2%	34.0%	25.6%
Retrofit ($$)	65.0%	52.6%	40.7%	24.6%	15.0%
Retrofit ($$$)	49.9%	35.0%	22.6%	12.0%	4.6%

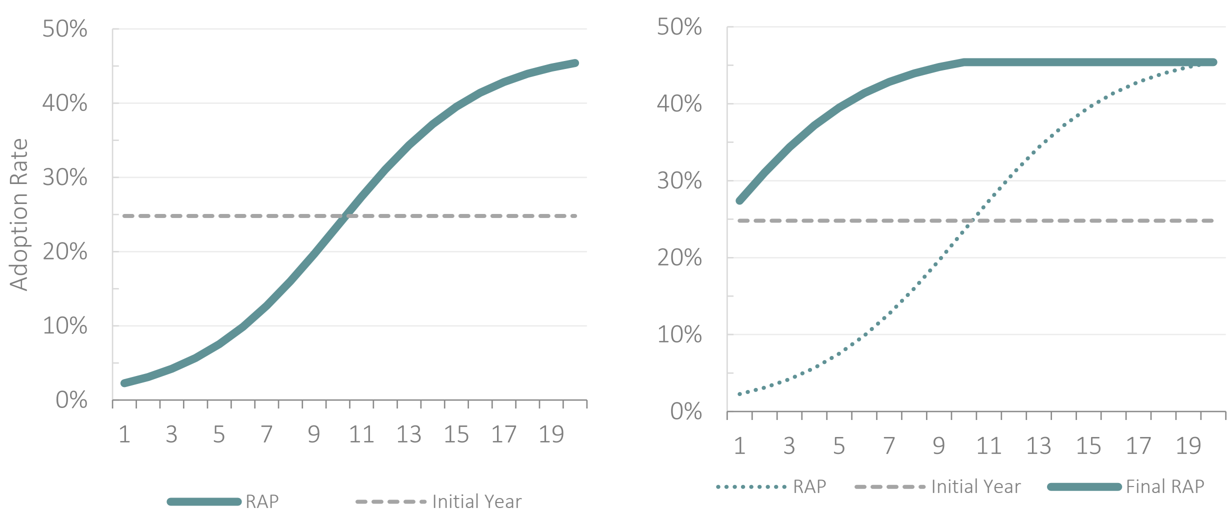
TABLE 2-2. C&I SECTOR MAXIMUM ADOPTION RATES

Generic Measure Description/Category	0 Year Payback	1 Year Payback	2 Year Payback	4 Year Payback	8 Year Payback
Lighting / ROB $	80.5%	64.4%	50.3%	38.5%	22.9%
HVAC / ROB $$$	83.0%	59.3%	49.4%	37.6%	24.7%
Early Replacement	36.8%	24.6%	15.7%	9.3%	8.8%
SEM/RCx/EMS / Retrofit $	71.0%	55.2%	44.3%	30.5%	21.4%
Cooking / Compressed Air / Industrial Process	76.7%	49.7%	43.9%	38.5%	26.7%
Retrofit $$$	68.3%	42.0%	37.0%	31.6%	19.1%

Adoption Curves. Once the initial year adoption rate and long-term adoption rates are determined, the remaining step was to determine the rate and duration to get from the first year adoption rate to the long term, which was never treated as greater than the 20 year forecast period. The 1st year point estimate (based on the historical calibration targets) was then used to establish the number of years remaining to reach the long-term adoption rate and the slope of adoption.

In the illustrative figure below (Figure 3-3), the initial s-shaped curve (left chart) reaches a long-term adoption rate of 45% of the annual eligible market over a period of 20 years. However, the initial year calibration indicates that the program has historically reached 25% of the annual eligible market. The curve (right chart) is reset so that the initial year adoption aligns with recent historical levels and the 45% long-term adoption rate target is reached in a shortened period of 9 years.

FIGURE 2-4. EXAMPLE INITIAL ADOPTION CURVE (LEFT) AND FINAL ADJUSTED ADOPTION CURVE (RIGHT) FOR ESTIMATING ACHIEVABLE POTENTIAL



2.1.7.2 Program Costs

GDS conducted a review of Entergy's PY9 program costs and savings. Program costs were split between incentive and non-incentive costs and converted to a dollars per kWh metric. This metric allows for scaling program costs to different levels of energy savings and adoption cases. The key metrics, for each of the residential and C&I sectors include:

- Verified Energy Savings, by sector, for PY9
- Non-incentive costs ($ per 1st-year kWh saved) from PY9
    - $0.105 per kWh savings residential
    - $0.11 per kWh savings C&I

The incentive costs were developed for each case and then combined with the non-incentive per kWh budget to arrive at annual budgets that would meet each case's kWh savings.

Consistent with National Action Plan for Energy Efficiency (NAPEE) guidelines[11], utility non-incentive costs were also included in the overall assessment of cost-effectiveness in the economic potential and

[11] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.

achievable cases. Non-incentive costs were escalated by the rate of inflation, from the Initial Year (2021, PY11).

2.2 ENERGY EFFICIENCY POTENTIAL FINDINGS

Figure 2-5 provides the technical, economic, HCAP, RAP, and 2% policy case results for the 3-year, 10-year, and 20-year timeframes. Over the duration of the study timeframe the technical and economic potential reach 43% and 38% of forecasted sales, respectively. This relatively close alignment of technical and economic potential suggests that a large portion of the technical potential is cost-effective. The HCAP case reaches 29% of forecasted ENO 2041 sales (or 76% of the economic potential). The RAP and 2% policy case achieve respectively to 21% and 23% of forecasted sales over the study timeframe. The gap between economic potential and the achievable policy cases represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

FIGURE 2-5. OVERVIEW OF ELECTRIC ENERGY EFFICIENCY POTENTIAL

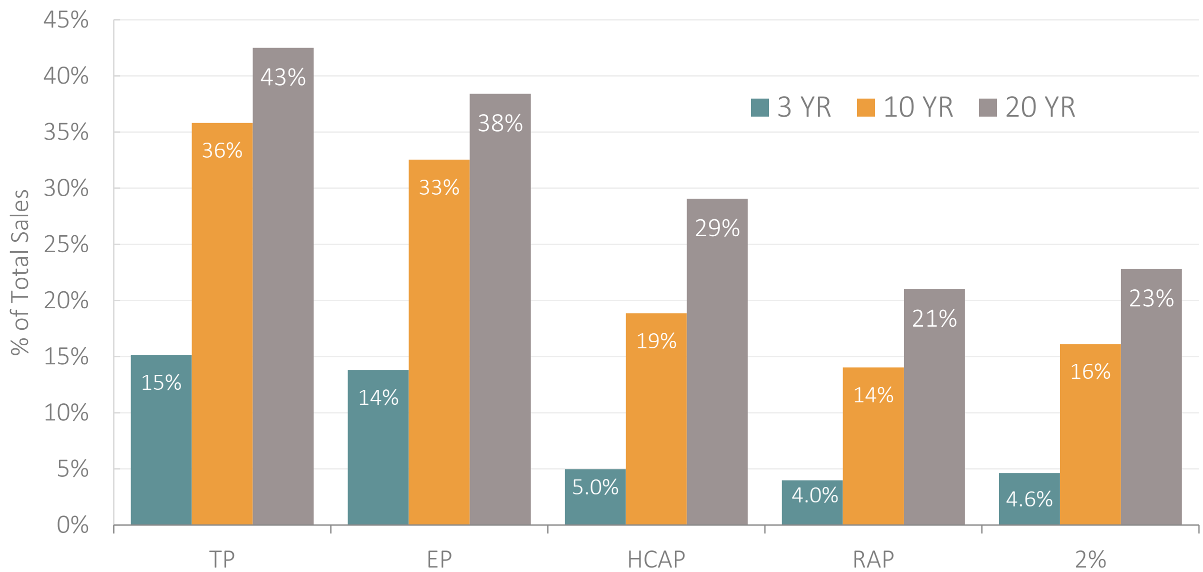


Table 2-3 shows the incremental energy and demand savings per year for each case. Figure 2-6 shows the cumulative annual energy savings for each case.

TABLE 2-3. ANNUAL INCREMENTAL ACHIEVABLE ENERGY EFFICIENCY SAVINGS BY CASE

Year	Energy (GWh/Year)			Peak Demand (MW)		
	RAP	HCAP	2%	RAP	HCAP	2%
2021	79	98	86	17	19	19
2022	87	106	98	21	23	24
2023	90	110	110	22	26	27
2024	91	115	116	23	26	29
2025	94	121	116	24	27	30
2026	99	128	116	27	30	31
2027	103	136	116	30	33	33
2028	106	142	109	33	35	32
2029	107	145	111	35	37	34
2030	105	143	109	36	38	35

Year	Energy (GWh/Year)			Peak Demand (MW)		
	RAP	HCAP	2%	RAP	HCAP	2%
2031	101	137	106	35	37	35
2032	94	129	100	33	35	33
2033	86	118	92	30	32	30
2034	79	106	84	26	28	26
2035	71	96	76	23	24	23
2036	72	99	79	20	22	21
2037	66	90	71	17	19	18
2038	60	80	66	15	16	16
2039	56	75	63	13	15	14
2040	53	71	58	11	13	12

FIGURE 2-6. CUMULATIVE ANNUAL ACHIEVABLE ELECTRIC ENERGY SAVINGS POTENTIAL BY CASE

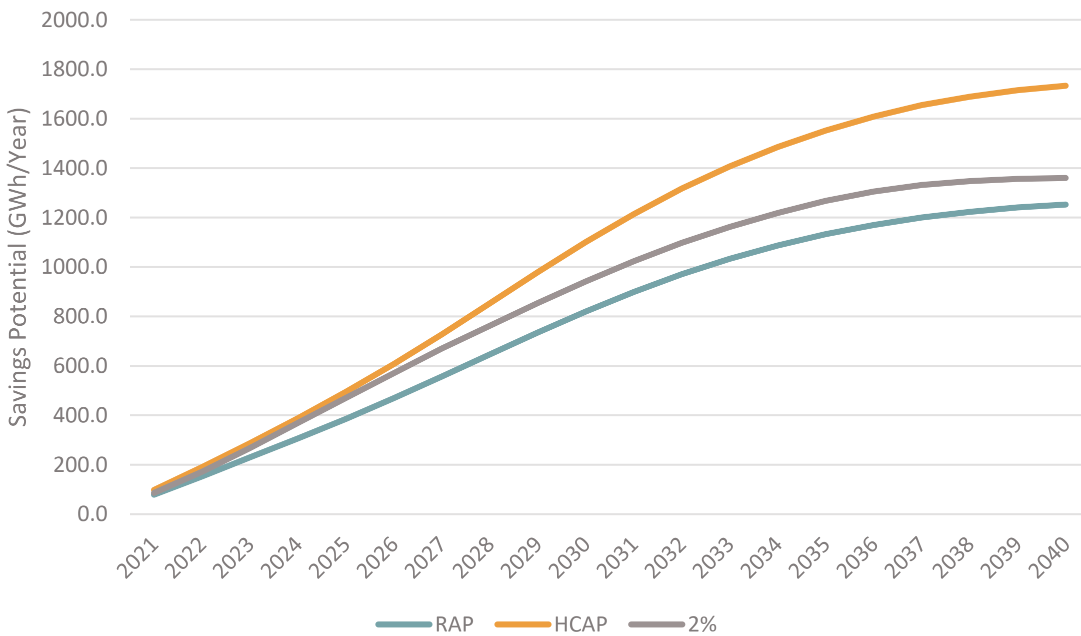


Table 2-4 shows the incremental electric energy achievable savings as a percentage of ENO's total sales for each case. For the 2% case, savings increase by 0.2% a year in 2021-2023, and 2% savings per year from 2024-2027. Savings decrease over time as energy efficiency potential becomes more limited in the second decade on an incremental annual basis. The 2% policy case is slightly higher than the RAP case because of higher incentives and increased marketing awareness. The HCAP, which assumes incentives that are equal to the incremental measure cost, can sustain 2% savings over a longer period, though again, savings decrease during the second decade as remaining efficiency potential from measures included in this analysis are depleted. However, over a long-term study horizon, new technologies and program designs could result in additional cost-effective energy savings.

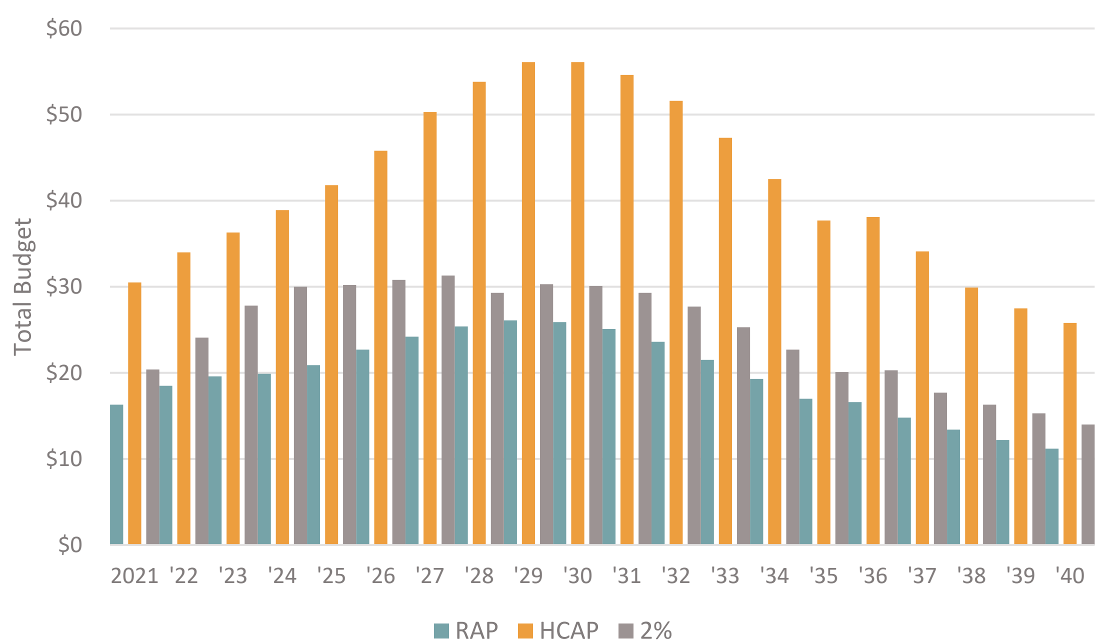
TABLE 2-4. ANNUAL INCREMENTAL ELECTRIC ENERGY SAVINGS POTENTIAL (AS A % OF SALES) BY CASE

Year	RAP	HCAP	2%
2021	1.4%	1.7%	1.5%
2022	1.5%	1.8%	1.7%
2023	1.6%	1.9%	1.9%
2024	1.6%	2.0%	2.0%

Year	RAP	HCAP	2%
2025	1.6%	2.1%	2.0%
2026	1.7%	2.2%	2.0%
2027	1.8%	2.3%	2.0%
2028	1.8%	2.4%	1.9%
2029	1.8%	2.5%	1.9%
2030	1.8%	2.4%	1.9%
2031	1.7%	2.3%	1.8%
2032	1.6%	2.2%	1.7%
2033	1.5%	2.0%	1.6%
2034	1.3%	1.8%	1.4%
2035	1.2%	1.6%	1.3%
2036	1.2%	1.7%	1.3%
2037	1.1%	1.5%	1.2%
2038	1.0%	1.3%	1.1%
2039	0.9%	1.3%	1.0%
2040	0.9%	1.2%	1.0%

The total costs for each case are provided in Figure 2-7. Total costs are comparable between the RAP and 2% policy case, with differences aligned with the savings achieved in both cases. However, the HCAP case demonstrates significantly higher costs as a result of the corresponding modeling assumption that incentives are equivalent to 100% of the modeled incremental measure cost. Overall, incentives average between 50%-55% in the RAP and 2% policy cases. In the HCAP case, incentives are roughly 70% of the overall costs.

FIGURE 2-7. ANNUAL BUDGETS FOR ACHIEVABLE POTENTIAL BY CASE ($ MILLIONS/YEAR)



GDS calculated TRC ratios for each measure based on the present value of the benefits and costs over each measure's effective useful life. GDS also examined the overall electric energy efficiency portfolios TRC ratio for each policy case. The TRC ratios for these cases are provided in Table 2-5. Despite the large increase in incentives noted above, the HCAP case remains cost effective. It is important to note that incentives are considered a transfer payment under the TRC Test and do not directly affect the TRC Test result. However, as noted from the Delphi Panel research, increased incentives are expected to result in increased market adoption rates for all measures and results in less cost-effective measures included in the overall analysis.

TABLE 2-5. PORTFOLIO TRC BENEFIT-COST RATIOS FOR ACHIEVABLE POTENTIAL BY CASE

Year	RAP	HCAP	2%
2021-2040	2.6	1.8	2.5

2.2.1 Residential Results

Figure 2-8 provides a summary of the cumulative annual electric energy efficiency potential results across the 2021-2023 (3YR) timeframe, as well as for 2030 (10th-year) and 2040 (20th-year). The technical potential represents 47% of residential sales in 2040. Economic potential, a subset of technical, represents 41% of sales. Achievable potential in the 20th year ranges from 26%-31% by case.

FIGURE 2-8. OVERVIEW OF RESIDENTIAL ELECTRIC ENERGY EFFICIENCY POTENTIAL

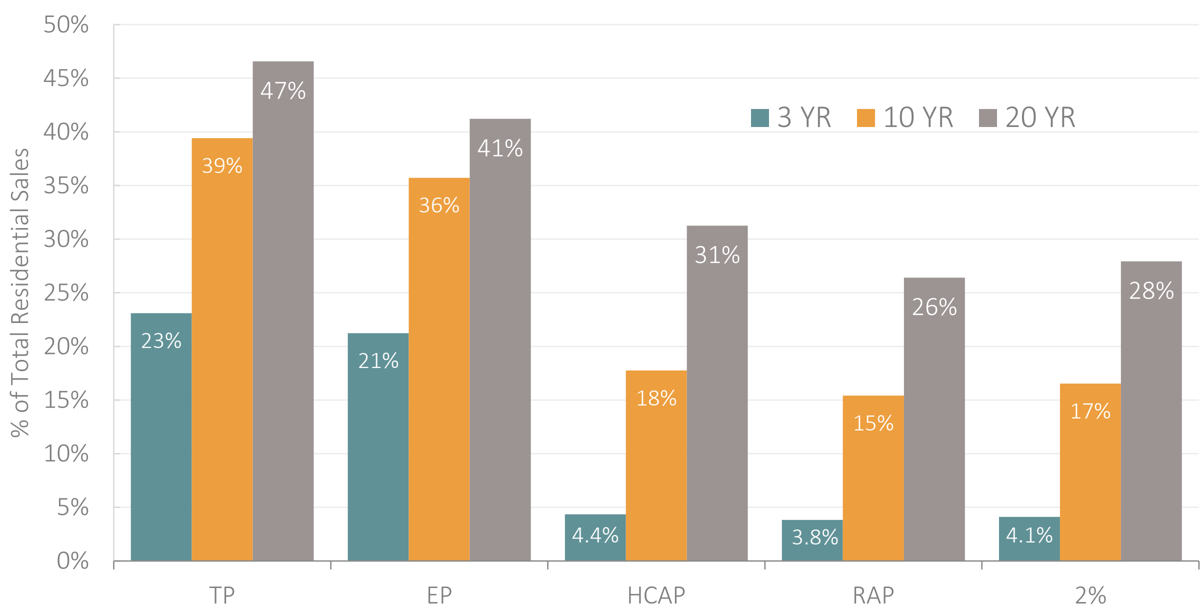


Table 2-7 shows the residential incremental electric energy achievable savings, by case, as a percentage of ENO's total residential sales. The reference case achievable averages 2.1% of residential sales. The high case achievable averages 2.4% of residential sales, and the 2% case averages 2.2% of residential sales.

TABLE 2-6. INCREMENTAL ANNUAL RESIDENTIAL ELECTRIC ENERGY ACHIEVABLE POTENTIAL SAVINGS BY CASE (AS A % OF RESIDENTIAL SALES)

Year	RAP	HCAP	2%
2021	1.47%	1.64%	1.48%
2022	1.70%	1.89%	1.78%
2023	1.80%	2.00%	1.98%
2024	1.87%	2.08%	2.12%
2025	1.97%	2.19%	2.22%
2026	2.17%	2.42%	2.38%
2027	2.37%	2.64%	2.53%
2028	2.55%	2.86%	2.55%
2029	2.68%	3.01%	2.69%

Year	RAP	HCAP	2%
2030	2.72%	3.07%	2.75%
2031	2.74%	3.10%	2.79%
2032	2.64%	3.02%	2.69%
2033	2.46%	2.83%	2.51%
2034	2.28%	2.64%	2.32%
2035	2.09%	2.43%	2.14%
2036	1.95%	2.30%	2.02%
2037	1.80%	2.14%	1.87%
2038	1.65%	1.99%	1.75%
2039	1.57%	1.92%	1.69%
2040	1.48%	1.82%	1.59%

Figure 2-13 provides the cumulative annual achievable potential across the 20-yr timeframe of the study. The reference case and 2% policy case achieve similar levels of potential by the 20th year, with the 2% policy case achieving the savings at an overall quicker pace in the first decade. The HCAP case aligns with the 2% policy case in early years but achieves nearly 31% of residential sector sales by 2040.

FIGURE 2-9 RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL ACHIEVABLE SAVINGS POTENTIAL BY CASE

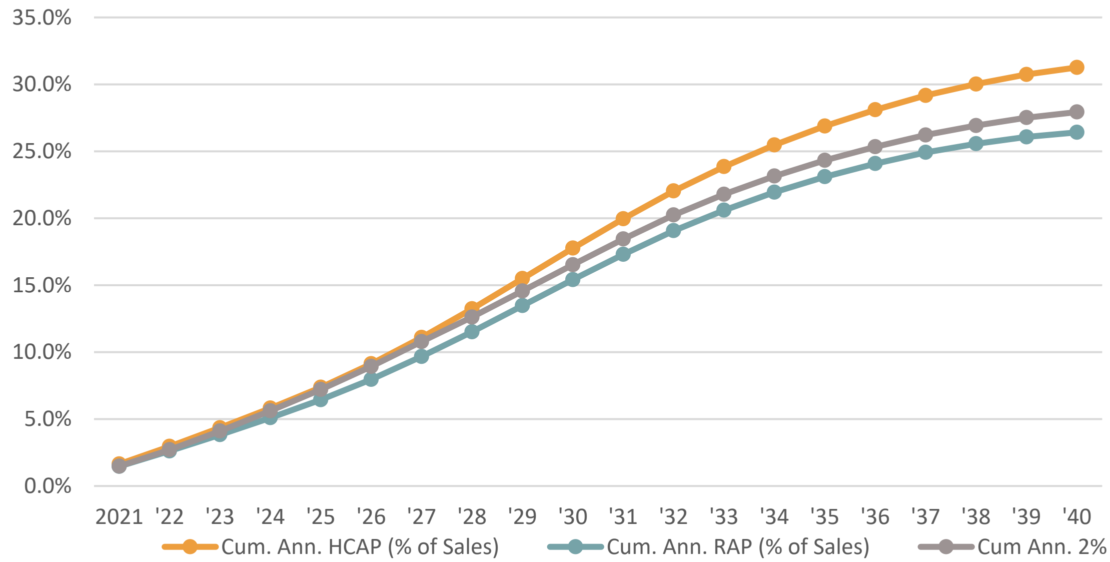


Figure 2-10 and Figure 2-11 provide a breakdown of the RAP potential in 2040 across end-uses and building type market segments. In the near-term, behavioral savings provide the greatest savings opportunity at 37% of the total in 2021. Over the long-term, HVAC measures and Building Envelope provide the greatest cumulative annual savings opportunity at close to 70% of the total by 2040. Existing single-family non-low-income ("NLI") homes provide the greatest potential among the housing type-income type market segments. Over time, the low-income segments and new construction segment grow as a proportion of the total, from 22% in 2021 to 26% in 2040.

FIGURE 2-10. RESIDENTIAL POTENTIAL BY END-USE AND BUILDING TYPE – RAP 2021

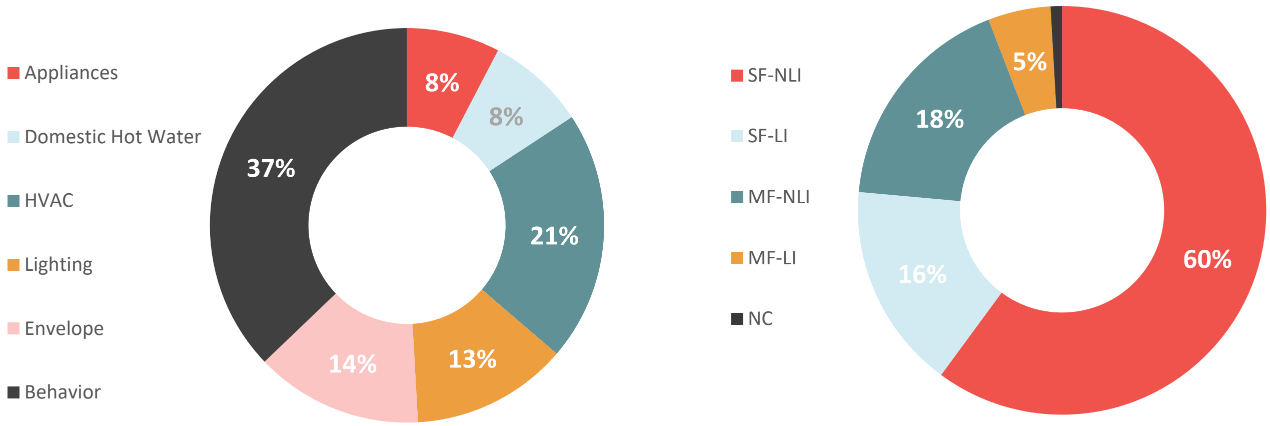
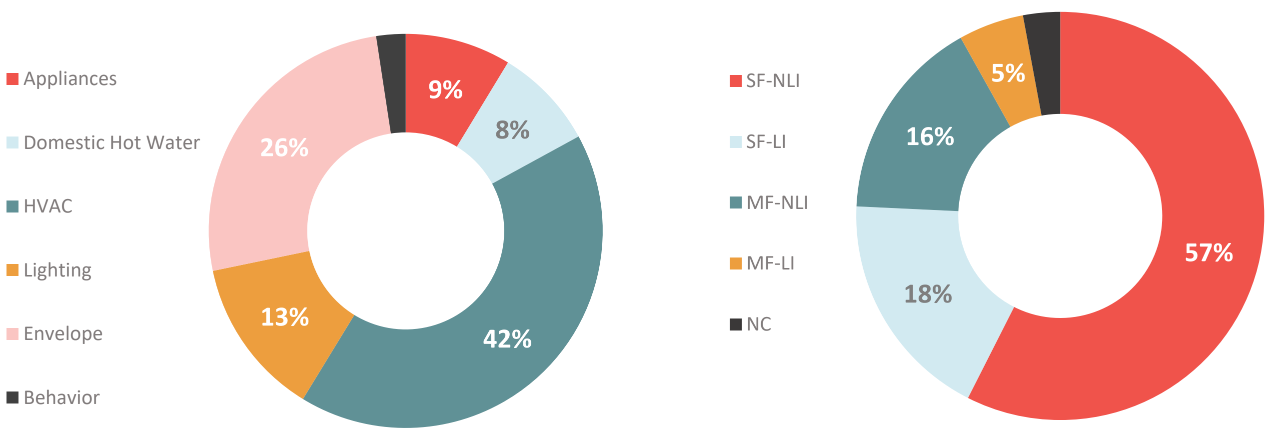


FIGURE 2-11. RESIDENTIAL POTENTIAL BY END-USE AND BUILDING TYPE – RAP 2040



2.2.2 C&I Energy Efficiency Potential

Figure 2-12 provides a summary of the cumulative annual electric energy efficiency potential results across the 2021-2023 (3YR) timeframe, as well as for 2030 (10th-year) and 2040 (20th-year). The technical potential represents 40% of C&I sales in 2040. Economic potential, a subset of technical, represents 37% of sales. Achievable potential in the 20th year ranges from 18%-28% by case.

FIGURE 2-12. OVERVIEW OF C&I ELECTRIC ENERGY EFFICIENCY POTENTIAL

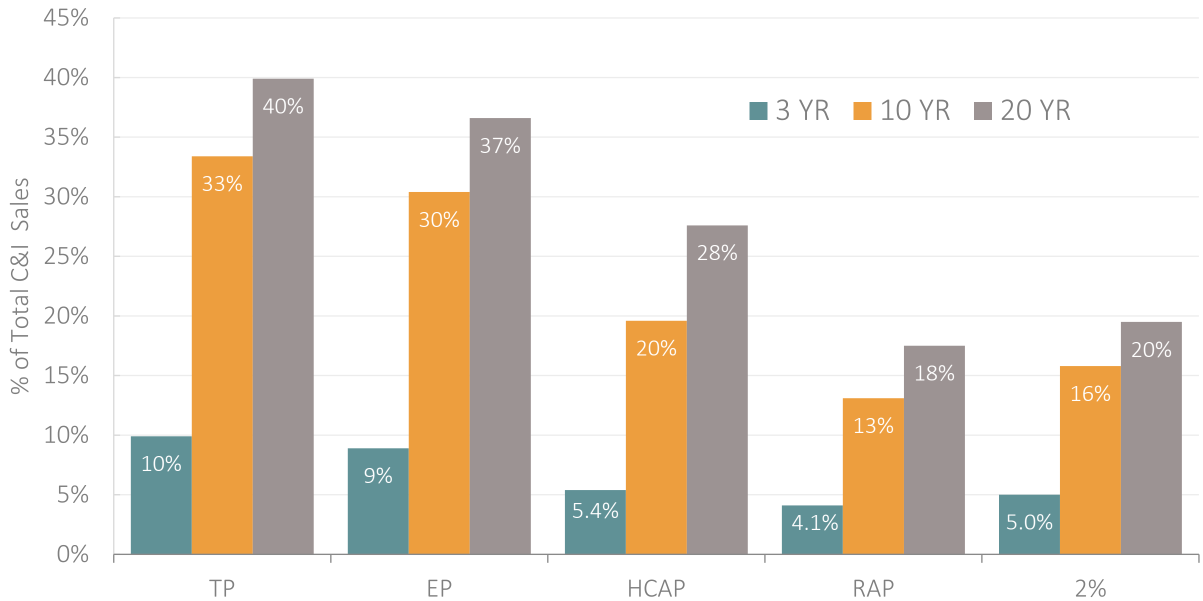


Table 2-7 shows the C&I incremental electric energy achievable savings, by case, as a percentage of ENO's total C&I sales. The reference case achievable averages 1.0% of C&I sales. The high case achievable averages 1.6% of C&I sales, and the 2% case averages 1.2% of sales. In the 2% case, C&I sector savings alone do not reach 2% of sales; residential and C&I savings need to be combined to meet the 2% goal.

TABLE 2-7. INCREMENTAL ANNUAL C&I ELECTRIC ENERGY ACHIEVABLE POTENTIAL SAVINGS BY CASE (AS A % OF C&I SALES)

Year	RAP	HCAP	2%
2021	1.3%	1.8%	1.5%
2022	1.4%	1.8%	1.6%
2023	1.4%	1.9%	1.8%
2024	1.4%	1.9%	1.9%
2025	1.4%	2.0%	1.9%
2026	1.4%	2.1%	1.8%
2027	1.4%	2.2%	1.7%
2028	1.3%	2.2%	1.4%
2029	1.3%	2.1%	1.4%
2030	1.2%	2.0%	1.3%
2031	1.0%	1.8%	1.2%
2032	0.9%	1.6%	1.1%
2033	0.8%	1.4%	0.9%
2034	0.7%	1.3%	0.8%
2035	0.6%	1.1%	0.7%
2036	0.7%	1.3%	0.9%
2037	0.7%	1.1%	0.8%
2038	0.6%	0.9%	0.7%
2039	0.5%	0.8%	0.6%
2040	0.5%	0.8%	0.6%

Figure 2-13 provides the cumulative annual achievable potential across the 20-yr timeframe of the study. The reference case and 2% policy case achieve similar levels of potential by the 20th year, with the 2% policy case achieving the savings at an overall quicker pace in the first decade. The HCAP case aligns with the 2% policy case in early years but achieves nearly 28% of C&I sector sales by 2040, significantly more than the other two achievable cases.

FIGURE 2-13.C&I ELECTRIC ENERGY CUMULATIVE ANNUAL ACHIEVABLE SAVINGS POTENTIAL BY CASE

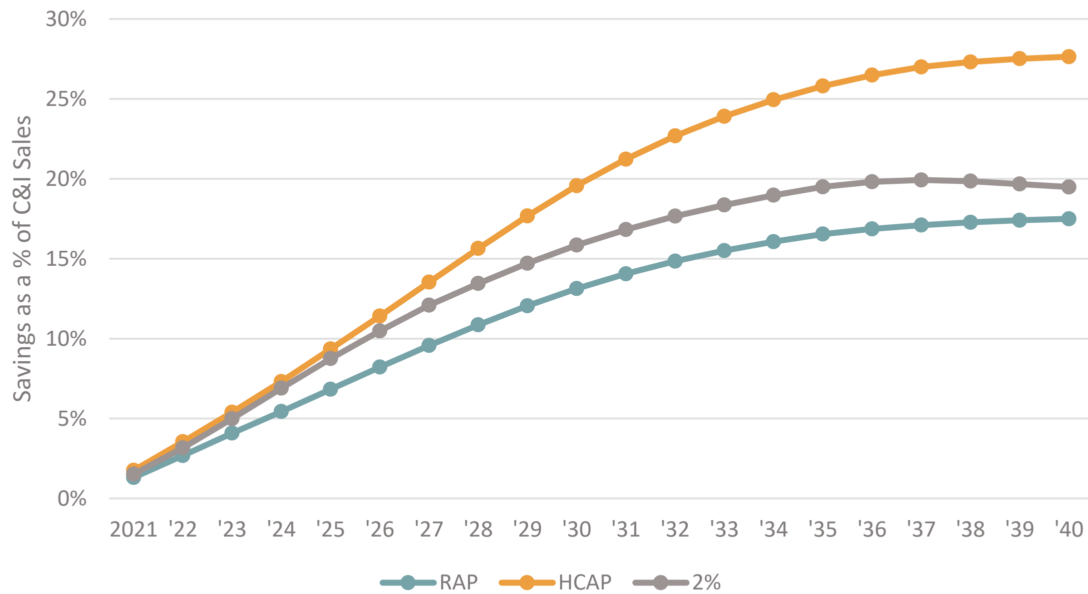
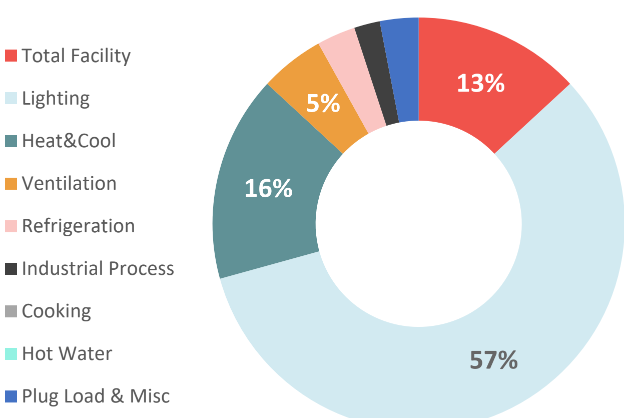


Figure 2-14. provides a breakdown of the RAP potential, across end-uses and building type market segments, in 2021 and 2040, respectively. While lighting is the dominant end-use for C&I savings early on, savings from heating and cooling and total facility energy efficiency measures increase over time and represent significant shares of C&I savings by 2040. Small office and other commercial facilities contribute the most savings for the C&I sector, followed by higher education and lodging. The share of savings by building type does not shift dramatically over the study horizon.

FIGURE 2-14. C&I POTENTIAL BY END-USE AND BUILDING TYPE – RAP 2021



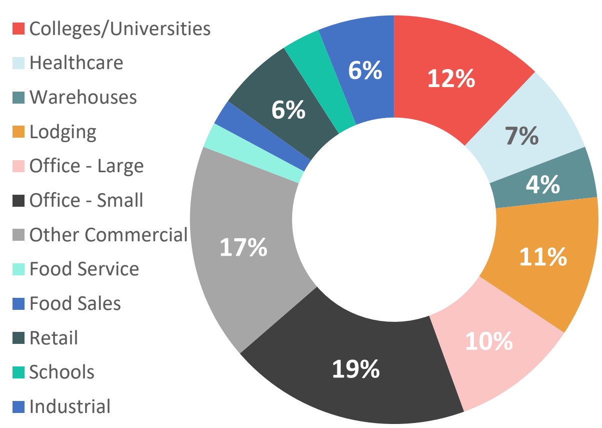
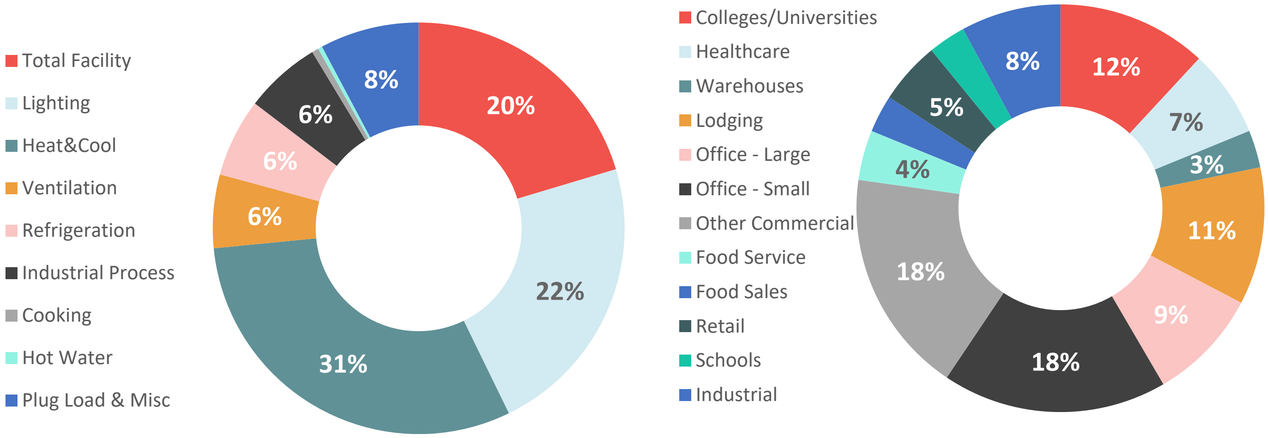


FIGURE 2-15. C&I POTENTIAL BY END-USE AND BUILDING TYPE – RAP 2040 (CUMULATIVE ANNUAL)



3 Demand Response Potential Results

3.1 ANALYSIS APPROACH

This section provides an overview of the demand response potential methodology.

3.1.1 Demand Response Program Options

Table 3-1 a brief description of the demand response (DR) program options considered and identifies the eligible customer segment for each demand response program that was considered in this study. This includes direct load control (DLC), rate, and aggregator design options.

TABLE 3-1. DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

Demand Response Option	Description	Eligible Sectors
DLC of Air Conditioners (Thermostats)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). Controlled via smart thermostat. Participant has option to override control.	Residential, Small C&I
DLC of Air Conditioners (Switches)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). Controlled via load control switch. Participant cannot override control.	Residential, Small C&I
DLC of Electric Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential, Small C&I
DLC of Swimming Pool Pumps	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Residential, Small C&I
DLC of Lighting	A portion of the lighting load (typically 25-33%) is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours	Small C&I
DLC of Room Air Conditioners	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). Controlled via load control switch. Participant cannot override control.	Residential, Small C&I
Critical Peak Pricing with Enabling Technology	A retail rate in which an extra-high price for electricity is provided during critical periods (e.g. 100 hours) of the year. Prices can be fixed or fluctuate with the market. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. Participants are required to have enabling technology (usually a smart thermostat) to help more consistently control the load during peak hours.	Residential, Small C&I, Large C&I

Demand Response Option	Description	Eligible Sectors
Critical Peak Pricing without Enabling Technology	A retail rate in which an extra-high price for electricity is provided during critical periods (e.g. 100 hours) of the year. Prices can be fixed or fluctuate with the market. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis. Participants not are required to have enabling technology.	Residential, Small C&I, Large C&I
Time of Use Rate with Enabling Technology	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. Participants are required to have enabling technology (usually a smart thermostat) to help more consistently control the load during peak hours.	Residential, Small C&I
Time of Use Rate without Enabling Technology	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. Participants are not required to have enabling technology.	Residential, Small C&I
Interruptible Rate	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period. The interruption is mandatory. No buy-through options are available.	Large C&I
Charging of Electric Vehicles Off Peak	Special rate service for electric vehicles that charge off-peak.	Residential, Small C&I
Charging of Electric Utility Vehicles Off Peak	Special rate service for electric vehicles that charge off-peak.	Small C&I
Charging of Golf Carts Off Peak	Special rate service for golf courses that charge electric golf carts off-peak.	Golf Courses
Electric Thermal Storage Rate	The use of a cold storage medium such as ice, chilled water, or other liquids. Off-peak energy is used to produce chilled water or ice for use in cooling during peak hours. The cool storage process is limited to off-peak periods.	Small C&I
Peak Time Rebate	12.9% Demand Response Market Research:Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.	Residential, Small C&I
Capacity Bidding	Flexible bidding program offering qualified businesses payments for agreeing to reduce load when an event is called. Participants make monthly nominations and receive capacity payments based on the amount of capacity reduction nominated each month, plus energy payments based on your actual kilowatt-hour (kWh) energy reduction when an event is called. The amount of capacity nomination can be adjusted on a monthly basis. The program can be Internet-based, providing ready access to program information and ease-of-use. Penalties occur if load nominations are not met.	Large C&I
Demand Bidding	Year-round, flexible, Internet-based bidding program that offers business customers credits for voluntarily reducing power when a DBP event is called.	Small C&I
Battery Storage	Triggers a power dispatch from battery storage systems that are grid-connected during peak load conditions.	Residential, Small C&I

3.1.1.1 Battery Storage Description

The GDS Team collected information on energy storage technologies from the National Renewable Energy Laboratory (NREL) and from battery manufacturers. The GDS Team obtained the information in this section of our report from an NREL report titled "Energy Storage Technology Modeling Input Data Report".[12] Direct quotes from this NREL report are place in quotation marks. "There is dramatic and growing interest in batteries from both distributed and grid-scale project developers amid recent dramatic price drops in Lithium-Ion Battery (LIB) chemistries. Lowerbattery storage costs combined with significant decreases in solar PV and wind costs have led many experts to postulate that the combination of technologies will be market leaders going forward, something the Storage Futures Study (SFS) will explore."

For its Energy Storage Technology Report, NREL collected battery costs for a variety of technologies. The reports states that "LIBs are the current market growth leader in energy storage deployments, with over 99% market share by capacity deployment in the United States in 2019 (Wood Mackenzie P&R/ESA 2020), but many of the other battery technologies have their own advantages and market niches." Throughout this NREL report, the terms "battery cell", "battery module" and "battery pack" are referenced. "These are stages of assembly of the overall battery system. The battery cell is the smallest unit of the battery system. The battery cells are wired together into a battery module of various cells to achieve a desired voltage level. These modules are then combined into a battery pack which contains sensors and controls to monitor the battery and provide safety controls."

3.1.2 Demand Response Potential Assessment Approach Overview

The analysis of DR, where possible, closely followed the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[13] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[14] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits.

The demand response analysis was conducted using the GDS Demand Response Model. The Model determines the estimated savings for each demand response program by performing a review of all benefits and cost associated with each program. GDS developed the model such that the value of future programs could be determined and to help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, coincident peak ("CP") kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between Entergy departments interested in the deployment of demand response resources.

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[12] Augustine, Chad; Blair, Nathan, National Renewable Energy Laboratory, "Energy Storage Technology Modeling Input Data Report". This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

[13] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.

[14] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

The TRC was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

The demand response analysis includes estimates of technical, economic, and achievable potential. Achievable potential is broken into maximum and RAP in this study:

HCAP represents an estimate of the highest cost-effective demand response potential that can be achieved over the 20-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practice" estimate of what could eventually be achieved. HCAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 20-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted HCAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

3.1.3 Avoided Costs

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by Entergy.[15] The primary benefit of demand responses is avoided generation capacity, resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that for load shifting, the energy is shifted with additional energy penalty. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is that would have been consumed during the control period is saved.

3.1.4 Demand Response Program Assumptions

This section briefly discusses the general assumptions and sources used to complete the demand response potential analysis.

Load Reduction: Demand reductions were based on load reductions found in Entergy's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies. DLC and thermostat-based DR options were calculated based on a per-unit kW demand reduction whereas rate-based DR options were assumed to reduce a percentage of the total facility peak load. Table 3-2 shows load reduction assumptions for each DR program option.

TABLE 33-2. DEMAND RESPONSE LOAD REDUCTION IMPACTS

Program	Residential Load Reduction (kW)	C&I Load Reduction (kW)
DLC Central AC (Switch)	0.56	N/A
DLC Central AC (Thermostat)	1.0	1.5

[15] Avoided costs are treated as Highly Sensitive Protected Materials and not disclosed in this report.

Program	Residential Load Reduction (kW)	C&I Load Reduction (kW)
DLC Room AC	0.504	N/A
DLC Water Heating	0.4	1.2
DLC Pool Pumps	1.36	N/A
DLC Lighting	N/A	1.97
Interruptible Rate	N/A	209.88
Critical Peak Pricing with Enabling Technology	1.0	5.55
Critical Peak Pricing without Enabling Technology	0.36	1.08
Time of Use with Enabling Technology	0.2	0.84
Time of Use without Enabling Technology	0.16	0.43
Peak Time Rebates	0.4	0.15
Capacity Bidding	N/A	35.0
Demand Bidding	N/A	1.54
PEV Charging Rate	0.66	N/A
Utility Vehicle Charging Rate	N/A	0.66
Golf Cart Charging Rate	N/A	42.75
Thermal Electric Storage Cooling Rate	N/A	19.4
Battery Storage	3.0	25.0

Useful Life: The useful life of equipment used in demand response programs, such as load control switches, smart thermostats, or AMI equipment, was determined using TRMs, and data from manufacturers. This useful life was used to determine when equipment needs to be re-installed in the program after the device has failed, therefore adding a second equipment cost. GDS used a useful life of 20 years for AMI meters[16], 11 years for smart thermostats[17], 10 years for level 2 EV chargers[18], and 15 years for load switches.[19]

Equipment and Incentive Costs: Equipment costs were included for each new participant. Incentives were included for all programs in the Base Case. These costs were either on a per participant, per kW or per kWh basis (noted in Table 3-3).[20]

[16] Ameren Illinois AMI Cost/Benefit Analysis, 2012

[17] Illinois Technical Reference Manual 2018

[18] US DOE, Costs Associated with Non-Residential EV Supply Equipment, 2015

[19] Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013

[20] 4 CSR 240-22.050 (3)(G)5A; 4 CSR 240-22.050 (3)(G)5B

TABLE 33-3. ASSUMED EQUIPMENT AND INCENTIVE COSTS

Sector	Program	Equipment & Installation Cost	Incentive Cost
Residential	DLC Central AC (Switch)	$295	$40/participant-year
	DLC Central AC (Thermostat)	$100	$40/participant-year
	DLC Room AC	$295	$40/participant-year
	DLC Water Heating	$295	$40/participant-year
	DLC Pool Pumps	$146	$40/participant-year
	Critical Peak Pricing with Enabling Technology	$100 for thermostat	0
	Critical Peak Pricing without Enabling Technology	$0	0
	Time of Use with Enabling Technology	$100 for thermostat	0
	Time of Use without Enabling Technology	$0	0
	Peak Time Rebates	$0	$0.75/kWh-year
	PEV Charging Rate	$0	0
	Battery Storage	Starts at $12.385 in 2021 and decreases to $8,049 in 2040 (based on NREL forecast)	0
C&I	DLC Central AC (Thermostat)	$100	$40/participant-year
	DLC Water Heating	$295	$40/participant-year
	DLC Lighting	$1,900	$40/participant-year
	Interruptible Rate	$0	$23.5/kW-Yr
	Critical Peak Pricing with Enabling Technology	$100 for thermostat	0
	Critical Peak Pricing without Enabling Technology	$0	0
	Time of Use with Enabling Technology	$100 for thermostat	0
	Time of Use without Enabling Technology	$0	0
	Peak Time Rebates	$0	$0.75/kWh-year
	Capacity Bidding	$0	$8.5/kW-year
	Demand Bidding	$0	$0.50/kWh-year
	Utility Vehicle Charging Rate	$0	0
	Golf Cart Charging Rate	$9,000	4500

Sector	Program	Equipment & Installation Cost	Incentive Cost
	Thermal Electric Storage Cooling Rate	$55,712	0
	Battery Storage	Starts at $299,036 in 2021 and decreases to $203,351 in 2040 (based on NREL forecast)	0

Program Costs: One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost. It was assumed that there would be a cost of $50[21] per new participant for marketing for the DLC programs. Marketing costs are assumed to be 33.3% higher for HCAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

Eligible Control Units: The number of control units per participant was assumed to be one for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per home was assumed to be 1.72 thermostats[22].

Eligible Market Size: For direct load control programs, the size of the eligible market was determined by multiplying the forecast of Entergy's customers by the saturation of the end use to be controlled. End use saturations were obtained from the 2016 RASS analysis provided by ENO as well as data from CBECS[23] for the C&I programs.

Entergy expects AMI infrastructure to be fully deployed in 2022, with saturation being at 99% in 2021. Two-way communication is fundamental for pricing programs and AMI meters allow for hourly load data to be read and transmitted to the utility. Since it is imperative that hourly data must be read for pricing programs, GDS assumed AMI meters were required to participate in the pricing programs.

3.1.5 DR Program Adoption Levels

Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS reviewed industry data and program adoption levels from several utility DR programs. As noted earlier in this section, for direct load control programs, HCAP participation rates rely on industry best adoption rates and RAP participation rates are based on industry average adoption levels. For the rate programs, the HCAP steady-state participation rates assumed programs were opt-out based and RAP participation assumed opt-in status.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows a "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure 3-1. Illustration of S-Shaped Market Adoption Curve). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate. Table 3-4 provides the long-term adoption rates for HCAP and RAP.

[21] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011

[22] EIA RECS database

[23] https://www.eia.gov/consumption/commercial/data/2012/

FIGURE 33-1. ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE

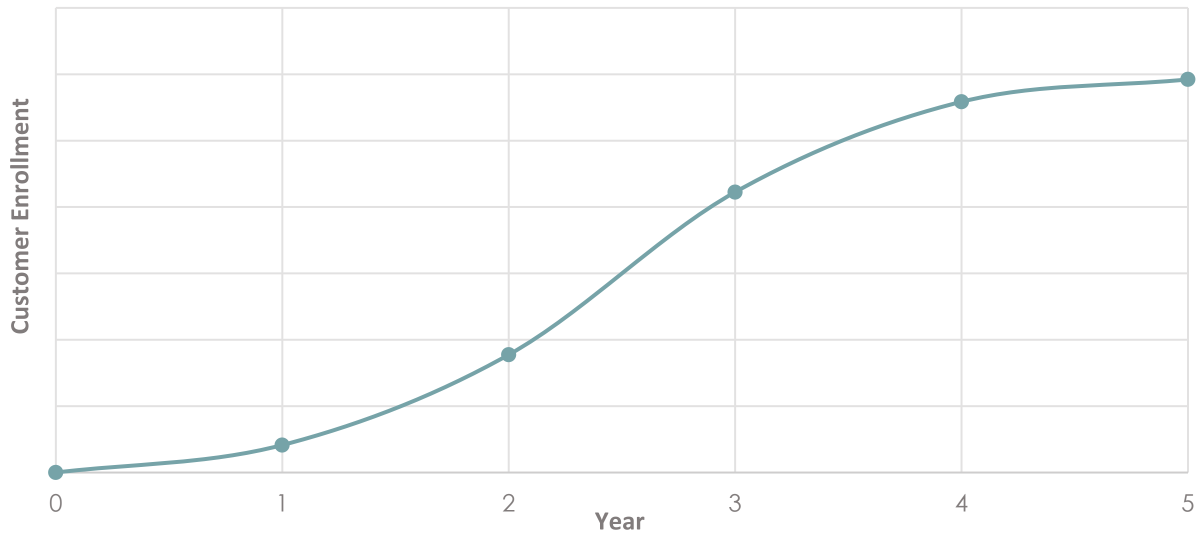


TABLE 33-4. ADOPTION RATES

Sector	Program	Steady State HCAP Adoption Rate	Steady State RAP Adoption Rate
Residential	DLC Central AC (Switch)	10%	7%
	DLC Central AC (Thermostat BYOT)	12%	8%
	DLC Central AC (Thermostat Utility Sponsored)	12%	8%
	DLC Room AC	31%	20%
	DLC Water Heating	36%	23%
	DLC Pool Pumps	38%	19%
	Critical Peak Pricing with Enabling Technology	91%	22%
	Critical Peak Pricing without Enabling Technology	82%	17%
	Time of Use with Enabling Technology	38%	14%
	Time of Use without Enabling Technology	85%	28%
	Peak Time Rebates	93%	21%
	PEV Charging Rate	94%	57%
	Battery Storage	1.1%	1.1%
C&I	DLC Central AC (Thermostat BYOT)	10%	4%
	DLC Central AC (Thermostat Utility Sponsored)	10%	4%
	DLC Water Heating	16%	7%
	DLC Lighting	19%	8%
	Interruptible Rate	21%	14%

Sector	Program	Steady State HCAP Adoption Rate	Steady State RAP Adoption Rate
	Critical Peak Pricing with Enabling Technology	69%	20%
	Critical Peak Pricing without Enabling Technology	63%	18%
	Time of Use with Enabling Technology	20%	7%
	Time of Use without Enabling Technology	74%	13%
	Peak Time Rebates	71%	22%
	Capacity Bidding	21%	3%
	Demand Bidding	8%	1%
	Utility Vehicle Charging Rate	94%	57%
	Golf Cart Charging Rate	81%	16%
	Thermal Electric Storage Cooling Rate	81%	16%
	Battery Storage	9.7%	9.7%

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a customer cannot elect to participate in both DLC programs and rate programs and claim savings from both programs for curtailing the same end use. One cannot save a kW of load in a specific hour more than once. In general, the hierarchy of demand response programs is accounted for by subtracting the number participants in a higher priority program from the eligible market for a lower priority program. Table 3-5 shows the hierarchy for each sector, ordered in decreasing priority.

TABLE 33-5. DR HIERARCHY FOR EACH SECTOR

Order	Residential Hierarchy	C&I Hierarchy
1	Direct Load Control	Direct Load Control
2	Critical Peak Pricing	Interruptible Rate
3	Peak Time Rebate	Capacity Bidding
4	Time of Use	Critical Peak Pricing
5		Time of Use
6		Peak Time Rebate

3.2 DEMAND RESPONSE POTENTIAL

This section provides results for the demand response study by sector as well as the total.

3.2.1 Residential Demand Response Potential

Figure 3-2 shows the residential HCAP demand response potential. The total residential HCAP potential in 2040 is 159 MW. The program with the largest potential is Critical Peak Pricing with 116 MW of potential. Figure -3 shows the residential RAP demand response potential. The total residential RAP potential in 2040 is 79 MW, with Critical Peak Pricing once again being the program with the largest potential at 37 MW. These demand reduction values are presented at the customer meter level of the Entergy New Orleans grid.

FIGURE 33-2. SUMMER PEAK MW RESIDENTIAL SECTOR HCAP POTENTIAL

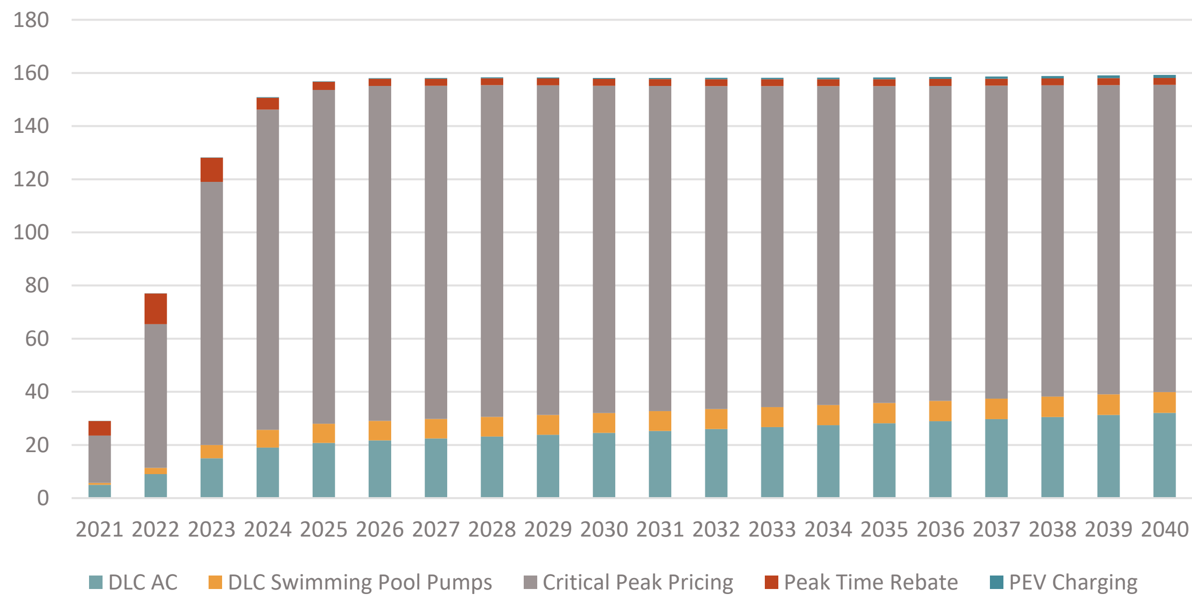
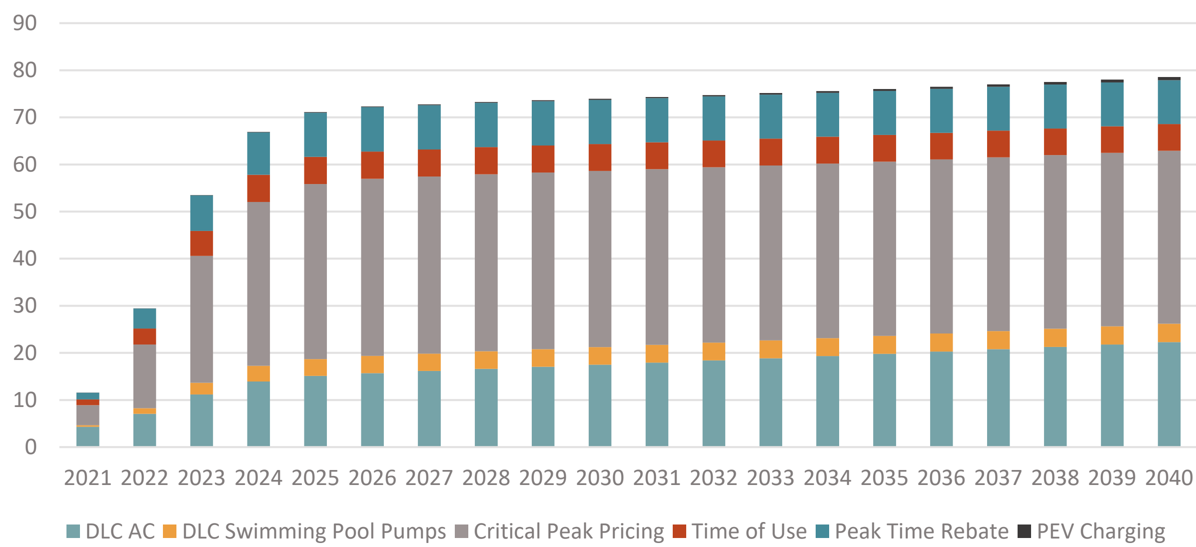


FIGURE 33-3. SUMMER PEAK MW RESIDENTIAL SECTOR RAP POTENTIAL



3.2.2 C&I Demand Response Potential

Figure 3-4 shows the C&I sector HCAP demand response potential. The total C&I sector HCAP potential in 2040 is 119 MW. The program with the largest potential is for interruptible rater for large C&I customers, with a potential of 36 MW. Entergy New Orleans already has a handful of customers on this rate program. Figure 3-5 shows the C&I sector RAP demand response potential. The total potential for C&I RAP in 2040 is 51 MW. The interruptible rate program is once again the program with the largest potential, at 24 MW. These demand reduction values are present at the customer meter level of the Entergy New Orleans grid.

FIGURE 33-4. SUMMER PEAK MW C&I SECTOR HCAP POTENTIAL

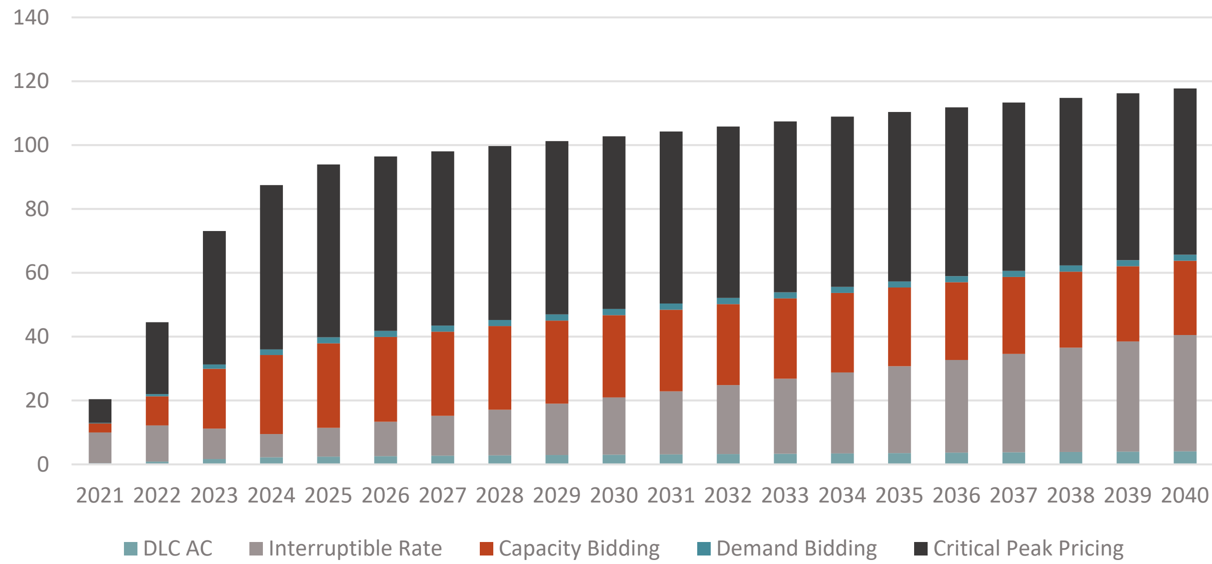
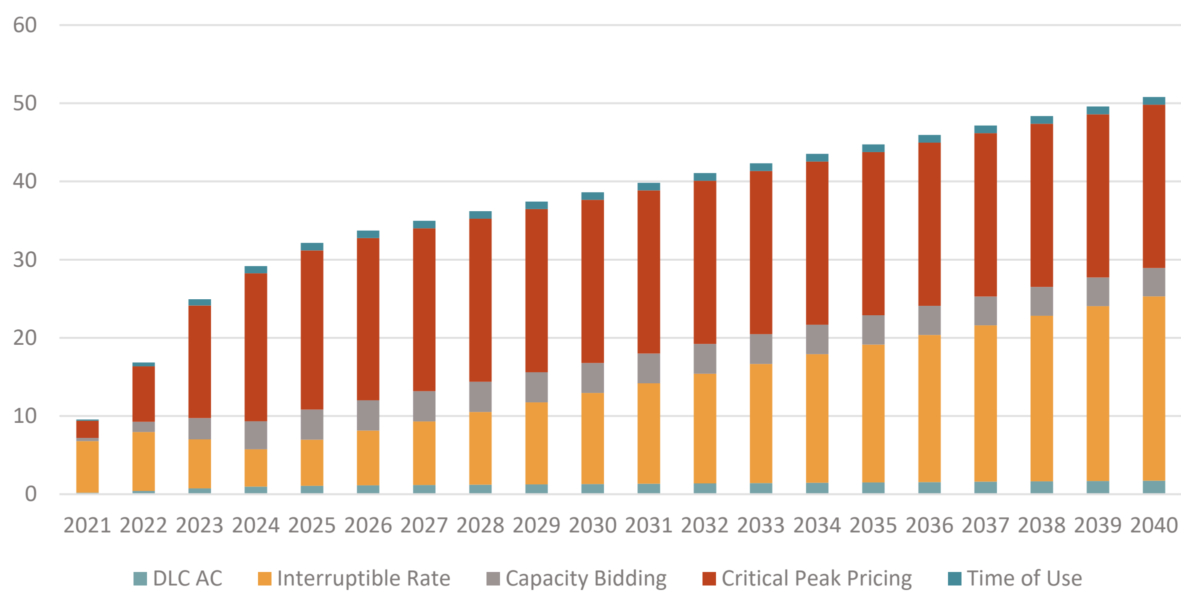


FIGURE 33-5. SUMMER PEAK MW C&I SECTOR RAP POTENTIAL



3.2.3 Total Demand Response Potential

Figure 3-6 shows the total annual demand response RAP potential by sector. The total RAP potential in 2040 is 130 MW. These demand reduction values are present at the customer meter level of the Entergy New Orleans grid. Figure 3-7 shows the total annual RAP by program as a percentage of peak load. The program with the largest potential is Critical Peak Pricing.

FIGURE 33-6. TOTAL ANNUAL SUMMER PEAK MW RAP POTENTIAL BY SECTOR

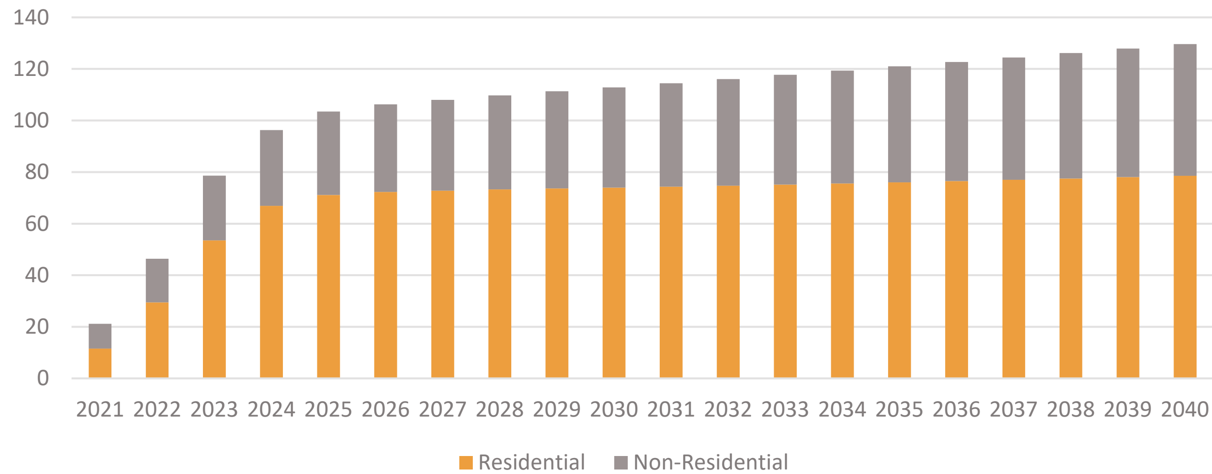
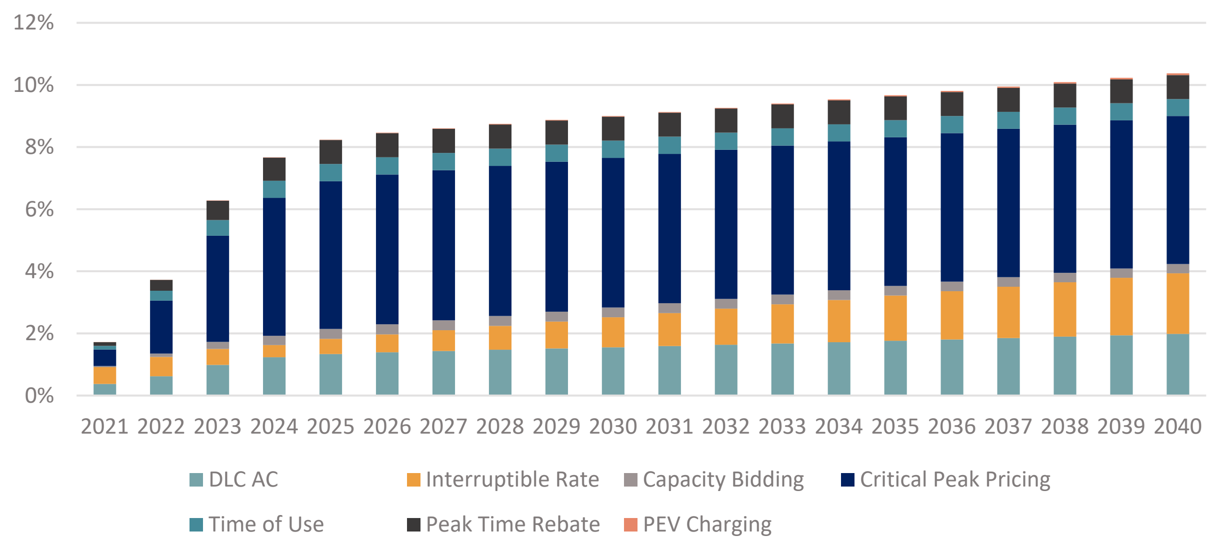


FIGURE 33-7. TOTAL ANNUAL SUMMER PEAK RAP BY PROGRAM AS A PERCENTAGE OF PEAK LOAD



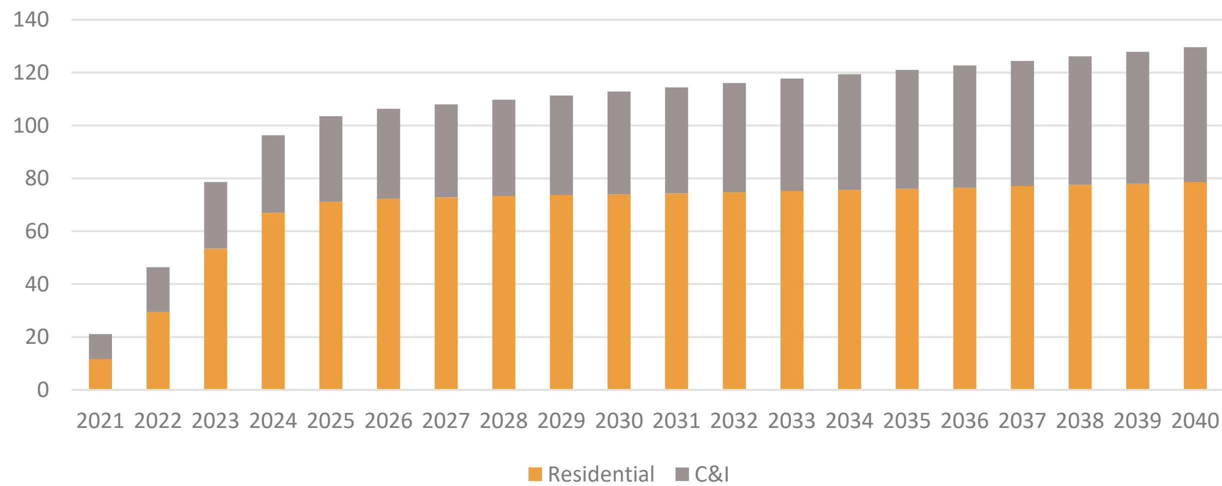
3.2.4 Battery Storage Cumulative Storage Capacity

GDS used an NREL study[24] on battery storage in the US to derive numbers for the DR model. This study provided annual costs for residential and C&I batteries, which are forecasted to decrease over the next 20 years. GDS chose a 3 kW battery to use for residential and 25 kW to use for C&I. This report provides the potential of battery storage for the MISO South region. GDS used this potential along with the MISO South peak load forecast for 2040 to determine the percentage of battery storage.

While demand response control of battery storage is currently not cost-effective, Figure 3-8 shows what the maximum cumulative storage capacity is for battery storage in the ENO service territory. Note that this is the capacity for battery storage, and the potential for demand response control of battery storage would be lower if customers do not want the utility to have control of the battery.

[24] NREL. Storage Futures Study. Economic Potential of Diurnal Storage in the US Power Sector. https://www.nrel.gov/docs/fy21osti/77449.pdf

FIGURE 33-8. BATTERY STORAGE CUMULATIVE STORAGE CAPACITY MW BY SECTOR



3.2.5 Benefits/Costs of Achievable Potential

Cost-effectiveness of demand response measures was determined based on screening with the TRC test. Table -6 and Table -7 shows the residential and C&I benefits, costs, and TRC ratios for each program for HCAP and RAP.

TABLE 3-6. BASE CASE HCAP BENEFITS, COSTS, AND TRC RATIOS

	Program	NPV Benefits	NPV Costs	TRC Ratio
Residential	DLC AC (BYOT Thermostat)	$8,282,842	$6,864,044	1.21
	DLC AC (Utility Incentivized Thermostat)	$12,718,076	$10,961,257	1.16
	DLC AC (Switch)	$4,663,115	$9,467,080	0.49
	DLC Swimming Pool Pumps	$6,176,845	$4,087,418	1.51
	DLC Water Heating	$10,686,860	$25,630,035	0.42
	DLC Room AC	$3,038,000	$6,690,006	0.45
	Critical Peak Pricing with Enabling Tech	$92,568,744	$24,974,819	3.71
	Critical Peak Pricing without Enabling Tech	$11,220,472	$3,176,540	3.53
	Time of Use with Enabling Tech	$238,485	$1,401,024	0.17
	Time of Use without Enabling Tech	$738,024	$1,505,029	0.49
	Peak Time Rebate	$3,928,513	$2,211,947	1.78
	PEV Charging Rate	$646,346	$364,412	1.77
	Battery Storage	$2,607,166	$17,292,056	0.15
C&I	DLC AC (BYOT Thermostat)	$911,072	$581,566	1.57
	DLC AC (Utility Incentivized Thermostat)	$1,636,316	$1,011,003	1.62
	DLC Water Heating	$1,203,528	$1,397,996	0.86
	DLC Lighting	$4,322,474	$8,375,363	0.52
	Interruptible Rate	$17,113,286	$5,125,332	3.34

	Program	NPV Benefits	NPV Costs	TRC Ratio
	Capacity Bidding	$21,232,677	$2,995,908	7.09
	Demand Bidding	$1,595,094	$1,154,212	1.38
	Critical Peak Pricing with Enabling Tech	$40,312,306	$2,112,645	19.08
	Critical Peak Pricing without Enabling Tech	$5,047,977	$633,506	7.97
	Time of Use with Enabling Tech	$51,617	$378,902	0.14
	Time of Use without Enabling Tech	$409,896	$450,396	0.91
	Peak Time Rebate	$90,350	$477,487	0.19
	Utility Vehicle Charging Rate	$200,943	$304,799	0.66
	Golf Cart Charging Rate	$199,542	$10,927,940	0.02
	Thermal Electric Storage Rate	$9,426,433	$25,653,456	0.37
	Battery Storage	$21,776,884	$364,050,561	0.06

TABLE 3-7. BASE CASE RAP BENEFITS, COSTS, AND TRC RATIOS

	Program	NPV Benefits	NPV Costs	TRC Ratio
Residential	DLC AC (BYOT Thermostat)	$6,228,322	$4,957,072	1.26
	DLC AC (Utility Incentivized Thermostat)	$8,831,997	$7,571,258	1.17
	DLC AC (Switch)	$3,204,899	$6,274,269	0.51
	DLC Swimming Pool Pumps	$3,088,423	$2,306,263	1.34
	DLC Water Heating	$6,827,716	$16,282,686	0.42
	DLC Room AC	$1,960,000	$4,460,386	0.44
	Critical Peak Pricing with Enabling Tech	$24,100,284	$6,134,694	3.93
	Critical Peak Pricing without Enabling Tech	$6,955,808	$1,357,557	5.12
	Time of Use with Enabling Tech	$3,023,364	$2,037,774	1.48
	Time of Use without Enabling Tech	$5,052,723	$1,356,088	3.73
	Peak Time Rebate	$7,961,911	$1,426,671	5.58
	PEV Charging Rate	$391,933	$327,422	1.20
	Battery Storage	$2,607,166	$17,276,185	0.15
C&I	DLC AC (BYOT Thermostat)	$410,157	$329,581	1.24
	DLC AC (Utility Incentivized Thermostat)	$688,975	$558,260	1.23
	DLC Water Heating	$526,543	$821,358	0.64
	DLC Lighting	$1,843,137	$3,763,480	0.49
	Interruptible Rate	$11,157,228	$3,352,958	3.33
	Capacity Bidding	$3,161,873	$764,747	4.13
	Demand Bidding	$213,654	$473,240	0.45

	Program	NPV Benefits	NPV Costs	TRC Ratio
	Critical Peak Pricing with Enabling Tech	$14,468,255	$895,193	16.16
	Critical Peak Pricing without Enabling Tech	$2,772,797	$438,048	6.33
	Time of Use with Enabling Tech	$559,366	$390,044	1.43
	Time of Use without Enabling Tech	$781,745	$357,646	2.19
	Peak Time Rebate	$255,683	$420,430	0.61
	Utility Vehicle Charging Rate	$121,848	$300,243	0.41
	Golf Cart Charging Rate	$39,416	$2,396,460	0.02
	Thermal Electric Storage Rate	$1,862,012	$5,290,562	0.35
	Battery Storage	$21,776,884	$364,034,701	0.06

APPENDIX A. Comparison of Recent Potential in Other Jurisdictions

The GDS Team gathered information from fourteen recent and publicly available potential studies conducted in or near the South and Southeast of the U.S. as well as other utilities in the MISO region. These studies and their outcomes can be used to compare the 2021 GDS potential study results for the City of New Orleans' to studies conducted elsewhere. This appendix provides summary information from fourteen studies, providing key metrics and a discussion of nuances that can drive differences between the studies and the interpretation of results.

All fourteen studies were completed between 2015 and 2021. They share common elements – modeling technical, economic, and achievable potential. Most utilize the TRC test for cost-effectiveness screening, one uses the UCT exclusively while others use more than one test. Achievable potential definitions and boundaries differ, but typically have realistic achievable potential estimates constraining a maximum achievable estimate with annual budget limitations or assumptions about market adoption of measures that pass the economic potential screening. Each study provides a different range of detail and information. Table A-1 summarizes key metrics, below. Following Table A-1, each study is summarized and includes additional information for further comparison.

Across the fourteen comparison studies, achievable potential varied as a percent of annual kWh sales and system peak load. Factors that can impact study results include underlying modeling assumptions or unique conditions not present in one study versus another. For example, Louisville Gas & Electric and Kentucky Utilities applied a value of $0 to any capacity savings for energy efficiency and allowed only replace-on-failure (i.e. lost opportunity) measures for the second ten years of their potential studies. Studies with longer time horizons tended to have higher achievable potential savings, reflecting a greater opportunity given more time. Other factors that may shape differences between the studies, but were not readily apparent because consistent information was not always available in the reports, include:

- Forecasts of avoided costs and other major modeling assumptions
- Demographic and firmographic differences between utilities
- Differences in utility climate and weather sensitive loads
- The assumptions used to account for current equipment saturation
- Differences in adoption curves or willingness-to-pay modeling

All of these factors can cause potential study outcomes to differ from the results of the GDS potential study for New Orleans. As a body of recent potential studies, however, they do provide context and perspective useful for making comparisons to the GDS potential study for New Orleans'.

Table A-1 below, provides a summary of key comparison metrics. Beneath the table, each of the utilities included in the comparison has a brief description of its potential study and more detail behind the summary results.

TABLE A-1 KEY POTENTIAL STUDY METRICS

Study Name	ISO	Subject	Year Published	Forecast Period	Market Size	Overall Achievable Potential (forecast period)
Ameren Illinois Demand Side Management Market Potential Study	MISO	Energy Efficiency	2016	2017-2036	2036 Forecast: Res: 11,300 GWh C&I: 24,000 GWh	RAP[25]: 12.5% MAP[26]: 16.4%
Arkansas Energy Efficiency Potential Study	MISO (mostly)	Energy Efficiency (statewide, IOUs only)	2015	2016-2025	2016 Statewide: C&I: ~14,000 GWh Res: ~11,500 GWh	Higher $: 9.0% Current $:7.8% Lower $:5.7%
		Demand Response (statewide, IOUs only)			Not presented for DR	9%
ComEd Energy Efficiency Potential Study	PJM	Energy Efficiency	2016	2017-2030	Res: 3.5 MM C&I: 376 k	Max: 10% PP[27] Ach: 7%
DTE Energy Efficiency Potential Study	MISO	Energy Efficiency	2016	2016-2025 and 2016-2035	2014 customers Res: 1.9 MM Com: 198k Ind: 778 2016 forecasted load: Res: 16,586 GWh Com: 21,439 GWh Ind: 12,551 GWh	2016-2025: 12.5% traditional 8.9% constrained 2016-2035: 18.8% traditional 13.5% constrained
Duke Energy North Carolina EE and DSM Market Potential Study (Duke Energy North Carolina)	N/A	Energy Efficiency	2020	2020-2044	Forecast 2020-2044 Res: 27,508 GWh C&I: 39,946 GWh Total: 67,545 GWh	Scenario: 25-yr % savings Base: 12.2% Enhanced: 12.8% Avoided Energy Cost: 12.3%
Duke Energy North Carolina EE and DSM Market Potential Study (Duke Energy Progress)	N/A	Energy Efficiency	2020	2020-2044	Forecast 2020-2044 Res: 21,138 GWh C&I: 20,266 GWh Total: 41,404 GWh	Scenario: 25-yr % savings Base: 14.2% Enhanced: 14.7% Avoided Energy Cost: 14.4%
Georgia Power Company's Report on Achievable Energy Efficiency Potential Assessment	N/A	Energy Efficiency	2021	2021-2032	Redacted	Incentive Scenarios % of 2032 Load (GWh): 25%: 4.0% 50%: 5.1% 75%: 6.6% 100%: 8.7%

[25] Realistically Achievable Potential (RAP) is the subset of economic potential describing EE and DSM measure adoption by customers participating in utility-sponsored programs operating within the subject market or jurisdiction.
[26] Maximum Achievable Potential (MAP) compares the expected costs and benefits of energy and demand savings provided by EE and DSM measures and applies the total resource cost (TRC) test to determine whether measures meet the scenario screening criterion of a benefit-cost ratio greater than 1.
[27] Program Potential (PP) includes the allocation and bundling of individual measures into specific program concepts to support utility program planning.

Study Name	ISO	Subject	Year Published	Forecast Period	Market Size	Overall Achievable Potential (forecast period)
Indianapolis Power & Light (IPL)	MISO	Energy Efficiency	2018	2021-2039	2020 forecasted load: Res: 5,000 GWh C&I: 7,000 GWh	RAP: 19% MAP: 31%
		Demand Response			Not presented for DR	RAP: 8% MAP: 12%
Kansas City Power & Light 2016 DSM Potential Study	SPP	Energy Efficiency	2017	2019-2037	2015 loads Res: 8,585 GWh Com: 8,760 GWh Ind: 5,208 GWh	RAP: 8.7% MAP: 12.0%
		Demand Response			Not presented for DR	RAP: 11.0% MAP: 13.0%
Louisville Gas & Electric and Kentucky Utilities	N/A	Energy Efficiency	2017	2019-2038	Res: 11,453 GWh Com: 10,200 GWh	Incentive Scenarios Low: 4.2% Mid: 5.5% High: 6.2%
Ameren Missouri 2020 DSM Market Potential Study	MISO	Energy Efficiency	2020	2022-2040	2040 Forecast: Res: 13,400 GWh C&I: 15,800 GWh	MAP: 14.9% RAP: 11.4%
MN Statewide	MISO	Energy Efficiency	2018	2020-2029	Res: 32% of market% Com: 36% Ind: 19% Opt-Out: 13%	PP Ach: 14% MAP: 21%
Energy Efficiency Potential Study for Pennsylvania	PJM	Energy Efficiency (Statewide)	2015	2016-2025	2010 load[28] Res: 54,193 GWh Com: 55,957 GWh Ind: 36,511 GWh	Max Ach: 13.2% Base Ach: 8.3% (% of 2010 load)
Focus on Energy Wisconsin Energy Efficiency Potential Study	MISO	Energy Efficiency (Statewide)	2017	2019-2030	Res: 2.5 MM C&I: 347 k	BAU: 9.1% Mid: 12.7% Max: 14.2%

Summary Descriptions of Comparison Potential Studies

In developing the data to support Table A-1, GDS researched the details of each of the example potential studies to help provide context to the underlying modeling and considerations for developing achievable potential. Below, each study is described in a mini-case study format, with information related to how achievable potential was defined and scenarios that that were used to test the sensitivity of multiple achievable potential perspectives.

Ameren Illinois Demand Side Management Market Potential Study (2016)

Ameren Illinois' 2016 DSM Market Potential Study served to assess various tiers of energy efficiency potential including technical, economic, maximum achievable, and realistic achievable potential. The study developed

[28] In Pennsylvania utilities must meet energy efficiency percentage reductions relative to their 2010 load.

updated baseline estimates with the latest information on federal, state, and local codes and standards for improving energy efficiency. The study consisted of three primary components: market research, a full energy efficiency potential analysis at the measure and program levels, and estimation of supply curves.

Ameren Illinois undertook primary market research to collect data for the Ameren Illinois service territory, including electric and natural gas end-use data, end-use saturation data, and customer psychographics, demographics, and firmographics. This information enables Ameren Illinois to understand how their customers make decisions related to their energy use and energy efficiency investment decisions.

Ameren Illinois' definition of maximum achievable assumed ideal market, implementation, and customer preference conditions, with well-established communication channels, trade allies and delivery partners, and high levels of incentives, administrative, and marketing costs. Realistic achievable potential assumed more conservative conditions as well as limited program budgets. Savings were presented as net.

Primary market research produced adoption rates that were typically lower than those produced from the 2019 Ameren Missouri market research, particularly for maximum achievable potential. In addition, estimates of technical and economic potential are generally lower, suggesting differences in electric equipment penetration or assumptions regarding the current saturation of efficient equipment. Avoided costs were not presented in the study.

TABLE A-2. AMEREN ILLINOIS 2017-2036 ENERGY EFFICIENCY POTENTIAL COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Share of Savings	Commercial Share of Savings	Industrial Share of Savings
2017-2036	TRC	Max: 16.4% PP: 12.5%	Max: 22% PP: 23%	Max: 54% PP: 52%	Max: 24% PP: 24%

Arkansas Energy Efficiency Potential Study (2016)

The Arkansas Public Service Commission filed its 2016-2025 potential study in mid-2015. Economic potential was estimated at 15.5 percent of the 2025 load forecast. Using current budgeting as the base achievable potential scenario, a cumulative saving of 7.8 percent was estimated as achievable across the 10-year forecast period. Additional scenarios also tested the effect of lower budgets, higher budgets, and in the event of a carbon value. The cumulative achievable potential ranged from 5.7 percent (low budget) to 9.0 percent (high budget), thus no scenario equivalent to maximum achievable potential was seemingly modeled. Savings are described as being net of free riders, though no details were offered on how net savings were developed. In Arkansas some customers have the option to operate their own self-direct program. Achievable savings were treated as net of self-direct customers, removing their underlying load from the analysis for all technical, economic, and achievable estimates of potential savings.

The market scope included all investor-owned utilities (IOUs) in Arkansas. The market size being modeled for the study was not explicitly described. However, graphical depictions of the residential and commercial/industrial loads were included. The residential market is approximately 11,500 GWh per year, with the commercial/industrial market at approximately 14,000 GWh per year. Technical potential is a 32% of the residential market, yet only 13% of the C&I market. To model achievable potential, the study incorporates Arkansas energy efficiency policy requiring that "all major end-uses" be covered, and that achievable potential include savings of "all achievable within a reasonable time-period and maximizing net benefits to customers and utility system." Achievable potential was determined by applying payback acceptance curves that were based on 2012 market research conducted for Kansas City Power & Light.

The potential study included a section related to demand response. The demand response "realistic" achievable potential was estimated at nine percent of capacity by 2025. The "realistic" demand response potential considered demand forecasts, customer acceptance rates, and programmatic best practices. Economic potential was not presented in the report.

Table A-3 summarizes key achievable potential metrics by sector resulting from the Arkansas Energy Efficiency Potential Study for energy efficiency. Sector-level details were not provided for the low and high incentive scenarios.

TABLE A-3. ARKANSAS ENERGY EFFICIENCY POTENTIAL STUDY KEY COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Ach Potential	C&I Ach Potential
2016-2025	TRC	Low $:5.7% Current $7.8% High $: 9.0%	Low $: N/A Current $: 10.3% High $: N/A	Low $: N/A Current $: 5.2% High $: N/A

ComEd Energy Efficiency Potential Study, 2017-2030

ComEd's distribution arm operates energy efficiency programs across its service territory. In 2016, ComEd published its potential study which forecasted opportunities for energy efficiency spanning the 14 years of 2017-2030. The study found an overall economic potential of roughly 29% at the end of 2030 and a maximum achievable potential of 10%. Once constrained by program assumptions that maintained current funding levels, the cumulative achievable potential in 2030 was found to be 7 percent. The share of savings was heavily weighted toward the commercial sector, with 66 percent of savings. The residential sector was estimated to achieve 25 percent of savings, with the industrial sector contributing the remaining eight percent.

In the ComEd study, achievable savings were presented as net savings and defined as:

1. Maximum achievable is the amount of cost-effective program potential that could be achieved absent program budget constraints and with incentives set at 100 percent of incremental cost.
2. Program achievable is based on the maximum budget under a two percent of customers' electricity costs limitation and follow current program budgets.

Net savings were derived from the historical evaluated net to gross ratios developed by program evaluators. The industrial sector does not appear to exclude any existing load from the energy efficiency potential analysis (a provision that exempts certain customers was signed into law in late 2016). Adoption rates were informed by interviews with program managers and often constrained by current participation levels and often assumed some potential decrease over time.

Avoided costs were not presented in the study. Savings by year were not tabulated, though were indicated as being influenced by known code and standards changes as well as the treatment of behavioral programs for persistence year-to-year.

TABLE A-4. COMED 2017-2030 ENERGY EFFICIENCY POTENTIAL COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Share of Savings	Commercial Share of Savings	Industrial Share of Savings
2017-2030	TRC	Max: 10% PP: 7%	Max: 22% PP: 25%	Max: 72% PP: 66%	Max: 6% PP: 8%

DTE Energy Efficiency Potential Study (2016)

In 2016, DTE completed its most recent energy efficiency potential study. This study presented gross savings across two forecast periods – a near-term 10-year estimate (2016-2025) and a longer-term 20-year estimate (2016-2035). Unlike most studies in this comparison analysis, DTE Energy utilized the Utility Cost Test, also known as the Program Administrator Cost Test. The economically achievable potential was estimated at 34.8 percent in the 10-year and 35.6 percent in the 20-year models. Maximum achievable potential (MAP) was estimated as 12.5 percent in the 10-year model and 18.8% in the 20-year model. Realistically achievable potential (RAP) was estimated 8.9 percent in the 10-year model and 13.5 percent in the 20-year model.

The MAP and RAP definitions for achievable potential utilized two scenarios to describe their treatment. In both scenarios, incentives were assumed to be 50 percent of incremental cost. The chief different between MAP and RAP is overall program spending. MAP analyzed savings by having no cap on program budgets, while RAP capped program budgets at two percent of retail sales. In the RAP scenario, cost-effective savings are constrained by Michigan's Public Act 295 of 2008, which limited utility expenditures to two percent of retail sales unless approved by the Michigan Public Service Commission.

TABLE A-5. DTE ENERGY EFFICIENCY POTENTIAL STUDY COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Achievable Potential	Commercial Achievable Potential	Industrial Achievable Potential
2016-2025	UCT	MAP: 12.5% RAP: 8.9%	MAP: 15.6% RAP: 10.3%	MAP: 12.5% RAP: 8.4%	MAP: 9.3% RAP: 7.7%
2016-2035	UCT	MAP:18.8% RAP: 13.5%	MAP:20.5% RAP: 17.6%	MAP:18.9% RAP: 10.6%	MAP:16.3% RAP: 13.2%

Duke Energy EE and DSM Market Potential Study (2020)

Duke Energy commissioned the potential study to determine the what savings could be achieved by energy efficiency (EE) and demand-side management (DSM) programs in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) service territories. The report described the potential for DSM savings for both of Duke's service territories in North Carolina. The main objectives of the study were:

- Provide a market potential study, which estimates the technical, economic and realistic achievable market potential energy savings over the short term (5 year projection), medium term (10 year projection), and long term (25 year projection).
- Estimate the potential energy and demand savings for Duke Energy's North Carolina service territory.
- Develop savings estimates with a focus on different perspectives: compliance and system planning.

The DSM savings potential was estimated by applying an analytical framework, Nexant's Microsoft Excel-based energy efficiency modeling tool, TEA-POT (Technical / Economic / Achievable POTential), to estimate baseline market conditions for energy consumption and demand and DSM opportunities. The assessment started with the current Duke Energy load and sales forecasts, which were disaggregated into customer-class and end use components. The assessment examined the effect of the range of energy efficiency measures and practices on each end-use, taking into account fuel shares, current market saturations, technical feasibility, and costs.

Nexant examined three scenarios for achievable potential: base, enhanced, and an avoided energy cost sensitivity. These scenarios provide a sensitivity for EE costs and benefits to understand how market conditions and trends affect the costs and benefits of utility-sponsored programs over the study's time horizon of twenty-five years:

- Base scenario – aligns with existing program portfolio, and includes existing EE programs and measures currently offered by DEC or DEP
- Enhanced scenario – includes the base scenario, but with increased program spending (via incentives) designed to attract new customers into the market for EE technology and program participation
- Avoided Energy Cost Sensitivity scenario – covers the base scenario, but with a sensitivity analysis around enhanced EE benefits, such as may occur if avoided energy costs were higher than current values. Higher benefits for EE may lead to additional cost-effective measures and increased achievable potential

TABLE A-6. DUKE ENERGY NORTH CAROLINA MARKET POTENTIAL STUDY FINDINGS

Baseline Period	Benefit-Cost Model	Technical Potential (GWh)	Economic Potential (GWh)	25-yr sum of annuals per scenario
2020	TRC	15,034	5,992	Base: 8,257 Enhanced: 8,663 Avoided Energy Cost Sensitivity: 8,336

TABLE A-6. DUKE ENERGY PROGRESS MARKET POTENTIAL STUDY FINDINGS

Baseline Period	Benefit-Cost Model	Technical Potential (GWh)	Economic Potential (GWh)	25-yr sum of annuals per scenario
2020	TRC	10,350	3,414	Base: 5,910 Enhanced: 6,107 Avoided Energy Cost Sensitivity: 5,972

Georgia Power Company's Report on Achievable Energy Efficiency Potential Assessment (2021)

The Georgia Power (GP) study uses the "TEAPOT" methodology, estimating the technical, economic, and achievable energy reduction potential for energy efficiency technologies for Georgia Power's residential, commercial, and industrial customers.

The technical potential includes all measures suitable for GP's customers, climate, building stock, and production facilities, and assumes there are no economic or other market barriers preventing customers from adopting these measures.

The economic potential is defined as taking all the technically-feasible measures and adopting all that are economic, as defined by the Total Resource Cost ("TRC") Test. The TRC Test is a measure of net societal value that compares the benefits of avoided utility supply costs (including electricity, natural gas, and water) with the costs to achieve those savings (incremental measure costs). Other cost tests that measure economic attractiveness from the participant's perspective (the Participant Cost Test), the non-participant's perspective (the Ratepayer Impact Measure Test), and the utility's perspective (the Program Administrator Cost Test) are also provided.

The achievable potential included in the report consists of four planning scenarios based on different levels of incentives provided by Georgia Power to customers to encourage the purchase and installation of energy efficiency measures. The scenarios are based on a 25%, 50%, 75%, and 100% monetary incentives to customers, equaling the respective percent of incremental costs of energy efficiency improvements.

TABLE -7. GEORGIA POWER EE ACHIEVABLE POTENTIAL ASSESSMENT METRICS

Forecast Period	Benefit-Cost Model	Achievable Potential by Scenario % of 2032 Load (GWh)	Residential Achievable Potential % of 2032 Load (GWh)	Commercial Achievable Potential % of 2032 Load (GWh)	Industrial Achievable Potential % of 2032 Load (GWh)l
2021-2032	TRC, RIM, PAC, PCT	25%: 4.0% 50%: 5.1% 75%: 6.6% 100%: 8.7%	25%	53%	22%

Indianapolis Power & Light Demand Side Management Market Potential Study (2018)

Conducted by GDS Associates, the IPL DSM Market Potential Study covered the 2021-2039 timeframe, and included an assessment of market potential for the residential, commercial, and industrial sectors. GDS used a bottom-up approach to estimate energy efficiency potential in the residential sector. In the C&I sectors, GDS utilized the bottom-up modeling approach to first estimate measure-level savings and costs, as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable energy shares of load. All savings estimates are provided at the gross level.

Economic potential was determined using the UCT Test. Economic potential represented nearly 37% of total system load. The analysis included estimates of maximum and realistic achievable potential, with definitions of each scenario like the 2020 Ameren MPS. In total, the IPL study included 187 residential measures, 237 commercial measures, and 130 industrial measures. Industrial opt-outs were excluded from the estimates of long-term potential. Traditional retail buydown for screw-based lighting was only included for the first two years of the analysis timeframe, and additional direct install opportunities were included from the 2023-2024 timeframe. Beginning in 2025, residential LED lighting savings were essentially eliminated. Behavioral potential represented a substantial portion of the incremental annual residential potential (~25% of the sector annual potential)

In the MAP scenario, incentive levels were assumed to represent 100% of the incremental measure cost. In the RAP scenario, incentives typically ranged from 25%-40% of measure cost in the residential sector, and less than 30% in the C&I sectors. Achievable potential adoption rates were based on primary WTP data collected as part of the MPS. Maximum adoption rates typically ranged from 70%-90%. Realistic achievable potential adoption rates typically ranged from 40%-60% of annual eligible measures over the analysis timeframe. Similar to the 2020 Ameren Missouri MPS, measures that reached the end of their useful life were allowed to re-enter the eligible potential market, assuming sustained savings and a new set of measure/program costs.

TABLE A-8. IPL DEMAND SIDE MANAGEMENT MARKET POTENTIAL STUDY COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Achievable Potential	Commercial Achievable Potential	Industrial Achievable Potential
2021-2039	UCT	MAP: 31% RAP: 19%	MAP: 35% RAP: 23%	MAP: 37% RAP: 20%	MAP: 14% RAP: 7%

Kansas City Power & Light 2016 DSM Potential Study

In early 2017, Kansas City Power & Light (KCP&L) completed its 2016 DSM Potential Study, estimating DSM potential from 2019 through 2037. This study considered both energy efficiency and demand response, with energy efficiency savings reflecting net savings (the baseline forecast incorporated naturally occurring energy efficiency). The savings percentages are presented as net savings relative to the baseline forecast year (2015 loads). The KCP&L potential study presented a cumulative economic potential for energy efficiency of 19.6 percent, using the TRC cost-effectiveness test. The economic potential for demand response was not presented due to many cost-effective but mutually exclusive program and measure options. KCP&L removed the potential savings from customers who have an option to not participate in KCP&L programs.

20-year technical potential is just under 30% of baseline sales, with economic at approximately 22% of baseline sales. These lower initial estimates of potential then produce lower estimates of achievable despite similar definitions of maximum and realistic achievable potential. The achievable potential was presented with two metrics – maximum achievable potential (MAP) and realistic achievable potential (RAP). The MAP was developed by assuming ideal program conditions with incentives that covered a substantial portion of measure costs, along with high administrative and marketing costs. The RAP was developed by assuming the current program conditions, including current participation rates and spending. The RAP was meant to reflect less-than-ideal program conditions that include constrained barriers, imperfect markets, and barriers to customer acceptance. Overall energy efficiency MAP and RAP were estimated at 12.0 percent and 8.7 percent across the forecast period. Demand response MAP and RAP were developed along similar logics, with an estimate of anticipated participation rates across different programs and measures, resulting in a MAP of 13 percent and RAP and 11 percent.

TABLE A-9. KCP&L 2016 DSM POTENTIAL STUDY COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Achievable Potential	Commercial Achievable Potential	Industrial Achievable Potential
2019-2037 Energy Efficiency	TRC	MAP: 12.0% RAP: 8.7%	MAP: 10.4% RAP: 8.2%	MAP: 16.4% RAP: 12.4%	MAP: 7.6% RAP: 5.2%
2019-2037 Demand Response	TRC	MAP: 13% RAP: 11%	Not available	Not available	Not available

Louisville Gas and Electric and Kentucky Utilities Demand-Side Potential Study (2017)

In 2017 Louisville Gas and Electric and Kentucky Utilities (LG&E and KU), as one company with two operating units, completed its DSM potential study for the 2019 through 2038 period. Using the TRC cost-effectiveness test, the study found economic energy efficiency potential equal to nine percent of LG&E and KU's forecasted 2038 loads (technical potential was approximately 33% of baseline sales). The baseline forecast includes the presence of naturally occurring energy efficiency, but otherwise describes savings as gross savings. This study exhibits the lowest economic potential of any of the compared studies. Of note, the analysts modeled avoided energy costs that had decreased 20 percent since the prior 2013 study. Additionally, avoided capacity from energy efficiency was valued at $0/kW, rather than the $100/kW value used in the 2013 study. This treatment of avoided costs may explain the lower economic and achievable potential found for LG&E and KU compared to other studies, with a sensitivity analysis showing economic potential increasing to 15 percent of the 2038 forecasted load if capacity values were set at $100/kW.

Achievable potential was developed using three scenarios, representing varying incentive levels. The scenarios presented incentive levels of 0 percent, 50 percent, and 75 percent of incremental cost coverage. Willingness-to-pay survey results were used to estimate achievable program adoption within the service territory. The outcome were achievable potentials of 4.0 percent, 5.8 percent, and 6.5 percent, increasing along with higher incentives. The study calculated achievable potential savings with only the first ten years allowing for measure retrofits and lost opportunity (natural replacement and new construction) measures. In the second half of the study period, only lost opportunity measures were considered for savings. The effect of this assumption on 2038 cumulative savings is unknown.

Table A-10 presents summary results of the achievable potential estimates, reflecting the three incentive scenarios described above.

TABLE A-10. LG&E AND KU ENERGY EFFICIENCY POTENTIAL COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Achievable Potential	Com & Ind Achievable Potential
2019-2038	TRC	75%: 6.5% 50%: 5.8% 0%: 4.0%	75%: 6.2% 50%: 5.5% 0%: 4.2%	75%: 6.8% 50%: 6.1% 0%: 3.8%

Minnesota Energy Efficiency Potential Study (2018)

The Minnesota Energy Efficiency Potential Study analyzed energy efficiency potential over a 10-year period, beginning in 2020 through 2029. The study included 117 residential and 186 business sector energy efficiency measure (comparable to the 2020 Ameren Missouri MPS). This included 18 emerging technology measures across within each sector. Whereas the 2020 Ameren MPS uses a "bottom-up" approach in the residential sector and "top-down" approach for the business sector, the MN MPS utilizes a "top-down" approach for all sectors. All savings are reported as gross savings.

The MN EE Potential Study used the Societal Test for screening. Avoided costs were typically lower than current Ameren Missouri avoided cost, but also included a value for avoided emissions to help balance out the total value of avoided energy across both jurisdictions. Overall economic potential for the state by 2029 was estimated to be 33%.

The definition of maximum achievable potential generally mirrored the 2020 Ameren Missouri MPS with financial incentives representing 100% of the incremental costs of each measure, along with aggressive marketing and program designs. Beyond maximum achievable, the study also provided an estimate of program achievable, which assumed a standard incentive that represents 50% of incremental measure costs for program planning purposes. To estimate achievable penetration, the MN MPS utilized a combination of program awareness and willingness factor. The awareness factors were not readily accessible, but the MN MPS does note that willingness factors generally ranged from 60% to 85% for market-drive measures and 50%-80% for retrofit measures. Maximum penetrations rates were generally met over a period of 5-15 years.

TABLE A-11. MINNESOTA ENERGY EFFICIENCY POTENTIAL COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Achievable Potential	Com & Ind Achievable Potential
2020-2029	Societal	MAP: 21% Prog Pot:14%	Program Potential: 8%	Program Potential: 18%

Ameren Missouri DSM Market Potential Study (2020)

Ameren Missouri's 2020 DSM Market Potential Study served to provide a foundation for the continuation of utility-administered energy efficiency and demand response programs in the Ameren Missouri service area, to determine the remaining opportunities for cost-effective energy savings, demand savings, and distributed energy resources for the Ameren Missouri service area. The study was commissioned by Ameren Missouri as part of their larger Integrated Resource Plan (IRP) process.

Energy efficiency potential included technical, economic, achievable potential (MAP and RAP), and program potential (MAP and RAP). For each level of potential, the study presented the energy savings, peak demand savings, benefits, and costs for the Ameren Missouri service area for the period of 2022-2040, a 19-year time frame.

The study consisted of four distinct areas of analyses: residential market-rate and business sector energy efficiency potential, income-eligible sector energy efficiency potential, demand response potential, and Distributed Energy Resource (DER) potential. Each study sought to identify and assess a wide-range of demand-side resources across all major customer classes, market segments, and end-uses.

To estimate energy efficiency potential in the residential sector, a bottom-up approach was used beginning with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the business sector (commercial and industrial), a top-down modeling approach was used to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of electric energy load. Bottom-up approaches were also used in the demand response and DER analyses for all sectors.

Ameren Missouri definition of maximum achievable included financial incentives representing 100% of the incremental costs of each measure, along with aggressive marketing and program designs. Beyond maximum achievable, the study also provided an estimate of program achievable, which assumed a standard incentive that represents 50% of incremental measure costs for program planning purposes.

TABLE A-12. AMEREN MISSOURI 2022-2040 ENERGY EFFICIENCY POTENTIAL COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Residential Achievable Potential	Business Achievable Potential	Demand-Response Potential
2022-2040	TRC	MAP: 22% RAP: 16%	MAP: 25% RAP: 17%	MAP: 9% RAP: 5%

Pennsylvania Energy Efficiency Potential Study (2015)

Pennsylvania completed its most recent potential study in 2015, spanning a 10-year forecast of potential savings from 2016 through 2025. As a statewide study, it reflects the potential energy efficiency savings from all investor owned utilities in the State. Pennsylvania's study is somewhat different from other studies in this comparison in that it used 2010 as a baseline year – substantially preceding the forecast period. Using the TRC and with no option for opt-out electricity customers, the study found an overall economic potential of 18.4 percent relative to the 2010 baseline year using the TRC cost-effectiveness test. The study presents savings at the gross-level, without net savings effects.

The Pennsylvania potential study presents two levels of achievable potential: Maximum Achievable Potential (MAP) and Base Achievable Potential (BAP). The MAP assumes an aggressive program scenario that includes 100 percent of measure incremental costs being paid for by the program. The BAP restricts the savings potential by using the historical program spending of the Pennsylvania utilities as well as the measure adoption rates evident in prior program years. The overall achievable potential (relative to the 2010 base year loads) is 13.2 percent under MAP and 8.3 percent under BAP.

TABLE A-13. PENNSYLVANIA STATEWIDE ENERGY EFFICIENCY POTENTIAL COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Achievable Potential	Commercial Achievable Potential	Industrial Achievable Potential
2016-2025	TRC	MAP: 13.2% BAP: 8.3%	MAP: 17.5% RAP: 12.2%	MAP: 9.8% RAP: 5.7%	MAP: 12.1% RAP: 6.4%

Focus on Energy Wisconsin Energy Efficiency Potential Study (2017)

Wisconsin has a state-wide energy efficiency program that includes all IOUs, most municipal utilities, and many cooperative utilities. In 2017, the Public Service Commission of Wisconsin published its Focus on Energy 2016 Energy Efficiency Potential Study. The study analyzed energy efficiency savings potential for the 2019-2030 time period. Data were based largely on loads associated with the IOUs and loads representing most municipal utilities. For 12-year span, the study found an economic potential of 21 percent of forecasted 2030 electricity sales and an achievable potential under a "business as usual" scenario as savings of 9.1 percent. 2030 forecasted sales included 19.6 million MWh for the residential sector and 48.5 million MWh for the combined commercial and industrial sectors.

For the Focus on Energy study, achievable potential was defined as representing "the portion of economic potential that might be reasonably achievable by Focus on Energy, after taking into account market barriers... and program funding limitations." The study authors do not consider the analysis results as program potential as program design elements were not incorporated into the analysis. Additionally, savings are only presented as gross savings and explicitly do not consider net to gross ratios or other considerations for program attribution or spillover. Wisconsin uses a modified TRC test that incorporates a $15 per ton of carbon value as well as criteria air pollutant emission values reflecting utility costs for avoidance.

The study presents several scenarios to compare the "business as usual" (BAU) case to other funding and incentive levels. The BAU demonstrated the lowest achievable potential, assuming 25 percent of incremental cost incentives as a cap on overall spending at historical percent-of-utility revenue levels (1.09 percent). The other scenarios included low, medium, high, and maximum incentives set at 25 percent, 50 percent, 75 percent, and 100 percent of incremental costs, respectively, but without the funding cap applied used in the BAU scenario. The maximum achievable was modeled as the 100 percent of measure cost incentive level. The achievable potentials across these scenarios ranged from 9.3 percent to 14.2 percent by 2025. Note that the BAU case is the lowest performing scenario.

Table A-14 summarizes key achievable metrics by sector for the Focus on Energy BAU scenario with sector-level results for each scenario.

TABLE A-14. FOCUS ON ENERGY WISCONSIN SCENARIO COMPARISON METRICS

Forecast Period	Benefit-Cost Model	Overall Ach Potential	Residential Ach Potential	C&I Ach Potential
2016-2025	Modified TRC	BAU: 9.1% Low: 9.3% Mid: 12.7% High: 13.7% Max: 14.2%	BAU: 11.5% Low: 11.7% Mid: 16.8% High: 17.6% Max: 18.2%	BAU: 8.1% Low: 8.2% Mid: 11.1% High: 12.1% Max: 12.6%

APPENDIX B. Delphi Panel Description

A Delphi Panel was utilized to inform possible market adoption levels and pacing. A Delphi Process develops consensus estimates for difficult for topics that are uncertain, difficult to quantify, or may have widely varying perspectives. For the GDS Team's New Orleans DSM potential study, the Delphi Process was used to estimate market adoption rates and speed for adoption for different types of technologies. A set of New Orleans experts knowledgeable in either the residential or C&I sector were recruited in panels. The Delphi Panels participated in two rounds of questioning. In the first round, the panelists, provided their best estimates for how the New Orleans market may adopt each technology type. In the second round, the panelists were provided with the average of the first round's responses and logic from the other panelists. In the second round, the panelists were given the opportunity to reconsider their initial estimates. The survey is done anonymously, giving panelists comfort in providing honest feedback to what may be contentious issues.

The panelists represented market actors familiar with either the residential or C&I buildings sectors in New Orleans. Panelists were asked to respond to the general technology types based on measure incentive levels (residential) or simple payback periods (C&I). Each panel had 10 participants that all provided responses. As part of panel recruitment, the GDS Team confirmed that the local expert had the appropriate knowledge to make reasonable judgements on market adoption rates.

Each panel contained representation from each of the following categories:

- Home builders
- HVAC contractors
- Builders of multi-family facilities
- Residential program implementers
- Residential program planner/managers
- Equipment distributors
- Low-income sector and housing advocates
- Real estate developers (residential sector)
- Multi-family building/facility managers
- Local energy efficiency business owners and managers

Panelists were first asked to gauge their view of each measure type for the maximum adoption rate of a measure if incentives were at 100 percent of incremental costs – an instant payback. They also provided the time they thought it would take for the market to reach that maximum adoption. No measure was estimated to achieve a 100 percent adoption rate, even with an instant payback. Panelists were then asked to provide their best estimate of how long it would take to achieve 10% and 90% of the maximum level they identified.

The responses to the "instant payback/100% incentive" questions form the basis to understand the maximum achievable potential. Panelists were additionally asked to provide their view on adoption levels and pacing for alternative incentive conditions.

Residential Sector: incentives equal to 0%, 25%, 50%, or 75% of incremental costs

C&I Sector: simple paybacks of 1 year, 2 years, 4 years, or 8 years

The case descriptions for both the residential and C&I sectors were the same, described below:

Case 1: These measures are easy for [sector customers] to understand: one-for-one replacements. They have low upfront costs and are not very disruptive to install. Examples would be LED lamps or pre-rinse spray valves that can easily pop into existing structures. Assume for now that this is a non-discretionary purchase: either the existing equipment has failed and the owner needs to buy a new unit, or this is new equipment for new construction. In both cases, the decision is between standard efficiency and high efficiency equipment.

Case 2: These measures are fairly easy for [sector customers] to understand, one-for-one replacements, but are higher cost than standard efficiency equipment and often require contractor involvement. Examples would be efficient unitary air conditioning or water heating equipment. Assume for now that this is a non-discretionary purchase: either the existing equipment has failed and the owner needs to buy a new unit, or this is new equipment for new construction. In both cases, the decision is between standard efficiency and high efficiency equipment.

Case 3: Now assume that the equipment is a discretionary purchase (one that is not needed to replace failed equipment). The current equipment is functioning correctly, but the program tries to convince the owner to replace it with a new, higher efficiency unit.

Case 4: These measures are fairly inexpensive but require active engagement and may require behavioral changes in the participant. Examples would be [lighting and controls – C&I] [programmable/learning thermostats – residential].

Case 5 (C&I): These are measures that impact equipment that is core to the central business. Examples may be commercial kitchen equipment for a restaurant, industrial process improvements, and compressed air measures. Assume for now that this is a non-discretionary purchase: either the existing equipment has failed, and the owner needs to buy a new unit or this is new equipment for new construction. In both cases, the decision is between standard efficiency and high efficiency equipment.

Case 5 (Residential): These measures are not that expensive, but are hard to understand, and any homeowner would have to rely on the word of a contractor that the action would have any impact. Examples would be Air Conditioner tune-ups or air sealing.

Case 6: These measures are both expensive and complex, and often have interactions with multiple major building systems. Examples would include [insulation retrofits, energy management systems, a change of cooling system (i.e. from rooftop units to a chilled water plant), as well as holistic above-code new construction – C&I] [insulation retrofits, solar water heaters, deep energy retrofits, and holistic efficiency on new construction projects]

Below we provide examples of qualitative feedback from each of the two panels to the varying cases and provide context to their scoring – considerations that could inform key market barriers or opportunities.

<u>Residential</u>

Case 1: “Situation depends on age of homeowner.”

“A 100% incentive would entice buyers to almost always choose this energy efficient system. Because why not? It seems as if they would cost about the same since the upfront costs are low and install is easy.”

“I would say that not many people are educated on these new energy efficiency methods and are unaware of how much money it can save down the road. I have put almost no change between the 0-25% incremental measure cost due to the lack of substantial money savings.”

“I believe many people in the New Orleans area will be reluctant to come out of their own pocket up front to buy new appliances that are more expensive specifically for the fact of being more energy efficient. Even though these appliances will likely pay for themselves over their 10–15-year lifespan, people often see more expensive and become very hesitant. The more of the total percentage that Entergy covered, the more participants they will get. In this case though with the easy installment of these appliances, there will likely be a good number of participants.”

Case 2: “Big ticket items like this scenario are hard to sell without high incentive.”

“Since the appliances are needed regardless this would still be higher %’s who would choose this option. Lower incentive % would be lower acceptance because of higher costs associated with contractor involvement.”

"When it comes to air conditioning and water heating systems, which usually have life spans of over 10 years, people will not change unless their system fails."

"Similar to case 1, participants will be hesitant to spend their own money if Entergy does not cover the full incremental cost. In case 2, I think less people will want to be involved strictly due to the need for some contractor involvement. Many would hear that they need a contractor and immediately say "oh no that's too expensive." However, there would still be a large number of participants due to the need of the appliances."

Case 3: "People won't want to upgrade something that isn't broken, potentially even with incentive."
"Getting people to switch will be difficult, even with 100% incentive."
"Like stated above, most people will not change their system unless they one running fails. Lack of education on the subject also plays a role."
"I think people will be very unwilling to go out of their way to replace perfectly good appliances."

Case 4: "Most older people would not like adopting however as time went on, I think this method could be widely adopted especially with incentive."
"The younger generations are more tech savvy and are incorporating these new devices in their homes already, there will still be older population that will not change. Again, most people won't change a system if theirs isn't broken."
"I think the younger crowd of New Orleans would be more than willing to learn some simple technological changes in their appliances or make some minor changes in their daily routines. The older crowd would be much more hesitant to update technology or change their behavior."

Case 5: "Almost depends on ability of contractor to convince homeowner."
"Some would be willing to rely on others because they don't understand the equipment anyway."
"Most homeowners wouldn't know that their system would need to be resealed unless a contractor was sent out to their homes and inspected the system."
"I think people would tend to be willing for someone else to make changes to their air conditioning if the measures are completely paid for."

Case 6: "Would be most used for new construction, some would not opt into the perceived very high cost."
"Many people will likely see these expensive and complicated changes as too big of a hassle, even with the full payment from Entergy. The less contribution that Entergy makes, exponentially less people will participate."

Commercial and Industrial

Case 1: "Payback needs to be more immediate for people to adopt."
"Better product, people will wait reasonable time period for payback."
"Assume that a long payback period would desensitize energy efficient use."
"Since its non-disruptive, most people would want it immediately. Some just may be able to cover the higher cost without getting paid back for too long."
"People would enjoy this since it is a cheap and needed cost."

Case 2: "Expensive equipment has higher incentive to adopt."
"Better product, people will wait reasonable time period for payback."
"Greater savings and benefit for high-cost equipment. Fewer people to want to payback because high cost of equipment."
"I see people in the real world moving to this option. I see it taking so long though due to the cost."

Case 3: "Hard to see spending discretionary replacement, only see owners swapping when needed or for tax credit."
"Lower adoption rate because some people will not want to be hassled with changing equipment that is functioning properly, even if 100% paid for."
"Some people will say, if it not broke, why fix it?"
"I do not see this being too highly praised. Especially since the existing unit has no problems."

Case 4: "Fully informed buyers play a key factor into the adoption percentages. Marketing this program is a large part of if it will be successful."
"Better product, people will wait reasonable time period for payback."
"Active engagement probably means fewer adopters, sadly."
"Some people may be stuck in their own ways."
"It is a simple transition to go to this option of lighting. The hardest factor would be getting use to the new systems behavior (automatic lights)"

Case 5: "The reliability factor plays a key role in the adoption of the higher energy efficiency measure. this scenario involves risk in the new measure."
"Better product, people will wait reasonable time period for payback."
"Businesses may understand the cost savings over long term, better than individuals."
"While most owners would want to upgrade equipment there will still be a few who don't want change."
"This would be a good option since commercial grade business enjoy saving money."

Case 6: "Hard to see happen for retrofit. So much more goes into construction cost than and MEP. New construction is more sellable."
"High cost, fewer want payback terms. Complexity means fewer may want to partake in adoption."
"I believe it will take to long for the owner to make their money back in long run."
"Complex equals confusing to most customers. This would be an expensive option as well and if not needed, I do not see people wanting to switch over to it."

The results of the Delphi panelists' quantiative results are presented below for each of the two sectors. The GDS Team provided naming conventions to summarize the concept of each case and that were ultimately used to assign adoption curve factors to each of the measures in the study. The data were used to inform the maximum adoption rate in each potential case.

C&I Delphi Panel Results

The following table presents the maximum adoption rates for the C&I sector. Inexpensive measures are tagged with a single "$" while more expensive measures are identifed with "$$$." In all technology cases, one can see that measures with longer paybacks are expected to achieve lower maximum adoption levels than those with shorter paybacks, indicating the importance of incentives to drive market adoption to decrease payback periods.

Table B-1 C&I Sector Maximum Adoption Rates

Measure Case	Description	0 Year Payback	1 Year Payback	2 Year Payback	4 Year Payback	8 Year Payback
1	Lighting / ROB $	80.5%	64.4%	50.3%	38.5%	22.9%
2	HVAC / ROB $$$	83.0%	59.3%	49.4%	37.6%	24.7%
3	Early Replacement	36.8%	24.6%	15.7%	9.3%	8.8%
4	SEM/RCx/EMS / Retrofit $	71.0%	55.2%	44.3%	30.5%	21.4%
5	Cooking / Compressed Air / Industrial Process	76.7%	49.7%	43.9%	38.5%	26.7%
6	Retrofit $$$	68.3%	42.0%	37.0%	31.6%	19.1%

Residential Delphi Panel Results

The following table presents the maximum adoption rates for the residential sector. Inexpensive measures are tagged with a single "$" while more expensive measures are identifed with "$$$." In all technology cases, one can see that measures with lower incentive levels are expected to achieve lower maximum adoption levels than those with higher incentive levels, indicating the importance of incentives to drive market adoption.

Table B-2 Residential Sector Maximum Adoption Rates

Measure Case	Description	100% Incentive	75% Incentive	50% Incentive	25% Incentive	0% Incentive
1	LED/Appliance (ROB)	75.2%	66.5%	56.5%	41.0%	29.0%
2	HVAC/WH Equip (ROB)	79.0%	66.5%	52.5%	35.8%	22.5%
3	Early Replacement	46.0%	34.1%	23.0%	11.0%	4.2%
4	Retrofit ($)	67.5%	62.5%	46.2%	34.0%	25.6%
5	Retrofit ($$)	65.0%	52.6%	40.7%	24.6%	15.0%
6	Retrofit ($$$)	49.9%	35.0%	22.6%	12.0%	4.6%

APPENDIX C. Residential Energy Efficiency Measure Detail

Appendix B: Residential Energy Efficiency Detail

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Incentive (%)	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	2% Adoption Rate	TRC Score	2040 TP	2040 EP	2040 HCAP	2040 RAP	2040 2% Case
1001	Appliances	ENERGY STAR Clothes Washer - electric WH / electric dryer	No program	SF	ROB	570	44%	251	0.06	14	$190	100%	18%	75%	26%	55%	78.9%	68.5%	68.5%	0.7	5,482	0	0	0	0
1002	Appliances	ENERGY STAR Clothes Washer - electric WH / electric dryer	No program	SF	ROB	570	44%	251	0.06	14	$190	100%	18%	75%	26%	55%	78.9%	68.5%	68.5%	0.7	1,703	0	0	0	0
1003	Appliances	ENERGY STAR Clothes Washer - electric WH / electric dryer	No program	SF	NC	570	44%	251	0.06	14	$190	100%	18%	75%	26%	0%	78.9%	37.4%	66.5%	0.7	876	0	0	0	0
1004	Appliances	ENERGY STAR Clothes Washer - electric WH / electric dryer	No program	MF	ROB	570	44%	251	0.06	14	$190	100%	18%	75%	26%	55%	78.9%	68.5%	68.5%	0.7	1,731	0	0	0	0
1005	Appliances	ENERGY STAR Clothes Washer - electric WH / electric dryer	No program	MF	ROB	570	44%	251	0.06	14	$190	100%	18%	75%	26%	55%	78.9%	68.5%	68.5%	0.7	538	0	0	0	0
1006	Appliances	ENERGY STAR Clothes Washer - electric WH / electric dryer	No program	MF	NC	570	44%	251	0.06	14	$190	100%	18%	75%	26%	0%	78.9%	37.4%	66.5%	0.7	277	0	0	0	0
1007	Appliances	ENERGY STAR Clothes Washer - electric WH / gas dryer	No program	SF	ROB	207	54%	112	0.03	14	$190	100%	18%	75%	17%	55%	78.9%	68.5%	68.5%	0.3	1,606	0	0	0	0
1008	Appliances	ENERGY STAR Clothes Washer - electric WH / gas dryer	No program	SF	ROB	207	54%	112	0.03	14	$190	100%	18%	75%	17%	55%	78.9%	68.5%	68.5%	0.3	499	0	0	0	0
1009	Appliances	ENERGY STAR Clothes Washer - electric WH / gas dryer	No program	SF	NC	207	54%	112	0.03	14	$190	100%	18%	75%	17%	0%	78.9%	37.4%	66.5%	0.3	257	0	0	0	0
1010	Appliances	ENERGY STAR Clothes Washer - electric WH / gas dryer	No program	MF	ROB	207	54%	112	0.03	14	$190	100%	18%	75%	17%	55%	78.9%	68.5%	68.5%	0.3	507	0	0	0	0
1011	Appliances	ENERGY STAR Clothes Washer - electric WH / gas dryer	No program	MF	ROB	207	54%	112	0.03	14	$190	100%	18%	75%	17%	55%	78.9%	68.5%	68.5%	0.3	158	0	0	0	0
1012	Appliances	ENERGY STAR Clothes Washer - electric WH / gas dryer	No program	MF	NC	207	54%	112	0.03	14	$190	100%	18%	75%	17%	0%	78.9%	37.4%	66.5%	0.3	81	0	0	0	0
1013	Appliances	ENERGY STAR Clothes Washer - gas WH / electric dryer	No program	SF	ROB	404	40%	161	0.04	14	$190	100%	18%	75%	29%	55%	78.9%	68.5%	68.5%	0.5	3,927	0	0	0	0
1014	Appliances	ENERGY STAR Clothes Washer - gas WH / electric dryer	No program	SF	ROB	404	40%	161	0.04	14	$190	100%	18%	75%	29%	55%	78.9%	68.5%	68.5%	0.5	1,220	0	0	0	0
1015	Appliances	ENERGY STAR Clothes Washer - gas WH / electric dryer	No program	SF	NC	404	40%	161	0.04	14	$190	100%	18%	75%	29%	0%	78.9%	37.4%	66.5%	0.5	628	0	0	0	0
1016	Appliances	ENERGY STAR Clothes Washer - gas WH / electric dryer	No program	MF	ROB	404	40%	161	0.04	14	$190	100%	18%	75%	29%	55%	78.9%	68.5%	68.5%	0.5	1,240	0	0	0	0
1017	Appliances	ENERGY STAR Clothes Washer - gas WH / electric dryer	No program	MF	ROB	404	40%	161	0.04	14	$190	100%	18%	75%	29%	55%	78.9%	68.5%	68.5%	0.5	385	0	0	0	0
1018	Appliances	ENERGY STAR Clothes Washer - gas WH / electric dryer	No program	MF	NC	404	40%	161	0.04	14	$190	100%	18%	75%	29%	0%	78.9%	37.4%	66.5%	0.5	198	0	0	0	0
1019	Appliances	ENERGY STAR Clothes Washer - gas WH / gas dryer	No program	SF	ROB	41	54%	22	0.01	14	$190	100%	18%	75%	19%	55%	78.9%	68.5%	68.5%	0.1	357	0	0	0	0
1020	Appliances	ENERGY STAR Clothes Washer - gas WH / gas dryer	No program	SF	ROB	41	54%	22	0.01	14	$190	100%	18%	75%	19%	55%	78.9%	68.5%	68.5%	0.1	111	0	0	0	0
1021	Appliances	ENERGY STAR Clothes Washer - gas WH / gas dryer	No program	SF	NC	41	54%	22	0.01	14	$190	100%	18%	75%	19%	0%	78.9%	37.4%	66.5%	0.1	57	0	0	0	0
1022	Appliances	ENERGY STAR Clothes Washer - gas WH / gas dryer	No program	MF	ROB	41	54%	22	0.01	14	$190	100%	18%	75%	19%	55%	78.9%	68.5%	68.5%	0.1	113	0	0	0	0
1023	Appliances	ENERGY STAR Clothes Washer - gas WH / gas dryer	No program	MF	ROB	41	54%	22	0.01	14	$190	100%	18%	75%	19%	55%	78.9%	68.5%	68.5%	0.1	35	0	0	0	0
1024	Appliances	ENERGY STAR Clothes Washer - gas WH / gas dryer	No program	MF	NC	41	54%	22	0.01	14	$190	100%	18%	75%	19%	0%	78.9%	37.4%	66.5%	0.1	18	0	0	0	0
1025	Appliances	ENERGY STAR Clothes Dryer - Vented Electric, Standard	No program	SF	ROB	730	21%	152	0.02	12	$40	100%	52%	75%	53%	55%	78.9%	68.5%	68.5%	1.6	1,718	2,273	1,794	1,557	1,557
1026	Appliances	ENERGY STAR Clothes Dryer - Vented Electric, Standard	No program	SF	ROB	730	21%	152	0.02	12	$40	100%	52%	75%	53%	55%	78.9%	68.5%	68.5%	1.6	534	706	557	484	484
1027	Appliances	ENERGY STAR Clothes Dryer - Vented Electric, Standard	No program	SF	NC	730	21%	152	0.02	12	$40	100%	52%	75%	53%	0%	78.9%	57.2%	66.5%	1.6	275	283	195	134	156
1028	Appliances	ENERGY STAR Clothes Dryer - Vented Electric, Standard	No program	MF	ROB	730	21%	152	0.02	12	$40	100%	52%	75%	53%	55%	78.9%	68.5%	68.5%	1.6	543	718	566	492	492
1029	Appliances	ENERGY STAR Clothes Dryer - Vented Electric, Standard	No program	MF	ROB	730	21%	152	0.02	12	$40	100%	52%	75%	53%	55%	78.9%	68.5%	68.5%	1.6	169	223	176	153	153
1030	Appliances	ENERGY STAR Clothes Dryer - Vented Electric, Standard	No program	MF	NC	730	21%	152	0.02	12	$40	100%	52%	75%	53%	0%	78.9%	57.2%	66.5%	1.6	87	89	62	42	49
1031	Appliances	Heat Pump Dryer	No program	SF	ROB	730	59%	432	0.06	12	$40	100%	52%	75%	53%	55%	78.9%	68.5%	68.5%	4.5	13,781	18,230	14,387	12,487	12,487
1032	Appliances	Heat Pump Dryer	No program	SF	ROB	730	59%	432	0.06	12	$40	100%	52%	75%	53%	55%	78.9%	68.5%	68.5%	4.5	4,281	5,662	4,469	3,879	3,879
1033	Appliances	Heat Pump Dryer	No program	SF	NC	730	59%	432	0.06	12	$40	100%	52%	75%	53%	0%	78.9%	57.2%	66.5%	4.5	2,203	2,273	1,563	1,078	1,252
1034	Appliances	Heat Pump Dryer	No program	MF	ROB	730	59%	432	0.06	12	$40	100%	52%	75%	53%	55%	78.9%	68.5%	68.5%	4.5	4,352	5,757	4,543	3,943	3,943
1035	Appliances	Heat Pump Dryer	No program	MF	ROB	730	59%	432	0.06	12	$40	100%	52%	75%	53%	55%	78.9%	68.5%	68.5%	4.5	1,352	1,788	1,411	1,225	1,225
1036	Appliances	Heat Pump Dryer	No program	MF	NC	730	59%	432	0.06	12	$40	100%	52%	75%	53%	0%	78.9%	57.2%	66.5%	4.5	696	718	493	340	396
1037	Appliances	ENERGY STAR Dishwasher - Electric WH	No program	SF	ROB	270	4%	12	0.00	15	$10	100%	20%	75%	29%	55%	78.9%	68.5%	68.5%	0.6	293	0	0	0	0
1038	Appliances	ENERGY STAR Dishwasher - Electric WH	No program	SF	ROB	270	4%	12	0.00	15	$10	100%	20%	75%	29%	55%	78.9%	68.5%	68.5%	0.6	91	0	0	0	0
1039	Appliances	ENERGY STAR Dishwasher - Electric WH	No program	SF	NC	270	4%	12	0.00	15	$10	100%	20%	75%	29%	0%	78.9%	38.3%	66.5%	0.6	47	0	0	0	0
1040	Appliances	ENERGY STAR Dishwasher - Electric WH	No program	MF	ROB	270	4%	12	0.00	15	$10	100%	20%	75%	29%	55%	78.9%	68.5%	68.5%	0.6	92	0	0	0	0
1041	Appliances	ENERGY STAR Dishwasher - Electric WH	No program	MF	ROB	270	4%	12	0.00	15	$10	100%	20%	75%	29%	55%	78.9%	68.5%	68.5%	0.6	29	0	0	0	0
1042	Appliances	ENERGY STAR Dishwasher - Electric WH	No program	MF	NC	270	4%	12	0.00	15	$10	100%	20%	75%	29%	0%	78.9%	38.3%	66.5%	0.6	17	0	0	0	0
1043	Appliances	ENERGY STAR Dishwasher - Gas WH	No program	SF	ROB	270	2%	5	0.00	15	$10	100%	20%	75%	33%	55%	78.9%	68.5%	68.5%	0.2	139	0	0	0	0
1044	Appliances	ENERGY STAR Dishwasher - Gas WH	No program	SF	ROB	270	2%	5	0.00	15	$10	100%	20%	75%	33%	55%	78.9%	68.5%	68.5%	0.2	43	0	0	0	0
1045	Appliances	ENERGY STAR Dishwasher - Gas WH	No program	SF	NC	270	2%	5	0.00	15	$10	100%	20%	75%	33%	0%	78.9%	38.3%	66.5%	0.2	22	0	0	0	0
1046	Appliances	ENERGY STAR Dishwasher - Gas WH	No program	MF	ROB	270	2%	5	0.00	15	$10	100%	20%	75%	33%	55%	78.9%	68.5%	68.5%	0.2	44	0	0	0	0
1047	Appliances	ENERGY STAR Dishwasher - Gas WH	No program	MF	ROB	270	2%	5	0.00	15	$10	100%	20%	75%	33%	55%	78.9%	68.5%	68.5%	0.2	14	0	0	0	0
1048	Appliances	ENERGY STAR Dishwasher - Gas WH	No program	MF	NC	270	2%	5	0.00	15	$10	100%	20%	75%	33%	0%	78.9%	38.3%	66.5%	0.2	7	0	0	0	0
1049	Appliances	ENERGY STAR Water Cooler - Hot and Cold	No program	SF	ROB	799	6%	47	0.01	10	$4	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	3.6	120	154	121	105	105
1050	Appliances	ENERGY STAR Water Cooler - Hot and Cold	No program	SF	ROB	799	6%	47	0.01	10	$4	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	3.6	37	48	38	33	33
1051	Appliances	ENERGY STAR Water Cooler - Hot and Cold	No program	SF	NC	799	6%	47	0.01	10	$4	100%	52%	75%	3%	0%	78.9%	57.2%	66.5%	3.6	19	19	13	9	11
1052	Appliances	ENERGY STAR Water Cooler - Hot and Cold	No program	MF	ROB	799	6%	47	0.01	10	$4	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	3.6	38	48	38	33	33
1053	Appliances	ENERGY STAR Water Cooler - Hot and Cold	No program	MF	ROB	799	6%	47	0.01	10	$4	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	3.6	12	15	12	10	10
1054	Appliances	ENERGY STAR Water Cooler - Hot and Cold	No program	MF	NC	799	6%	47	0.01	10	$4	100%	52%	75%	3%	0%	78.9%	57.2%	66.5%	3.6	6	6	4	3	3
1055	Appliances	ENERGY STAR Air Purifier - CADR 151-200	No program	SF	ROB	1,025	29%	295	0.07	9	$50	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	2.1	744	954	753	654	654
1056	Appliances	ENERGY STAR Air Purifier - CADR 151-200	No program	SF	ROB	1,025	29%	295	0.07	9	$50	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	2.1	231	296	234	203	203
1057	Appliances	ENERGY STAR Air Purifier - CADR 151-200	No program	SF	NC	1,025	29%	295	0.07	9	$50	100%	52%	75%	3%	0%	78.9%	57.2%	66.5%	2.1	119	119	87	61	71
1058	Appliances	ENERGY STAR Air Purifier - CADR 151-200	No program	MF	ROB	1,025	29%	295	0.07	9	$50	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	2.1	235	301	238	206	206
1059	Appliances	ENERGY STAR Air Purifier - CADR 151-200	No program	MF	ROB	1,025	29%	295	0.07	9	$50	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	2.1	73	94	74	64	64
1060	Appliances	ENERGY STAR Air Purifier - CADR 151-200	No program	MF	NC	1,025	29%	295	0.07	9	$50	100%	52%	75%	3%	0%	78.9%	57.2%	66.5%	2.1	38	38	28	19	22
1061	Appliances	ENERGY STAR Ceiling Fan	No program	SF	ROB	105	15%	16	0.01	20	$46	100%	52%	75%	100%	55%	78.9%	68.5%	68.5%	0.4	1,346	0	0	0	0
1062	Appliances	ENERGY STAR Ceiling Fan	No program	SF	ROB	105	15%	16	0.01	20	$46	100%	52%	75%	100%	55%	78.9%	68.5%	68.5%	0.4	418	0	0	0	0
1063	Appliances	ENERGY STAR Ceiling Fan	No program	SF	NC	105	15%	16	0.01	20	$46	100%	52%	75%	100%	0%	78.9%	57.2%	66.5%	0.4	215	0	0	0	0
1064	Appliances	ENERGY STAR Ceiling Fan	No program	MF	ROB	105	15%	16	0.01	20	$46	100%	52%	75%	100%	55%	78.9%	68.5%	68.5%	0.4	425	0	0	0	0
1065	Appliances	ENERGY STAR Ceiling Fan	No program	MF	ROB	105	15%	16	0.01	20	$46	100%	52%	75%	100%	55%	78.9%	68.5%	68.5%	0.4	132	0	0	0	0
1066	Appliances	ENERGY STAR Ceiling Fan	No program	MF	NC	105	15%	16	0.01	20	$46	100%	52%	75%	100%	0%	78.9%	57.2%	66.5%	0.4	68	0	0	0	0
1067	Appliances	Advanced Power Strips - Tier 1	Home Performance	SF	Retrofit	400	13%	53	0.01	10	$21	100%	95%	95%	200%	10%	72.4%	70.4%	70.4%	0.8	0	0	0	0	0
1068	Appliances	Advanced Power Strips - Tier 1	Home Performance	SF	Retrofit	400	13%	53	0.01	10	$21	100%	95%	95%	200%	10%	72.4%	70.4%	70.4%	0.8	0	0	0	0	0
1069	Appliances	Advanced Power Strips - Tier 1	Home Performance	SF	NC	400	13%	53	0.01	10	$21	100%	95%	95%	200%	0%	78.9%	76.4%	76.4%	0.8	0	0	0	0	0
1070	Appliances	Advanced Power Strips - Tier 1	Home Performance	MF	Retrofit	400	13%	53	0.01	10	$21	100%	95%	95%	200%	10%	72.4%	70.4%	70.4%	0.8	0	0	0	0	0
1071	Appliances	Advanced Power Strips - Tier 1	Home Performance	MF	Retrofit	400	13%	53	0.01	10	$21	100%	95%	95%	200%	10%	72.4%	70.4%	70.4%	0.8	0	0	0	0	0
1072	Appliances	Advanced Power Strips - Tier 1	Home Performance	MF	NC	400	13%	53	0.01	10	$21	100%	95%	95%	200%	0%	78.9%	76.4%	76.4%	0.8	0	0	0	0	0
1073	Appliances	Advanced Power Strips - Tier 2	Home Performance	SF	Retrofit	400	51%	204	0.02	10	$65	100%	31%	75%	200%	10%	72.4%	37.0%	62.5%	1.0	40,738	40,738	28,572	12,992	18,286
1074	Appliances	Advanced Power Strips - Tier 2	Home Performance	SF	Retrofit	400	51%	204	0.02	10	$65	100%	31%	75%	200%	10%	72.4%	37.0%	62.5%	1.0	12,654	12,654	8,875	4,036	5,680
1075	Appliances	Advanced Power Strips - Tier 2	Home Performance	SF	NC	400	51%	204	0.02	10	$65	100%	31%	75%	200%	0%	78.9%	44.1%	66.5%	1.0	5,491	5,491	3,604	2,016	3,036
1076	Appliances	Advanced Power Strips - Tier 2	Home Performance	MF	Retrofit	400	51%	204	0.02	10	$65	100%	31%	75%	200%	10%	72.4%	37.0%	62.5%	1.0	12,865	12,865	9,023	4,103	5,775
1077	Appliances	Advanced Power Strips - Tier 2	Home Performance	MF	Retrofit	400	51%	204	0.02	10	$65	100%	31%	75%	200%	10%	72.4%	37.0%	62.5%	1.0	3,996	3,996	2,803	1,274	1,794
1078	Appliances	Advanced Power Strips - Tier 2	Home Performance	MF	NC	400	51%	204	0.02	10	$65	100%	31%	75%	200%	0%	78.9%	44.1%	66.5%	1.0	1,734	1,734	1,138	637	959
1079	Appliances	ENERGY STAR Dehumidifier	No program	SF	ROB	838	17%	142	0.03	15	$10	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	7.9	295	379	299	259	259
1080	Appliances	ENERGY STAR Dehumidifier	No program	SF	ROB	838	17%	142	0.03	15	$10	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	7.9	92	118	93	81	81
1081	Appliances	ENERGY STAR Dehumidifier	No program	SF	NC	838	17%	142	0.03	15	$10	100%	52%	75%	3%	0%	78.9%	57.2%	66.5%	7.9	47	47	30	21	24

Appendix B: Residential Energy Efficiency Detail

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Incentive (%)	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	2% Adoption Rate	TRC Score	2040 TP	2040 EP	2040 HCAP	2040 RAP	2040 2% Case
1082	Appliances	ENERGY STAR Dehumidifier	No program	MF	ROB	838	17%	142	0.03	15	$10	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	7.9	93	120	94	82	82
1083	Appliances	ENERGY STAR Dehumidifier	No program	MF	ROB	838	17%	142	0.03	15	$10	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	7.9	29	37	29	25	25
1084	Appliances	ENERGY STAR Dehumidifier	No program	MF	NC	838	17%	142	0.03	15	$10	100%	52%	75%	3%	0%	78.9%	57.2%	66.5%	7.9	15	15	10	7	8
1085	Appliances	ENERGY STAR Most Efficient Dehumidifier	No program	SF	ROB	838	25%	210	0.05	15	$75	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	1.7	93	119	94	82	82
1086	Appliances	ENERGY STAR Most Efficient Dehumidifier	No program	SF	ROB	838	25%	210	0.05	15	$75	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	1.7	29	37	29	25	25
1087	Appliances	ENERGY STAR Most Efficient Dehumidifier	No program	SF	NC	838	25%	210	0.05	15	$75	100%	52%	75%	3%	0%	78.9%	57.2%	66.5%	1.7	15	15	9	7	8
1088	Appliances	ENERGY STAR Most Efficient Dehumidifier	No program	MF	ROB	838	25%	210	0.05	15	$75	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	1.7	29	38	30	26	26
1089	Appliances	ENERGY STAR Most Efficient Dehumidifier	No program	MF	ROB	838	25%	210	0.05	15	$75	100%	52%	75%	3%	55%	78.9%	68.5%	68.5%	1.7	9	12	9	8	8
1090	Appliances	ENERGY STAR Most Efficient Dehumidifier	No program	MF	NC	838	25%	210	0.05	15	$75	100%	52%	75%	3%	0%	78.9%	57.2%	66.5%	1.7	5	5	3	2	2
1091	Appliances	ENERGY STAR Pool Pump(Variable Spd)	Residential Lighting & Appliance	SF	ROB	3,383	15%	520	0.06	10	$314	100%	56%	75%	9%	55%	78.9%	68.5%	68.5%	0.6	3,937	0	0	0	0
1092	Appliances	ENERGY STAR Pool Pump(Variable Spd)	Residential Lighting & Appliance	SF	ROB	3,383	15%	520	0.06	10	$314	100%	56%	75%	9%	55%	78.9%	68.5%	68.5%	0.6	1,223	0	0	0	0
1093	Appliances	ENERGY STAR Pool Pump(Variable Spd)	Residential Lighting & Appliance	SF	NC	3,383	15%	520	0.06	10	$314	100%	56%	75%	9%	0%	78.9%	58.7%	66.5%	0.6	629	0	0	0	0
1094	Appliances	ENERGY STAR Pool Pump(Variable Spd)	Residential Lighting & Appliance	MF	ROB	3,383	15%	520	0.06	10	$314	100%	56%	75%	9%	55%	78.9%	68.5%	68.5%	0.6	1,243	0	0	0	0
1095	Appliances	ENERGY STAR Pool Pump(Variable Spd)	Residential Lighting & Appliance	MF	ROB	3,383	15%	520	0.06	10	$314	100%	56%	75%	9%	55%	78.9%	68.5%	68.5%	0.6	386	0	0	0	0
1096	Appliances	ENERGY STAR Pool Pump(Variable Spd)	Residential Lighting & Appliance	MF	NC	3,383	15%	520	0.06	10	$314	100%	56%	75%	9%	0%	78.9%	58.7%	66.5%	0.6	199	0	0	0	0
1097	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	SF	ROB	564	10%	56	0.01	17	$40	100%	100%	100%	100%	55%	78.9%	78.9%	78.9%	0.8	8,564	0	0	0	0
1098	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	SF	ROB	564	10%	56	0.01	17	$40	100%	100%	100%	100%	55%	78.9%	78.9%	78.9%	0.8	2,660	0	0	0	0
1099	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	SF	ER	564	10%	56	0.01	17	$70	100%	57%	75%	100%	55%	68.5%	68.5%	68.5%	0.5	582	0	0	0	0
1100	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	SF	ER	564	10%	56	0.01	17	$70	100%	57%	75%	100%	55%	68.5%	68.5%	68.5%	0.5	181	0	0	0	0
1101	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	SF	NC	564	10%	56	0.01	17	$40	100%	100%	100%	100%	0%	78.9%	78.9%	78.9%	0.8	531	0	0	0	0
1102	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	MF	ROB	564	10%	56	0.01	17	$40	100%	100%	100%	100%	55%	78.9%	78.9%	78.9%	0.8	657	0	0	0	0
1103	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	MF	ROB	564	10%	56	0.01	17	$40	100%	100%	100%	100%	55%	78.9%	78.9%	78.9%	0.8	204	0	0	0	0
1104	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	MF	ER	564	10%	56	0.01	17	$70	100%	57%	75%	100%	55%	68.5%	68.5%	68.5%	0.5	190	0	0	0	0
1105	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	MF	ER	564	10%	56	0.01	17	$70	100%	57%	75%	100%	55%	68.5%	68.5%	68.5%	0.5	59	0	0	0	0
1106	Appliances	ENERGY STAR Refrigerator	Residential Lighting & Appliance	MF	NC	564	10%	56	0.01	17	$40	100%	100%	100%	100%	0%	78.9%	78.9%	78.9%	0.8	168	0	0	0	0
1107	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	SF	ROB	564	15%	85	0.01	17	$140	100%	29%	75%	100%	55%	78.9%	68.5%	68.5%	0.3	1,295	0	0	0	0
1108	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	SF	ROB	564	15%	85	0.01	17	$140	100%	29%	75%	100%	55%	78.9%	68.5%	68.5%	0.3	402	0	0	0	0
1109	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	SF	ER	564	15%	85	0.01	17	$170	100%	24%	75%	100%	55%	68.5%	68.5%	68.5%	0.3	539	0	0	0	0
1110	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	SF	ER	564	15%	85	0.01	17	$170	100%	24%	75%	100%	55%	68.5%	68.5%	68.5%	0.3	167	0	0	0	0
1111	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	SF	NC	564	15%	85	0.01	17	$140	100%	29%	75%	100%	0%	78.9%	42.9%	66.5%	0.3	341	0	0	0	0
1112	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	MF	ROB	564	15%	85	0.01	17	$170	100%	24%	75%	100%	55%	78.9%	68.5%	68.5%	0.3	348	0	0	0	0
1113	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	MF	ROB	564	15%	85	0.01	17	$170	100%	24%	75%	100%	55%	78.9%	68.5%	68.5%	0.3	108	0	0	0	0
1114	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	MF	ER	564	15%	85	0.01	17	$170	100%	24%	75%	100%	55%	68.5%	68.5%	68.5%	0.3	176	0	0	0	0
1115	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	MF	ER	564	15%	85	0.01	17	$170	100%	24%	75%	100%	55%	68.5%	68.5%	68.5%	0.3	55	0	0	0	0
1116	Appliances	ENERGY STAR Refrigerator - Tier 2	Residential Lighting & Appliance	MF	NC	564	15%	85	0.01	17	$140	100%	29%	75%	100%	0%	78.9%	42.9%	66.5%	0.3	108	0	0	0	0
1117	Appliances	ENERGY STAR Freezer	No program	SF	ROB	349	10%	35	0.01	22	$42	100%	52%	75%	20%	55%	78.9%	68.5%	68.5%	0.6	535	0	0	0	0
1118	Appliances	ENERGY STAR Freezer	No program	SF	ROB	349	10%	35	0.01	22	$42	100%	52%	75%	20%	55%	78.9%	68.5%	68.5%	0.6	166	0	0	0	0
1119	Appliances	ENERGY STAR Freezer	No program	SF	NC	349	10%	35	0.01	22	$42	100%	52%	75%	20%	0%	78.9%	57.2%	66.5%	0.6	94	0	0	0	0
1120	Appliances	ENERGY STAR Freezer	No program	MF	ROB	349	10%	35	0.01	22	$42	100%	52%	75%	20%	55%	78.9%	68.5%	68.5%	0.6	169	0	0	0	0
1121	Appliances	ENERGY STAR Freezer	No program	MF	ROB	349	10%	35	0.01	22	$42	100%	52%	75%	20%	55%	78.9%	68.5%	68.5%	0.6	53	0	0	0	0
1122	Appliances	ENERGY STAR Freezer	No program	MF	NC	349	10%	35	0.01	22	$42	100%	52%	75%	20%	0%	78.9%	57.2%	66.5%	0.6	30	0	0	0	0
1123	Appliances	Refrigerator Recycling	No program	SF	Recycle	1,192	93%	1,111	0.14	17	$170	100%	29%	75%	8%	0%	70.3%	30.0%	52.6%	3.6	8,147	8,147	3,875	437	417
1124	Appliances	Refrigerator Recycling	No program	SF	Recycle	1,192	93%	1,111	0.14	17	$170	100%	29%	75%	8%	0%	70.3%	30.0%	52.6%	3.6	2,531	2,531	1,204	136	130
1125	Appliances	Refrigerator Recycling	No program	MF	Recycle	1,192	93%	1,111	0.14	17	$170	100%	29%	75%	8%	0%	70.3%	30.0%	52.6%	3.6	2,573	2,573	1,224	138	132
1126	Appliances	Refrigerator Recycling	No program	MF	Recycle	1,192	93%	1,111	0.14	17	$170	100%	29%	75%	8%	0%	70.3%	30.0%	52.6%	3.6	799	799	380	43	41
1127	Appliances	Freezer Recycling	No program	SF	Recycle	772	85%	660	0.08	12	$170	100%	29%	75%	6%	0%	70.3%	30.0%	52.6%	1.5	2,562	2,562	1,509	138	125
1128	Appliances	Freezer Recycling	No program	SF	Recycle	772	85%	660	0.08	12	$170	100%	29%	75%	6%	0%	70.3%	30.0%	52.6%	1.5	796	796	469	43	39
1129	Appliances	Freezer Recycling	No program	MF	Recycle	772	85%	660	0.08	12	$170	100%	29%	75%	6%	0%	70.3%	30.0%	52.6%	1.5	809	809	477	44	40
1130	Appliances	Freezer Recycling	No program	MF	Recycle	772	85%	660	0.08	12	$170	100%	29%	75%	6%	0%	70.3%	30.0%	52.6%	1.5	251	251	148	14	12
2001	Domestic Hot Water	Heat Pump Water Heater - Gas Furnace	Residential Lighting & Appliance	SF	ROB	2,455	74%	1,826	0.16	10	$404	100%	37%	75%	8%	1%	82.2%	43.1%	66.5%	1.4	3,650	3,672	3,328	1,751	2,667
2002	Domestic Hot Water	Heat Pump Water Heater - Gas Furnace	Residential Lighting & Appliance	SF	ROB	2,455	74%	1,826	0.16	10	$404	100%	37%	75%	8%	1%	82.2%	43.1%	66.5%	1.4	1,134	1,141	1,034	544	829
2003	Domestic Hot Water	Heat Pump Water Heater - Gas Furnace	Residential Lighting & Appliance	SF	NC	2,455	74%	1,826	0.16	10	$404	100%	37%	75%	8%	0%	82.2%	43.1%	66.5%	1.4	595	595	536	278	429
2004	Domestic Hot Water	Heat Pump Water Heater - Gas Furnace	Residential Lighting & Appliance	MF	ROB	2,455	74%	1,826	0.16	10	$404	100%	37%	75%	8%	1%	82.2%	43.1%	66.5%	1.4	576	580	525	277	421
2005	Domestic Hot Water	Heat Pump Water Heater - Gas Furnace	Residential Lighting & Appliance	MF	ROB	2,455	74%	1,826	0.16	10	$404	100%	37%	75%	8%	1%	82.2%	43.1%	66.5%	1.4	179	180	163	86	131
2006	Domestic Hot Water	Heat Pump Water Heater - Gas Furnace	Residential Lighting & Appliance	MF	NC	2,455	74%	1,826	0.16	10	$404	100%	37%	75%	8%	0%	82.2%	43.1%	66.5%	1.4	94	94	85	44	68
2007	Domestic Hot Water	Heat Pump Water Heater - Heat Pump	Residential Lighting & Appliance	SF	ROB	2,455	66%	1,631	0.14	10	$404	100%	37%	75%	3%	1%	82.2%	43.1%	66.5%	1.3	1,143	1,150	1,042	548	835
2008	Domestic Hot Water	Heat Pump Water Heater - Heat Pump	Residential Lighting & Appliance	SF	ROB	2,455	66%	1,631	0.14	10	$404	100%	37%	75%	3%	1%	82.2%	43.1%	66.5%	1.3	355	357	324	170	259
2009	Domestic Hot Water	Heat Pump Water Heater - Heat Pump	Residential Lighting & Appliance	SF	NC	2,455	66%	1,631	0.14	10	$404	100%	37%	75%	3%	0%	82.2%	43.1%	66.5%	1.3	186	186	168	87	134
2010	Domestic Hot Water	Heat Pump Water Heater - Heat Pump	Residential Lighting & Appliance	MF	ROB	2,455	66%	1,631	0.14	10	$404	100%	37%	75%	3%	1%	82.2%	43.1%	66.5%	1.3	181	182	165	87	132
2011	Domestic Hot Water	Heat Pump Water Heater - Heat Pump	Residential Lighting & Appliance	MF	ROB	2,455	66%	1,631	0.14	10	$404	100%	37%	75%	3%	1%	82.2%	43.1%	66.5%	1.3	56	56	51	27	41
2012	Domestic Hot Water	Heat Pump Water Heater - Heat Pump	Residential Lighting & Appliance	MF	NC	2,455	66%	1,631	0.14	10	$404	100%	37%	75%	3%	0%	82.2%	43.1%	66.5%	1.3	29	29	27	14	21
2013	Domestic Hot Water	Heat Pump Water Heater - Electric Resistance	Residential Lighting & Appliance	SF	ROB	2,455	61%	1,497	0.13	10	$404	100%	37%	75%	37%	1%	82.2%	43.1%	66.5%	1.2	14,186	14,271	12,934	6,806	10,366
2014	Domestic Hot Water	Heat Pump Water Heater - Electric Resistance	Residential Lighting & Appliance	SF	ROB	2,455	61%	1,497	0.13	10	$404	100%	37%	75%	37%	1%	82.2%	43.1%	66.5%	1.2	4,406	4,433	4,017	2,114	3,220
2015	Domestic Hot Water	Heat Pump Water Heater - Electric Resistance	Residential Lighting & Appliance	SF	NC	2,455	61%	1,497	0.13	10	$404	100%	37%	75%	37%	0%	82.2%	43.1%	66.5%	1.2	2,311	2,313	2,084	1,079	1,666
2016	Domestic Hot Water	Heat Pump Water Heater - Electric Resistance	Residential Lighting & Appliance	MF	ROB	2,455	61%	1,497	0.13	10	$404	100%	37%	75%	37%	1%	82.2%	43.1%	66.5%	1.2	2,240	2,253	2,042	1,075	1,637
2017	Domestic Hot Water	Heat Pump Water Heater - Electric Resistance	Residential Lighting & Appliance	MF	ROB	2,455	61%	1,497	0.13	10	$404	100%	37%	75%	37%	1%	82.2%	43.1%	66.5%	1.2	696	700	634	334	508
2018	Domestic Hot Water	Heat Pump Water Heater - Electric Resistance	Residential Lighting & Appliance	MF	NC	2,455	61%	1,497	0.13	10	$404	100%	37%	75%	37%	0%	82.2%	43.1%	66.5%	1.2	365	365	329	170	263
2019	Domestic Hot Water	Heat Pump Water Heater - Unconditioned	Residential Lighting & Appliance	SF	ROB	2,455	69%	1,690	0.15	10	$404	100%	37%	75%	47%	1%	82.2%	43.1%	66.5%	1.3	20,622	20,746	18,801	9,893	15,068
2020	Domestic Hot Water	Heat Pump Water Heater - Unconditioned	Residential Lighting & Appliance	SF	ROB	2,455	69%	1,690	0.15	10	$404	100%	37%	75%	47%	1%	82.2%	43.1%	66.5%	1.3	6,405	6,444	5,840	3,073	4,680
2021	Domestic Hot Water	Heat Pump Water Heater - Unconditioned	Residential Lighting & Appliance	SF	NC	2,455	69%	1,690	0.15	10	$404	100%	37%	75%	47%	0%	82.2%	43.1%	66.5%	1.3	3,360	3,363	3,029	1,569	2,421
2022	Domestic Hot Water	Heat Pump Water Heater - Unconditioned	Residential Lighting & Appliance	MF	ROB	2,455	69%	1,690	0.15	10	$404	100%	37%	75%	47%	1%	82.2%	43.1%	66.5%	1.3	3,256	3,276	2,969	1,562	2,379
2023	Domestic Hot Water	Heat Pump Water Heater - Unconditioned	Residential Lighting & Appliance	MF	ROB	2,455	69%	1,690	0.15	10	$404	100%	37%	75%	47%	1%	82.2%	43.1%	66.5%	1.3	1,011	1,017	922	485	739
2024	Domestic Hot Water	Heat Pump Water Heater - Unconditioned	Residential Lighting & Appliance	MF	NC	2,455	69%	1,690	0.15	10	$404	100%	37%	75%	47%	0%	82.2%	43.1%	66.5%	1.3	531	531	478	248	382
2025	Domestic Hot Water	Solar with Electric Backup	No program	SF	ROB	2,455	90%	2,212	0.19	15	$8,401	100%	5%	75%	0%	1%	82.2%	30.9%	66.5%	0.1	0	0	0	0	0
2026	Domestic Hot Water	Solar with Electric Backup	No program	SF	ROB	2,455	90%	2,212	0.19	15	$8,401	100%	5%	75%	0%	1%	82.2%	30.9%	66.5%	0.1	0	0	0	0	0
2027	Domestic Hot Water	Solar with Electric Backup	No program	SF	NC	2,455	90%	2,212	0.19	15	$8,401	100%	5%	75%	0%	0%	82.2%	30.0%	66.5%	0.1	0	0	0	0	0
2028	Domestic Hot Water	Solar with Electric Backup	No program	MF	ROB	2,455	90%	2,212	0.19	15	$8,401	100%	5%	75%	0%	1%	82.2%	30.9%	66.5%	0.1	0	0	0	0	0
2029	Domestic Hot Water	Solar with Electric Backup	No program	MF	ROB	2,455	90%	2,212	0.19	15	$8,401	100%	5%	75%	0%	1%	82.2%	30.9%	66.5%	0.1	0	0	0	0	0
2030	Domestic Hot Water	Solar with Electric Backup	No program	MF	NC	2,455	90%	2,212	0.19	15	$8,401	100%	5%	75%	0%	0%	82.2%	30.0%	66.5%	0.1	0	0	0	0	0
2031	Domestic Hot Water	Water Heater Jacket (3"WHJ)	No program	SF	Retrofit	2,455	4%	104	0.01	13	$35	100%	100%	100%	47%	36%	72.4%	72.4%	72.4%	1.2	3,848	3,848	2,392	2,392	2,356
2032	Domestic Hot Water	Water Heater Jacket (3"WHJ)	No program	SF	Retrofit	2,455	4%	104	0.01	13	$35	100%	100%	100%	47%	36%	72.4%	72.4%	72.4%	1.2	1,195	1,195	743	743	732

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Incentive (%)	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	2% Adoption Rate	TRC Score	2040 TP	2040 EP	2040 HCAP	2040 RAP	2040 2% Case
2033	Domestic Hot Water	Water Heater Jacket (3"WHJ)	No program	SF	NC	2,455	4%	104	0.01	13	$35	100%	100%	100%	47%	0%	72.4%	72.4%	72.4%	1.2	657	657	404	383	383
2034	Domestic Hot Water	Water Heater Jacket (3"WHJ)	No program	MF	Retrofit	2,455	4%	104	0.01	13	$35	100%	100%	100%	47%	36%	72.4%	72.4%	72.4%	1.2	1,215	1,215	755	755	744
2035	Domestic Hot Water	Water Heater Jacket (3"WHJ)	No program	MF	Retrofit	2,455	4%	104	0.01	13	$35	100%	100%	100%	47%	36%	72.4%	72.4%	72.4%	1.2	377	377	235	235	231
2036	Domestic Hot Water	Water Heater Jacket (3"WHJ)	No program	MF	NC	2,455	4%	104	0.01	13	$35	100%	100%	100%	47%	0%	72.4%	72.4%	72.4%	1.2	208	208	127	121	121
2037	Domestic Hot Water	Water Heater Pipe Insulation (3/4"pipe) See C.2.3.1 (NE for residential retrofit & NC)	Home Performance	SF	Retrofit	2,455	2%	38	0.00	11	$15	100%	100%	100%	47%	36%	72.4%	72.4%	72.4%	0.9	1,406	1,406	874	874	851
2038	Domestic Hot Water	Water Heater Pipe Insulation (3/4"pipe) See C.2.3.1 (NE for residential retrofit & NC)	Low Income	SF	Retrofit	2,455	2%	38	0.00	11	$15	100%	100%	100%	47%	36%	72.4%	72.4%	72.4%	0.9	437	437	271	271	257
2039	Domestic Hot Water	Water Heater Pipe Insulation (3/4"pipe) See C.2.3.1 (NE for residential retrofit & NC)	Home Performance	SF	NC	2,456	102%	38	0.00	11	$15	100%	100%	100%	47%	0%	72.4%	72.4%	72.4%	0.9	240	240	145	145	145
2040	Domestic Hot Water	Water Heater Pipe Insulation (3/4"pipe) See C.2.3.1 (NE for residential retrofit & NC)	Multifamily	MF	Retrofit	2,457	202%	38	0.00	11	$15	100%	100%	100%	47%	36%	72.4%	72.4%	72.4%	0.9	444	444	276	276	274
2041	Domestic Hot Water	Water Heater Pipe Insulation (3/4"pipe) See C.2.3.1 (NE for residential retrofit & NC)	Low Income	MF	Retrofit	2,458	302%	38	0.00	11	$15	100%	100%	100%	47%	36%	72.4%	72.4%	72.4%	0.9	138	138	86	86	81
2042	Domestic Hot Water	Water Heater Pipe Insulation (3/4"pipe) See C.2.3.1 (NE for residential retrofit & NC)	Multifamily	MF	NC	2,459	402%	38	0.00	11	$15	100%	100%	100%	47%	0%	72.4%	72.4%	72.4%	0.9	76	76	46	46	46
2043	Domestic Hot Water	Faucet Aerators - 1.5 gpm, electric resistance WH	Home Performance	SF	Retrofit	173	15%	27	0.00	10	$4	100%	100%	100%	73%	60%	72.4%	72.4%	72.4%	9.7	433	433	216	216	215
2044	Domestic Hot Water	Faucet Aerators - 1.5 gpm, electric resistance WH	Low Income	SF	Retrofit	173	15%	27	0.00	10	$4	100%	100%	100%	73%	60%	72.4%	72.4%	72.4%	9.7	135	135	67	67	66
2045	Domestic Hot Water	Faucet Aerators - 1.5 gpm, electric resistance WH	Multifamily	MF	Retrofit	173	15%	27	0.00	10	$4	100%	100%	100%	73%	60%	72.4%	72.4%	72.4%	9.7	137	137	68	68	68
2046	Domestic Hot Water	Faucet Aerators - 1.5 gpm, electric resistance WH	Low Income	MF	Retrofit	173	15%	27	0.00	10	$4	100%	100%	100%	73%	60%	72.4%	72.4%	72.4%	9.7	42	42	21	21	21
2047	Domestic Hot Water	Faucet Aerators - 1.5 gpm, heat pump WH	Home Performance	SF	Retrofit	77	15%	12	0.00	10	$4	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	8.4	14	14	7	7	7
2048	Domestic Hot Water	Faucet Aerators - 1.5 gpm, heat pump WH	Low Income	SF	Retrofit	77	15%	12	0.00	10	$4	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	8.4	4	4	2	2	2
2049	Domestic Hot Water	Faucet Aerators - 1.5 gpm, heat pump WH	Multifamily	MF	Retrofit	77	15%	12	0.00	10	$4	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	8.4	5	5	2	2	2
2050	Domestic Hot Water	Faucet Aerators - 1.5 gpm, heat pump WH	Low Income	MF	Retrofit	77	15%	12	0.00	10	$4	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	8.4	1	1	1	1	1
2051	Domestic Hot Water	Faucet Aerators - 1.0 gpm, electric resistance WH	Home Performance	SF	Retrofit	173	26%	45	0.00	10	$4	100%	100%	100%	73%	60%	72.4%	72.4%	72.4%	16.1	1,202	1,202	598	598	597
2052	Domestic Hot Water	Faucet Aerators - 1.0 gpm, electric resistance WH	Low Income	SF	Retrofit	173	26%	45	0.00	10	$4	100%	100%	100%	73%	60%	72.4%	72.4%	72.4%	16.1	373	373	186	186	183
2053	Domestic Hot Water	Faucet Aerators - 1.0 gpm, electric resistance WH	Multifamily	MF	Retrofit	173	26%	45	0.00	10	$4	100%	100%	100%	73%	60%	72.4%	72.4%	72.4%	16.1	380	380	189	189	189
2054	Domestic Hot Water	Faucet Aerators - 1.0 gpm, electric resistance WH	Low Income	MF	Retrofit	173	26%	45	0.00	10	$4	100%	100%	100%	73%	60%	72.4%	72.4%	72.4%	16.1	118	118	59	59	58
2055	Domestic Hot Water	Faucet Aerators - 1.0 gpm, heat pump WH	Home Performance	SF	Retrofit	77	26%	20	0.00	10	$4	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	14.1	40	40	20	20	20
2056	Domestic Hot Water	Faucet Aerators - 1.0 gpm, heat pump WH	Low Income	SF	Retrofit	77	26%	20	0.00	10	$4	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	14.1	12	12	6	6	6
2057	Domestic Hot Water	Faucet Aerators - 1.0 gpm, heat pump WH	Multifamily	MF	Retrofit	77	26%	20	0.00	10	$4	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	14.1	13	13	6	6	6
2058	Domestic Hot Water	Faucet Aerators - 1.0 gpm, heat pump WH	Low Income	MF	Retrofit	77	26%	20	0.00	10	$4	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	14.1	4	4	2	2	2
2059	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, electric resistance WH	Home Performance	SF	Retrofit	608	17%	102	0.01	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	14.7	784	784	390	390	389
2060	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, electric resistance WH	Low Income	SF	Retrofit	608	17%	102	0.01	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	14.7	243	243	121	121	119
2061	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, electric resistance WH	Home Performance	SF	NC	608	17%	102	0.01	10	$10	100%	100%	100%	63%	0%	72.4%	72.4%	72.4%	14.7	178	178	107	107	107
2062	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, electric resistance WH	Multifamily	MF	Retrofit	608	17%	102	0.01	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	14.7	248	248	123	123	123
2063	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, electric resistance WH	Low Income	MF	Retrofit	608	17%	102	0.01	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	14.7	77	77	38	38	38
2064	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, electric resistance WH	Multifamily	MF	NC	608	17%	102	0.01	10	$10	100%	100%	100%	63%	0%	72.4%	72.4%	72.4%	14.7	56	56	34	34	34
2065	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, heat pump WH	Home Performance	SF	Retrofit	271	17%	46	0.00	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	12.9	26	26	13	13	13
2066	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, heat pump WH	Low Income	SF	Retrofit	271	17%	46	0.00	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	12.9	8	8	4	4	4
2067	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, heat pump WH	Home Performance	SF	NC	271	17%	46	0.00	10	$10	100%	100%	100%	5%	0%	72.4%	72.4%	72.4%	12.9	6	6	4	4	4
2068	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, heat pump WH	Multifamily	MF	Retrofit	271	17%	46	0.00	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	12.9	8	8	4	4	4
2069	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, heat pump WH	Low Income	MF	Retrofit	271	17%	46	0.00	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	12.9	3	3	1	1	1
2070	Domestic Hot Water	Low Flow Showerhead - 2.0 gpm, heat pump WH	Multifamily	MF	NC	271	17%	46	0.00	10	$10	100%	100%	100%	5%	0%	72.4%	72.4%	72.4%	12.9	2	2	1	1	1
2071	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, electric resistance WH	Home Performance	SF	Retrofit	271	61%	165	0.02	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	23.8	2,048	2,048	1,019	1,019	1,017
2072	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, electric resistance WH	Low Income	SF	Retrofit	271	61%	165	0.02	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	23.8	636	636	317	317	312
2073	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, electric resistance WH	Home Performance	SF	NC	271	61%	165	0.02	10	$10	100%	100%	100%	63%	0%	72.4%	72.4%	72.4%	23.8	464	464	279	279	279
2074	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, electric resistance WH	Multifamily	MF	Retrofit	271	61%	165	0.02	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	23.8	647	647	322	322	322
2075	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, electric resistance WH	Low Income	MF	Retrofit	271	61%	165	0.02	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	23.8	201	201	100	100	98
2076	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, electric resistance WH	Multifamily	MF	NC	271	61%	165	0.02	10	$10	100%	100%	100%	63%	0%	72.4%	72.4%	72.4%	23.8	147	147	88	88	88
2077	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, heat pump WH	Home Performance	SF	Retrofit	271	27%	74	0.01	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	20.8	68	68	34	34	34
2078	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, heat pump WH	Low Income	SF	Retrofit	271	27%	74	0.01	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	20.8	21	21	11	11	10
2079	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, heat pump WH	Home Performance	SF	NC	271	27%	74	0.01	10	$10	100%	100%	100%	5%	0%	72.4%	72.4%	72.4%	20.8	15	15	9	9	9
2080	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, heat pump WH	Multifamily	MF	Retrofit	271	27%	74	0.01	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	20.8	21	21	11	11	11
2081	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, heat pump WH	Low Income	MF	Retrofit	271	27%	74	0.01	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	20.8	7	7	3	3	3
2082	Domestic Hot Water	Low Flow Showerhead - 1.75 gpm, heat pump WH	Multifamily	MF	NC	271	27%	74	0.01	10	$10	100%	100%	100%	5%	0%	72.4%	72.4%	72.4%	20.8	5	5	3	3	3
2083	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, electric resistance WH	Home Performance	SF	Retrofit	271	84%	228	0.02	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	32.9	3,908	3,908	1,945	1,945	1,941
2084	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, electric resistance WH	Low Income	SF	Retrofit	271	84%	228	0.02	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	32.9	1,214	1,214	604	604	595
2085	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, electric resistance WH	Home Performance	SF	NC	271	84%	228	0.02	10	$10	100%	100%	100%	63%	0%	72.4%	72.4%	72.4%	32.9	886	886	533	533	533
2086	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, electric resistance WH	Multifamily	MF	Retrofit	271	84%	228	0.02	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	32.9	1,234	1,234	614	614	614
2087	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, electric resistance WH	Low Income	MF	Retrofit	271	84%	228	0.02	10	$10	100%	100%	100%	63%	60%	72.4%	72.4%	72.4%	32.9	383	383	191	191	188
2088	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, electric resistance WH	Multifamily	MF	NC	271	84%	228	0.02	10	$10	100%	100%	100%	63%	0%	72.4%	72.4%	72.4%	32.9	280	280	168	168	168
2089	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, heat pump WH	Home Performance	SF	Retrofit	271	38%	102	0.01	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	28.8	129	129	64	64	64
2090	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, heat pump WH	Low Income	SF	Retrofit	271	38%	102	0.01	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	28.8	40	40	20	20	20
2091	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, heat pump WH	Home Performance	SF	NC	271	38%	102	0.01	10	$10	100%	100%	100%	5%	0%	72.4%	72.4%	72.4%	28.8	29	29	18	18	18
2092	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, heat pump WH	Multifamily	MF	Retrofit	271	38%	102	0.01	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	28.8	41	41	20	20	20
2093	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, heat pump WH	Low Income	MF	Retrofit	271	38%	102	0.01	10	$10	100%	100%	100%	5%	60%	72.4%	72.4%	72.4%	28.8	13	13	6	6	6
2094	Domestic Hot Water	Low Flow Showerhead - 1.5 gpm, heat pump WH	Multifamily	MF	NC	271	38%	102	0.01	10	$10	100%	100%	100%	5%	0%	72.4%	72.4%	72.4%	28.8	9	9	6	6	6
2095	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Electric Resistance WH	Home Performance	SF	Retrofit	271	21%	58	0.01	10	$45	100%	22%	75%	63%	60%	72.0%	72.0%	72.0%	1.4	1,295	1,295	636	636	606
2096	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Electric Resistance WH	Low Income	SF	Retrofit	271	21%	58	0.01	10	$45	100%	100%	100%	63%	60%	72.0%	72.0%	72.0%	1.4	402	402	197	197	194
2097	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Electric Resistance WH	Home Performance	SF	NC	271	21%	58	0.01	10	$45	100%	22%	75%	63%	0%	70.3%	30.0%	52.6%	1.4	293	293	171	73	128
2098	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Electric Resistance WH	Multifamily	MF	Retrofit	271	21%	58	0.01	10	$45	100%	22%	75%	63%	60%	72.0%	72.0%	72.0%	1.4	409	409	201	201	191
2099	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Electric Resistance WH	Low Income	MF	Retrofit	271	21%	58	0.01	10	$45	100%	100%	100%	63%	60%	72.0%	72.0%	72.0%	1.4	127	127	62	62	61
2100	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Electric Resistance WH	Multifamily	MF	NC	271	21%	58	0.01	10	$45	100%	22%	75%	63%	0%	70.3%	30.0%	52.6%	1.4	93	93	54	23	41
2101	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Heat Pump WH	Home Performance	SF	Retrofit	271	10%	26	0.00	10	$45	100%	22%	75%	5%	60%	72.0%	72.0%	72.0%	1.1	49	72	35	35	34
2102	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Heat Pump WH	Low Income	SF	Retrofit	271	10%	26	0.00	10	$45	100%	100%	100%	5%	60%	72.0%	72.0%	72.0%	1.1	15	15	7	7	7
2103	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Heat Pump WH	Home Performance	SF	NC	271	10%	26	0.00	10	$45	100%	22%	75%	5%	0%	70.3%	30.0%	52.6%	1.1	11	16	9	4	7
2104	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Heat Pump WH	Multifamily	MF	Retrofit	271	10%	26	0.00	10	$45	100%	22%	75%	5%	60%	72.0%	72.0%	72.0%	1.1	15	23	11	11	11
2105	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Heat Pump WH	Low Income	MF	Retrofit	271	10%	26	0.00	10	$45	100%	100%	100%	5%	60%	72.0%	72.0%	72.0%	1.1	5	5	2	2	2

Appendix B: Residential Energy Efficiency Detail

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Incentive (%)	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	2% Adoption Rate	TRC Score	2040 TP	2040 EP	2040 HCAP	2040 RAP	2040 2% Case
2106	Domestic Hot Water	Showerhead Thermostatic Restrictor Valves - Heat Pump WH	Multifamily	MF	NC	271	10%	26	0.00	10	$45	100%	22%	75%	5%	0%	70.3%	30.0%	52.6%	1.1	3	5	3	1	2
2107	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Electric Resistance WH	Home Performance	SF	Retrofit	271	86%	232	0.02	10	$111	100%	9%	75%	63%	60%	72.0%	72.0%	72.0%	0.9	3,460	3,460	1,699	1,699	1,621
2108	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Electric Resistance WH	Low Income	SF	Retrofit	271	86%	232	0.02	10	$111	100%	100%	100%	63%	60%	72.0%	72.0%	72.0%	0.9	1,075	1,075	528	528	520
2109	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Electric Resistance WH	Home Performance	SF	NC	271	86%	232	0.02	10	$111	100%	9%	75%	63%	0%	70.3%	30.0%	52.6%	0.9	784	784	458	196	343
2110	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Electric Resistance WH	Multifamily	MF	Retrofit	271	86%	232	0.02	10	$111	100%	9%	75%	63%	60%	72.0%	72.0%	72.0%	0.9	1,093	1,093	536	536	512
2111	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Electric Resistance WH	Low Income	MF	Retrofit	271	86%	232	0.02	10	$111	100%	100%	100%	63%	60%	72.0%	72.0%	72.0%	0.9	339	339	167	167	164
2112	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Electric Resistance WH	Multifamily	MF	NC	271	86%	232	0.02	10	$111	100%	9%	75%	63%	0%	70.3%	30.0%	52.6%	0.9	248	248	145	62	108
2113	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Heat Pump WH	Home Performance	SF	Retrofit	271	38%	103	0.01	10	$111	100%	9%	75%	5%	60%	72.0%	72.0%	72.0%	0.5	91	0	0	0	0
2114	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Heat Pump WH	Low Income	SF	Retrofit	271	38%	103	0.01	10	$111	100%	100%	100%	5%	60%	72.0%	72.0%	72.0%	0.5	28	28	14	14	14
2115	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Heat Pump WH	Home Performance	SF	NC	271	38%	103	0.01	10	$111	100%	9%	75%	5%	0%	70.3%	30.0%	52.6%	0.5	21	0	0	0	0
2116	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Heat Pump WH	Multifamily	MF	Retrofit	271	38%	103	0.01	10	$111	100%	9%	75%	5%	60%	72.0%	72.0%	72.0%	0.5	29	0	0	0	0
2117	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Heat Pump WH	Low Income	MF	Retrofit	271	38%	103	0.01	10	$111	100%	100%	100%	5%	60%	72.0%	72.0%	72.0%	0.5	9	9	4	4	4
2118	Domestic Hot Water	Tub Sport Diverters and Thermostatic Restrictor Valve - Heat Pump WH	Multifamily	MF	NC	271	38%	103	0.01	10	$111	100%	9%	75%	5%	0%	70.3%	30.0%	52.6%	0.5	6	0	0	0	0
2119	Domestic Hot Water	Tankless Water Heater	No program	SF	ROB	2,455	0%	0	0.00	20	$1,850	100%	22%	75%	47%	1%	82.2%	33.6%	66.5%	0.0	0	0	0	0	0
2120	Domestic Hot Water	Tankless Water Heater	No program	SF	ROB	2,455	0%	0	0.00	20	$1,850	100%	22%	75%	47%	1%	82.2%	33.6%	66.5%	0.0	0	0	0	0	0
2121	Domestic Hot Water	Tankless Water Heater	No program	SF	NC	2,455	0%	0	0.00	20	$1,850	100%	22%	75%	47%	0%	82.2%	33.6%	66.5%	0.0	0	0	0	0	0
2122	Domestic Hot Water	Tankless Water Heater	No program	MF	ROB	2,455	0%	0	0.00	20	$1,850	100%	22%	75%	47%	1%	82.2%	33.6%	66.5%	0.0	0	0	0	0	0
2123	Domestic Hot Water	Tankless Water Heater	No program	MF	ROB	2,455	0%	0	0.00	20	$1,850	100%	22%	75%	47%	1%	82.2%	33.6%	66.5%	0.0	0	0	0	0	0
2124	Domestic Hot Water	Tankless Water Heater	No program	MF	NC	2,455	0%	0	0.00	20	$1,850	100%	22%	75%	47%	0%	82.2%	33.6%	66.5%	0.0	0	0	0	0	0
3001	HVAC	Central Air Conditioner - 16 SEER	High Efficiency Tune Ups	SF	ROB	4,780	6%	299	0.22	19	$869	100%	17%	75%	81%	17%	82.2%	42.1%	66.5%	0.4	0	0	0	0	0
3002	HVAC	Central Air Conditioner - 16 SEER	High Efficiency Tune Ups	SF	ROB	4,780	6%	299	0.22	19	$869	100%	17%	75%	81%	17%	82.2%	42.1%	66.5%	0.4	959	0	0	0	0
3003	HVAC	Central Air Conditioner - 16 SEER	High Efficiency Tune Ups	SF	NC	4,780	6%	299	0.22	19	$869	100%	17%	75%	81%	0%	82.2%	31.0%	66.5%	0.4	0	0	0	0	0
3004	HVAC	Central Air Conditioner - 16 SEER	High Efficiency Tune Ups	MF	ROB	4,780	6%	299	0.22	19	$869	100%	17%	75%	81%	17%	82.2%	42.1%	66.5%	0.4	0	0	0	0	0
3005	HVAC	Central Air Conditioner - 16 SEER	High Efficiency Tune Ups	MF	ROB	4,780	6%	299	0.22	19	$869	100%	17%	75%	81%	17%	82.2%	42.1%	66.5%	0.4	303	0	0	0	0
3006	HVAC	Central Air Conditioner - 16 SEER	High Efficiency Tune Ups	MF	NC	4,780	6%	299	0.22	19	$869	100%	17%	75%	81%	0%	82.2%	31.0%	66.5%	0.4	0	0	0	0	0
3007	HVAC	Central Air Conditioner - 17 SEER	High Efficiency Tune Ups	SF	ROB	4,780	12%	562	0.40	19	$1,303	100%	13%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	0	0	0	0	0
3008	HVAC	Central Air Conditioner - 17 SEER	High Efficiency Tune Ups	SF	ROB	4,780	12%	562	0.40	19	$1,303	100%	13%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	2,250	0	0	0	0
3009	HVAC	Central Air Conditioner - 17 SEER	High Efficiency Tune Ups	SF	NC	4,780	12%	562	0.40	19	$1,303	100%	13%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	0	0	0	0	0
3010	HVAC	Central Air Conditioner - 17 SEER	High Efficiency Tune Ups	MF	ROB	4,780	12%	562	0.40	19	$1,303	100%	13%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	0	0	0	0	0
3011	HVAC	Central Air Conditioner - 17 SEER	High Efficiency Tune Ups	MF	ROB	4,780	12%	562	0.40	19	$1,303	100%	13%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	710	0	0	0	0
3012	HVAC	Central Air Conditioner - 17 SEER	High Efficiency Tune Ups	MF	NC	4,780	12%	562	0.40	19	$1,303	100%	13%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	0	0	0	0	0
3013	HVAC	Central Air Conditioner - 18 SEER	High Efficiency Tune Ups	SF	ROB	4,780	17%	797	0.56	19	$1,741	100%	11%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	0	0	0	0	0
3014	HVAC	Central Air Conditioner - 18 SEER	High Efficiency Tune Ups	SF	ROB	4,780	17%	797	0.56	19	$1,741	100%	11%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	3,356	0	0	0	0
3015	HVAC	Central Air Conditioner - 18 SEER	High Efficiency Tune Ups	SF	NC	4,780	17%	797	0.56	19	$1,741	100%	11%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	0	0	0	0	0
3016	HVAC	Central Air Conditioner - 18 SEER	High Efficiency Tune Ups	MF	ROB	4,780	17%	797	0.56	19	$1,741	100%	11%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	0	0	0	0	0
3017	HVAC	Central Air Conditioner - 18 SEER	High Efficiency Tune Ups	MF	ROB	4,780	17%	797	0.56	19	$1,741	100%	11%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	1,060	0	0	0	0
3018	HVAC	Central Air Conditioner - 18 SEER	High Efficiency Tune Ups	MF	NC	4,780	17%	797	0.56	19	$1,741	100%	11%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	0	0	0	0	0
3019	HVAC	Central Air Conditioner - 19 SEER	High Efficiency Tune Ups	SF	ROB	4,780	21%	1,006	0.70	19	$2,175	100%	9%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	0	0	0	0	0
3020	HVAC	Central Air Conditioner - 19 SEER	High Efficiency Tune Ups	SF	ROB	4,780	21%	1,006	0.70	19	$2,175	100%	9%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	4,260	0	0	0	0
3021	HVAC	Central Air Conditioner - 19 SEER	High Efficiency Tune Ups	SF	NC	4,780	21%	1,006	0.70	19	$2,175	100%	9%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	0	0	0	0	0
3022	HVAC	Central Air Conditioner - 19 SEER	High Efficiency Tune Ups	MF	ROB	4,780	21%	1,006	0.70	19	$2,175	100%	9%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	0	0	0	0	0
3023	HVAC	Central Air Conditioner - 19 SEER	High Efficiency Tune Ups	MF	ROB	4,780	21%	1,006	0.70	19	$2,175	100%	9%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	1,345	0	0	0	0
3024	HVAC	Central Air Conditioner - 19 SEER	High Efficiency Tune Ups	MF	NC	4,780	21%	1,006	0.70	19	$2,175	100%	9%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	0	0	0	0	0
3025	HVAC	Central Air Conditioner - 20 SEER	High Efficiency Tune Ups	SF	ROB	4,780	25%	1,195	0.83	19	$2,610	100%	8%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	0	0	0	0	0
3026	HVAC	Central Air Conditioner - 20 SEER	High Efficiency Tune Ups	SF	ROB	4,780	25%	1,195	0.83	19	$2,610	100%	8%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	4,980	0	0	0	0
3027	HVAC	Central Air Conditioner - 20 SEER	High Efficiency Tune Ups	SF	NC	4,780	25%	1,195	0.83	19	$2,610	100%	8%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	0	0	0	0	0
3028	HVAC	Central Air Conditioner - 20 SEER	High Efficiency Tune Ups	MF	ROB	4,780	25%	1,195	0.83	19	$2,610	100%	8%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	0	0	0	0	0
3029	HVAC	Central Air Conditioner - 20 SEER	High Efficiency Tune Ups	MF	ROB	4,780	25%	1,195	0.83	19	$2,610	100%	8%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	1,573	0	0	0	0
3030	HVAC	Central Air Conditioner - 20 SEER	High Efficiency Tune Ups	MF	NC	4,780	25%	1,195	0.83	19	$2,610	100%	8%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	0	0	0	0	0
3031	HVAC	Central Air Conditioner - 21 SEER	High Efficiency Tune Ups	SF	ROB	4,780	29%	1,366	0.94	19	$2,880	100%	7%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	74,239	0	0	0	0
3032	HVAC	Central Air Conditioner - 21 SEER	High Efficiency Tune Ups	SF	ROB	4,780	29%	1,366	0.94	19	$2,880	100%	7%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	5,867	0	0	0	0
3033	HVAC	Central Air Conditioner - 21 SEER	High Efficiency Tune Ups	SF	NC	4,780	29%	1,366	0.94	19	$2,880	100%	7%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	9,944	0	0	0	0
3034	HVAC	Central Air Conditioner - 21 SEER	High Efficiency Tune Ups	MF	ROB	4,780	29%	1,366	0.94	19	$2,880	100%	7%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	23,444	0	0	0	0
3035	HVAC	Central Air Conditioner - 21 SEER	High Efficiency Tune Ups	MF	ROB	4,780	29%	1,366	0.94	19	$2,880	100%	7%	75%	81%	17%	82.2%	42.1%	66.5%	0.5	1,853	0	0	0	0
3036	HVAC	Central Air Conditioner - 21 SEER	High Efficiency Tune Ups	MF	NC	4,780	29%	1,366	0.94	19	$2,880	100%	7%	75%	81%	0%	82.2%	30.0%	66.5%	0.5	3,140	0	0	0	0
3037	HVAC	Window Air Conditioner	Residential Lighting & Appliance	SF	ROB	813	9%	75	0.07	11	$50	100%	50%	75%	12%	41%	82.2%	58.8%	66.5%	1.3	806	965	793	567	642
3038	HVAC	Window Air Conditioner	Residential Lighting & Appliance	SF	ROB	813	9%	75	0.07	11	$50	100%	50%	75%	12%	41%	82.2%	58.8%	66.5%	1.3	250	300	246	176	199
3039	HVAC	Window Air Conditioner	Residential Lighting & Appliance	SF	NC	813	9%	75	0.07	11	$50	100%	50%	75%	12%	0%	82.2%	52.5%	66.5%	1.3	120	120	96	61	77
3040	HVAC	Window Air Conditioner	Residential Lighting & Appliance	MF	ROB	813	9%	75	0.07	11	$50	100%	50%	75%	12%	41%	82.2%	58.8%	66.5%	1.3	255	305	250	179	203
3041	HVAC	Window Air Conditioner	Residential Lighting & Appliance	MF	ROB	813	9%	75	0.07	11	$50	100%	50%	75%	12%	41%	82.2%	58.8%	66.5%	1.3	79	95	78	56	63
3042	HVAC	Window Air Conditioner	Residential Lighting & Appliance	MF	NC	813	9%	75	0.07	11	$50	100%	50%	75%	12%	0%	82.2%	52.5%	66.5%	1.3	38	38	30	19	24
3043	HVAC	ECM on Furnace Fan (SP motors)	No program	SF	Retrofit	3,864	30%	1,159	0.00	15	$475	100%	44%	75%	83%	32%	70.3%	52.3%	52.6%	1.0	8,628	8,967	5,935	4,079	4,107
3044	HVAC	ECM on Furnace Fan (SP motors)	No program	SF	Retrofit	3,864	30%	1,159	0.00	15	$475	100%	44%	75%	83%	32%	70.3%	52.3%	52.6%	1.0	2,680	2,785	1,844	1,267	1,276
3045	HVAC	ECM on Furnace Fan (SP motors)	No program	MF	Retrofit	3,864	30%	1,159	0.00	15	$475	100%	44%	75%	83%	32%	70.3%	52.3%	52.6%	1.0	2,725	2,832	1,874	1,288	1,297
3046	HVAC	ECM on Furnace Fan (SP motors)	No program	MF	Retrofit	3,864	30%	1,159	0.00	15	$475	100%	44%	75%	83%	32%	70.3%	52.3%	52.6%	1.0	846	880	582	400	403
3047	HVAC	ECM on Furnace Fan (PSC motors)	No program	SF	Retrofit	1,932	10%	193	0.00	15	$475	100%	44%	75%	83%	32%	70.3%	52.3%	52.6%	0.2	1,438	0	0	0	0
3048	HVAC	ECM on Furnace Fan (PSC motors)	No program	SF	Retrofit	1,932	10%	193	0.00	15	$475	100%	44%	75%	83%	32%	70.3%	52.3%	52.6%	0.2	447	0	0	0	0
3049	HVAC	ECM on Furnace Fan (PSC motors)	No program	MF	Retrofit	1,932	10%	193	0.00	15	$475	100%	44%	75%	83%	32%	70.3%	52.3%	52.6%	0.2	454	0	0	0	0
3050	HVAC	ECM on Furnace Fan (PSC motors)	No program	MF	Retrofit	1,932	10%	193	0.00	15	$475	100%	44%	75%	83%	32%	70.3%	52.3%	52.6%	0.2	141	0	0	0	0
3051	HVAC	Heat Pump - 16 SEER	High Efficiency Tune Ups	SF	ROB	6,350	4%	246	0.12	16	$406	100%	49%	75%	58%	27%	82.2%	51.9%	66.5%	0.5	0	0	0	0	0
3052	HVAC	Heat Pump - 16 SEER	High Efficiency Tune Ups	SF	ROB	6,350	4%	246	0.12	16	$406	100%	49%	75%	58%	27%	82.2%	51.9%	66.5%	0.5	347	0	0	0	0
3053	HVAC	Heat Pump - 16 SEER	High Efficiency Tune Ups	SF	NC	6,350	4%	246	0.12	16	$406	100%	49%	75%	58%	0%	82.2%	51.9%	66.5%	0.5	0	0	0	0	0
3054	HVAC	Heat Pump - 16 SEER	High Efficiency Tune Ups	MF	ROB	6,350	4%	246	0.12	16	$406	100%	49%	75%	58%	27%	82.2%	51.9%	66.5%	0.5	0	0	0	0	0

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Incentive (%)	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	2% Adoption Rate	TRC Score	2040 TP	2040 EP	2040 HCAP	2040 RAP	2040 2% Case
3055	HVAC	Heat Pump - 16 SEER	High Efficiency Tune Ups	MF	ROB	6,350	4%	246	0.12	16	$406	100%	49%	75%	58%	27%	82.2%	51.9%	66.5%	0.5	154	0	0	0	0
3056	HVAC	Heat Pump - 16 SEER	High Efficiency Tune Ups	MF	NC	6,350	4%	246	0.12	16	$406	100%	49%	75%	58%	0%	82.2%	51.9%	66.5%	0.5	0	0	0	0	0
3057	HVAC	Heat Pump - 17 SEER	High Efficiency Tune Ups	SF	ROB	6,350	7%	464	0.22	16	$1,267	100%	18%	75%	58%	27%	82.2%	49.2%	66.5%	0.3	0	0	0	0	0
3058	HVAC	Heat Pump - 17 SEER	High Efficiency Tune Ups	SF	ROB	6,350	7%	464	0.22	16	$1,267	100%	18%	75%	58%	27%	82.2%	49.2%	66.5%	0.3	525	0	0	0	0
3059	HVAC	Heat Pump - 17 SEER	High Efficiency Tune Ups	SF	NC	6,350	7%	464	0.22	16	$1,267	100%	18%	75%	58%	0%	82.2%	31.3%	66.5%	0.3	0	0	0	0	0
3060	HVAC	Heat Pump - 17 SEER	High Efficiency Tune Ups	MF	ROB	6,350	7%	464	0.22	16	$1,267	100%	18%	75%	58%	27%	82.2%	49.2%	66.5%	0.3	0	0	0	0	0
3061	HVAC	Heat Pump - 17 SEER	High Efficiency Tune Ups	MF	ROB	6,350	7%	464	0.22	16	$1,267	100%	18%	75%	58%	27%	82.2%	49.2%	66.5%	0.3	174	0	0	0	0
3062	HVAC	Heat Pump - 17 SEER	High Efficiency Tune Ups	MF	NC	6,350	7%	464	0.22	16	$1,267	100%	18%	75%	58%	0%	82.2%	31.3%	66.5%	0.3	0	0	0	0	0
3063	HVAC	Heat Pump - 18 SEER	High Efficiency Tune Ups	SF	ROB	6,350	10%	657	0.31	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.4	0	0	0	0	0
3064	HVAC	Heat Pump - 18 SEER	High Efficiency Tune Ups	SF	ROB	6,350	10%	657	0.31	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.4	1,054	0	0	0	0
3065	HVAC	Heat Pump - 18 SEER	High Efficiency Tune Ups	SF	NC	6,350	10%	657	0.31	16	$1,267	100%	20%	75%	58%	0%	82.2%	32.5%	66.5%	0.4	0	0	0	0	0
3066	HVAC	Heat Pump - 18 SEER	High Efficiency Tune Ups	MF	ROB	6,350	10%	657	0.31	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.4	0	0	0	0	0
3067	HVAC	Heat Pump - 18 SEER	High Efficiency Tune Ups	MF	ROB	6,350	10%	657	0.31	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.4	350	0	0	0	0
3068	HVAC	Heat Pump - 18 SEER	High Efficiency Tune Ups	MF	NC	6,350	10%	657	0.31	16	$1,267	100%	20%	75%	58%	0%	82.2%	32.5%	66.5%	0.4	0	0	0	0	0
3069	HVAC	Heat Pump - 19 SEER	High Efficiency Tune Ups	SF	ROB	6,350	13%	830	0.39	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.5	0	0	0	0	0
3070	HVAC	Heat Pump - 19 SEER	High Efficiency Tune Ups	SF	ROB	6,350	13%	830	0.39	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.5	1,681	0	0	0	0
3071	HVAC	Heat Pump - 19 SEER	High Efficiency Tune Ups	SF	NC	6,350	13%	830	0.39	16	$1,267	100%	20%	75%	58%	0%	82.2%	32.5%	66.5%	0.5	0	0	0	0	0
3072	HVAC	Heat Pump - 19 SEER	High Efficiency Tune Ups	MF	ROB	6,350	13%	830	0.39	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.5	0	0	0	0	0
3073	HVAC	Heat Pump - 19 SEER	High Efficiency Tune Ups	MF	ROB	6,350	13%	830	0.39	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.5	558	0	0	0	0
3074	HVAC	Heat Pump - 19 SEER	High Efficiency Tune Ups	MF	NC	6,350	13%	830	0.39	16	$1,267	100%	20%	75%	58%	0%	82.2%	32.5%	66.5%	0.5	0	0	0	0	0
3075	HVAC	Heat Pump - 20 SEER	High Efficiency Tune Ups	SF	ROB	6,350	16%	985	0.46	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.6	0	0	0	0	0
3076	HVAC	Heat Pump - 20 SEER	High Efficiency Tune Ups	SF	ROB	6,350	16%	985	0.46	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.6	2,370	0	0	0	0
3077	HVAC	Heat Pump - 20 SEER	High Efficiency Tune Ups	SF	NC	6,350	16%	985	0.46	16	$1,267	100%	20%	75%	58%	0%	82.2%	32.5%	66.5%	0.6	0	0	0	0	0
3078	HVAC	Heat Pump - 20 SEER	High Efficiency Tune Ups	MF	ROB	6,350	16%	985	0.46	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.6	0	0	0	0	0
3079	HVAC	Heat Pump - 20 SEER	High Efficiency Tune Ups	MF	ROB	6,350	16%	985	0.46	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.6	787	0	0	0	0
3080	HVAC	Heat Pump - 20 SEER	High Efficiency Tune Ups	MF	NC	6,350	16%	985	0.46	16	$1,267	100%	20%	75%	58%	0%	82.2%	32.5%	66.5%	0.6	0	0	0	0	0
3081	HVAC	Heat Pump - 21 SEER	High Efficiency Tune Ups	SF	ROB	6,350	18%	1,126	0.53	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.7	0	0	0	0	0
3082	HVAC	Heat Pump - 21 SEER	High Efficiency Tune Ups	SF	ROB	6,350	18%	1,126	0.53	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.7	3,095	0	0	0	0
3083	HVAC	Heat Pump - 21 SEER	High Efficiency Tune Ups	SF	NC	6,350	18%	1,126	0.53	16	$1,267	100%	20%	75%	58%	0%	82.2%	32.5%	66.5%	0.7	0	0	0	0	0
3084	HVAC	Heat Pump - 21 SEER	High Efficiency Tune Ups	MF	ROB	6,350	18%	1,126	0.53	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.7	0	0	0	0	0
3085	HVAC	Heat Pump - 21 SEER	High Efficiency Tune Ups	MF	ROB	6,350	18%	1,126	0.53	16	$1,267	100%	20%	75%	58%	27%	82.2%	49.2%	66.5%	0.7	1,027	0	0	0	0
3086	HVAC	Heat Pump - 21 SEER	High Efficiency Tune Ups	MF	NC	6,350	18%	1,126	0.53	16	$1,267	100%	20%	75%	58%	0%	82.2%	32.5%	66.5%	0.7	0	0	0	0	0
3087	HVAC	Ground Source Heat Pump	High Efficiency Tune Ups	SF	ROB	6,350	40%	2,552	1.23	25	$8,723	100%	3%	75%	58%	27%	82.2%	49.2%	66.5%	0.3	81,785	0	0	0	0
3088	HVAC	Ground Source Heat Pump	High Efficiency Tune Ups	SF	ROB	6,350	40%	2,552	1.23	25	$8,723	100%	3%	75%	58%	27%	82.2%	49.2%	66.5%	0.3	2,612	0	0	0	0
3089	HVAC	Ground Source Heat Pump	High Efficiency Tune Ups	SF	NC	6,350	40%	2,552	1.23	25	$8,723	100%	3%	75%	58%	0%	82.2%	30.0%	66.5%	0.3	14,318	0	0	0	0
3090	HVAC	Ductless Heat Pump	High Efficiency Tune Ups	SF	ROB	5,251	26%	1,366	0.14	18	$730	100%	27%	75%	58%	27%	82.2%	49.2%	66.5%	1.0	0	85,159	57,942	37,547	46,903
3091	HVAC	Ductless Heat Pump	High Efficiency Tune Ups	SF	ROB	5,251	26%	1,366	0.14	18	$730	100%	27%	75%	58%	27%	82.2%	49.2%	66.5%	1.0	5,450	26,452	17,998	11,663	14,569
3092	HVAC	Ductless Heat Pump	High Efficiency Tune Ups	SF	NC	5,251	26%	1,366	0.14	18	$730	100%	27%	75%	58%	0%	82.2%	37.1%	66.5%	1.0	0	10,618	5,652	2,556	4,575
3093	HVAC	Ductless Heat Pump	High Efficiency Tune Ups	MF	ROB	5,251	26%	1,366	0.14	18	$730	100%	27%	75%	58%	27%	82.2%	49.2%	66.5%	1.0	17,277	26,892	18,297	11,857	14,812
3094	HVAC	Ductless Heat Pump	High Efficiency Tune Ups	MF	ROB	5,251	26%	1,366	0.14	18	$730	100%	27%	75%	58%	27%	82.2%	49.2%	66.5%	1.0	1,809	8,353	5,683	3,683	4,601
3095	HVAC	Ductless Heat Pump	High Efficiency Tune Ups	MF	NC	5,251	26%	1,366	0.14	18	$730	100%	27%	75%	58%	0%	82.2%	37.1%	66.5%	1.0	2,420	3,353	1,785	807	1,445
3096	HVAC	Central AC Tune-Up	High Efficiency Tune Ups	SF	Retrofit	5,401	17%	929	0.44	10	$175	100%	86%	86%	81%	85%	89.5%	89.5%	89.5%	2.9	14,047	14,598	10,413	10,413	9,934
3097	HVAC	Central AC Tune-Up	Low Income	SF	Retrofit	5,401	17%	929	0.44	10	$175	100%	100%	100%	81%	85%	89.5%	89.5%	89.5%	2.9	4,363	4,534	3,234	3,234	3,086
3098	HVAC	Central AC Tune-Up	Multifamily	MF	Retrofit	4,052	17%	697	0.33	10	$175	100%	71%	75%	81%	85%	89.5%	89.5%	89.5%	2.2	3,328	3,459	2,467	2,467	2,354
3099	HVAC	Central AC Tune-Up	Low Income	MF	Retrofit	4,052	17%	697	0.33	10	$175	100%	100%	100%	81%	85%	89.5%	89.5%	89.5%	2.2	1,034	1,074	766	766	731
3100	HVAC	Central HP Tune-Up	High Efficiency Tune Ups	SF	Retrofit	11,500	17%	1,978	0.44	10	$175	100%	86%	86%	4%	85%	89.5%	89.5%	89.5%	4.5	1,584	1,646	1,174	1,174	1,120
3101	HVAC	Central HP Tune-Up	Low Income	SF	Retrofit	11,500	17%	1,978	0.44	10	$175	100%	100%	100%	4%	85%	89.5%	89.5%	89.5%	4.5	492	511	365	365	348
3102	HVAC	Central HP Tune-Up	Multifamily	MF	Retrofit	8,628	17%	1,484	0.33	10	$175	100%	71%	75%	4%	85%	89.5%	89.5%	89.5%	3.4	375	390	278	278	265
3103	HVAC	Central HP Tune-Up	Low Income	MF	Retrofit	8,628	17%	1,484	0.33	10	$175	100%	100%	100%	4%	85%	89.5%	89.5%	89.5%	3.4	117	121	86	86	82
3104	HVAC	Duct Sealing - AC with Gas Heat	High Efficiency Tune Ups	SF	Retrofit	6,156	40%	2,465	1.16	18	$368	100%	44%	75%	38%	89%	92.3%	92.3%	92.3%	5.9	31,997	33,254	25,659	25,659	24,752
3105	HVAC	Duct Sealing - AC with Gas Heat	Low Income	SF	Retrofit	6,156	40%	2,465	1.16	18	$368	100%	100%	100%	38%	89%	92.3%	92.3%	92.3%	5.9	9,939	10,329	7,970	7,970	7,688
3106	HVAC	Duct Sealing - AC with Gas Heat	Multifamily	MF	Retrofit	5,790	40%	2,317	1.09	18	$368	100%	44%	75%	38%	89%	92.3%	92.3%	92.3%	5.6	9,498	9,871	7,616	7,616	7,347
3107	HVAC	Duct Sealing - AC with Gas Heat	Low Income	MF	Retrofit	5,790	40%	2,317	1.09	18	$368	100%	100%	100%	38%	89%	92.3%	92.3%	92.3%	5.6	2,950	3,066	2,366	2,366	2,282
3108	HVAC	Duct Sealing - Heat Pump	High Efficiency Tune Ups	SF	Retrofit	7,192	40%	2,879	1.16	18	$368	100%	44%	75%	4%	89%	92.3%	92.3%	92.3%	6.5	4,229	4,395	3,391	3,391	3,271
3109	HVAC	Duct Sealing - Heat Pump	Low Income	SF	Retrofit	7,192	40%	2,879	1.16	18	$368	100%	100%	100%	4%	89%	92.3%	92.3%	92.3%	6.5	1,314	1,365	1,053	1,053	1,016
3110	HVAC	Duct Sealing - Heat Pump	Multifamily	MF	Retrofit	6,764	40%	2,707	1.09	18	$368	100%	44%	75%	4%	89%	92.3%	92.3%	92.3%	6.1	1,256	1,305	1,007	1,007	971
3111	HVAC	Duct Sealing - Heat Pump	Low Income	MF	Retrofit	6,764	40%	2,707	1.09	18	$368	100%	100%	100%	4%	89%	92.3%	92.3%	92.3%	6.1	390	405	313	313	302
3112	HVAC	Duct Sealing - AC with Electric Resistance Heat	High Efficiency Tune Ups	SF	Retrofit	10,260	40%	4,106	1.16	18	$369	100%	44%	75%	56%	89%	92.3%	92.3%	92.3%	8.0	78,545	81,631	62,988	62,988	60,760
3113	HVAC	Duct Sealing - AC with Electric Resistance Heat	Low Income	SF	Retrofit	10,260	40%	4,106	1.16	18	$370	100%	100%	100%	56%	89%	92.3%	92.3%	92.3%	8.0	24,397	25,356	19,565	19,565	18,873
3114	HVAC	Duct Sealing - AC with Electric Resistance Heat	Multifamily	MF	Retrofit	9,668	40%	3,869	1.09	18	$371	100%	44%	75%	56%	89%	92.3%	92.3%	92.3%	7.5	23,372	24,290	18,743	18,743	18,080
3115	HVAC	Duct Sealing - AC with Electric Resistance Heat	Low Income	MF	Retrofit	9,668	40%	3,869	1.09	18	$372	100%	100%	100%	56%	89%	92.3%	92.3%	92.3%	7.5	7,260	7,545	5,822	5,822	5,616
3116	HVAC	Duct Sealing - Electric Resistance Heat, no AC	High Efficiency Tune Ups	SF	Retrofit	4,100	40%	1,641	0.00	18	$373	100%	44%	75%	2%	89%	92.3%	92.3%	92.3%	2.0	1,121	1,165	899	899	867
3117	HVAC	Duct Sealing - Electric Resistance Heat, no AC	Low Income	SF	Retrofit	4,100	40%	1,641	0.00	18	$374	100%	100%	100%	2%	89%	92.3%	92.3%	92.3%	2.0	348	362	279	279	269
3118	HVAC	Duct Sealing - Electric Resistance Heat, no AC	Multifamily	MF	Retrofit	3,856	40%	1,543	0.00	18	$375	100%	44%	75%	2%	89%	92.3%	92.3%	92.3%	1.9	333	346	267	267	258
3119	HVAC	Duct Sealing - Electric Resistance Heat, no AC	Low Income	MF	Retrofit	3,856	40%	1,543	0.00	18	$376	100%	100%	100%	2%	89%	92.3%	92.3%	92.3%	1.9	103	107	83	83	80
3120	HVAC	Smart Thermostats	Home Performance	SF	Retrofit	12,822	3%	343	0.00	11	$394	100%	25%	75%	86%	38%	70.3%	56.6%	56.6%	0.3	22,753	0	0	0	0
3121	HVAC	Smart Thermostats	Low Income	SF	Retrofit	12,822	3%	343	0.00	11	$394	100%	100%	100%	86%	38%	70.3%	70.3%	70.3%	0.3	7,067	7,067	4,127	4,127	3,933
3122	HVAC	Smart Thermostats	Home Performance	SF	NC	12,822	3%	343	0.00	11	$199	100%	50%	75%	86%	0%	82.2%	52.6%	66.5%	0.5	3,968	0	0	0	0
3123	HVAC	Smart Thermostats	Multifamily	MF	Retrofit	12,822	3%	343	0.00	11	$394	100%	44%	75%	86%	38%	70.3%	56.6%	56.6%	0.3	7,185	0	0	0	0
3124	HVAC	Smart Thermostats	Low Income	MF	Retrofit	12,822	3%	343	0.00	11	$394	100%	100%	100%	86%	38%	70.3%	70.3%	70.3%	0.3	2,232	2,232	1,303	1,303	1,242
3125	HVAC	Smart Thermostats	Multifamily	MF	NC	12,822	3%	343	0.00	11	$199	100%	44%	75%	86%	0%	82.2%	47.9%	66.5%	0.5	1,253	0	0	0	0
4001	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2007)	Home Performance	SF	Retrofit	23	76%	17	0.00	17	$3	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	3.2	712	745	539	515	493
4002	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2007)	Low Income	SF	Retrofit	23	76%	17	0.00	17	$3	100%	100%	100%	100%	0%	72.4%	72.4%	72.4%	3.2	221	231	168	168	160
4003	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2007)	Multifamily	MF	Retrofit	23	76%	17	0.00	17	$3	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	3.2	225	235	170	162	156
4004	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2007)	Low Income	MF	Retrofit	23	76%	17	0.00	17	$3	100%	100%	100%	100%	0%	72.4%	72.4%	72.4%	3.2	70	73	53	53	51
4005	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2007)	Home Performance	SF	Retrofit	33	79%	26	0.00	17	$3	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	5.0	1,101	1,151	833	795	762
4006	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2007)	Low Income	SF	Retrofit	33	79%	26	0.00	17	$3	100%	100%	100%	100%	0%	72.4%	72.4%	72.4%	5.0	342	358	259	259	248
4007	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2007)	Multifamily	MF	Retrofit	33	79%	26	0.00	17	$3	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	5.0	348	364	263	251	241
4008	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2007)	Low Income	MF	Retrofit	33	79%	26	0.00	17	$3	100%	100%	100%	100%	0%	72.4%	72.4%	72.4%	5.0	108	113	82	82	78
4009	Lighting	ENERGY STAR Omni-Directional LED (1,050-1,489 lumens, EISA 2007)	Home Performance	SF	Retrofit	41	77%	32	0.01	17	$3	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	6.0	1,328	1,389	1,005	959	919

Appendix B: Residential Energy Efficiency Detail

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Incentive (%)	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	2% Adoption Rate	TRC Score	2040 TP	2040 EP	2040 HCAP	2040 RAP	2040 2% Case
4010	Lighting	ENERGY STAR Omni-Directional LED (1,050-1,489 lumens, EISA 2007)	Low Income	SF	Retrofit	41	77%	32	0.01	17	$3	100%	100%	100%	100%	0%	72.4%	72.4%	72.4%	6.0	412	431	312	312	299
4011	Lighting	ENERGY STAR Omni-Directional LED (1,050-1,489 lumens, EISA 2007)	Multifamily	MF	Retrofit	41	77%	32	0.01	17	$3	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	6.0	419	438	317	303	290
4012	Lighting	ENERGY STAR Omni-Directional LED (1,050-1,489 lumens, EISA 2007)	Low Income	MF	Retrofit	41	77%	32	0.01	17	$3	100%	100%	100%	100%	0%	72.4%	72.4%	72.4%	6.0	130	136	99	99	94
4013	Lighting	ENERGY STAR Omni-Directional LED (1,490-2,600 lumens, EISA 2007)	Home Performance	SF	Retrofit	56	79%	44	0.01	17	$3	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	8.4	1,846	1,930	1,397	1,333	1,277
4014	Lighting	ENERGY STAR Omni-Directional LED (1,490-2,600 lumens, EISA 2007)	Low Income	SF	Retrofit	56	79%	44	0.01	17	$3	100%	100%	100%	100%	0%	72.4%	72.4%	72.4%	8.4	573	600	434	434	416
4015	Lighting	ENERGY STAR Omni-Directional LED (1,490-2,600 lumens, EISA 2007)	Multifamily	MF	Retrofit	56	79%	44	0.01	17	$3	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	8.4	583	610	441	421	403
4016	Lighting	ENERGY STAR Omni-Directional LED (1,490-2,600 lumens, EISA 2007)	Low Income	MF	Retrofit	56	79%	44	0.01	17	$3	100%	100%	100%	100%	0%	72.4%	72.4%	72.4%	8.4	181	189	137	137	131
4017	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2023)	Residential Lighting & Appliance	SF	ROB	9	42%	4	0.00	17	$2	100%	27%	75%	890%	60%	78.9%	72.0%	72.0%	1.2	2,660	3,660	2,888	2,635	2,635
4018	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2023)	Low Income	SF	ROB	9	42%	4	0.00	17	$2	100%	100%	100%	890%	60%	78.9%	78.9%	78.9%	1.2	826	1,137	765	731	731
4019	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2023)	Residential Lighting & Appliance	SF	NC	9	42%	4	0.00	17	$2	100%	27%	75%	990%	0%	78.9%	42.0%	66.5%	1.2	400	418	292	150	238
4020	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2023)	Residential Lighting & Appliance	MF	ROB	9	42%	4	0.00	17	$2	100%	27%	75%	465%	60%	78.9%	72.0%	72.0%	1.2	439	604	477	435	435
4021	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2023)	Low Income	MF	ROB	9	42%	4	0.00	17	$2	100%	100%	100%	465%	60%	78.9%	78.9%	78.9%	1.2	136	188	126	121	121
4022	Lighting	ENERGY STAR Omni-Directional LED (310-749 lumens, EISA 2023)	Residential Lighting & Appliance	MF	NC	9	42%	4	0.00	17	$2	100%	27%	75%	565%	0%	78.9%	42.0%	66.5%	1.2	72	75	53	27	43
4023	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2023)	Residential Lighting & Appliance	SF	ROB	16	55%	9	0.00	17	$2	100%	27%	75%	890%	60%	78.9%	72.0%	72.0%	2.7	5,852	8,052	6,354	5,797	5,797
4024	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2023)	Low Income	SF	ROB	16	55%	9	0.00	17	$2	100%	100%	100%	890%	60%	78.9%	78.9%	78.9%	2.7	1,818	2,501	1,683	1,608	1,608
4025	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2023)	Residential Lighting & Appliance	SF	NC	16	55%	9	0.00	17	$2	100%	27%	75%	990%	0%	78.9%	42.0%	66.5%	2.7	879	920	642	330	523
4026	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2023)	Residential Lighting & Appliance	MF	ROB	16	55%	9	0.00	17	$2	100%	27%	75%	465%	60%	78.9%	72.0%	72.0%	2.7	965	1,328	1,048	956	956
4027	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2023)	Low Income	MF	ROB	16	55%	9	0.00	17	$2	100%	100%	100%	465%	60%	78.9%	78.9%	78.9%	2.7	300	413	278	265	265
4028	Lighting	ENERGY STAR Omni-Directional LED (750-1,049 lumens, EISA 2023)	Residential Lighting & Appliance	MF	NC	16	55%	9	0.00	17	$2	100%	27%	75%	565%	0%	78.9%	42.0%	66.5%	2.7	158	166	116	60	94
4029	Lighting	ENERGY STAR Omni-Directional LED (1,049-1,489 lumens, EISA 2023)	Residential Lighting & Appliance	SF	ROB	22	57%	12	0.00	17	$2	100%	27%	75%	890%	60%	78.9%	72.0%	72.0%	3.9	8,511	11,712	9,243	8,432	8,432
4030	Lighting	ENERGY STAR Omni-Directional LED (1,049-1,489 lumens, EISA 2023)	Low Income	SF	ROB	22	57%	12	0.00	17	$2	100%	100%	100%	890%	60%	78.9%	78.9%	78.9%	3.9	2,644	3,638	2,448	2,338	2,338
4031	Lighting	ENERGY STAR Omni-Directional LED (1,049-1,489 lumens, EISA 2023)	Residential Lighting & Appliance	SF	NC	22	57%	12	0.00	17	$2	100%	27%	75%	990%	0%	78.9%	42.0%	66.5%	3.9	1,279	1,338	934	480	760
4032	Lighting	ENERGY STAR Omni-Directional LED (1,049-1,489 lumens, EISA 2023)	Residential Lighting & Appliance	MF	ROB	22	57%	12	0.00	17	$2	100%	27%	75%	465%	60%	78.9%	72.0%	72.0%	3.9	1,404	1,932	1,525	1,391	1,391
4033	Lighting	ENERGY STAR Omni-Directional LED (1,049-1,489 lumens, EISA 2023)	Low Income	MF	ROB	22	57%	12	0.00	17	$2	100%	100%	100%	465%	60%	78.9%	78.9%	78.9%	3.9	436	600	404	386	386
4034	Lighting	ENERGY STAR Omni-Directional LED (1,049-1,489 lumens, EISA 2023)	Residential Lighting & Appliance	MF	NC	22	57%	12	0.00	17	$2	100%	27%	75%	565%	0%	78.9%	42.0%	66.5%	3.9	231	241	168	87	137
4035	Lighting	ENERGY STAR Omni-Directional LED (1.490-2,600 lumens, EISA 2023)	Residential Lighting & Appliance	SF	ROB	35	67%	23	0.00	17	$2	100%	27%	75%	890%	60%	78.9%	72.0%	72.0%	7.4	15,959	21,959	17,330	15,811	15,811
4036	Lighting	ENERGY STAR Omni-Directional LED (1.490-2,600 lumens, EISA 2023)	Low Income	SF	ROB	35	67%	23	0.00	17	$2	100%	100%	100%	890%	60%	78.9%	78.9%	78.9%	7.4	4,957	6,821	4,590	4,384	4,384
4037	Lighting	ENERGY STAR Omni-Directional LED (1.490-2,600 lumens, EISA 2023)	Residential Lighting & Appliance	SF	NC	35	67%	23	0.00	17	$2	100%	27%	75%	990%	0%	78.9%	42.0%	66.5%	7.4	2,398	2,508	1,751	900	1,426
4038	Lighting	ENERGY STAR Omni-Directional LED (1.490-2,600 lumens, EISA 2023)	Residential Lighting & Appliance	MF	ROB	35	67%	23	0.00	17	$2	100%	27%	75%	465%	60%	78.9%	72.0%	72.0%	7.4	2,633	3,623	2,859	2,609	2,609
4039	Lighting	ENERGY STAR Omni-Directional LED (1.490-2,600 lumens, EISA 2023)	Low Income	MF	ROB	35	67%	23	0.00	17	$2	100%	100%	100%	465%	60%	78.9%	78.9%	78.9%	7.4	818	1,125	757	723	723
4040	Lighting	ENERGY STAR Omni-Directional LED (1.490-2,600 lumens, EISA 2023)	Residential Lighting & Appliance	MF	NC	35	67%	23	0.00	17	$2	100%	27%	75%	565%	0%	78.9%	42.0%	66.5%	7.4	432	452	316	162	257
4041	Lighting	ENERGY STAR Directional LED	Residential Lighting & Appliance	SF	ROB	43	80%	34	0.01	20	$2	100%	30%	75%	570%	60%	78.9%	72.0%	72.0%	14.0	12,345	16,987	13,397	12,222	12,222
4042	Lighting	ENERGY STAR Directional LED	Low Income	SF	ROB	43	80%	34	0.01	20	$2	100%	100%	100%	570%	60%	78.9%	78.9%	78.9%	14.0	3,835	5,276	3,195	3,021	3,021
4043	Lighting	ENERGY STAR Directional LED	Residential Lighting & Appliance	SF	NC	43	80%	34	0.01	20	$2	100%	30%	75%	570%	0%	78.9%	43.9%	66.5%	14.0	2,025	2,118	1,180	615	931
4044	Lighting	ENERGY STAR Directional LED	Residential Lighting & Appliance	MF	ROB	43	80%	34	0.01	20	$2	100%	30%	75%	330%	60%	78.9%	72.0%	72.0%	14.0	2,257	3,106	2,449	2,235	2,235
4045	Lighting	ENERGY STAR Directional LED	Low Income	MF	ROB	43	80%	34	0.01	20	$2	100%	100%	100%	330%	60%	78.9%	78.9%	78.9%	14.0	701	965	584	552	552
4046	Lighting	ENERGY STAR Directional LED	Residential Lighting & Appliance	MF	NC	43	80%	34	0.01	20	$2	100%	30%	75%	330%	0%	78.9%	43.9%	66.5%	14.0	370	387	216	112	170
4047	Lighting	ENERGY STAR Specialty LED	Residential Lighting & Appliance	SF	ROB	16	55%	9	0.00	20	$2	100%	30%	75%	530%	60%	78.9%	72.0%	72.0%	3.5	2,870	3,949	3,114	2,841	2,841
4048	Lighting	ENERGY STAR Specialty LED	Low Income	SF	ROB	16	55%	9	0.00	17	$2	100%	100%	100%	530%	60%	78.9%	78.9%	78.9%	3.0	1,082	1,489	1,002	957	957
4049	Lighting	ENERGY STAR Specialty LED	Residential Lighting & Appliance	SF	NC	16	55%	9	0.00	17	$2	100%	30%	75%	530%	0%	78.9%	43.8%	66.5%	3.0	471	492	344	184	280
4050	Lighting	ENERGY STAR Specialty LED	Residential Lighting & Appliance	MF	ROB	16	55%	9	0.00	17	$2	100%	30%	75%	300%	60%	78.9%	72.0%	72.0%	3.0	623	857	676	617	617
4051	Lighting	ENERGY STAR Specialty LED	Low Income	MF	ROB	16	55%	9	0.00	17	$2	100%	100%	100%	300%	60%	78.9%	78.9%	78.9%	3.0	193	266	179	171	171
4052	Lighting	ENERGY STAR Specialty LED	Residential Lighting & Appliance	MF	NC	16	55%	9	0.00	17	$2	100%	30%	75%	300%	0%	78.9%	43.8%	66.5%	3.0	84	88	61	33	50
4053	Lighting	Occupancy Sensor - Wall-Mounted	No program	SF	ROB	134	30%	40	0.00	10	$89	100%	92%	92%	100%	22%	78.9%	74.7%	74.7%	0.2	2,924	0	0	0	0
4054	Lighting	Occupancy Sensor - Wall-Mounted	No program	SF	ROB	134	30%	40	0.00	10	$89	100%	92%	92%	100%	22%	78.9%	74.7%	74.7%	0.2	908	0	0	0	0
4055	Lighting	Occupancy Sensor - Wall-Mounted	No program	SF	NC	134	30%	40	0.00	10	$89	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	0.2	437	0	0	0	0
4056	Lighting	Occupancy Sensor - Wall-Mounted	No program	MF	ROB	134	30%	40	0.00	10	$89	100%	92%	92%	100%	22%	78.9%	74.7%	74.7%	0.2	923	0	0	0	0
4057	Lighting	Occupancy Sensor - Wall-Mounted	No program	MF	ROB	134	30%	40	0.00	10	$89	100%	92%	92%	100%	22%	78.9%	74.7%	74.7%	0.2	287	0	0	0	0
4058	Lighting	Occupancy Sensor - Wall-Mounted	No program	MF	NC	134	30%	40	0.00	10	$89	100%	92%	92%	100%	0%	72.4%	69.1%	69.1%	0.2	138	0	0	0	0
5001	Envelope	Ceiling Insulation (AC/Gas heat)	Home Performance	SF	Retrofit	6,156	31%	1,879	9.48	20	$2,172	100%	46%	75%	38%	89%	92.3%	92.3%	92.3%	4.6	5,132	7,098	6,682	7,131	6,895
5002	Envelope	Ceiling Insulation (AC/Gas heat)	Low Income	SF	Retrofit	6,156	31%	1,879	9.48	20	$2,172	100%	100%	100%	38%	89%	92.3%	92.3%	92.3%	4.6	1,594	2,205	2,075	2,215	2,142
5003	Envelope	Ceiling Insulation (AC/Gas heat)	Multifamily	MF	Retrofit	5,790	32%	1,879	9.48	20	$2,172	100%	28%	75%	38%	89%	92.3%	92.3%	92.3%	4.6	1,621	2,242	2,110	2,252	2,177
5004	Envelope	Ceiling Insulation (AC/Gas heat)	Low Income	MF	Retrofit	5,790	32%	1,879	9.48	20	$2,172	100%	100%	100%	38%	89%	92.3%	92.3%	92.3%	4.6	503	696	655	699	676
5005	Envelope	Ceiling Insulation (AC/Electric resistance heat)	Home Performance	SF	Retrofit	10,260	47%	4,798	9.48	20	$2,172	100%	46%	75%	54%	89%	92.3%	92.3%	92.3%	5.3	18,658	25,805	24,291	25,923	25,065
5006	Envelope	Ceiling Insulation (AC/Electric resistance heat)	Low Income	SF	Retrofit	10,260	47%	4,798	9.48	20	$2,172	100%	100%	100%	54%	89%	92.3%	92.3%	92.3%	5.3	5,795	8,015	7,545	8,052	7,786
5007	Envelope	Ceiling Insulation (AC/Electric resistance heat)	Multifamily	MF	Retrofit	9,668	50%	4,798	9.48	20	$2,172	100%	28%	75%	54%	89%	92.3%	92.3%	92.3%	5.3	5,892	8,149	7,671	8,186	7,915
5008	Envelope	Ceiling Insulation (AC/Electric resistance heat)	Low Income	MF	Retrofit	9,668	50%	4,798	9.48	20	$2,172	100%	100%	100%	54%	89%	92.3%	92.3%	92.3%	5.3	1,830	2,531	2,383	2,543	2,459
5009	Envelope	Ceiling Insulation (heat pump)	Home Performance	SF	Retrofit	7,192	33%	2,393	9.48	20	$2,172	100%	46%	75%	4%	89%	92.3%	92.3%	92.3%	4.7	740	1,023	963	1,028	994
5010	Envelope	Ceiling Insulation (heat pump)	Low Income	SF	Retrofit	7,192	33%	2,393	9.48	20	$2,172	100%	100%	100%	4%	89%	92.3%	92.3%	92.3%	4.7	230	318	299	319	309
5011	Envelope	Ceiling Insulation (heat pump)	Multifamily	MF	Retrofit	6,764	35%	2,393	9.48	20	$2,172	100%	28%	75%	4%	89%	92.3%	92.3%	92.3%	4.7	234	323	304	325	314
5012	Envelope	Ceiling Insulation (heat pump)	Low Income	MF	Retrofit	6,764	35%	2,393	9.48	20	$2,172	100%	100%	100%	4%	89%	92.3%	92.3%	92.3%	4.7	73	100	94	101	97
5013	Envelope	Wall Insulation (AC/gas heat)	Home Performance	SF	Retrofit	6,156	20%	1,239	0.90	20	$1,381	100%	72%	75%	38%	89%	92.3%	92.3%	92.3%	1.1	3,385	4,682	4,407	4,704	4,548
5014	Envelope	Wall Insulation (AC/gas heat)	Low Income	SF	Retrofit	6,156	20%	1,239	0.90	20	$1,381	100%	100%	100%	38%	89%	92.3%	92.3%	92.3%	1.1	1,052	1,454	1,369	1,461	1,413
5015	Envelope	Wall Insulation (AC/gas heat)	Multifamily	MF	Retrofit	5,790	21%	1,239	0.90	20	$1,381	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	1.1	1,069	1,479	1,392	1,485	1,436
5016	Envelope	Wall Insulation (AC/gas heat)	Low Income	MF	Retrofit	5,790	21%	1,239	0.90	20	$1,381	100%	100%	100%	38%	89%	92.3%	92.3%	92.3%	1.1	332	459	432	461	446
5017	Envelope	Wall Insulation (AC/Electric resistance heat)	Home Performance	SF	Retrofit	10,260	55%	5,627	0.90	20	$1,381	100%	72%	75%	54%	89%	92.3%	92.3%	92.3%	2.7	21,882	30,264	28,488	30,402	29,396
5018	Envelope	Wall Insulation (AC/Electric resistance heat)	Low Income	SF	Retrofit	10,260	55%	5,627	0.90	20	$1,381	100%	100%	100%	54%	89%	92.3%	92.3%	92.3%	2.7	6,797	9,400	8,849	9,443	9,131
5019	Envelope	Wall Insulation (AC/Electric resistance heat)	Multifamily	MF	Retrofit	9,668	58%	5,627	0.90	20	$1,381	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	2.7	6,910	9,557	8,996	9,601	9,283

Appendix B: Residential Energy Efficiency Detail

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Incentive (%)	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	2% Adoption Rate	TRC Score	2040 TP	2040 EP	2040 HCAP	2040 RAP	2040 2% Case
5020	Envelope	Wall Insulation (AC/Electric resistance heat)	Low Income	MF	Retrofit	9,668	58%	5,627	0.90	20	$1,381	100%	100%	100%	54%	89%	92.3%	92.3%	92.3%	2.7	2,146	2,969	2,794	2,982	2,883
5021	Envelope	Wall Insulation (heat pump)	Home Performance	SF	Retrofit	7,192	24%	1,697	0.77	20	$1,381	100%	72%	75%	4%	89%	92.3%	92.3%	92.3%	1.2	525	725	683	729	705
5022	Envelope	Wall Insulation (heat pump)	Low Income	SF	Retrofit	7,192	24%	1,697	0.77	20	$1,381	100%	100%	100%	4%	89%	92.3%	92.3%	92.3%	1.2	163	225	212	226	219
5023	Envelope	Wall Insulation (heat pump)	Multifamily	MF	Retrofit	6,764	25%	1,697	0.77	20	$1,381	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	1.2	166	229	216	230	223
5024	Envelope	Wall Insulation (heat pump)	Low Income	MF	Retrofit	6,764	25%	1,697	0.77	20	$1,381	100%	100%	100%	4%	89%	92.3%	92.3%	92.3%	1.2	51	71	67	71	69
5025	Envelope	Floor Insulation (AC/Electric resistance heat)	Home Performance	SF	Retrofit	10,260	1%	109	0.00	20	$2,172	100%	46%	75%	54%	89%	92.3%	92.3%	92.3%	0.0	845	0	0	0	0
5026	Envelope	Floor Insulation (AC/Electric resistance heat)	Low Income	SF	Retrofit	10,260	1%	109	0.00	20	$2,172	100%	100%	100%	54%	89%	92.3%	92.3%	92.3%	0.0	262	0	0	0	0
5027	Envelope	Floor Insulation (AC/Electric resistance heat)	Multifamily	MF	Retrofit	9,668	1%	109	0.00	20	$2,172	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	0.0	267	0	0	0	0
5028	Envelope	Floor Insulation (AC/Electric resistance heat)	Low Income	MF	Retrofit	9,668	1%	109	0.00	20	$2,172	100%	100%	100%	54%	89%	92.3%	92.3%	92.3%	0.0	83	0	0	0	0
5029	Envelope	Floor Insulation (Heat pump)	Home Performance	SF	Retrofit	7,192	11%	808	0.00	20	$2,172	100%	46%	75%	4%	89%	92.3%	92.3%	92.3%	0.2	499	0	0	0	0
5030	Envelope	Floor Insulation (Heat pump)	Low Income	SF	Retrofit	7,192	11%	808	0.00	20	$2,172	100%	100%	100%	4%	89%	92.3%	92.3%	92.3%	0.2	155	214	202	215	208
5031	Envelope	Floor Insulation (Heat pump)	Multifamily	MF	Retrofit	6,764	12%	808	0.00	20	$2,172	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	0.2	158	0	0	0	0
5032	Envelope	Floor Insulation (Heat pump)	Low Income	MF	Retrofit	6,764	12%	808	0.00	20	$2,172	100%	100%	100%	4%	89%	92.3%	92.3%	92.3%	0.2	49	68	64	68	66
5033	Envelope	ENERGY STAR Window (AC/gas heat) - double pane replacement	No program	SF	Retrofit	6,156	7%	435	0.19	20	$67	100%	90%	90%	38%	61%	72.7%	72.7%	72.7%	6.0	2,775	3,838	2,336	2,493	2,410
5034	Envelope	ENERGY STAR Window (AC/gas heat) - double pane replacement	No program	SF	Retrofit	6,156	7%	435	0.19	20	$67	100%	90%	90%	38%	61%	72.7%	72.7%	72.7%	6.0	862	1,192	725	774	749
5035	Envelope	ENERGY STAR Window (AC/gas heat) - double pane replacement	No program	MF	Retrofit	5,790	8%	435	0.19	20	$67	100%	90%	90%	38%	61%	72.7%	72.7%	72.7%	6.0	876	1,212	738	787	761
5036	Envelope	ENERGY STAR Window (AC/gas heat) - double pane replacement	No program	MF	Retrofit	5,790	8%	435	0.19	20	$67	100%	90%	90%	38%	61%	72.7%	72.7%	72.7%	6.0	272	376	229	244	236
5037	Envelope	ENERGY STAR Window (AC/Electric resistance heat) - double pane replacement	No program	SF	Retrofit	10,260	4%	442	0.19	20	$67	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	6.0	3,512	4,858	2,956	3,155	3,050
5038	Envelope	ENERGY STAR Window (AC/Electric resistance heat) - double pane replacement	No program	SF	Retrofit	10,260	4%	442	0.19	20	$67	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	6.0	1,091	1,509	918	980	948
5039	Envelope	ENERGY STAR Window (AC/Electric resistance heat) - double pane replacement	No program	MF	Retrofit	9,668	5%	442	0.19	20	$67	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	6.0	1,109	1,534	934	996	963
5040	Envelope	ENERGY STAR Window (AC/Electric resistance heat) - double pane replacement	No program	MF	Retrofit	9,668	5%	442	0.19	20	$67	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	6.0	345	477	290	309	299
5041	Envelope	ENERGY STAR Window (heat pump) - double pane replacement	No program	SF	Retrofit	7,192	6%	446	0.19	20	$67	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	6.1	310	428	261	278	269
5042	Envelope	ENERGY STAR Window (heat pump) - double pane replacement	No program	SF	Retrofit	7,192	6%	446	0.19	20	$67	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	6.1	96	133	81	86	84
5043	Envelope	ENERGY STAR Window (heat pump) - double pane replacement	No program	MF	Retrofit	6,764	7%	446	0.19	20	$67	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	6.1	98	135	82	88	85
5044	Envelope	ENERGY STAR Window (heat pump) - double pane replacement	No program	MF	Retrofit	6,764	7%	446	0.19	20	$67	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	6.1	30	42	26	27	26
5045	Envelope	ENERGY STAR Storm Window (AC/gas heat) - double pane replacement	No program	SF	Retrofit	6,156	3%	167	0.08	20	$67	100%	90%	90%	38%	61%	72.7%	72.7%	72.7%	2.4	423	584	356	380	367
5046	Envelope	ENERGY STAR Storm Window (AC/gas heat) - double pane replacement	No program	SF	Retrofit	6,156	3%	167	0.08	20	$67	100%	90%	90%	38%	61%	72.7%	72.7%	72.7%	2.4	131	182	110	118	114
5047	Envelope	ENERGY STAR Storm Window (AC/gas heat) - double pane replacement	No program	MF	Retrofit	5,790	3%	167	0.08	20	$67	100%	90%	90%	38%	61%	72.7%	72.7%	72.7%	2.4	133	185	112	120	116
5048	Envelope	ENERGY STAR Storm Window (AC/gas heat) - double pane replacement	No program	MF	Retrofit	5,790	3%	167	0.08	20	$67	100%	90%	90%	38%	61%	72.7%	72.7%	72.7%	2.4	41	57	35	37	36
5049	Envelope	ENERGY STAR Storm Window (AC/Electric resistance heat) - double pane replacement	No program	SF	Retrofit	10,260	3%	330	0.08	20	$67	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	3.6	1,565	2,164	1,317	1,406	1,359
5050	Envelope	ENERGY STAR Storm Window (AC/Electric resistance heat) - double pane replacement	No program	SF	Retrofit	10,260	3%	330	0.08	20	$67	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	3.6	486	672	409	437	422
5051	Envelope	ENERGY STAR Storm Window (AC/Electric resistance heat) - double pane replacement	No program	MF	Retrofit	9,668	3%	330	0.08	20	$67	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	3.6	494	683	416	444	429
5052	Envelope	ENERGY STAR Storm Window (AC/Electric resistance heat) - double pane replacement	No program	MF	Retrofit	9,668	3%	330	0.08	20	$67	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	3.6	153	212	129	138	133
5053	Envelope	ENERGY STAR Storm Window (heat pump) - double pane replacement	No program	SF	Retrofit	7,192	3%	217	0.08	20	$67	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	2.8	68	94	57	61	59
5054	Envelope	ENERGY STAR Storm Window (heat pump) - double pane replacement	No program	SF	Retrofit	7,192	3%	217	0.08	20	$67	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	2.8	21	29	18	19	18
5055	Envelope	ENERGY STAR Storm Window (heat pump) - double pane replacement	No program	MF	Retrofit	6,764	3%	217	0.08	20	$67	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	2.8	22	30	18	19	19
5056	Envelope	ENERGY STAR Storm Window (heat pump) - double pane replacement	No program	MF	Retrofit	6,764	3%	217	0.08	20	$67	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	2.8	7	9	6	6	6
5057	Envelope	Air Infiltration (AC/gas heat)	Home Performance	SF	Retrofit	6,156	14%	840	0.68	11	$441	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	1.5	2,294	3,173	2,987	3,188	3,015
5058	Envelope	Air Infiltration (AC/gas heat)	Low Income	SF	Retrofit	6,156	14%	840	0.68	11	$441	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	1.5	713	986	928	990	937
5059	Envelope	Air Infiltration (AC/gas heat)	Multifamily	MF	Retrofit	5,790	15%	840	0.68	11	$441	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	1.5	725	1,002	943	1,007	952
5060	Envelope	Air Infiltration (AC/gas heat)	Low Income	MF	Retrofit	5,790	15%	840	0.68	11	$441	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	1.5	225	311	293	313	296
5061	Envelope	Air Infiltration (AC/Electric resistance heat)	Home Performance	SF	Retrofit	10,260	20%	2,082	0.68	11	$441	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	2.4	8,096	11,198	10,540	11,249	10,640
5062	Envelope	Air Infiltration (AC/Electric resistance heat)	Low Income	SF	Retrofit	10,260	20%	2,082	0.68	11	$441	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	2.4	2,515	3,478	3,274	3,494	3,305
5063	Envelope	Air Infiltration (AC/Electric resistance heat)	Multifamily	MF	Retrofit	9,668	22%	2,082	0.68	11	$441	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	2.4	2,557	3,536	3,329	3,552	3,360
5064	Envelope	Air Infiltration (AC/Electric resistance heat)	Low Income	MF	Retrofit	9,668	22%	2,082	0.68	11	$441	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	2.4	794	1,098	1,034	1,103	1,044
5065	Envelope	Air Infiltration (Heat pump)	Home Performance	SF	Retrofit	7,192	20%	1,474	0.68	11	$441	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	2.0	456	630	593	633	599
5066	Envelope	Air Infiltration (Heat pump)	Low Income	SF	Retrofit	7,192	20%	1,474	0.68	11	$441	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	2.0	142	196	184	197	186
5067	Envelope	Air Infiltration (Heat pump)	Multifamily	MF	Retrofit	6,764	22%	1,474	0.68	11	$441	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	2.0	144	199	187	200	189
5068	Envelope	Air Infiltration (Heat pump)	Low Income	MF	Retrofit	6,764	22%	1,474	0.68	11	$441	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	2.0	45	62	58	62	59
5069	Envelope	Window Film (AC/Electric resistance heat)(Single Pane)	No program	SF	Retrofit	10,260	-1%	-73	0.11	10	$220	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	0.2	0	0	0	0	0
5070	Envelope	Window Film (AC/Electric resistance heat)(Single Pane)	No program	SF	Retrofit	10,260	-1%	-73	0.11	10	$220	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	0.2	0	0	0	0	0
5071	Envelope	Window Film (AC/Electric resistance heat)(Single Pane)	No program	MF	Retrofit	9,668	-1%	-73	0.11	10	$220	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	0.2	0	0	0	0	0
5072	Envelope	Window Film (AC/Electric resistance heat)(Single Pane)	No program	MF	Retrofit	9,668	-1%	-73	0.11	10	$220	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	0.2	0	0	0	0	0
5073	Envelope	Window Film (AC/Electric resistance heat)(Double Pane)	No program	SF	Retrofit	10,260	0%	-25	0.11	10	$220	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	0.3	0	0	0	0	0
5074	Envelope	Window Film (AC/Electric resistance heat)(Double Pane)	No program	SF	Retrofit	10,260	0%	-25	0.11	10	$220	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	0.3	0	0	0	0	0
5075	Envelope	Window Film (AC/Electric resistance heat)(Double Pane)	No program	MF	Retrofit	9,668	0%	-25	0.11	10	$220	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	0.3	0	0	0	0	0
5076	Envelope	Window Film (AC/Electric resistance heat)(Double Pane)	No program	MF	Retrofit	9,668	0%	-25	0.11	10	$220	100%	90%	90%	54%	61%	72.7%	72.7%	72.7%	0.3	0	0	0	0	0
5077	Envelope	Window Film (Heat pump)(Single Pane)	No program	SF	Retrofit	7,192	2%	178	0.11	10	$220	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	0.5	180	0	0	0	0
5078	Envelope	Window Film (Heat pump)(Single Pane)	No program	SF	Retrofit	7,192	2%	178	0.11	10	$220	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	0.5	56	0	0	0	0
5079	Envelope	Window Film (Heat pump)(Single Pane)	No program	MF	Retrofit	6,764	3%	178	0.11	10	$220	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	0.5	57	0	0	0	0
5080	Envelope	Window Film (Heat pump)(Single Pane)	No program	MF	Retrofit	6,764	3%	178	0.11	10	$220	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	0.5	18	0	0	0	0
5081	Envelope	Window Film (Heat pump)(Double Pane)	No program	SF	Retrofit	7,192	1%	91	0.11	10	$220	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	0.4	92	0	0	0	0
5082	Envelope	Window Film (Heat pump)(Double Pane)	No program	SF	Retrofit	7,192	1%	91	0.11	10	$220	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	0.4	29	0	0	0	0
5083	Envelope	Window Film (Heat pump)(Double Pane)	No program	MF	Retrofit	6,764	1%	91	0.11	10	$220	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	0.4	29	0	0	0	0
5084	Envelope	Window Film (Heat pump)(Double Pane)	No program	MF	Retrofit	6,764	1%	91	0.11	10	$220	100%	90%	90%	4%	61%	72.7%	72.7%	72.7%	0.4	9	0	0	0	0
5085	Envelope	Radiant Barrier (AC/Gas heat)	No program	SF	Retrofit	6,156	4%	222	0.16	25	$450	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	0.7	1,214	0	0	0	0
5086	Envelope	Radiant Barrier (AC/Gas heat)	No program	SF	Retrofit	6,156	4%	222	0.16	25	$450	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	0.7	377	0	0	0	0
5087	Envelope	Radiant Barrier (AC/Gas heat)	No program	MF	Retrofit	5,790	4%	222	0.16	25	$450	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	0.7	383	0	0	0	0
5088	Envelope	Radiant Barrier (AC/Gas heat)	No program	MF	Retrofit	5,790	4%	222	0.16	25	$450	100%	90%	90%	38%	89%	92.3%	92.3%	92.3%	0.7	119	0	0	0	0
5089	Envelope	Radiant Barrier (AC/Electric resistance heat)	No program	SF	Retrofit	10,260	3%	303	0.16	25	$450	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	0.8	2,353	0	0	0	0

Appendix B: Residential Energy Efficiency Detail

Measure #	End-Use	Measure Name	Program	Building Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Incentive (%)	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	2% Adoption Rate	TRC Score	2040 TP	2040 EP	2040 HCAP	2040 RAP	2040 2% Case
5090	Envelope	Radiant Barrier (AC/Electric resistance heat)	No program	SF	Retrofit	10,260	3%	303	0.16	25	$450	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	0.8	731	0	0	0	0
5091	Envelope	Radiant Barrier (AC/Electric resistance heat)	No program	MF	Retrofit	9,668	3%	303	0.16	25	$450	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	0.8	743	0	0	0	0
5092	Envelope	Radiant Barrier (AC/Electric resistance heat)	No program	MF	Retrofit	9,668	3%	303	0.16	25	$450	100%	90%	90%	54%	89%	92.3%	92.3%	92.3%	0.8	231	0	0	0	0
5093	Envelope	Radiant Barrier (Heat pump)	No program	SF	Retrofit	7,192	2%	162	0.16	25	$450	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	0.6	100	0	0	0	0
5094	Envelope	Radiant Barrier (Heat pump)	No program	SF	Retrofit	7,192	2%	162	0.16	25	$450	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	0.6	31	0	0	0	0
5095	Envelope	Radiant Barrier (Heat pump)	No program	MF	Retrofit	6,764	2%	162	0.16	25	$450	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	0.6	32	0	0	0	0
5096	Envelope	Radiant Barrier (Heat pump)	No program	MF	Retrofit	6,764	2%	162	0.16	25	$450	100%	90%	90%	4%	89%	92.3%	92.3%	92.3%	0.6	10	0	0	0	0
6001	Behavior	Home Energy Report	Scorecard	SF	ROB	10,200	1%	102	0.01	1	$1	100%	0%	75%	100%	70%	79.0%	79.0%	79.0%	3.7	9,900	9,900	7,821	7,821	7,821
6002	Behavior	Home Energy Report	Scorecard	SF	ROB	10,200	1%	102	0.01	1	$1	100%	0%	75%	100%	70%	79.0%	79.0%	79.0%	3.7	3,075	3,075	2,429	2,429	2,429
6003	Behavior	Home Energy Report	Scorecard	SF	NC	10,200	1%	102	0.01	1	$1	100%	0%	75%	100%	70%	79.0%	79.0%	79.0%	3.7	1,371	1,371	1,083	1,083	1,083
6004	Behavior	Home Energy Report	Scorecard	MF	ROB	10,200	1%	102	0.01	1	$1	100%	0%	75%	100%	70%	79.0%	79.0%	79.0%	3.7	3,126	3,126	2,470	2,470	2,470
6005	Behavior	Home Energy Report	Scorecard	MF	ROB	10,200	1%	102	0.01	1	$1	100%	0%	75%	100%	70%	79.0%	79.0%	79.0%	3.7	971	971	767	767	767
6006	Behavior	Home Energy Report	Scorecard	MF	NC	10,200	1%	102	0.01	1	$1	100%	0%	75%	100%	70%	79.0%	79.0%	79.0%	3.7	433	433	342	342	342

APPENDIX D. C&I Energy Efficiency Measure Detail

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
1	Cooking	Commercial Griddles	Colleges/Universities	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	84	47	56	51
2	Cooking	Convection Ovens	Colleges/Universities	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	101	67	74	71
3	Cooking	Combination Ovens	Colleges/Universities	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	47	27	35	28
4	Cooking	Commercial Fryers	Colleges/Universities	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	202	0	0	0
5	Cooking	Commercial Steam Cookers	Colleges/Universities	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	144	90	107	97
6	Cooling	Air-Cooled Chillers	Colleges/Universities	ROB	11%	166	0.186	20	$127	100%	33%	75%	1	21%	20%	85.6%	44.0%	63.6%	2.1	1,592	454	858	616
7	Cooling	Water-Cooled Chillers	Colleges/Universities	ROB	12%	104	0.077	20	$107	100%	22%	75%	2	21%	20%	85.6%	44.0%	56.3%	1.2	1,772	505	955	638
8	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Colleges/Universities	Retro	29%	815	0.036	15	$190	100%	50%	75%	3	8%	10%	75.4%	43.2%	61.2%	1.8	2,116	833	1,580	1,157
9	Cooling	Unitary and Split System AC	Colleges/Universities	ROB	24%	410	0.228	15	$123	100%	50%	75%	4	43%	20%	85.6%	54.9%	71.0%	2.8	9,436	4,014	6,298	5,116
10	Cooling	Unitary and Split System HP	Colleges/Universities	ROB	24%	488	0.228	15	$123	100%	50%	75%	5	6%	20%	85.6%	56.1%	72.2%	3.0	1,236	539	825	642
11	Cooling	Ductless Mini-Split HP	Colleges/Universities	ROB	11%	259	0.210	18	$143	100%	50%	75%	6	6%	20%	85.6%	48.5%	64.8%	2.1	567	186	334	244
12	Cooling	PTAC Equipment	Colleges/Universities	ROB	4%	60	0.110	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	61.9%	1.0	0	0	0	0
13	Cooling	PTHP Equipment	Colleges/Universities	ROB	6%	125	0.114	10	$77	100%	41%	75%	8	0%	20%	85.6%	45.7%	64.5%	1.3	0	0	0	0
14	Cooling	Commercial AC and HP Tune Up	Colleges/Universities	Retro	4%	60	0.033	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.3	2,361	0	0	0
15	Cooling	ECM - HVAC	Colleges/Universities	Retro	78%	351	0.066	15	$177	100%	24%	75%	10	2%	5%	73.1%	33.5%	47.1%	1.1	696	247	571	332
16	Cooling	ERV	Colleges/Universities	Retro	24%	2	0.003	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	45.3%	0.8	9,847	0	0	0
17	Cooling	Window Film	Colleges/Universities	Retro	8%	7	0.004	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	53.1%	1.6	3,269	1,527	2,839	1,640
18	Cooling	Cool Roof	Colleges/Universities	Retro	3%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	1,031	0	0	0
19	Cooling	Smart Thermostats	Colleges/Universities	Retro	4%	545	0.303	11	$208	100%	50%	75%	14	100%	9%	75.4%	45.9%	62.9%	1.7	131	76	131	99
20	Ext Lighting	LED wallpack (existing W<250)	Colleges/Universities	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	12%	83.4%	38.1%	56.8%	0.7	274	0	0	0
21	Ext Lighting	LED parking lot fixture (existing W≥250)	Colleges/Universities	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	12%	83.4%	38.1%	48.0%	0.4	250	0	0	0
22	Ext Lighting	LED parking lot fixture (existing W<250)	Colleges/Universities	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	12%	83.4%	38.1%	56.8%	0.7	274	0	0	0
23	Ext Lighting	LED parking garage fixture (existing W≥250)	Colleges/Universities	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	12%	83.4%	43.4%	62.7%	0.5	251	0	0	0
24	Ext Lighting	LED parking garage fixture (existing W<250)	Colleges/Universities	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	12%	83.4%	53.6%	71.4%	1.0	276	136	226	171
25	Ext Lighting	Bi-Level Garage Lighting	Colleges/Universities	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	171	0	0	0
26	Ext Lighting	LED Traffic Signals	Colleges/Universities	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
27	Hot Water	Electric Storage Water Heater	Colleges/Universities	ROB	4%	158	0.018	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	8	0	0	0
28	Hot Water	Heat Pump Water Heater	Colleges/Universities	ROB	68%	2,917	0.333	10	$1,350	100%	23%	75%	1	95%	3%	85.6%	31.8%	57.8%	0.7	1,975	0	0	0
29	Hot Water	Electric tankless water heater	Colleges/Universities	ROB	60%	133	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.4	4	0	0	0
30	Hot Water	Water Heater Pipe Insulation	Colleges/Universities	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	1%	80%	86.0%	86.0%	86.0%	0.1	4	0	0	0
31	Hot Water	Faucet Aerator	Colleges/Universities	Retro	32%	473	0.118	10	$8	100%	75%	75%	4	34%	80%	86.0%	86.0%	86.0%	24.3	55	88	88	79
32	Hot Water	Low-Flow Showerheads	Colleges/Universities	Retro	20%	39	1.939	10	$12	100%	33%	75%	5	4%	80%	86.0%	86.0%	86.0%	94.7	5	7	7	7
33	Hot Water	PRSV	Colleges/Universities	Retro	33%	1,253	0.313	5	$93	100%	75%	75%	6	20%	50%	75.4%	67.0%	72.0%	2.9	54	62	80	66
34	Hot Water	ENERGY STAR Clothes Washers	Colleges/Universities	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	123	0	0	0
35	Int Lighting	Interior 4 ft LED	Colleges/Universities	Retro	49%	102	0.024	15	$13	100%	50%	75%	1	86%	12%	83.4%	66.3%	77.4%	4.5	14,762	9,381	12,162	10,420
36	Int Lighting	LED Screw In - Interior	Colleges/Universities	Retro	80%	121	0.029	9	$2	100%	50%	75%	2	2%	50%	83.4%	79.0%	82.8%	27.0	384	255	282	252
37	Int Lighting	LED Fixture - Interior	Colleges/Universities	Retro	69%	130	0.031	15	$27	100%	60%	75%	3	10%	12%	83.4%	62.4%	73.7%	2.8	2,373	1,406	1,955	1,584
38	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Colleges/Universities	Retro	52%	423	0.098	15	$201	100%	50%	75%	4	1%	12%	83.4%	42.7%	62.0%	1.2	203	76	167	111
39	Int Lighting	Interior LED High Bay | Replacing HID	Colleges/Universities	Retro	73%	2,047	0.475	15	$458	100%	50%	75%	5	1%	12%	83.4%	56.7%	72.8%	2.6	284	151	234	187
40	Int Lighting	Advanced Lighting Controls	Colleges/Universities	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	502	0	0	0
41	Int Lighting	Controls Cont Dimming	Colleges/Universities	Retro	30%	62	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	51.8%	70.5%	1.2	2,142	1,846	2,771	2,189
42	Int Lighting	Controls Photocells	Colleges/Universities	Retro	10%	21	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	42.6%	61.9%	0.7	428	0	0	0
43	Int Lighting	Controls Occ Sensor	Colleges/Universities	Retro	30%	62	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	51.8%	70.5%	1.2	2,142	1,846	2,771	2,189
44	Int Lighting	Custom Lighting	Colleges/Universities	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	4,713	1,896	3,623	2,326
45	Misc	Vend Machine Ctrls	Colleges/Universities	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	71	0	0	0
46	Misc	Vend Machine Ctrls -refrigerated	Colleges/Universities	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	295	177	177	160
47	Misc	Power Distribution Equipment Upgrades	Colleges/Universities	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	49%	20%	73.1%	44.0%	44.0%	0.9	202	69	138	71
48	Misc	Custom Miscellaneous	Colleges/Universities	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	10,887	3,891	7,984	5,009
49	Plug Loads Office	Plug Load Occupancy Sensors	Colleges/Universities	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	2,971	0	0	0
50	Plug Loads Office	Advanced Power Strips	Colleges/Universities	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	2,602	1,039	2,213	1,503
51	Plug Loads Office	Computer Power Management	Colleges/Universities	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	1,041	0	0	0
52	Refrigeration	Solid Door Commercial Refrigeration Equipment	Colleges/Universities	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	32%	56%	85.6%	69.2%	73.1%	2.6	3,017	1,804	2,417	1,954
53	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Colleges/Universities	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	8%	54%	85.6%	67.8%	67.8%	0.8	246	0	0	0
54	Refrigeration	Door Heater Controls	Colleges/Universities	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	28	0	0	0
55	Refrigeration	Zero Energy Doors	Colleges/Universities	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	507	214	410	287
56	Refrigeration	Night Covers	Colleges/Universities	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	160	0	0	0
57	Refrigeration	Strip Curtain	Colleges/Universities	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	12%	36%	75.4%	55.2%	61.0%	0.7	2,143	0	0	0
58	Refrigeration	Evap Fan Ctrls	Colleges/Universities	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	2%	33%	73.1%	53.1%	53.1%	2.3	443	167	284	162
59	Refrigeration	Refrigeration ECMs	Colleges/Universities	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	12%	20%	75.4%	48.9%	63.2%	2.2	1,167	465	827	616
60	Refrigeration	Refrigerated Case Lighting	Colleges/Universities	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	732	0	0	0
61	Refrigeration	Ice Maker	Colleges/Universities	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	4%	50%	85.6%	65.0%	65.0%	0.4	185	0	0	0
62	Refrigeration	Custom Refrigeration	Colleges/Universities	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	3,435	1,759	2,526	1,750
63	Ventilation	VFDs of Supply and Return Fans	Colleges/Universities	Retro	59%	25,845	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	54.1%	2.3	11,434	4,042	7,623	4,660
64	Whole Building_HVAC	Variable Air Volume HVAC	Colleges/Universities	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	43%	25%	73.1%	65.2%	71.7%	33.6	13,910	10,385	11,881	11,002
65	Whole Building_HVAC	Demand Controlled Ventilation	Colleges/Universities	Retro	3%	45	0.032	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	41.2%	0.5	1,618	0	0	0
66	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Colleges/Universities	Retro	15%	3,460	0.428	15	$1,778	100%	50%	75%	3	11%	24%	73.1%	46.8%	46.8%	1.0	1,238	567	1,062	530
67	Whole Building_HVAC	GREM Controls	Colleges/Universities	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
68	Whole Building_HVAC	Custom Whole Building HVAC	Colleges/Universities	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	16,609	7,363	14,445	7,330
69	Whole Buildings	Whole Building Retrofit	Colleges/Universities	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	60.2%	66.2%	6.1	5,463	4,368	5,116	4,600
70	Whole Buildings	Custom Whole Building Controls (BAS)	Colleges/Universities	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	22,405	10,925	19,777	10,522
71	Whole Buildings	Commercial Behavior	Colleges/Universities	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	3,757	1,587	1,525	1,635
72	Cooking	Commercial Griddles	Healthcare	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	68	38	45	41
73	Cooking	Convection Ovens	Healthcare	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	81	54	60	57
74	Cooking	Combination Ovens	Healthcare	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	38	22	28	23
75	Cooking	Commercial Fryers	Healthcare	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	163	0	0	0
76	Cooking	Commercial Steam Cookers	Healthcare	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	116	72	86	78

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
77	Cooling	Air-Cooled Chillers	Healthcare	ROB	11%	219	0.188	20	$127	100%	33%	75%	1	24%	20%	85.6%	44.0%	64.6%	2.3	926	264	499	365
78	Cooling	Water-Cooled Chillers	Healthcare	ROB	12%	137	0.077	20	$107	100%	22%	75%	2	24%	20%	85.6%	44.0%	58.1%	1.3	1,032	294	556	359
79	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Healthcare	Retro	29%	1,288	0.036	15	$190	100%	50%	75%	3	10%	10%	75.4%	50.8%	65.9%	2.8	1,228	588	919	733
80	Cooling	Unitary and Split System AC	Healthcare	ROB	24%	540	0.231	15	$123	100%	50%	75%	4	50%	20%	85.6%	56.9%	73.0%	3.2	5,605	2,357	3,741	2,946
81	Cooling	Unitary and Split System HP	Healthcare	ROB	24%	555	0.231	15	$123	100%	50%	75%	5	0%	20%	85.6%	57.1%	73.2%	3.3	0	0	0	0
82	Cooling	Ductless Mini-Split HP	Healthcare	ROB	13%	307	0.216	18	$143	100%	50%	75%	6	0%	20%	85.6%	49.6%	65.6%	2.3	0	0	0	0
83	Cooling	PTAC Equipment	Healthcare	ROB	4%	78	0.111	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	62.7%	1.1	0	0	0	0
84	Cooling	PTHP Equipment	Healthcare	ROB	5%	114	0.121	10	$77	100%	41%	75%	8	0%	20%	85.6%	45.8%	64.5%	1.3	0	0	0	0
85	Cooling	Commercial AC and HP Tune Up	Healthcare	Retro	4%	79	0.034	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.4	1,180	0	0	0
86	Cooling	ECM - HVAC	Healthcare	Retro	78%	351	0.072	15	$177	100%	24%	75%	10	3%	5%	73.1%	33.5%	47.3%	1.1	411	147	339	198
87	Cooling	ERV	Healthcare	Retro	24%	2	0.004	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	47.0%	1.1	4,924	1,772	4,080	2,375
88	Cooling	Window Film	Healthcare	Retro	8%	9	0.004	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	55.8%	1.8	1,632	755	1,361	867
89	Cooling	Cool Roof	Healthcare	Retro	3%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	563	0	0	0
90	Cooling	Smart Thermostats	Healthcare	Retro	4%	718	0.307	11	$208	100%	50%	75%	14	100%	9%	75.4%	48.7%	64.6%	1.9	66	40	63	50
91	Ext Lighting	LED wallpack (existing W<250)	Healthcare	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	14%	83.4%	39.8%	56.8%	0.7	217	0	0	0
92	Ext Lighting	LED parking lot fixture (existing W≥250)	Healthcare	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	14%	83.4%	39.8%	48.0%	0.4	198	0	0	0
93	Ext Lighting	LED parking lot fixture (existing W<250)	Healthcare	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	14%	83.4%	39.8%	56.8%	0.7	217	0	0	0
94	Ext Lighting	LED parking garage fixture (existing W≥250)	Healthcare	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	14%	83.4%	43.4%	62.7%	0.5	199	0	0	0
95	Ext Lighting	LED parking garage fixture (existing W<250)	Healthcare	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	14%	83.4%	53.6%	71.4%	1.0	218	105	178	134
96	Ext Lighting	Bi-Level Garage Lighting	Healthcare	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	138	0	0	0
97	Ext Lighting	LED Traffic Signals	Healthcare	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
98	Hot Water	Electric Storage Water Heater	Healthcare	ROB	4%	220	0.025	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	6	0	0	0
99	Hot Water	Heat Pump Water Heater	Healthcare	ROB	68%	4,048	0.462	10	$1,350	100%	23%	75%	1	95%	3%	85.6%	36.8%	62.3%	1.0	1,590	504	1,197	867
100	Hot Water	Electric tankless water heater	Healthcare	ROB	60%	185	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.6	3	0	0	0
101	Hot Water	Water Heater Pipe Insulation	Healthcare	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	1%	80%	86.0%	86.0%	86.0%	0.1	3	0	0	0
102	Hot Water	Faucet Aerator	Healthcare	Retro	32%	86	0.007	10	$8	100%	75%	75%	4	4%	80%	86.0%	86.0%	86.0%	3.4	6	9	9	8
103	Hot Water	Low-Flow Showerheads	Healthcare	Retro	20%	26	0.784	10	$12	100%	33%	75%	5	2%	80%	86.0%	86.0%	86.0%	38.5	2	3	3	2
104	Hot Water	PRSV	Healthcare	Retro	33%	4,574	0.376	5	$93	100%	75%	75%	6	20%	50%	75.4%	69.6%	74.2%	8.1	44	50	51	48
105	Hot Water	ENERGY STAR Clothes Washers	Healthcare	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	100	0	0	0
106	Int Lighting	Interior 4 ft LED	Healthcare	Retro	49%	114	0.027	15	$13	100%	50%	75%	1	79%	14%	83.4%	67.9%	78.1%	5.1	6,958	4,489	5,708	4,919
107	Int Lighting	LED Screw In - Interior	Healthcare	Retro	80%	136	0.032	9	$2	100%	50%	75%	2	3%	50%	83.4%	79.2%	82.9%	30.2	336	224	247	221
108	Int Lighting	LED Fixture - Interior	Healthcare	Retro	69%	146	0.035	15	$27	100%	60%	75%	3	17%	14%	83.4%	64.2%	74.7%	3.1	2,035	1,229	1,669	1,368
109	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Healthcare	Retro	52%	475	0.125	15	$201	100%	50%	75%	4	1%	14%	83.4%	45.5%	64.9%	1.4	51	20	42	29
110	Int Lighting	Interior LED High Bay | Replacing HID	Healthcare	Retro	73%	2,300	0.603	15	$458	100%	50%	75%	5	1%	14%	83.4%	59.8%	74.4%	3.0	72	40	59	48
111	Int Lighting	Advanced Lighting Controls	Healthcare	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	243	0	0	0
112	Int Lighting	Controls Cont Dimming	Healthcare	Retro	30%	70	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	53.8%	71.4%	1.3	1,118	999	1,444	1,154
113	Int Lighting	Controls Photocells	Healthcare	Retro	10%	23	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	43.4%	62.8%	0.8	215	0	0	0
114	Int Lighting	Controls Occ Sensor	Healthcare	Retro	30%	70	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	53.8%	71.4%	1.3	1,118	999	1,444	1,154
115	Int Lighting	Custom Lighting	Healthcare	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	2,463	991	1,894	1,216
116	Misc	Vend Machine Ctrls	Healthcare	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	54	0	0	0
117	Misc	Vend Machine Ctrls -refrigerated	Healthcare	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	221	133	133	120
118	Misc	Power Distribution Equipment Upgrades	Healthcare	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	66%	20%	73.1%	44.0%	44.0%	0.9	203	70	139	72
119	Misc	Custom Miscellaneous	Healthcare	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	8,159	2,917	5,986	3,756
120	Plug Loads Office	Plug Load Occupancy Sensors	Healthcare	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	1,066	0	0	0
121	Plug Loads Office	Advanced Power Strips	Healthcare	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	934	373	794	540
122	Plug Loads Office	Computer Power Management	Healthcare	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	374	0	0	0
123	Refrigeration	Solid Door Commercial Refrigeration Equipment	Healthcare	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	36%	56%	85.6%	69.2%	73.1%	2.6	1,028	615	823	666
124	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Healthcare	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	9%	54%	85.6%	67.8%	67.8%	0.8	84	0	0	0
125	Refrigeration	Door Heater Controls	Healthcare	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	9	0	0	0
126	Refrigeration	Zero Energy Doors	Healthcare	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	154	65	124	87
127	Refrigeration	Night Covers	Healthcare	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	48	0	0	0
128	Refrigeration	Strip Curtain	Healthcare	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	6%	39%	75.4%	57.3%	61.0%	0.7	312	0	0	0
129	Refrigeration	Evap Fan Ctrls	Healthcare	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	1%	33%	73.1%	53.1%	53.1%	2.3	67	25	43	25
130	Refrigeration	Refrigeration ECMs	Healthcare	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	12%	20%	75.4%	48.9%	63.2%	2.2	354	141	251	187
131	Refrigeration	Refrigerated Case Lighting	Healthcare	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	222	0	0	0
132	Refrigeration	Ice Maker	Healthcare	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	6%	50%	85.6%	65.0%	65.0%	0.4	84	0	0	0
133	Refrigeration	Custom Refrigeration	Healthcare	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	1,067	532	764	529
134	Ventilation	VFDs of Supply and Return Fans	Healthcare	Retro	59%	30,976	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	57.2%	2.8	9,235	3,264	6,157	4,098
135	Whole Building_HVAC	Variable Air Volume HVAC	Healthcare	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	50%	39%	73.1%	65.2%	71.7%	33.6	8,299	5,501	6,396	6,035
136	Whole Building_HVAC	Demand Controlled Ventilation	Healthcare	Retro	3%	55	0.039	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	43.1%	0.6	880	0	0	0
137	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Healthcare	Retro	0%	0	0.000	15	$1,778	100%	50%	75%	3	4%	24%	73.1%	68.3%	73.1%	0.0	0	0	0	0
138	Whole Building_HVAC	GREM Controls	Healthcare	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
139	Whole Building_HVAC	Custom Whole Building HVAC	Healthcare	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	9,756	4,290	8,302	4,242
140	Whole Buildings	Whole Building Retrofit	Healthcare	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	60.3%	66.3%	6.1	3,155	2,501	2,908	2,623
141	Whole Buildings	Custom Whole Building Controls (BAS)	Healthcare	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	13,007	6,247	11,216	5,986
142	Whole Buildings	Commercial Behavior	Healthcare	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	2,205	906	856	925
143	Cooking	Commercial Griddles	Warehouses	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	0	0	0	0
144	Cooking	Convection Ovens	Warehouses	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	0	0	0	0
145	Cooking	Combination Ovens	Warehouses	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	0	0	0	0
146	Cooking	Commercial Fryers	Warehouses	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	0	0	0	0
147	Cooking	Commercial Steam Cookers	Warehouses	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	0	0	0	0
148	Cooling	Air-Cooled Chillers	Warehouses	ROB	11%	147	0.167	20	$127	100%	33%	75%	1	0%	20%	85.6%	44.0%	62.4%	1.8	0	0	0	0
149	Cooling	Water-Cooled Chillers	Warehouses	ROB	12%	92	0.069	20	$107	100%	22%	75%	2	0%	20%	85.6%	44.0%	55.0%	1.0	0	0	0	0
150	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Warehouses	Retro	29%	640	0.036	15	$190	100%	50%	75%	3	0%	10%	75.4%	39.6%	58.7%	1.5	0	0	0	0
151	Cooling	Unitary and Split System AC	Warehouses	ROB	24%	363	0.205	15	$123	100%	50%	75%	4	91%	20%	85.6%	53.1%	69.2%	2.5	2,281	934	1,522	1,202
152	Cooling	Unitary and Split System HP	Warehouses	ROB	24%	597	0.224	15	$123	100%	50%	75%	5	0%	20%	85.6%	57.4%	73.5%	3.3	0	0	0	0

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
153	Cooling	Ductless Mini-Split HP	Warehouses	ROB	13%	207	0.192	18	$143	100%	50%	75%	6	0%	20%	85.6%	46.5%	63.4%	1.9	0	0	0	0
154	Cooling	PTAC Equipment	Warehouses	ROB	4%	53	0.099	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	60.5%	0.9	0	0	0	0
155	Cooling	PTHP Equipment	Warehouses	ROB	5%	79	0.108	10	$77	100%	41%	75%	8	0%	20%	85.6%	44.0%	62.5%	1.1	0	0	0	0
156	Cooling	Commercial AC and HP Tune Up	Warehouses	Retro	4%	53	0.030	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.3	257	0	0	0
157	Cooling	ECM - HVAC	Warehouses	Retro	78%	351	0.066	15	$177	100%	24%	75%	10	5%	5%	73.1%	33.5%	47.1%	1.1	162	60	137	80
158	Cooling	ERV	Warehouses	Retro	24%	1	0.002	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	42.6%	0.5	1,073	0	0	0
159	Cooling	Window Film	Warehouses	Retro	8%	6	0.003	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	50.7%	1.4	352	173	320	172
160	Cooling	Cool Roof	Warehouses	Retro	2%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	87	0	0	0
161	Cooling	Smart Thermostats	Warehouses	Retro	4%	482	0.273	11	$208	100%	50%	75%	14	100%	9%	75.4%	43.8%	61.6%	1.5	14	8	15	11
162	Ext Lighting	LED wallpack (existing W<250)	Warehouses	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	13%	83.4%	39.4%	56.8%	0.7	258	0	0	0
163	Ext Lighting	LED parking lot fixture (existing W≥250)	Warehouses	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	13%	83.4%	39.4%	48.0%	0.4	235	0	0	0
164	Ext Lighting	LED parking lot fixture (existing W<250)	Warehouses	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	13%	83.4%	39.4%	56.8%	0.7	258	0	0	0
165	Ext Lighting	LED parking garage fixture (existing W≥250)	Warehouses	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	13%	83.4%	43.4%	62.7%	0.5	237	0	0	0
166	Ext Lighting	LED parking garage fixture (existing W<250)	Warehouses	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	13%	83.4%	53.6%	71.4%	1.0	260	126	212	160
167	Ext Lighting	Bi-Level Garage Lighting	Warehouses	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	163	0	0	0
168	Ext Lighting	LED Traffic Signals	Warehouses	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
169	Hot Water	Electric Storage Water Heater	Warehouses	ROB	4%	95	0.011	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	0	0	0	0
170	Hot Water	Heat Pump Water Heater	Warehouses	ROB	68%	1,752	0.200	10	$1,350	100%	23%	75%	1	95%	0%	85.6%	30.0%	51.2%	0.4	0	0	0	0
171	Hot Water	Electric tankless water heater	Warehouses	ROB	60%	80	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.3	0	0	0	0
172	Hot Water	Water Heater Pipe Insulation	Warehouses	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	2%	80%	86.0%	86.0%	86.0%	0.1	0	0	0	0
173	Hot Water	Faucet Aerator	Warehouses	Retro	32%	591	0.189	10	$8	100%	75%	75%	4	70%	80%	86.0%	86.0%	86.0%	33.4	0	0	0	0
174	Hot Water	Low-Flow Showerheads	Warehouses	Retro	20%	29	2.280	10	$12	100%	33%	75%	5	5%	80%	86.0%	86.0%	86.0%	111.0	0	0	0	0
175	Hot Water	PRSV	Warehouses	Retro	0%	0	0.000	5	$93	100%	75%	75%	6	0%	50%	75.4%	71.0%	75.4%	0.0	0	0	0	0
176	Hot Water	ENERGY STAR Clothes Washers	Warehouses	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	0	0	0	0
177	Int Lighting	Interior 4 ft LED	Warehouses	Retro	49%	69	0.027	15	$13	100%	50%	75%	1	77%	13%	83.4%	63.3%	76.0%	3.7	5,153	3,068	4,228	3,540
178	Int Lighting	LED Screw In - Interior	Warehouses	Retro	80%	82	0.032	9	$2	100%	50%	75%	2	2%	50%	83.4%	78.6%	82.6%	22.3	158	104	116	104
179	Int Lighting	LED Fixture - Interior	Warehouses	Retro	68%	88	0.034	15	$27	100%	60%	75%	3	14%	13%	83.4%	58.6%	71.3%	2.3	1,282	697	1,052	818
180	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Warehouses	Retro	52%	286	0.074	15	$201	100%	50%	75%	4	3%	13%	83.4%	39.4%	56.0%	0.8	243	0	0	0
181	Int Lighting	Interior LED High Bay | Replacing HID	Warehouses	Retro	73%	1,383	0.358	15	$458	100%	50%	75%	5	3%	13%	83.4%	49.1%	68.5%	1.8	342	149	280	208
182	Int Lighting	Advanced Lighting Controls	Warehouses	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	233	0	0	0
183	Int Lighting	Controls Cont Dimming	Warehouses	Retro	30%	42	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	48.0%	67.4%	1.0	798	688	1,108	840
184	Int Lighting	Controls Photocells	Warehouses	Retro	10%	14	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	39.9%	59.2%	0.6	177	0	0	0
185	Int Lighting	Controls Occ Sensor	Warehouses	Retro	30%	42	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	48.0%	67.4%	1.0	798	688	1,108	840
186	Int Lighting	Custom Lighting	Warehouses	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	1,856	747	1,427	916
187	Misc	Vend Machine Ctrls	Warehouses	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	29	0	0	0
188	Misc	Vend Machine Ctrls -refrigerated	Warehouses	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	121	73	73	66
189	Misc	Power Distribution Equipment Upgrades	Warehouses	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	30%	20%	73.1%	44.0%	44.0%	0.9	51	17	35	18
190	Misc	Custom Miscellaneous	Warehouses	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	4,467	1,595	3,274	2,054
191	Plug Loads Office	Plug Load Occupancy Sensors	Warehouses	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	316	0	0	0
192	Plug Loads Office	Advanced Power Strips	Warehouses	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	277	110	235	160
193	Plug Loads Office	Computer Power Management	Warehouses	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	111	0	0	0
194	Refrigeration	Solid Door Commercial Refrigeration Equipment	Warehouses	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	26%	56%	85.6%	69.2%	73.1%	2.6	866	518	693	561
195	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Warehouses	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	6%	54%	85.6%	67.8%	67.8%	0.8	71	0	0	0
196	Refrigeration	Door Heater Controls	Warehouses	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	10	0	0	0
197	Refrigeration	Zero Energy Doors	Warehouses	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	182	77	147	103
198	Refrigeration	Night Covers	Warehouses	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	57	0	0	0
199	Refrigeration	Strip Curtain	Warehouses	Retro	53%	423	0.048	5	$10	100%	50%	75%	5	17%	75%	82.5%	82.5%	82.5%	7.2	572	343	343	310
200	Refrigeration	Evap Fan Ctrls	Warehouses	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	3%	33%	73.1%	53.1%	53.1%	2.3	231	87	148	84
201	Refrigeration	Refrigeration ECMs	Warehouses	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	12%	20%	75.4%	48.9%	63.2%	2.2	419	167	297	221
202	Refrigeration	Refrigerated Case Lighting	Warehouses	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	263	0	0	0
203	Refrigeration	Ice Maker	Warehouses	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	0%	50%	85.6%	65.0%	65.0%	0.4	0	0	0	0
204	Refrigeration	Custom Refrigeration	Warehouses	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	1,271	620	890	617
205	Ventilation	VFDs of Supply and Return Fans	Warehouses	Retro	59%	36,512	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	59.6%	3.3	781	276	521	367
206	Whole Building_HVAC	Variable Air Volume HVAC	Warehouses	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	50%	17%	73.1%	65.2%	71.7%	33.6	1,709	1,381	1,555	1,435
207	Whole Building_HVAC	Demand Controlled Ventilation	Warehouses	Retro	10%	149	0.033	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	46.2%	0.9	596	248	566	326
208	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Warehouses	Retro	0%	0	0.000	15	$1,778	100%	50%	75%	3	0%	24%	73.1%	68.3%	73.1%	0.0	0	0	0	0
209	Whole Building_HVAC	GREM Controls	Warehouses	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
210	Whole Building_HVAC	Custom Whole Building HVAC	Warehouses	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	1,620	742	1,457	738
211	Whole Buildings	Whole Building Retrofit	Warehouses	Retro	15%	1	0.001	20	$0	100%	82%	82%	6	100%	0%	73.1%	61.2%	67.0%	6.9	1,407	1,079	1,233	1,123
212	Whole Buildings	Custom Whole Building Controls (BAS)	Warehouses	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	5,814	2,659	4,772	2,537
213	Whole Buildings	Commercial Behavior	Warehouses	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	982	389	373	398
214	Cooking	Commercial Griddles	Lodging	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	316	177	209	190
215	Cooking	Convection Ovens	Lodging	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	378	251	279	266
216	Cooking	Combination Ovens	Lodging	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	177	102	130	105
217	Cooking	Commercial Fryers	Lodging	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	760	0	0	0
218	Cooking	Commercial Steam Cookers	Lodging	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	540	337	400	364
219	Cooling	Air-Cooled Chillers	Lodging	ROB	11%	230	0.171	20	$127	100%	33%	75%	1	19%	20%	85.6%	44.0%	64.3%	2.2	964	275	520	377
220	Cooling	Water-Cooled Chillers	Lodging	ROB	12%	145	0.070	20	$107	100%	22%	75%	2	19%	20%	85.6%	44.0%	57.7%	1.3	1,073	306	579	371
221	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Lodging	Retro	29%	723	0.036	15	$190	100%	50%	75%	3	8%	10%	75.4%	41.5%	60.0%	1.7	1,284	480	957	686
222	Cooling	Unitary and Split System AC	Lodging	ROB	24%	569	0.209	15	$123	100%	50%	75%	4	34%	20%	85.6%	56.7%	72.8%	3.2	4,934	2,180	3,293	2,587
223	Cooling	Unitary and Split System HP	Lodging	ROB	24%	622	0.209	15	$123	100%	50%	75%	5	0%	20%	85.6%	57.4%	73.5%	3.3	0	0	0	0
224	Cooling	Ductless Mini-Split HP	Lodging	ROB	12%	338	0.194	18	$143	100%	50%	75%	6	0%	20%	85.6%	49.3%	65.4%	2.3	0	0	0	0
225	Cooling	PTAC Equipment	Lodging	ROB	4%	82	0.101	10	$77	100%	41%	75%	7	8%	20%	85.6%	44.0%	62.1%	1.0	172	65	135	94
226	Cooling	PTHP Equipment	Lodging	ROB	5%	142	0.108	10	$77	100%	41%	75%	8	8%	20%	85.6%	45.9%	64.5%	1.3	248	99	194	141
227	Cooling	Commercial AC and HP Tune Up	Lodging	Retro	4%	83	0.031	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.4	1,616	0	0	0
228	Cooling	ECM - HVAC	Lodging	Retro	78%	351	0.067	15	$177	100%	24%	75%	10	2%	5%	73.1%	33.5%	47.1%	1.1	538	187	432	251

Appendix D: C&I Measure Assumption Detail

																				MWH	MWH	MWH	MWH
Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	Tech Potential in 2040	RAP Potential in 2040	HCAP Potential in 2040	2% Potential in 2040
229	Cooling	ERV	Lodging	Retro	24%	2	0.002	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	43.7%	0.6	6,653	0	0	0
230	Cooling	Window Film	Lodging	Retro	8%	9	0.003	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	55.6%	1.8	2,227	1,008	1,880	1,166
231	Cooling	Cool Roof	Lodging	Retro	3%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	723	0	0	0
232	Cooling	Smart Thermostats	Lodging	Retro	4%	756	0.278	11	$208	100%	50%	75%	14	100%	9%	75.4%	48.5%	64.5%	1.9	90	54	87	67
233	Ext Lighting	LED wallpack (existing W<250)	Lodging	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	13%	83.4%	38.9%	56.8%	0.7	340	0	0	0
234	Ext Lighting	LED parking lot fixture (existing W≥250)	Lodging	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	13%	83.4%	38.9%	48.0%	0.4	310	0	0	0
235	Ext Lighting	LED parking lot fixture (existing W<250)	Lodging	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	13%	83.4%	38.9%	56.8%	0.7	340	0	0	0
236	Ext Lighting	LED parking garage fixture (existing W≥250)	Lodging	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	13%	83.4%	43.4%	62.7%	0.5	312	0	0	0
237	Ext Lighting	LED parking garage fixture (existing W<250)	Lodging	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	13%	83.4%	53.6%	71.4%	1.0	342	167	279	212
238	Ext Lighting	Bi-Level Garage Lighting	Lodging	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	214	0	0	0
239	Ext Lighting	LED Traffic Signals	Lodging	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
240	Hot Water	Electric Storage Water Heater	Lodging	ROB	4%	200	0.023	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	10	0	0	0
241	Hot Water	Heat Pump Water Heater	Lodging	ROB	68%	3,677	0.420	10	$1,350	100%	23%	75%	1	95%	3%	85.6%	35.5%	61.2%	0.9	2,467	753	1,858	1,320
242	Hot Water	Electric tankless water heater	Lodging	ROB	60%	168	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.6	5	0	0	0
243	Hot Water	Water Heater Pipe Insulation	Lodging	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	1%	80%	86.0%	86.0%	86.0%	0.1	4	0	0	0
244	Hot Water	Faucet Aerator	Lodging	Retro	32%	86	0.005	10	$8	100%	75%	75%	4	5%	80%	86.0%	86.0%	86.0%	3.2	10	15	15	13
245	Hot Water	Low-Flow Showerheads	Lodging	Retro	20%	37	0.734	10	$12	100%	33%	75%	5	3%	80%	86.0%	86.0%	86.0%	36.3	4	7	6	6
246	Hot Water	PRSV	Lodging	Retro	33%	3,434	0.501	5	$93	100%	75%	75%	6	20%	50%	75.4%	69.3%	73.9%	6.8	68	77	80	74
247	Hot Water	ENERGY STAR Clothes Washers	Lodging	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	155	0	0	0
248	Int Lighting	Interior 4 ft LED	Lodging	Retro	49%	117	0.029	15	$13	100%	50%	75%	1	48%	13%	83.4%	68.4%	78.3%	5.3	6,020	3,940	4,946	4,287
249	Int Lighting	LED Screw In - Interior	Lodging	Retro	80%	140	0.034	9	$2	100%	50%	75%	2	10%	50%	83.4%	79.2%	82.9%	31.4	1,456	974	1,072	960
250	Int Lighting	LED Fixture - Interior	Lodging	Retro	68%	150	0.036	15	$27	100%	60%	75%	3	41%	13%	83.4%	64.6%	75.0%	3.2	7,139	4,370	5,865	4,835
251	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Lodging	Retro	52%	488	0.134	15	$201	100%	50%	75%	4	1%	13%	83.4%	46.2%	65.6%	1.5	68	28	56	39
252	Int Lighting	Interior LED High Bay | Replacing HID	Lodging	Retro	73%	2,362	0.651	15	$458	100%	50%	75%	5	1%	13%	83.4%	60.6%	74.7%	3.1	95	54	78	64
253	Int Lighting	Advanced Lighting Controls	Lodging	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	307	0	0	0
254	Int Lighting	Controls Cont Dimming	Lodging	Retro	30%	72	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	54.2%	71.7%	1.3	1,434	1,363	1,920	1,553
255	Int Lighting	Controls Photocells	Lodging	Retro	10%	24	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	43.7%	63.0%	0.8	275	0	0	0
256	Int Lighting	Controls Occ Sensor	Lodging	Retro	30%	72	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	54.2%	71.7%	1.3	1,434	1,363	1,920	1,553
257	Int Lighting	Custom Lighting	Lodging	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	3,473	1,397	2,670	1,714
258	Misc	Vend Machine Ctrls	Lodging	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	121	0	0	0
259	Misc	Vend Machine Ctrls -refrigerated	Lodging	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	501	301	301	272
260	Misc	Power Distribution Equipment Upgrades	Lodging	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	68%	20%	73.1%	44.0%	44.0%	0.9	478	163	328	168
261	Misc	Custom Miscellaneous	Lodging	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	18,496	6,614	13,570	8,516
262	Plug Loads Office	Plug Load Occupancy Sensors	Lodging	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	2,378	0	0	0
263	Plug Loads Office	Advanced Power Strips	Lodging	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	2,082	832	1,771	1,203
264	Plug Loads Office	Computer Power Management	Lodging	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	833	0	0	0
265	Refrigeration	Solid Door Commercial Refrigeration Equipment	Lodging	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	18%	56%	85.6%	69.2%	73.1%	2.6	2,126	1,271	1,703	1,377
266	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Lodging	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	18%	54%	85.6%	67.8%	67.8%	0.8	693	0	0	0
267	Refrigeration	Door Heater Controls	Lodging	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	35	0	0	0
268	Refrigeration	Zero Energy Doors	Lodging	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	636	269	513	360
269	Refrigeration	Night Covers	Lodging	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	200	0	0	0
270	Refrigeration	Strip Curtain	Lodging	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	12%	39%	75.4%	57.3%	61.0%	0.7	2,602	0	0	0
271	Refrigeration	Evap Fan Ctrls	Lodging	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	2%	33%	73.1%	53.1%	53.1%	2.3	556	209	356	203
272	Refrigeration	Refrigeration ECMs	Lodging	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	7%	20%	75.4%	48.9%	63.2%	2.2	914	364	648	483
273	Refrigeration	Refrigerated Case Lighting	Lodging	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	917	0	0	0
274	Refrigeration	Ice Maker	Lodging	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	6%	50%	85.6%	65.0%	65.0%	0.4	347	0	0	0
275	Refrigeration	Custom Refrigeration	Lodging	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	4,478	2,233	3,221	2,225
276	Ventilation	VFDs of Supply and Return Fans	Lodging	Retro	59%	19,581	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	50.2%	1.8	11,256	3,979	7,504	4,081
277	Whole Building_HVAC	Variable Air Volume HVAC	Lodging	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	49%	24%	73.1%	65.2%	71.7%	33.6	12,293	9,051	10,322	9,599
278	Whole Building_HVAC	Demand Controlled Ventilation	Lodging	Retro	2%	57	0.039	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	43.3%	0.6	1,145	0	0	0
279	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Lodging	Retro	20%	5,771	0.540	15	$1,778	100%	50%	75%	3	13%	24%	73.1%	46.8%	49.4%	1.5	1,564	702	1,313	718
280	Whole Building_HVAC	GREM Controls	Lodging	Retro	15%	355	0.109	8	$260	100%	50%	75%	4	100%	33%	73.1%	53.1%	53.1%	0.5	7,899	0	0	0
281	Whole Building_HVAC	Custom Whole Building HVAC	Lodging	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	12,693	5,518	10,811	5,510
282	Whole Buildings	Whole Building Retrofit	Lodging	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	59.4%	65.5%	5.5	6,245	4,753	5,690	5,034
283	Whole Buildings	Custom Whole Building Controls (BAS)	Lodging	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	25,914	12,115	22,114	11,703
284	Whole Buildings	Commercial Behavior	Lodging	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	4,428	1,783	1,748	1,853
285	Cooking	Commercial Griddles	Office - Large	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	0	0	0	0
286	Cooking	Convection Ovens	Office - Large	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	0	0	0	0
287	Cooking	Combination Ovens	Office - Large	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	0	0	0	0
288	Cooking	Commercial Fryers	Office - Large	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	0	0	0	0
289	Cooking	Commercial Steam Cookers	Office - Large	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	0	0	0	0
290	Cooling	Air-Cooled Chillers	Office - Large	ROB	11%	163	0.186	20	$127	100%	33%	75%	1	20%	20%	85.6%	44.0%	63.6%	2.0	870	248	469	336
291	Cooling	Water-Cooled Chillers	Office - Large	ROB	12%	102	0.077	20	$107	100%	22%	75%	2	20%	20%	85.6%	44.0%	56.2%	1.2	969	276	523	348
292	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Office - Large	Retro	29%	785	0.036	15	$190	100%	50%	75%	3	8%	10%	75.4%	42.7%	60.8%	1.8	1,158	449	864	629
293	Cooling	Unitary and Split System AC	Office - Large	ROB	24%	403	0.228	15	$123	100%	50%	75%	4	55%	20%	85.6%	54.8%	70.9%	2.7	6,932	2,941	4,626	3,751
294	Cooling	Unitary and Split System HP	Office - Large	ROB	24%	454	0.228	15	$123	100%	50%	75%	5	0%	20%	85.6%	55.6%	71.7%	2.9	0	0	0	0
295	Cooling	Ductless Mini-Split HP	Office - Large	ROB	12%	244	0.211	18	$143	100%	50%	75%	6	0%	20%	85.6%	48.2%	64.6%	2.1	0	0	0	0
296	Cooling	PTAC Equipment	Office - Large	ROB	4%	58	0.110	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	61.8%	1.0	0	0	0	0
297	Cooling	PTHP Equipment	Office - Large	ROB	5%	108	0.116	10	$77	100%	41%	75%	8	0%	20%	85.6%	45.1%	64.1%	1.2	0	0	0	0
298	Cooling	Commercial AC and HP Tune Up	Office - Large	Retro	4%	59	0.033	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.3	1,337	0	0	0
299	Cooling	ECM - HVAC	Office - Large	Retro	78%	351	0.068	15	$177	100%	24%	75%	10	3%	5%	73.1%	33.5%	47.2%	1.1	507	181	419	244
300	Cooling	ERV	Office - Large	Retro	24%	1	0.006	15	$4	100%	50%	75%	11	100%	5%	73.1%	34.5%	48.7%	1.4	5,574	2,070	4,624	2,791
301	Cooling	Window Film	Office - Large	Retro	8%	7	0.004	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	52.9%	1.6	1,846	854	1,543	902
302	Cooling	Cool Roof	Office - Large	Retro	5%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	1,035	0	0	0
303	Cooling	Smart Thermostats	Office - Large	Retro	4%	535	0.303	11	$208	100%	50%	75%	14	100%	9%	75.4%	45.8%	62.8%	1.7	73	43	71	54
304	Ext Lighting	LED wallpack (existing W<250)	Office - Large	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	10%	83.4%	37.2%	56.8%	0.7	389	0	0	0

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
305	Ext Lighting	LED parking lot fixture (existing W≥250)	Office - Large	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	10%	83.4%	37.2%	48.0%	0.4	355	0	0	0
306	Ext Lighting	LED parking lot fixture (existing W<250)	Office - Large	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	10%	83.4%	37.2%	56.8%	0.7	389	0	0	0
307	Ext Lighting	LED parking garage fixture (existing W≥250)	Office - Large	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	10%	83.4%	43.4%	62.7%	0.5	357	0	0	0
308	Ext Lighting	LED parking garage fixture (existing W<250)	Office - Large	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	10%	83.4%	53.6%	71.4%	1.0	392	195	321	244
309	Ext Lighting	Bi-Level Garage Lighting	Office - Large	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	240	0	0	0
310	Ext Lighting	LED Traffic Signals	Office - Large	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
311	Hot Water	Electric Storage Water Heater	Office - Large	ROB	4%	143	0.016	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	0	0	0	0
312	Hot Water	Heat Pump Water Heater	Office - Large	ROB	68%	2,629	0.300	10	$1,350	100%	23%	75%	1	95%	0%	85.6%	30.0%	56.4%	0.6	0	0	0	0
313	Hot Water	Electric tankless water heater	Office - Large	ROB	60%	120	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.4	0	0	0	0
314	Hot Water	Water Heater Pipe Insulation	Office - Large	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	2%	80%	86.0%	86.0%	86.0%	0.1	0	0	0	0
315	Hot Water	Faucet Aerator	Office - Large	Retro	32%	591	0.189	10	$8	100%	75%	75%	4	47%	80%	86.0%	86.0%	86.0%	33.4	0	0	0	0
316	Hot Water	Low-Flow Showerheads	Office - Large	Retro	20%	29	2.280	10	$12	100%	33%	75%	5	4%	80%	86.0%	86.0%	86.0%	111.0	0	0	0	0
317	Hot Water	PRSV	Office - Large	Retro	0%	0	0.000	5	$93	100%	75%	75%	6	0%	50%	75.4%	71.0%	75.4%	0.0	0	0	0	0
318	Hot Water	ENERGY STAR Clothes Washers	Office - Large	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	0	0	0	0
319	Int Lighting	Interior 4 ft LED	Office - Large	Retro	49%	147	0.027	15	$13	100%	50%	75%	1	79%	10%	83.4%	70.0%	78.9%	6.1	10,150	6,883	8,373	7,347
320	Int Lighting	LED Screw In - Interior	Office - Large	Retro	80%	174	0.032	9	$2	100%	50%	75%	2	4%	50%	83.4%	79.4%	82.9%	35.8	554	372	408	365
321	Int Lighting	LED Fixture - Interior	Office - Large	Retro	69%	187	0.034	15	$27	100%	60%	75%	3	17%	10%	83.4%	66.7%	76.1%	3.7	3,081	1,981	2,541	2,141
322	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Office - Large	Retro	52%	610	0.158	15	$201	100%	50%	75%	4	0%	10%	83.4%	49.1%	68.5%	1.8	29	13	24	18
323	Int Lighting	Interior LED High Bay | Replacing HID	Office - Large	Retro	73%	2,953	0.764	15	$458	100%	50%	75%	5	0%	10%	83.4%	63.9%	76.3%	3.8	41	25	34	29
324	Int Lighting	Advanced Lighting Controls	Office - Large	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	296	0	0	0
325	Int Lighting	Controls Cont Dimming	Office - Large	Retro	30%	90	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	57.7%	73.4%	1.5	1,601	1,499	2,034	1,652
326	Int Lighting	Controls Photocells	Office - Large	Retro	10%	30	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	45.4%	64.7%	0.8	289	0	0	0
327	Int Lighting	Controls Occ Sensor	Office - Large	Retro	30%	90	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	57.7%	73.4%	1.5	1,601	1,499	2,034	1,652
328	Int Lighting	Custom Lighting	Office - Large	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	3,507	1,411	2,697	1,731
329	Misc	Vend Machine Ctrls	Office - Large	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	57	0	0	0
330	Misc	Vend Machine Ctrls -refrigerated	Office - Large	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	237	142	142	129
331	Misc	Power Distribution Equipment Upgrades	Office - Large	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	49%	20%	73.1%	44.0%	44.0%	0.9	162	55	111	57
332	Misc	Custom Miscellaneous	Office - Large	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	8,746	3,125	6,413	4,024
333	Plug Loads Office	Plug Load Occupancy Sensors	Office - Large	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	2,320	0	0	0
334	Plug Loads Office	Advanced Power Strips	Office - Large	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	2,032	811	1,728	1,174
335	Plug Loads Office	Computer Power Management	Office - Large	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	813	0	0	0
336	Refrigeration	Solid Door Commercial Refrigeration Equipment	Office - Large	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	10%	56%	85.6%	69.2%	73.1%	2.6	338	202	271	219
337	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Office - Large	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	41%	54%	85.6%	67.8%	67.8%	0.8	441	0	0	0
338	Refrigeration	Door Heater Controls	Office - Large	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	10	0	0	0
339	Refrigeration	Zero Energy Doors	Office - Large	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	178	75	144	101
340	Refrigeration	Night Covers	Office - Large	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	56	0	0	0
341	Refrigeration	Strip Curtain	Office - Large	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	1%	39%	75.4%	57.3%	61.0%	0.7	74	0	0	0
342	Refrigeration	Evap Fan Ctrls	Office - Large	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	0%	33%	73.1%	53.1%	53.1%	2.3	16	6	10	6
343	Refrigeration	Refrigeration ECMs	Office - Large	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	3%	20%	75.4%	48.9%	63.2%	2.2	103	41	73	54
344	Refrigeration	Refrigerated Case Lighting	Office - Large	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	257	0	0	0
345	Refrigeration	Ice Maker	Office - Large	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	8%	50%	85.6%	65.0%	65.0%	0.4	130	0	0	0
346	Refrigeration	Custom Refrigeration	Office - Large	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	1,353	633	918	632
347	Ventilation	VFDs of Supply and Return Fans	Office - Large	Retro	59%	15,497	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	48.9%	1.4	13,778	4,870	9,185	4,797
348	Whole Building_HVAC	Variable Air Volume HVAC	Office - Large	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	55%	59%	73.1%	71.3%	71.7%	33.6	8,968	5,682	5,731	5,352
349	Whole Building_HVAC	Demand Controlled Ventilation	Office - Large	Retro	3%	41	0.039	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	42.1%	0.5	1,115	0	0	0
350	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Office - Large	Retro	0%	0	0.000	15	$1,778	100%	50%	75%	3	0%	24%	73.1%	68.3%	73.1%	0.0	0	0	0	0
351	Whole Building_HVAC	GREM Controls	Office - Large	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
352	Whole Building_HVAC	Custom Whole Building HVAC	Office - Large	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	12,373	5,446	10,545	5,424
353	Whole Buildings	Whole Building Retrofit	Office - Large	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	60.7%	66.6%	6.4	3,907	3,092	3,593	3,252
354	Whole Buildings	Custom Whole Building Controls (BAS)	Office - Large	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	16,099	7,682	13,864	7,401
355	Whole Buildings	Commercial Behavior	Office - Large	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	2,724	1,118	1,066	1,156
356	Cooking	Commercial Griddles	Office - Small	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	0	0	0	0
357	Cooking	Convection Ovens	Office - Small	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	0	0	0	0
358	Cooking	Combination Ovens	Office - Small	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	0	0	0	0
359	Cooking	Commercial Fryers	Office - Small	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	0	0	0	0
360	Cooking	Commercial Steam Cookers	Office - Small	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	0	0	0	0
361	Cooling	Air-Cooled Chillers	Office - Small	ROB	11%	227	0.186	20	$127	100%	33%	75%	1	7%	20%	85.6%	44.0%	64.7%	2.3	684	195	369	269
362	Cooling	Water-Cooled Chillers	Office - Small	ROB	12%	142	0.077	20	$107	100%	22%	75%	2	7%	20%	85.6%	44.0%	58.2%	1.4	761	217	411	266
363	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Office - Small	Retro	29%	711	0.036	15	$190	100%	50%	75%	3	3%	10%	75.4%	41.3%	59.9%	1.6	922	339	680	486
364	Cooling	Unitary and Split System AC	Office - Small	ROB	24%	559	0.228	15	$123	100%	50%	75%	4	63%	20%	85.6%	57.0%	73.2%	3.2	17,909	7,558	11,952	9,439
365	Cooling	Unitary and Split System HP	Office - Small	ROB	24%	592	0.228	15	$123	100%	50%	75%	5	7%	20%	85.6%	57.4%	73.6%	3.4	1,865	794	1,245	989
366	Cooling	Ductless Mini-Split HP	Office - Small	ROB	13%	325	0.213	18	$143	100%	50%	75%	6	7%	20%	85.6%	49.9%	65.9%	2.4	1,008	341	593	443
367	Cooling	PTAC Equipment	Office - Small	ROB	4%	82	0.110	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	62.8%	1.1	0	0	0	0
368	Cooling	PTHP Equipment	Office - Small	ROB	5%	129	0.119	10	$77	100%	41%	75%	8	0%	20%	85.6%	46.2%	64.8%	1.3	0	0	0	0
369	Cooling	Commercial AC and HP Tune Up	Office - Small	Retro	4%	82	0.033	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.4	3,026	0	0	0
370	Cooling	ECM - HVAC	Office - Small	Retro	78%	351	0.068	15	$177	100%	24%	75%	10	2%	5%	73.1%	33.5%	47.2%	1.1	979	353	813	475
371	Cooling	ERV	Office - Small	Retro	24%	2	0.006	15	$4	100%	50%	75%	11	100%	5%	73.1%	34.6%	48.8%	1.4	12,629	4,750	10,538	6,393
372	Cooling	Window Film	Office - Small	Retro	8%	9	0.004	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	56.1%	1.9	4,177	1,948	3,517	2,254
373	Cooling	Cool Roof	Office - Small	Retro	2%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	805	0	0	0
374	Cooling	Smart Thermostats	Office - Small	Retro	4%	744	0.303	11	$208	100%	50%	75%	14	100%	9%	75.4%	49.0%	64.8%	2.0	1,689	1,051	1,624	1,286
375	Ext Lighting	LED wallpack (existing W<250)	Office - Small	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	11%	83.4%	37.6%	56.8%	0.7	613	0	0	0
376	Ext Lighting	LED parking lot fixture (existing W≥250)	Office - Small	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	11%	83.4%	37.6%	48.0%	0.4	559	0	0	0
377	Ext Lighting	LED parking lot fixture (existing W<250)	Office - Small	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	11%	83.4%	37.6%	56.8%	0.7	613	0	0	0
378	Ext Lighting	LED parking garage fixture (existing W≥250)	Office - Small	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	11%	83.4%	43.4%	62.7%	0.5	562	0	0	0
379	Ext Lighting	LED parking garage fixture (existing W<250)	Office - Small	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	11%	83.4%	53.6%	71.4%	1.0	617	306	506	384
380	Ext Lighting	Bi-Level Garage Lighting	Office - Small	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	380	0	0	0

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
381	Ext Lighting	LED Traffic Signals	Office - Small	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
382	Hot Water	Electric Storage Water Heater	Office - Small	ROB	4%	143	0.016	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	18	0	0	0
383	Hot Water	Heat Pump Water Heater	Office - Small	ROB	68%	2,629	0.300	10	$1,350	100%	23%	75%	1	95%	0%	85.6%	30.0%	56.4%	0.6	4,441	0	0	0
384	Hot Water	Electric tankless water heater	Office - Small	ROB	60%	120	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.4	9	0	0	0
385	Hot Water	Water Heater Pipe Insulation	Office - Small	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	2%	80%	86.0%	86.0%	86.0%	0.1	11	0	0	0
386	Hot Water	Faucet Aerator	Office - Small	Retro	32%	591	0.189	10	$8	100%	75%	75%	4	47%	80%	86.0%	86.0%	86.0%	33.4	168	271	270	245
387	Hot Water	Low-Flow Showerheads	Office - Small	Retro	20%	29	2.280	10	$12	100%	33%	75%	5	4%	80%	86.0%	86.0%	86.0%	111.0	6	10	10	9
388	Hot Water	PRSV	Office - Small	Retro	0%	0	0.000	5	$93	100%	75%	75%	6	0%	50%	75.4%	71.0%	75.4%	0.0	0	0	0	0
389	Hot Water	ENERGY STAR Clothes Washers	Office - Small	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	269	0	0	0
390	Int Lighting	Interior 4 ft LED	Office - Small	Retro	49%	134	0.027	15	$13	100%	50%	75%	1	79%	11%	83.4%	69.3%	78.6%	5.7	23,126	15,473	19,076	16,647
391	Int Lighting	LED Screw In - Interior	Office - Small	Retro	80%	160	0.032	9	$2	100%	50%	75%	2	4%	50%	83.4%	79.3%	82.9%	33.7	1,200	804	884	790
392	Int Lighting	LED Fixture - Interior	Office - Small	Retro	69%	171	0.034	15	$27	100%	60%	75%	3	16%	11%	83.4%	65.8%	75.6%	3.5	6,637	4,190	5,475	4,572
393	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Office - Small	Retro	52%	559	0.145	15	$201	100%	50%	75%	4	1%	11%	83.4%	47.9%	67.3%	1.7	252	110	208	152
394	Int Lighting	Interior LED High Bay | Replacing HID	Office - Small	Retro	73%	2,706	0.700	15	$458	100%	50%	75%	5	1%	11%	83.4%	62.6%	75.7%	3.5	354	211	292	244
395	Int Lighting	Advanced Lighting Controls	Office - Small	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	713	0	0	0
396	Int Lighting	Controls Cont Dimming	Office - Small	Retro	30%	82	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	56.4%	72.7%	1.4	3,641	3,362	4,631	3,758
397	Int Lighting	Controls Photocells	Office - Small	Retro	10%	27	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	44.7%	64.0%	0.8	672	0	0	0
398	Int Lighting	Controls Occ Sensor	Office - Small	Retro	30%	82	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	56.4%	72.7%	1.4	3,641	3,362	4,631	3,758
399	Int Lighting	Custom Lighting	Office - Small	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	8,017	3,225	6,164	3,957
400	Misc	Vend Machine Ctrls	Office - Small	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	136	0	0	0
401	Misc	Vend Machine Ctrls -refrigerated	Office - Small	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	562	337	337	305
402	Misc	Power Distribution Equipment Upgrades	Office - Small	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	41%	20%	73.1%	44.0%	44.0%	0.9	320	109	219	113
403	Misc	Custom Miscellaneous	Office - Small	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	20,765	7,418	15,224	9,552
404	Plug Loads Office	Plug Load Occupancy Sensors	Office - Small	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	5,874	0	0	0
405	Plug Loads Office	Advanced Power Strips	Office - Small	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	5,144	2,054	4,375	2,972
406	Plug Loads Office	Computer Power Management	Office - Small	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	2,059	0	0	0
407	Refrigeration	Solid Door Commercial Refrigeration Equipment	Office - Small	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	9%	56%	85.6%	69.2%	73.1%	2.6	472	282	378	306
408	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Office - Small	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	36%	54%	85.6%	67.8%	67.8%	0.8	616	0	0	0
409	Refrigeration	Door Heater Controls	Office - Small	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	16	0	0	0
410	Refrigeration	Zero Energy Doors	Office - Small	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	282	119	228	160
411	Refrigeration	Night Covers	Office - Small	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	89	0	0	0
412	Refrigeration	Strip Curtain	Office - Small	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	0%	39%	75.4%	57.3%	61.0%	0.7	0	0	0	0
413	Refrigeration	Evap Fan Ctrls	Office - Small	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	0%	33%	73.1%	53.1%	53.1%	2.3	25	9	16	9
414	Refrigeration	Refrigeration ECMs	Office - Small	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	3%	20%	75.4%	48.9%	63.2%	2.2	162	65	115	86
415	Refrigeration	Refrigerated Case Lighting	Office - Small	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	407	0	0	0
416	Refrigeration	Ice Maker	Office - Small	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	8%	50%	85.6%	65.0%	65.0%	0.4	206	0	0	0
417	Refrigeration	Custom Refrigeration	Office - Small	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	2,165	1,003	1,454	1,001
418	Ventilation	VFDs of Supply and Return Fans	Office - Small	Retro	59%	26,147	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	54.3%	2.4	32,702	11,559	21,801	13,409
419	Whole Building_HVAC	Variable Air Volume HVAC	Office - Small	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	26%	21%	73.1%	65.2%	71.7%	33.6	15,165	11,523	12,869	12,064
420	Whole Building_HVAC	Demand Controlled Ventilation	Office - Small	Retro	3%	57	0.039	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	43.2%	0.6	2,597	0	0	0
421	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Office - Small	Retro	0%	0	0.000	15	$1,778	100%	50%	75%	3	0%	24%	73.1%	68.3%	73.1%	0.0	0	0	0	0
422	Whole Building_HVAC	GREM Controls	Office - Small	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
423	Whole Building_HVAC	Custom Whole Building HVAC	Office - Small	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	28,627	12,626	24,417	12,513
424	Whole Buildings	Whole Building Retrofit	Office - Small	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	59.9%	65.9%	5.8	9,301	7,199	8,444	7,572
425	Whole Buildings	Custom Whole Building Controls (BAS)	Office - Small	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	22,340	10,558	19,014	10,141
426	Whole Buildings	Commercial Behavior	Office - Small	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	6,448	2,629	2,499	2,699
427	Cooking	Commercial Griddles	Other Commercial	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	0	0	0	0
428	Cooking	Convection Ovens	Other Commercial	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	0	0	0	0
429	Cooking	Combination Ovens	Other Commercial	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	0	0	0	0
430	Cooking	Commercial Fryers	Other Commercial	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	0	0	0	0
431	Cooking	Commercial Steam Cookers	Other Commercial	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	0	0	0	0
432	Cooling	Air-Cooled Chillers	Other Commercial	ROB	11%	218	0.200	20	$127	100%	33%	75%	1	14%	20%	85.6%	44.5%	65.0%	2.4	1,474	426	795	584
433	Cooling	Water-Cooled Chillers	Other Commercial	ROB	12%	137	0.082	20	$107	100%	22%	75%	2	14%	20%	85.6%	44.0%	58.5%	1.4	1,642	468	885	576
434	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Other Commercial	Retro	29%	1,018	0.036	15	$190	100%	50%	75%	3	6%	10%	75.4%	47.0%	63.6%	2.3	1,991	861	1,478	1,130
435	Cooling	Unitary and Split System AC	Other Commercial	ROB	25%	558	0.224	15	$123	100%	50%	75%	4	58%	20%	85.6%	56.9%	73.1%	3.2	18,862	7,944	12,589	9,925
436	Cooling	Unitary and Split System HP	Other Commercial	ROB	25%	597	0.224	15	$123	100%	50%	75%	5	4%	20%	85.6%	57.4%	73.5%	3.3	1,241	528	828	658
437	Cooling	Ductless Mini-Split HP	Other Commercial	ROB	13%	314	0.210	18	$143	100%	50%	75%	6	4%	20%	85.6%	49.4%	65.5%	2.3	637	213	374	278
438	Cooling	PTAC Equipment	Other Commercial	ROB	4%	88	0.108	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	62.9%	1.1	0	0	0	0
439	Cooling	PTHP Equipment	Other Commercial	ROB	6%	136	0.120	10	$77	100%	41%	75%	8	0%	20%	85.6%	46.7%	65.0%	1.4	0	0	0	0
440	Cooling	Commercial AC and HP Tune Up	Other Commercial	Retro	4%	79	0.033	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.4	3,279	0	0	0
441	Cooling	ECM - HVAC	Other Commercial	Retro	78%	351	0.070	15	$177	100%	24%	75%	10	3%	5%	73.1%	33.5%	47.2%	1.1	1,319	476	1,098	641
442	Cooling	ERV	Other Commercial	Retro	24%	2	0.002	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	43.5%	0.6	13,689	0	0	0
443	Cooling	Window Film	Other Commercial	Retro	8%	9	0.004	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	55.6%	1.8	4,522	2,159	4,001	2,489
444	Cooling	Cool Roof	Other Commercial	Retro	3%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	1,518	0	0	0
445	Cooling	Smart Thermostats	Other Commercial	Retro	4%	718	0.301	11	$208	100%	50%	75%	14	100%	9%	75.4%	48.6%	64.5%	1.9	1,817	1,154	1,845	1,432
446	Ext Lighting	LED wallpack (existing W<250)	Other Commercial	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	13%	83.4%	39.2%	56.8%	0.7	684	0	0	0
447	Ext Lighting	LED parking lot fixture (existing W≥250)	Other Commercial	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	13%	83.4%	39.2%	48.0%	0.4	624	0	0	0
448	Ext Lighting	LED parking lot fixture (existing W<250)	Other Commercial	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	13%	83.4%	39.2%	56.8%	0.7	684	0	0	0
449	Ext Lighting	LED parking garage fixture (existing W≥250)	Other Commercial	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	13%	83.4%	43.4%	62.7%	0.5	628	0	0	0
450	Ext Lighting	LED parking garage fixture (existing W<250)	Other Commercial	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	13%	83.4%	53.6%	71.4%	1.0	689	335	562	425
451	Ext Lighting	Bi-Level Garage Lighting	Other Commercial	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	432	0	0	0
452	Ext Lighting	LED Traffic Signals	Other Commercial	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
453	Hot Water	Electric Storage Water Heater	Other Commercial	ROB	4%	95	0.011	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	0	0	0	0
454	Hot Water	Heat Pump Water Heater	Other Commercial	ROB	68%	1,752	0.200	10	$1,350	100%	23%	75%	1	95%	8%	85.6%	35.8%	51.2%	0.4	0	0	0	0
455	Hot Water	Electric tankless water heater	Other Commercial	ROB	60%	80	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.3	0	0	0	0
456	Hot Water	Water Heater Pipe Insulation	Other Commercial	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	2%	80%	86.0%	86.0%	86.0%	0.1	0	0	0	0

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
457	Hot Water	Faucet Aerator	Other Commercial	Retro	32%	406	0.070	10	$8	100%	75%	75%	4	48%	80%	86.0%	86.0%	86.0%	18.6	0	0	0	0
458	Hot Water	Low-Flow Showerheads	Other Commercial	Retro	20%	29	2.280	10	$12	100%	33%	75%	5	5%	80%	86.0%	86.0%	86.0%	111.0	0	0	0	0
459	Hot Water	PRSV	Other Commercial	Retro	33%	2,287	0.251	5	$93	100%	75%	75%	6	5%	50%	75.4%	68.3%	73.1%	4.3	0	0	0	0
460	Hot Water	ENERGY STAR Clothes Washers	Other Commercial	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	0	0	0	0
461	Int Lighting	Interior 4 ft LED	Other Commercial	Retro	49%	118	0.027	15	$13	100%	50%	75%	1	74%	13%	83.4%	68.2%	78.2%	5.2	17,741	11,548	14,566	12,594
462	Int Lighting	LED Screw In - Interior	Other Commercial	Retro	80%	140	0.033	9	$2	100%	50%	75%	2	3%	50%	83.4%	79.2%	82.9%	31.1	925	619	681	610
463	Int Lighting	LED Fixture - Interior	Other Commercial	Retro	69%	151	0.035	15	$27	100%	60%	75%	3	19%	13%	83.4%	64.5%	74.9%	3.2	6,468	3,947	5,311	4,374
464	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Other Commercial	Retro	52%	491	0.127	15	$201	100%	50%	75%	4	2%	13%	83.4%	45.9%	65.3%	1.5	429	173	353	247
465	Int Lighting	Interior LED High Bay | Replacing HID	Other Commercial	Retro	73%	2,375	0.614	15	$458	100%	50%	75%	5	2%	13%	83.4%	60.3%	74.6%	3.1	603	340	495	406
466	Int Lighting	Advanced Lighting Controls	Other Commercial	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	626	0	0	0
467	Int Lighting	Controls Cont Dimming	Other Commercial	Retro	31%	73	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	54.6%	71.8%	1.3	3,023	2,776	3,935	3,161
468	Int Lighting	Controls Photocells	Other Commercial	Retro	11%	25	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	44.1%	63.4%	0.8	604	0	0	0
469	Int Lighting	Controls Occ Sensor	Other Commercial	Retro	31%	73	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	54.6%	71.8%	1.3	3,023	2,776	3,935	3,161
470	Int Lighting	Custom Lighting	Other Commercial	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	6,660	2,680	5,121	3,288
471	Misc	Vend Machine Ctrls	Other Commercial	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	193	0	0	0
472	Misc	Vend Machine Ctrls -refrigerated	Other Commercial	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	799	479	479	434
473	Misc	Power Distribution Equipment Upgrades	Other Commercial	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	38%	20%	73.1%	44.0%	44.0%	0.9	420	143	288	148
474	Misc	Custom Miscellaneous	Other Commercial	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	29,513	10,543	21,636	13,575
475	Plug Loads Office	Plug Load Occupancy Sensors	Other Commercial	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	2,296	0	0	0
476	Plug Loads Office	Advanced Power Strips	Other Commercial	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	2,010	803	1,710	1,162
477	Plug Loads Office	Computer Power Management	Other Commercial	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	805	0	0	0
478	Refrigeration	Solid Door Commercial Refrigeration Equipment	Other Commercial	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	27%	56%	85.6%	69.2%	73.1%	2.6	2,414	1,444	1,934	1,563
479	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Other Commercial	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	27%	54%	85.6%	67.8%	67.8%	0.8	787	0	0	0
480	Refrigeration	Door Heater Controls	Other Commercial	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	27	0	0	0
481	Refrigeration	Zero Energy Doors	Other Commercial	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	481	203	389	272
482	Refrigeration	Night Covers	Other Commercial	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	152	0	0	0
483	Refrigeration	Strip Curtain	Other Commercial	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	12%	39%	75.4%	57.3%	61.0%	0.7	1,970	0	0	0
484	Refrigeration	Evap Fan Ctrls	Other Commercial	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	2%	33%	73.1%	53.1%	53.1%	2.3	421	158	269	154
485	Refrigeration	Refrigeration ECMs	Other Commercial	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	7%	20%	75.4%	48.9%	63.2%	2.2	692	276	490	365
486	Refrigeration	Refrigerated Case Lighting	Other Commercial	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	694	0	0	0
487	Refrigeration	Ice Maker	Other Commercial	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	5%	50%	85.6%	65.0%	65.0%	0.4	219	0	0	0
488	Refrigeration	Custom Refrigeration	Other Commercial	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	3,297	1,679	2,417	1,672
489	Ventilation	VFDs of Supply and Return Fans	Other Commercial	Retro	59%	33,354	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	58.4%	3.0	10,327	3,650	6,885	4,702
490	Whole Building_HVAC	Variable Air Volume HVAC	Other Commercial	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	40%	20%	73.1%	65.2%	71.7%	33.6	16,804	13,260	14,992	13,829
491	Whole Building_HVAC	Demand Controlled Ventilation	Other Commercial	Retro	11%	228	0.033	15	$90	100%	50%	75%	2	100%	5%	73.1%	34.1%	48.4%	1.3	7,788	3,291	7,339	4,448
492	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Other Commercial	Retro	0%	0	0.000	15	$1,778	100%	50%	75%	3	12%	24%	73.1%	68.3%	73.1%	0.0	0	0	0	0
493	Whole Building_HVAC	GREM Controls	Other Commercial	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
494	Whole Building_HVAC	Custom Whole Building HVAC	Other Commercial	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	20,540	9,351	18,325	9,295
495	Whole Buildings	Whole Building Retrofit	Other Commercial	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	60.0%	66.0%	5.9	8,871	6,775	7,985	7,134
496	Whole Buildings	Custom Whole Building Controls (BAS)	Other Commercial	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	36,592	17,046	30,905	16,396
497	Whole Buildings	Commercial Behavior	Other Commercial	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	6,160	2,485	2,394	2,557
498	Cooking	Commercial Griddles	Food Service	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	585	327	387	352
499	Cooking	Convection Ovens	Food Service	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	701	464	516	492
500	Cooking	Combination Ovens	Food Service	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	328	189	241	195
501	Cooking	Commercial Fryers	Food Service	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	1,408	0	0	0
502	Cooking	Commercial Steam Cookers	Food Service	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	999	624	741	674
503	Cooling	Air-Cooled Chillers	Food Service	ROB	11%	240	0.181	20	$127	100%	33%	75%	1	0%	20%	85.6%	44.1%	64.8%	2.3	0	0	0	0
504	Cooling	Water-Cooled Chillers	Food Service	ROB	12%	151	0.074	20	$107	100%	22%	75%	2	0%	20%	85.6%	44.0%	58.5%	1.4	0	0	0	0
505	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Food Service	Retro	29%	1,063	0.036	15	$190	100%	50%	75%	3	0%	10%	75.4%	47.7%	64.0%	2.4	0	0	0	0
506	Cooling	Unitary and Split System AC	Food Service	ROB	24%	594	0.221	15	$123	100%	50%	75%	4	86%	20%	85.6%	57.3%	73.4%	3.3	4,463	1,894	2,979	2,362
507	Cooling	Unitary and Split System HP	Food Service	ROB	24%	622	0.221	15	$123	100%	50%	75%	5	5%	20%	85.6%	57.6%	73.8%	3.4	268	114	179	142
508	Cooling	Ductless Mini-Split HP	Food Service	ROB	13%	342	0.207	18	$143	100%	50%	75%	6	5%	20%	85.6%	50.0%	66.1%	2.4	147	50	87	65
509	Cooling	PTAC Equipment	Food Service	ROB	4%	87	0.107	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	62.7%	1.1	0	0	0	0
510	Cooling	PTHP Equipment	Food Service	ROB	5%	133	0.116	10	$77	100%	41%	75%	8	0%	20%	85.6%	46.2%	64.7%	1.3	0	0	0	0
511	Cooling	Commercial AC and HP Tune Up	Food Service	Retro	4%	87	0.032	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.4	529	0	0	0
512	Cooling	ECM - HVAC	Food Service	Retro	78%	351	0.070	15	$177	100%	24%	75%	10	3%	5%	73.1%	33.5%	47.2%	1.1	228	84	194	113
513	Cooling	ERV	Food Service	Retro	24%	2	0.002	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	43.9%	0.6	2,221	0	0	0
514	Cooling	Window Film	Food Service	Retro	8%	10	0.004	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	56.4%	1.9	729	358	663	423
515	Cooling	Cool Roof	Food Service	Retro	2%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	149	0	0	0
516	Cooling	Smart Thermostats	Food Service	Retro	4%	789	0.294	11	$208	100%	50%	75%	14	100%	9%	75.4%	49.3%	65.0%	2.0	294	195	306	240
517	Ext Lighting	LED wallpack (existing W<250)	Food Service	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	16%	83.4%	41.2%	56.8%	0.7	0	0	0	0
518	Ext Lighting	LED parking lot fixture (existing W≥250)	Food Service	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	16%	83.4%	41.2%	48.0%	0.4	0	0	0	0
519	Ext Lighting	LED parking lot fixture (existing W<250)	Food Service	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	16%	83.4%	41.2%	56.8%	0.7	0	0	0	0
520	Ext Lighting	LED parking garage fixture (existing W≥250)	Food Service	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	16%	83.4%	43.4%	62.7%	0.5	0	0	0	0
521	Ext Lighting	LED parking garage fixture (existing W<250)	Food Service	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	16%	83.4%	53.6%	71.4%	1.0	0	0	0	0
522	Ext Lighting	Bi-Level Garage Lighting	Food Service	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	0	0	0	0
523	Ext Lighting	LED Traffic Signals	Food Service	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
524	Hot Water	Electric Storage Water Heater	Food Service	ROB	4%	174	0.020	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	5	0	0	0
525	Hot Water	Heat Pump Water Heater	Food Service	ROB	68%	3,200	0.365	10	$1,350	100%	23%	75%	1	95%	7%	85.6%	34.7%	59.3%	0.8	1,127	0	0	0
526	Hot Water	Electric tankless water heater	Food Service	ROB	60%	146	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.5	2	0	0	0
527	Hot Water	Water Heater Pipe Insulation	Food Service	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	1%	80%	86.0%	86.0%	86.0%	0.1	2	0	0	0
528	Hot Water	Faucet Aerator	Food Service	Retro	32%	591	0.189	10	$8	100%	75%	75%	4	38%	80%	86.0%	86.0%	86.0%	33.4	37	58	58	52
529	Hot Water	Low-Flow Showerheads	Food Service	Retro	20%	29	2.280	10	$12	100%	33%	75%	5	3%	80%	86.0%	86.0%	86.0%	111.0	1	2	2	2
530	Hot Water	PRSV	Food Service	Retro	33%	980	0.134	5	$93	100%	75%	75%	6	20%	50%	75.4%	65.0%	70.3%	1.9	32	34	46	36
531	Hot Water	ENERGY STAR Clothes Washers	Food Service	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	73	0	0	0
532	Int Lighting	Interior 4 ft LED	Food Service	Retro	49%	159	0.028	15	$13	100%	50%	75%	1	52%	16%	83.4%	70.7%	79.2%	6.5	1,178	791	962	843

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
533	Int Lighting	LED Screw In - Interior	Food Service	Retro	80%	189	0.034	9	$2	100%	50%	75%	2	2%	50%	83.4%	79.5%	83.0%	38.6	40	27	29	26
534	Int Lighting	LED Fixture - Interior	Food Service	Retro	69%	203	0.036	15	$27	100%	60%	75%	3	11%	16%	83.4%	67.7%	76.6%	4.0	334	213	273	230
535	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Food Service	Retro	52%	662	0.180	15	$201	100%	50%	75%	4	1%	16%	83.4%	50.4%	69.8%	2.0	18	8	15	11
536	Int Lighting	Interior LED High Bay | Replacing HID	Food Service	Retro	73%	3,206	0.873	15	$458	100%	50%	75%	5	1%	16%	83.4%	65.4%	77.0%	4.3	25	16	21	18
537	Int Lighting	Advanced Lighting Controls	Food Service	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	68	0	0	0
538	Int Lighting	Controls Cont Dimming	Food Service	Retro	30%	97	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	59.0%	73.9%	1.6	390	259	361	292
539	Int Lighting	Controls Photocells	Food Service	Retro	10%	32	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	46.0%	65.4%	0.9	69	34	64	45
540	Int Lighting	Controls Occ Sensor	Food Service	Retro	30%	97	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	59.0%	73.9%	1.6	390	259	361	292
541	Int Lighting	Custom Lighting	Food Service	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	643	259	494	317
542	Misc	Vend Machine Ctrls	Food Service	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	15	0	0	0
543	Misc	Vend Machine Ctrls -refrigerated	Food Service	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	61	37	37	33
544	Misc	Power Distribution Equipment Upgrades	Food Service	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	76%	20%	73.1%	44.0%	44.0%	0.9	65	22	44	23
545	Misc	Custom Miscellaneous	Food Service	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	2,253	806	1,653	1,037
546	Plug Loads Office	Plug Load Occupancy Sensors	Food Service	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	191	0	0	0
547	Plug Loads Office	Advanced Power Strips	Food Service	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	168	67	143	97
548	Plug Loads Office	Computer Power Management	Food Service	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	67	0	0	0
549	Refrigeration	Solid Door Commercial Refrigeration Equipment	Food Service	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	32%	56%	85.6%	69.2%	73.1%	2.6	5,249	3,139	4,205	3,400
550	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Food Service	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	8%	54%	85.6%	67.8%	67.8%	0.8	428	0	0	0
551	Refrigeration	Door Heater Controls	Food Service	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	49	0	0	0
552	Refrigeration	Zero Energy Doors	Food Service	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	883	373	713	499
553	Refrigeration	Night Covers	Food Service	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	278	0	0	0
554	Refrigeration	Strip Curtain	Food Service	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	6%	36%	75.4%	55.2%	61.0%	0.7	1,849	0	0	0
555	Refrigeration	Evap Fan Ctrls	Food Service	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	1%	33%	73.1%	53.1%	53.1%	2.3	386	145	247	141
556	Refrigeration	Refrigeration ECMs	Food Service	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	12%	20%	75.4%	48.9%	63.2%	2.2	2,031	810	1,440	1,072
557	Refrigeration	Refrigerated Case Lighting	Food Service	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	1,273	0	0	0
558	Refrigeration	Ice Maker	Food Service	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	5%	50%	85.6%	65.0%	65.0%	0.4	402	0	0	0
559	Refrigeration	Custom Refrigeration	Food Service	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	6,198	3,066	4,406	3,050
560	Ventilation	VFDs of Supply and Return Fans	Food Service	Retro	59%	39,024	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	60.5%	3.5	3,316	1,172	2,211	1,591
561	Whole Building_HVAC	Variable Air Volume HVAC	Food Service	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	34%	19%	73.1%	65.2%	71.7%	33.6	2,870	2,286	2,572	2,376
562	Whole Building_HVAC	Demand Controlled Ventilation	Food Service	Retro	7%	167	0.013	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	45.7%	0.8	1,009	0	0	0
563	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Food Service	Retro	20%	3,952	0.570	15	$1,778	100%	50%	75%	3	16%	24%	73.1%	46.8%	47.5%	1.1	609	288	537	274
564	Whole Building_HVAC	GREM Controls	Food Service	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
565	Whole Building_HVAC	Custom Whole Building HVAC	Food Service	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	4,023	1,837	3,591	1,824
566	Whole Buildings	Whole Building Retrofit	Food Service	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	59.7%	65.7%	5.7	2,635	1,994	2,395	2,116
567	Whole Buildings	Custom Whole Building Controls (BAS)	Food Service	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	1,832	843	1,556	818
568	Whole Buildings	Commercial Behavior	Food Service	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	1,893	743	742	777
569	Cooking	Commercial Griddles	Food Sales	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	90	51	60	54
570	Cooking	Convection Ovens	Food Sales	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	108	72	80	76
571	Cooking	Combination Ovens	Food Sales	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	51	29	37	30
572	Cooking	Commercial Fryers	Food Sales	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	218	0	0	0
573	Cooking	Commercial Steam Cookers	Food Sales	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	155	97	115	104
574	Cooling	Air-Cooled Chillers	Food Sales	ROB	11%	168	0.200	20	$127	100%	33%	75%	1	0%	20%	85.6%	44.0%	64.2%	2.2	0	0	0	0
575	Cooling	Water-Cooled Chillers	Food Sales	ROB	12%	105	0.082	20	$107	100%	22%	75%	2	0%	20%	85.6%	44.0%	56.8%	1.2	0	0	0	0
576	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Food Sales	Retro	29%	1,136	0.036	15	$190	100%	50%	75%	3	0%	10%	75.4%	48.9%	64.7%	2.5	0	0	0	0
577	Cooling	Unitary and Split System AC	Food Sales	ROB	24%	414	0.244	15	$123	100%	50%	75%	4	82%	20%	85.6%	55.5%	71.6%	2.9	1,353	583	903	696
578	Cooling	Unitary and Split System HP	Food Sales	ROB	24%	680	0.244	15	$123	100%	50%	75%	5	6%	20%	85.6%	58.7%	74.8%	3.7	101	44	68	55
579	Cooling	Ductless Mini-Split HP	Food Sales	ROB	13%	239	0.228	18	$143	100%	50%	75%	6	6%	20%	85.6%	48.7%	65.0%	2.2	56	18	33	24
580	Cooling	PTAC Equipment	Food Sales	ROB	4%	60	0.118	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	62.6%	1.1	0	0	0	0
581	Cooling	PTHP Equipment	Food Sales	ROB	5%	93	0.128	10	$77	100%	41%	75%	8	0%	20%	85.6%	45.4%	64.3%	1.3	0	0	0	0
582	Cooling	Commercial AC and HP Tune Up	Food Sales	Retro	4%	61	0.036	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.4	169	0	0	0
583	Cooling	ECM - HVAC	Food Sales	Retro	78%	351	0.068	15	$177	100%	24%	75%	10	3%	5%	73.1%	33.5%	47.2%	1.1	64	24	54	32
584	Cooling	ERV	Food Sales	Retro	24%	1	0.002	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	42.1%	0.5	708	0	0	0
585	Cooling	Window Film	Food Sales	Retro	8%	7	0.004	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	53.9%	1.7	233	113	211	125
586	Cooling	Cool Roof	Food Sales	Retro	6%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	166	0	0	0
587	Cooling	Smart Thermostats	Food Sales	Retro	4%	551	0.325	11	$208	100%	50%	75%	14	100%	9%	75.4%	46.8%	63.4%	1.8	9	6	10	7
588	Ext Lighting	LED wallpack (existing W<250)	Food Sales	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	11%	83.4%	37.4%	56.8%	0.7	0	0	0	0
589	Ext Lighting	LED parking lot fixture (existing W≥250)	Food Sales	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	11%	83.4%	37.4%	48.0%	0.4	0	0	0	0
590	Ext Lighting	LED parking lot fixture (existing W<250)	Food Sales	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	11%	83.4%	37.4%	56.8%	0.7	0	0	0	0
591	Ext Lighting	LED parking garage fixture (existing W≥250)	Food Sales	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	11%	83.4%	43.4%	62.7%	0.5	0	0	0	0
592	Ext Lighting	LED parking garage fixture (existing W<250)	Food Sales	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	11%	83.4%	53.6%	71.4%	1.0	0	0	0	0
593	Ext Lighting	Bi-Level Garage Lighting	Food Sales	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	0	0	0	0
594	Ext Lighting	LED Traffic Signals	Food Sales	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
595	Hot Water	Electric Storage Water Heater	Food Sales	ROB	4%	147	0.017	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	4	0	0	0
596	Hot Water	Heat Pump Water Heater	Food Sales	ROB	68%	2,712	0.310	10	$1,350	100%	23%	75%	1	95%	0%	85.6%	30.1%	56.8%	0.7	1,074	0	0	0
597	Hot Water	Electric tankless water heater	Food Sales	ROB	60%	124	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.4	2	0	0	0
598	Hot Water	Water Heater Pipe Insulation	Food Sales	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	2%	80%	86.0%	86.0%	86.0%	0.1	2	0	0	0
599	Hot Water	Faucet Aerator	Food Sales	Retro	32%	591	0.189	10	$8	100%	75%	75%	4	45%	80%	86.0%	86.0%	86.0%	33.4	39	63	63	57
600	Hot Water	Low-Flow Showerheads	Food Sales	Retro	20%	29	2.280	10	$12	100%	33%	75%	5	3%	80%	86.0%	86.0%	86.0%	111.0	1	2	2	2
601	Hot Water	PRSV	Food Sales	Retro	0%	0	0.000	5	$93	100%	75%	75%	6	0%	50%	75.4%	71.0%	75.4%	0.0	0	0	0	0
602	Hot Water	ENERGY STAR Clothes Washers	Food Sales	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	65	0	0	0
603	Int Lighting	Interior 4 ft LED	Food Sales	Retro	49%	59	0.033	15	$13	100%	50%	75%	1	86%	11%	83.4%	63.5%	76.1%	3.8	1,423	864	1,174	988
604	Int Lighting	LED Screw In - Interior	Food Sales	Retro	80%	70	0.039	9	$2	100%	50%	75%	2	6%	50%	83.4%	78.7%	82.6%	22.8	115	76	85	75
605	Int Lighting	LED Fixture - Interior	Food Sales	Retro	69%	75	0.042	15	$27	100%	60%	75%	3	42%	11%	83.4%	58.9%	71.5%	2.3	956	533	789	620
606	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Food Sales	Retro	52%	243	0.078	15	$201	100%	50%	75%	4	0%	11%	83.4%	37.4%	54.9%	0.8	0	0	0	0
607	Int Lighting	Interior LED High Bay | Replacing HID	Food Sales	Retro	73%	1,178	0.376	15	$458	100%	50%	75%	5	0%	11%	83.4%	47.9%	67.3%	1.7	0	0	0	0
608	Int Lighting	Advanced Lighting Controls	Food Sales	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	38	0	0	0

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
609	Int Lighting	Controls Cont Dimming	Food Sales	Retro	30%	36	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	46.8%	66.1%	0.9	121	132	193	153
610	Int Lighting	Controls Photocells	Food Sales	Retro	10%	12	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	38.9%	58.2%	0.6	28	0	0	0
611	Int Lighting	Controls Occ Sensor	Food Sales	Retro	30%	36	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	46.8%	66.1%	0.9	121	132	193	153
612	Int Lighting	Custom Lighting	Food Sales	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	448	180	344	221
613	Misc	Vend Machine Ctrls	Food Sales	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	5	0	0	0
614	Misc	Vend Machine Ctrls -refrigerated	Food Sales	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	23	14	14	12
615	Misc	Power Distribution Equipment Upgrades	Food Sales	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	80%	20%	73.1%	44.0%	44.0%	0.9	25	9	17	9
616	Misc	Custom Miscellaneous	Food Sales	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	836	299	614	385
617	Plug Loads Office	Plug Load Occupancy Sensors	Food Sales	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	89	0	0	0
618	Plug Loads Office	Advanced Power Strips	Food Sales	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	78	31	66	45
619	Plug Loads Office	Computer Power Management	Food Sales	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	31	0	0	0
620	Refrigeration	Solid Door Commercial Refrigeration Equipment	Food Sales	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	2%	56%	85.6%	69.2%	73.1%	2.6	365	219	293	237
621	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Food Sales	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	1%	54%	85.6%	67.8%	67.8%	0.8	30	0	0	0
622	Refrigeration	Door Heater Controls	Food Sales	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	45	0	0	0
623	Refrigeration	Zero Energy Doors	Food Sales	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	819	346	662	463
624	Refrigeration	Night Covers	Food Sales	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	258	0	0	0
625	Refrigeration	Strip Curtain	Food Sales	Retro	65%	111	0.013	5	$10	100%	50%	75%	5	16%	61%	75.4%	72.7%	72.7%	1.9	3,718	1,848	2,029	1,671
626	Refrigeration	Evap Fan Ctrls	Food Sales	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	3%	33%	73.1%	53.1%	53.1%	2.3	988	372	633	362
627	Refrigeration	Refrigeration ECMs	Food Sales	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	12%	20%	75.4%	48.9%	63.2%	2.2	1,885	752	1,336	996
628	Refrigeration	Refrigerated Case Lighting	Food Sales	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	1,182	0	0	0
629	Refrigeration	Ice Maker	Food Sales	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	1%	50%	85.6%	65.0%	65.0%	0.4	37	0	0	0
630	Refrigeration	Custom Refrigeration	Food Sales	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	5,964	2,833	4,079	2,824
631	Ventilation	VFDs of Supply and Return Fans	Food Sales	Retro	59%	45,657	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	62.3%	4.1	879	311	586	440
632	Whole Building_HVAC	Variable Air Volume HVAC	Food Sales	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	27%	20%	73.1%	65.2%	71.7%	33.6	680	540	611	563
633	Whole Building_HVAC	Demand Controlled Ventilation	Food Sales	Retro	5%	75	0.027	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	42.9%	0.6	196	0	0	0
634	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Food Sales	Retro	20%	3,404	0.630	15	$1,778	100%	50%	75%	3	7%	24%	73.1%	46.8%	46.8%	1.0	80	38	71	35
635	Whole Building_HVAC	GREM Controls	Food Sales	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
636	Whole Building_HVAC	Custom Whole Building HVAC	Food Sales	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	1,207	553	1,084	550
637	Whole Buildings	Whole Building Retrofit	Food Sales	Retro	15%	1	0.001	20	$0	100%	82%	82%	6	100%	0%	73.1%	61.3%	67.1%	6.9	1,575	1,186	1,386	1,251
638	Whole Buildings	Custom Whole Building Controls (BAS)	Food Sales	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	7,157	3,181	5,866	3,085
639	Whole Buildings	Commercial Behavior	Food Sales	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	1,149	435	439	457
640	Cooking	Commercial Griddles	Retail	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	49	27	32	29
641	Cooking	Convection Ovens	Retail	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	59	39	43	41
642	Cooking	Combination Ovens	Retail	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	27	16	20	16
643	Cooking	Commercial Fryers	Retail	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	118	0	0	0
644	Cooking	Commercial Steam Cookers	Retail	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	84	52	62	56
645	Cooling	Air-Cooled Chillers	Retail	ROB	11%	351	0.195	20	$127	100%	33%	75%	1	14%	20%	85.6%	47.4%	67.9%	2.9	369	108	199	154
646	Cooling	Water-Cooled Chillers	Retail	ROB	12%	220	0.080	20	$107	100%	22%	75%	2	14%	20%	85.6%	44.0%	61.8%	1.8	411	117	221	154
647	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Retail	Retro	29%	985	0.036	15	$190	100%	50%	75%	3	5%	10%	75.4%	46.4%	63.2%	2.2	494	210	366	278
648	Cooling	Unitary and Split System AC	Retail	ROB	24%	866	0.239	15	$123	100%	50%	75%	4	56%	20%	85.6%	61.1%	76.2%	4.3	4,399	2,009	2,936	2,427
649	Cooling	Unitary and Split System HP	Retail	ROB	24%	933	0.239	15	$123	100%	50%	75%	5	7%	20%	85.6%	62.1%	76.7%	4.5	533	248	356	296
650	Cooling	Ductless Mini-Split HP	Retail	ROB	13%	509	0.223	18	$143	100%	50%	75%	6	7%	20%	85.6%	54.1%	70.2%	3.0	281	105	165	133
651	Cooling	PTAC Equipment	Retail	ROB	4%	126	0.115	10	$77	100%	41%	75%	7	0%	20%	85.6%	45.8%	64.5%	1.3	0	0	0	0
652	Cooling	PTHP Equipment	Retail	ROB	5%	208	0.124	10	$77	100%	41%	75%	8	0%	20%	85.6%	49.2%	68.2%	1.7	0	0	0	0
653	Cooling	Commercial AC and HP Tune Up	Retail	Retro	4%	127	0.035	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.5	831	0	0	0
654	Cooling	ECM - HVAC	Retail	Retro	78%	351	0.066	15	$177	100%	24%	75%	10	2%	5%	73.1%	33.5%	47.1%	1.1	252	91	210	122
655	Cooling	ERV	Retail	Retro	24%	3	0.002	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	44.9%	0.8	3,475	0	0	0
656	Cooling	Window Film	Retail	Retro	8%	14	0.004	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	60.3%	2.4	1,149	546	1,014	709
657	Cooling	Cool Roof	Retail	Retro	2%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	235	0	0	0
658	Cooling	Smart Thermostats	Retail	Retro	4%	1,152	0.318	11	$208	100%	50%	75%	14	100%	9%	75.4%	53.2%	67.4%	2.6	464	324	467	380
659	Ext Lighting	LED wallpack (existing W<250)	Retail	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	15%	83.4%	40.3%	56.8%	0.7	156	0	0	0
660	Ext Lighting	LED parking lot fixture (existing W≥250)	Retail	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	15%	83.4%	40.3%	48.0%	0.4	142	0	0	0
661	Ext Lighting	LED parking lot fixture (existing W<250)	Retail	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	15%	83.4%	40.3%	56.8%	0.7	156	0	0	0
662	Ext Lighting	LED parking garage fixture (existing W≥250)	Retail	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	15%	83.4%	43.4%	62.7%	0.5	143	0	0	0
663	Ext Lighting	LED parking garage fixture (existing W<250)	Retail	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	15%	83.4%	53.6%	71.4%	1.0	157	75	127	96
664	Ext Lighting	Bi-Level Garage Lighting	Retail	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	100	0	0	0
665	Ext Lighting	LED Traffic Signals	Retail	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
666	Hot Water	Electric Storage Water Heater	Retail	ROB	4%	147	0.017	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	5	0	0	0
667	Hot Water	Heat Pump Water Heater	Retail	ROB	68%	2,712	0.310	10	$1,350	100%	23%	75%	1	95%	0%	85.6%	30.1%	56.8%	0.7	1,163	0	0	0
668	Hot Water	Electric tankless water heater	Retail	ROB	60%	124	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.4	2	0	0	0
669	Hot Water	Water Heater Pipe Insulation	Retail	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	2%	80%	86.0%	86.0%	86.0%	0.1	3	0	0	0
670	Hot Water	Faucet Aerator	Retail	Retro	32%	591	0.189	10	$8	100%	75%	75%	4	45%	80%	86.0%	86.0%	86.0%	33.4	43	69	69	62
671	Hot Water	Low-Flow Showerheads	Retail	Retro	20%	29	2.280	10	$12	100%	33%	75%	5	3%	80%	86.0%	86.0%	86.0%	111.0	2	2	2	2
672	Hot Water	PRSV	Retail	Retro	0%	0	0.000	5	$93	100%	75%	75%	6	0%	50%	75.4%	71.0%	75.4%	0.0	0	0	0	0
673	Hot Water	ENERGY STAR Clothes Washers	Retail	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	71	0	0	0
674	Int Lighting	Interior 4 ft LED	Retail	Retro	49%	100	0.031	15	$13	100%	50%	75%	1	77%	15%	83.4%	67.4%	77.8%	4.9	7,534	4,803	6,172	5,298
675	Int Lighting	LED Screw In - Interior	Retail	Retro	80%	119	0.037	9	$2	100%	50%	75%	2	0%	50%	83.4%	79.1%	82.8%	29.3	21	14	16	14
676	Int Lighting	LED Fixture - Interior	Retail	Retro	68%	127	0.040	15	$27	100%	60%	75%	3	19%	15%	83.4%	63.6%	74.4%	3.0	2,573	1,530	2,108	1,715
677	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Retail	Retro	52%	416	0.126	15	$201	100%	50%	75%	4	2%	15%	83.4%	44.0%	63.4%	1.3	195	73	160	108
678	Int Lighting	Interior LED High Bay | Replacing HID	Retail	Retro	73%	2,012	0.608	15	$458	100%	50%	75%	5	2%	15%	83.4%	58.2%	73.6%	2.8	274	146	225	180
679	Int Lighting	Advanced Lighting Controls	Retail	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	290	0	0	0
680	Int Lighting	Controls Cont Dimming	Retail	Retro	30%	61	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	51.6%	70.3%	1.2	1,228	1,068	1,605	1,270
681	Int Lighting	Controls Photocells	Retail	Retro	10%	20	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	42.4%	61.8%	0.7	245	0	0	0
682	Int Lighting	Controls Occ Sensor	Retail	Retro	30%	61	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	51.6%	70.3%	1.2	1,228	1,068	1,605	1,270
683	Int Lighting	Custom Lighting	Retail	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	2,747	1,105	2,112	1,356
684	Misc	Vend Machine Ctrls	Retail	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	36	0	0	0

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
685	Misc	Vend Machine Ctrls -refrigerated	Retail	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	147	88	88	80
686	Misc	Power Distribution Equipment Upgrades	Retail	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	56%	20%	73.1%	44.0%	44.0%	0.9	116	39	79	41
687	Misc	Custom Miscellaneous	Retail	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	5,438	1,944	3,988	2,503
688	Plug Loads Office	Plug Load Occupancy Sensors	Retail	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	385	0	0	0
689	Plug Loads Office	Advanced Power Strips	Retail	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	337	135	287	195
690	Plug Loads Office	Computer Power Management	Retail	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	135	0	0	0
691	Refrigeration	Solid Door Commercial Refrigeration Equipment	Retail	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	25%	56%	85.6%	69.2%	73.1%	2.6	3,534	2,114	2,831	2,289
692	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Retail	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	25%	54%	85.6%	67.8%	67.8%	0.8	1,153	0	0	0
693	Refrigeration	Door Heater Controls	Retail	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	43	0	0	0
694	Refrigeration	Zero Energy Doors	Retail	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	776	328	627	439
695	Refrigeration	Night Covers	Retail	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	245	0	0	0
696	Refrigeration	Strip Curtain	Retail	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	6%	39%	75.4%	57.3%	61.0%	0.7	1,575	0	0	0
697	Refrigeration	Evap Fan Ctrls	Retail	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	1%	33%	73.1%	53.1%	53.1%	2.3	339	128	217	124
698	Refrigeration	Refrigeration ECMs	Retail	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	7%	20%	75.4%	48.9%	63.2%	2.2	1,116	445	791	589
699	Refrigeration	Refrigerated Case Lighting	Retail	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	1,120	0	0	0
700	Refrigeration	Ice Maker	Retail	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	3%	50%	85.6%	65.0%	65.0%	0.4	212	0	0	0
701	Refrigeration	Custom Refrigeration	Retail	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	5,574	2,718	3,919	2,707
702	Ventilation	VFDs of Supply and Return Fans	Retail	Retro	59%	37,613	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	60.0%	3.4	6,665	2,356	4,443	3,162
703	Whole Building_HVAC	Variable Air Volume HVAC	Retail	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	25%	39%	73.1%	65.2%	71.7%	33.6	2,948	1,986	2,341	2,186
704	Whole Building_HVAC	Demand Controlled Ventilation	Retail	Retro	5%	163	0.027	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	46.3%	1.0	1,159	471	1,069	617
705	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Retail	Retro	0%	0	0.000	15	$1,778	100%	50%	75%	3	4%	24%	73.1%	68.3%	73.1%	0.0	0	0	0	0
706	Whole Building_HVAC	GREM Controls	Retail	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
707	Whole Building_HVAC	Custom Whole Building HVAC	Retail	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	6,907	3,084	6,030	3,060
708	Whole Buildings	Whole Building Retrofit	Retail	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	58.5%	64.8%	5.0	3,176	2,387	2,879	2,526
709	Whole Buildings	Custom Whole Building Controls (BAS)	Retail	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	1,095	513	930	493
710	Whole Buildings	Commercial Behavior	Retail	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	2,232	903	876	930
711	Cooking	Commercial Griddles	Schools	ROB	13%	758	0.145	12	$60	100%	75%	75%	1	19%	17%	80.2%	68.9%	73.6%	5.6	22	12	14	13
712	Cooking	Convection Ovens	Schools	ROB	18%	1,988	0.381	12	$50	100%	75%	75%	2	23%	53%	80.2%	74.2%	78.1%	17.8	26	17	19	18
713	Cooking	Combination Ovens	Schools	ROB	48%	6,368	0.740	12	$800	100%	75%	75%	2	23%	53%	80.2%	67.1%	68.4%	3.2	12	7	9	7
714	Cooking	Commercial Fryers	Schools	ROB	17%	1,858	0.355	12	$1,200	100%	19%	75%	3	36%	23%	80.2%	46.1%	51.5%	0.7	52	0	0	0
715	Cooking	Commercial Steam Cookers	Schools	ROB	57%	43,015	8.250	12	$2,490	100%	75%	75%	4	8%	42%	80.2%	71.0%	75.3%	7.7	37	23	27	25
716	Cooling	Air-Cooled Chillers	Schools	ROB	11%	256	0.158	20	$127	100%	33%	75%	1	21%	20%	85.6%	44.0%	64.3%	2.2	408	116	220	160
717	Cooling	Water-Cooled Chillers	Schools	ROB	12%	161	0.065	20	$107	100%	22%	75%	2	21%	20%	85.6%	44.0%	58.0%	1.3	455	130	245	158
718	Cooling	VFDs for HVAC Pumps and Cooling Tower Fans	Schools	Retro	29%	741	0.036	15	$190	100%	50%	75%	3	8%	10%	75.4%	41.9%	60.3%	1.7	543	206	406	292
719	Cooling	Unitary and Split System AC	Schools	ROB	24%	632	0.193	15	$123	100%	50%	75%	4	43%	20%	85.6%	57.1%	73.2%	3.3	2,420	1,023	1,615	1,277
720	Cooling	Unitary and Split System HP	Schools	ROB	24%	650	0.193	15	$123	100%	50%	75%	5	6%	20%	85.6%	57.3%	73.5%	3.3	317	135	212	168
721	Cooling	Ductless Mini-Split HP	Schools	ROB	13%	360	0.180	18	$143	100%	50%	75%	6	6%	20%	85.6%	49.2%	65.3%	2.3	179	60	106	78
722	Cooling	PTAC Equipment	Schools	ROB	4%	92	0.093	10	$77	100%	41%	75%	7	0%	20%	85.6%	44.0%	61.9%	1.0	0	0	0	0
723	Cooling	PTHP Equipment	Schools	ROB	5%	135	0.102	10	$77	100%	41%	75%	8	0%	20%	85.6%	45.0%	64.0%	1.2	0	0	0	0
724	Cooling	Commercial AC and HP Tune Up	Schools	Retro	4%	92	0.028	3	$35	100%	75%	75%	9	100%	50%	75.4%	65.0%	65.0%	0.4	605	0	0	0
725	Cooling	ECM - HVAC	Schools	Retro	78%	351	0.066	15	$177	100%	24%	75%	10	2%	5%	73.1%	33.5%	47.1%	1.1	178	64	147	85
726	Cooling	ERV	Schools	Retro	24%	2	0.003	15	$4	100%	50%	75%	11	100%	5%	73.1%	33.5%	45.5%	0.8	2,525	0	0	0
727	Cooling	Window Film	Schools	Retro	8%	10	0.003	10	$3	100%	36%	75%	12	100%	25%	73.1%	47.5%	56.2%	1.9	838	393	729	460
728	Cooling	Cool Roof	Schools	Retro	1%	0	0.000	15	$8	100%	50%	75%	13	100%	5%	73.1%	33.5%	33.5%	0.0	131	0	0	0
729	Cooling	Smart Thermostats	Schools	Retro	4%	841	0.256	11	$208	100%	50%	75%	14	100%	9%	75.4%	49.0%	64.8%	2.0	34	21	34	26
730	Ext Lighting	LED wallpack (existing W<250)	Schools	Retro	66%	567	0.000	12	$248	100%	50%	75%	1	20%	12%	83.4%	38.1%	56.8%	0.7	70	0	0	0
731	Ext Lighting	LED parking lot fixture (existing W≥250)	Schools	Retro	60%	959	0.000	12	$756	100%	50%	75%	2	20%	12%	83.4%	38.1%	48.0%	0.4	64	0	0	0
732	Ext Lighting	LED parking lot fixture (existing W<250)	Schools	Retro	66%	567	0.000	12	$248	100%	50%	75%	3	20%	12%	83.4%	38.1%	56.8%	0.7	70	0	0	0
733	Ext Lighting	LED parking garage fixture (existing W≥250)	Schools	Retro	60%	1,953	0.223	6	$756	100%	50%	75%	4	20%	12%	83.4%	43.4%	62.7%	0.5	65	0	0	0
734	Ext Lighting	LED parking garage fixture (existing W<250)	Schools	Retro	66%	1,154	0.132	6	$248	100%	50%	75%	5	20%	12%	83.4%	53.6%	71.4%	1.0	71	35	58	44
735	Ext Lighting	Bi-Level Garage Lighting	Schools	Retro	15%	75	0.036	8	$161	100%	50%	75%	6	60%	5%	83.4%	33.5%	42.5%	0.2	44	0	0	0
736	Ext Lighting	LED Traffic Signals	Schools	Retro	31%	405	0.046	6	$254	100%	50%	75%	7	0%	80%	86.0%	86.0%	86.0%	0.3	0	0	0	0
737	Hot Water	Electric Storage Water Heater	Schools	ROB	4%	158	0.018	15	$916	100%	28%	75%	1	95%	25%	85.6%	47.5%	47.5%	0.1	2	0	0	0
738	Hot Water	Heat Pump Water Heater	Schools	ROB	68%	2,917	0.333	10	$1,350	100%	23%	75%	1	95%	3%	85.6%	31.8%	57.8%	0.7	507	0	0	0
739	Hot Water	Electric tankless water heater	Schools	ROB	60%	133	0.000	20	$155	100%	50%	75%	2	5%	50%	85.6%	65.0%	65.0%	0.4	1	0	0	0
740	Hot Water	Water Heater Pipe Insulation	Schools	Retro	59%	35	0.004	4	$36	100%	50%	75%	3	1%	80%	86.0%	86.0%	86.0%	0.1	1	0	0	0
741	Hot Water	Faucet Aerator	Schools	Retro	32%	473	0.118	10	$8	100%	75%	75%	4	34%	80%	86.0%	86.0%	86.0%	24.3	14	23	22	20
742	Hot Water	Low-Flow Showerheads	Schools	Retro	20%	39	1.939	10	$12	100%	33%	75%	5	4%	80%	86.0%	86.0%	86.0%	94.7	1	2	2	2
743	Hot Water	PRSV	Schools	Retro	33%	1,253	0.313	5	$93	100%	75%	75%	6	20%	50%	75.4%	67.0%	72.0%	2.9	14	16	21	17
744	Hot Water	ENERGY STAR Clothes Washers	Schools	ROB	43%	671	0.017	7	$250	100%	50%	75%	7	25%	35%	85.6%	54.5%	58.9%	0.5	32	0	0	0
745	Int Lighting	Interior 4 ft LED	Schools	Retro	49%	66	0.016	15	$13	100%	50%	75%	1	86%	12%	83.4%	59.6%	74.3%	3.0	3,790	2,128	3,122	2,553
746	Int Lighting	LED Screw In - Interior	Schools	Retro	80%	79	0.019	9	$2	100%	50%	75%	2	2%	50%	83.4%	78.2%	82.4%	17.7	98	64	72	64
747	Int Lighting	LED Fixture - Interior	Schools	Retro	69%	85	0.021	15	$27	100%	60%	75%	3	10%	12%	83.4%	54.1%	68.8%	1.8	609	305	502	375
748	Int Lighting	Interior LED High Bay | Replacing T8HO HB	Schools	Retro	52%	276	0.044	15	$201	100%	50%	75%	4	1%	12%	83.4%	38.1%	53.8%	0.7	52	0	0	0
749	Int Lighting	Interior LED High Bay | Replacing HID	Schools	Retro	73%	1,335	0.211	15	$458	100%	50%	75%	5	1%	12%	83.4%	46.6%	66.0%	1.5	73	31	60	43
750	Int Lighting	Advanced Lighting Controls	Schools	Retro	47%	7,650	2.857	8	$16,800	100%	50%	75%	6	100%	10%	73.1%	37.0%	37.0%	0.2	107	0	0	0
751	Int Lighting	Controls Cont Dimming	Schools	Retro	70%	94	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	58.5%	73.7%	1.6	1,401	1,335	1,670	1,419
752	Int Lighting	Controls Photocells	Schools	Retro	10%	14	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	39.7%	59.0%	0.6	80	0	0	0
753	Int Lighting	Controls Occ Sensor	Schools	Retro	70%	94	0.018	8	$18	100%	50%	75%	6	100%	10%	83.4%	58.5%	73.7%	1.6	1,401	1,335	1,670	1,419
754	Int Lighting	Custom Lighting	Schools	Retro	50%	1	0.000	15	$0	100%	50%	75%	7	100%	40%	83.4%	58.0%	67.9%	1.7	1,210	487	930	597
755	Misc	Vend Machine Ctrls	Schools	Retro	46%	343	0.006	5	$80	100%	50%	75%	1	0%	75%	82.5%	82.5%	82.5%	0.6	18	0	0	0
756	Misc	Vend Machine Ctrls -refrigerated	Schools	Retro	38%	1,411	0.033	5	$180	100%	50%	75%	2	2%	75%	82.5%	82.5%	82.5%	1.1	76	45	45	41
757	Misc	Power Distribution Equipment Upgrades	Schools	Retro	1%	6	0.002	30	$8	100%	50%	75%	3	49%	20%	73.1%	44.0%	44.0%	0.9	52	18	36	18
758	Misc	Custom Miscellaneous	Schools	Retro	17%	1	0.000	15	$0	100%	50%	75%	4	100%	0%	73.1%	35.6%	49.6%	1.6	2,794	998	2,049	1,286
759	Plug Loads Office	Plug Load Occupancy Sensors	Schools	Retro	59%	129	0.000	8	$70	100%	50%	75%	1	45%	5%	75.4%	33.5%	48.5%	0.4	762	0	0	0
760	Plug Loads Office	Advanced Power Strips	Schools	Retro	27%	71	0.000	10	$21	100%	49%	75%	1	45%	5%	75.4%	37.4%	57.5%	0.9	668	267	568	386

Appendix D: C&I Measure Assumption Detail

Measure #	End-Use	Measure Name	Building Type	Replacement Type	% Elec Savings	Per Unit Elec Savings	Per Unit Summer kW	EE EUL	Measure Cost	HCAP Incentive (%)	RAP Incentive (%)	2% Case Incentive (%)	End Use Measure Group	Base Saturation	EE Saturation	HCAP Adoption Rate	RAP Adoption Rate	PP Adoption Rate	TRC Score	MWH Tech Potential in 2040	MWH RAP Potential in 2040	MWH HCAP Potential in 2040	MWH 2% Potential in 2040
761	Plug Loads Office	Computer Power Management	Schools	Retro	81%	198	0.010	4	$29	100%	75%	75%	2	5%	33%	75.4%	60.4%	66.4%	0.8	267	0	0	0
762	Refrigeration	Solid Door Commercial Refrigeration Equipment	Schools	ROB	31%	1,105	0.118	12	$165	100%	50%	75%	1	32%	56%	85.6%	69.2%	73.1%	2.6	774	463	620	501
763	Refrigeration	ENERGY STAR Residential-size Refrigerator in Commerical Buildings	Schools	ROB	10%	56	0.008	17	$40	100%	50%	75%	2	8%	54%	85.6%	67.8%	67.8%	0.8	63	0	0	0
764	Refrigeration	Door Heater Controls	Schools	Retro	60%	254	0.005	12	$300	100%	10%	75%	3	2%	36%	75.4%	55.2%	55.2%	0.3	7	0	0	0
765	Refrigeration	Zero Energy Doors	Schools	Retro	100%	1,701	0.193	12	$290	100%	50%	75%	3	2%	5%	73.1%	40.0%	57.4%	2.3	130	55	105	74
766	Refrigeration	Night Covers	Schools	Retro	7%	145	0.000	4	$42	100%	41%	75%	4	9%	25%	75.4%	47.5%	57.7%	0.4	41	0	0	0
767	Refrigeration	Strip Curtain	Schools	Retro	62%	38	0.004	5	$10	100%	50%	75%	5	12%	36%	75.4%	55.2%	61.0%	0.7	550	0	0	0
768	Refrigeration	Evap Fan Ctrls	Schools	Retro	72%	502	0.573	16	$291	100%	19%	75%	6	2%	33%	73.1%	53.1%	53.1%	2.3	114	43	73	42
769	Refrigeration	Refrigeration ECMs	Schools	Retro	60%	804	0.092	15	$177	100%	56%	75%	7	12%	20%	75.4%	48.9%	63.2%	2.2	300	119	212	158
770	Refrigeration	Refrigerated Case Lighting	Schools	Retro	53%	264	0.042	8	$250	100%	50%	75%	8	5%	35%	83.4%	54.5%	54.5%	0.3	188	0	0	0
771	Refrigeration	Ice Maker	Schools	ROB	15%	1,214	0.139	10	$981	100%	7%	75%	9	4%	50%	85.6%	65.0%	65.0%	0.4	47	0	0	0
772	Refrigeration	Custom Refrigeration	Schools	ROB	17%	1	0.000	15	$0	100%	50%	75%	10	100%	33%	73.1%	53.1%	53.1%	2.2	882	451	648	449
773	Ventilation	VFDs of Supply and Return Fans	Schools	Retro	59%	19,306	0.000	15	$4,386	100%	50%	75%	1	100%	25%	73.1%	47.5%	50.1%	1.7	2,935	1,037	1,956	1,062
774	Whole Building_HVAC	Variable Air Volume HVAC	Schools	Retro	51%	5	0.000	15	$0	100%	50%	75%	1	43%	25%	73.1%	65.2%	71.7%	33.6	3,581	2,667	3,049	2,831
775	Whole Building_HVAC	Demand Controlled Ventilation	Schools	Retro	3%	68	0.032	15	$90	100%	50%	75%	2	100%	5%	73.1%	33.5%	43.1%	0.6	410	0	0	0
776	Whole Building_HVAC	Demand Controlled Ventilation (DCV) Exhaust Hood	Schools	Retro	20%	1,995	0.498	15	$1,778	100%	50%	75%	3	11%	24%	73.1%	46.8%	46.8%	0.7	439	0	0	0
777	Whole Building_HVAC	GREM Controls	Schools	Retro	0%	0	0.000	8	$0	100%	0%	75%	4	100%	0%	73.1%	68.3%	73.1%	0.0	0	0	0	0
778	Whole Building_HVAC	Custom Whole Building HVAC	Schools	Retro	25%	1	0.000	15	$0	100%	50%	75%	5	100%	20%	73.1%	44.0%	45.9%	0.9	4,275	1,891	3,707	1,886
779	Whole Buildings	Whole Building Retrofit	Schools	Retro	15%	1	0.000	20	$0	100%	82%	82%	6	100%	0%	73.1%	59.2%	65.3%	5.4	1,369	1,092	1,297	1,152
780	Whole Buildings	Custom Whole Building Controls (BAS)	Schools	Retro	20%	1	0.000	15	$0	100%	50%	75%	7	100%	25%	73.1%	47.5%	48.6%	1.3	5,594	2,777	5,003	2,668
781	Whole Buildings	Commercial Behavior	Schools	Retro	2%	37	0.001	1	$1	100%	50%	75%	8	100%	0%	32.0%	30.0%	32.0%	1.1	934	401	382	411
782	Compressed Air	Efficient Air Compressor Equipment	Industrial	ROB	11%	1	0.000	13	$0	100%	50%	75%	1	100%	25%	80.2%	47.5%	53.3%	1.1	6,262	2,808	4,470	3,070
783	Compressed Air	Efficient Air Compressor Controls	Industrial	Retro	3%	1	0.000	3	$0	100%	50%	75%	2	100%	25%	75.4%	54.2%	68.0%	1.0	1,138	480	815	639
784	HVAC	Efficient HVAC Equipment	Industrial	ROB	13%	1	0.000	15	$0	100%	50%	75%	1	100%	25%	85.6%	52.3%	68.4%	2.7	5,275	2,410	3,775	3,017
785	HVAC	Efficient HVAC O&M	Industrial	Retro	3%	1	0.000	3	$0	100%	50%	75%	2	100%	25%	75.4%	57.7%	69.7%	1.2	822	395	597	485
786	Lighting	Efficient Lighting Equipment	Industrial	Retro	42%	1	0.000	15	$0	100%	50%	75%	1	100%	25%	83.4%	56.8%	72.9%	3.0	11,780	6,003	9,590	7,573
787	Lighting	Efficient Lighting O&M	Industrial	Retro	3%	1	0.000	3	$0	100%	50%	75%	2	100%	25%	75.4%	61.3%	71.2%	1.7	472	294	356	312
788	Machine Drive	Efficient MachDr Equipment	Industrial	ROB	12%	1	0.000	15	$0	100%	50%	75%	1	100%	25%	80.2%	47.5%	62.8%	3.1	34,696	14,918	23,275	18,233
789	Machine Drive	Efficient MachDr O&M	Industrial	Retro	3%	1	0.000	3	$0	100%	50%	75%	2	100%	25%	75.4%	57.7%	69.7%	1.2	5,923	2,820	4,285	3,477
790	Process Heat	Efficient ProcHeat Equipment	Industrial	ROB	3%	1	0.000	15	$0	100%	50%	75%	1	100%	25%	80.2%	47.5%	62.5%	3.0	1,313	564	880	686
791	Process Heat	Efficient ProcHeat O&M	Industrial	Retro	3%	1	0.000	3	$0	100%	50%	75%	2	100%	25%	75.4%	60.2%	70.8%	1.5	984	472	673	554
792	Process Ref	Efficient ProcRefrig Equipment	Industrial	ROB	16%	1	0.000	15	$0	100%	50%	75%	1	100%	25%	80.2%	47.5%	62.1%	3.0	12,543	5,393	8,414	6,517
793	Process Ref	Efficient ProcRefrig O&M	Industrial	Retro	3%	1	0.000	3	$0	100%	50%	75%	2	100%	25%	75.4%	56.1%	69.0%	1.1	1,570	734	1,166	936
794	Other Process	Efficient Other Facility Process Equipment	Industrial	ROB	26%	1	0.000	11	$0	100%	50%	75%	1	100%	25%	80.2%	47.5%	54.6%	1.1	18,680	8,620	13,984	9,744
795	Other Process	Efficient Other Facility Process O&M	Industrial	Retro	7%	1	0.000	11	$0	100%	50%	75%	2	100%	25%	75.4%	47.5%	58.7%	1.3	2,879	1,081	2,369	1,462
796	Whole Buildings	Power Distribution (Transformers)	Industrial	Retro	1%	1	0.000	30	$1	100%	50%	75%	1	100%	25%	80.2%	47.5%	47.5%	0.8	2,384	0	0	0
797	Whole Buildings	Strategic Energy Management	Industrial	Retro	3%	1	0.000	3	$0	100%	50%	75%	2	100%	10%	75.4%	58.7%	70.1%	1.3	7,414	4,503	5,880	4,981
798	WaterWasteWater	Water Supply & Wastewater treatment pumps and process efficiency	Industrial	Retro	19%	1	0.000	11	$0	100%	50%	75%	1	100%	10%	80.2%	38.6%	52.4%	0.9	0	0	0	0
810	Exterior Lighting	LED Streetlighting	StreetLight	Retro	45%	577	0.000	20	$506	100%	50%	75%	1	100%	80%	86.0%	86.0%	86.0%	0.6	0	0	0	0

CITY COUNCIL OF NEW ORLEANS

2021 DSM Market Potential Study

FINAL REPORT

July 2021

prepared by

GDS Associates, Inc. *with*

MSMM Engineering, LLC

The Villavaso Group, LLC

Casey DeMoss

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2021 TRIENNIAL**	**)**	
INTEGRATED RESOURCE PLAN OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	**DOCKET NO. UD-20-02**
	)	

APPENDIX F

HIGHLY SENSITIVE PROTECTED MATERIALS

INTENTIONALLY OMITTED

MARCH 2022

BEFORE THE

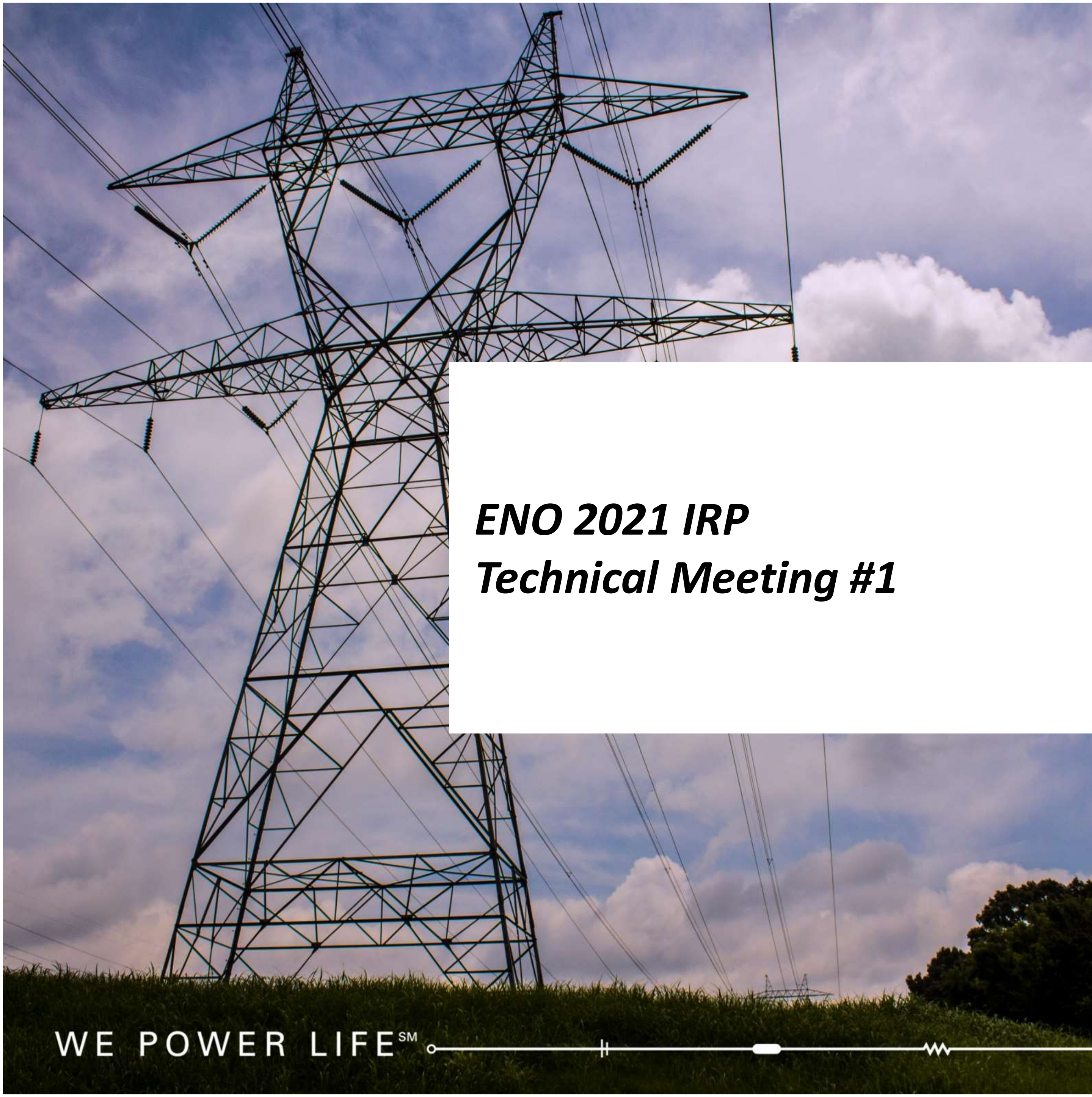
COUNCIL OF THE CITY OF NEW ORLEANS

EX PARTE: IN RE**: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX G

Entergy New Orleans, LLC
Technical Meeting Presentations

MARCH 2022



Entergy®

ENO 2021 IRP
Technical Meeting #1

December 9, 2020

Goals and Agenda of Technical Meeting #1

Goals

- As described in the Initiating Resolution (R-20-257), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to discuss Planning Scenarios and Strategies with a view towards reaching consensus on the Scenarios and Strategies to be used in developing the 2021 IRP. Scenarios and Strategies are to be finalized no later than at Technical Meeting #3.
- ENO will present its proposed reference and alternative Planning Scenarios and its proposed least-cost and RCPS/Council Policy Planning Strategies.
- Prior to the meeting, Intervenors should have discussed among themselves their priorities regarding Planning Scenarios and Strategies.
- Should the parties not agree that the proposed Scenarios and/or Strategies, or any Scenarios and/or Strategies developed during Technical Meeting #1, will adequately capture the Intervenors' point of view, the Intervenors shall prepare and submit, with the Advisors' assistance as needed, their proposed Planning Scenario and/or Strategy before Technical Meeting #2.

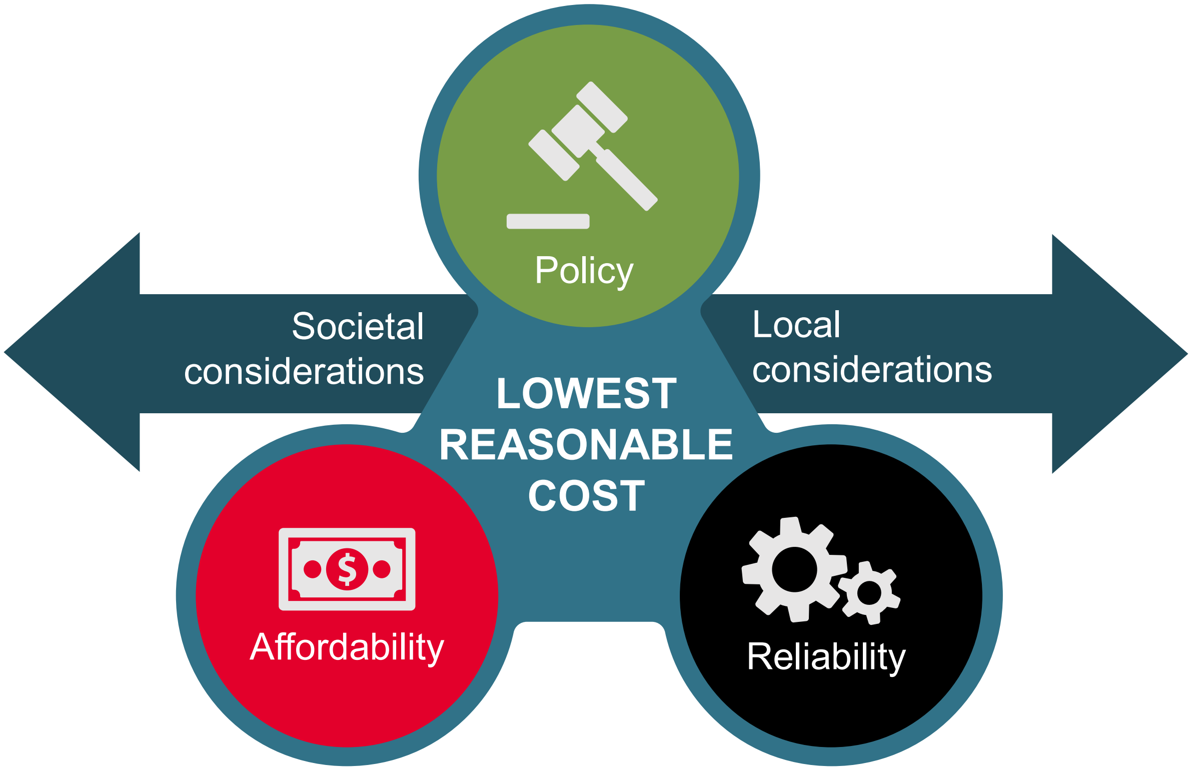
Agenda

1. 2021 IRP Objectives
2. Analytical Framework
3. Inputs and Assumptions
4. Resource Options
5. Timeline

Section 1
2021 IRP Objectives

ENO Planning Objectives

The 2021 IRP process seeks to identify a range of possible approaches to serving the electricity needs of ENO customers over the period 2022-2041 while addressing three main planning objectives: **reliability, affordability, and policy considerations**



In the 2021 IRP, ENO will consider the ongoing evolution of the utility industry

Customer Preferences

ENO's planning processes seek to address changing customer needs. Planning processes and tools will continue to evolve to help identify customer needs and wants.

Advancing Technologies

Ever advancing technology provides new opportunities to meet future customer needs reliably and affordably. Planning processes strive to understand these technological changes in order to enable us to design optimal portfolios of resources and services.

Grid Modernization

ENO's distribution planning process will need to accommodate the integration of distributed energy resources safely and securely so they can be interoperable with the grid.

Section 2
Analytical Framework

Analytic Process to Create and Value Portfolios

Development of Planning Scenarios and Strategies

Development of assumptions and inputs for Scenarios and Strategies

Market Modeling

Projection of MISO market **outside of ENO** for each Scenario

Portfolio Development

Construction of resource portfolios for each Scenario/Strategy combination

Total Relevant Supply Cost

Production costs and fixed costs are determined for each portfolio under each Scenario/Strategy combination following downselection to representative subset

Risk Assessment

Assessment of each downselected portfolio to measure potential risk

ENO Planning Scenarios—Proposed

	Scenario 1	Scenario 2	Scenario 3
Description	Reference	Current Environment Persists	Economic Growth with an Emphasis on Renewables
Peak / Energy Load Growth	Reference	Reference	High
Natural Gas Prices (Levelized Real, 2021$/MMBtu)	Reference	Low	High
DR / EE / DER Additions	Medium	Low	Medium
Market Coal Retirements	Reference (60 years)	Reference (60 years)	Accelerated (50 years)
Legacy Gas Fleet Retirements	Reference (60 years)	Reference (60 years)	Accelerated (50 years)
Magnitude of Coal & Legacy Gas Deactivations	23% by 2030 69% by 2040	23% by 2030 69% by 2040	67% by 2030 89% by 2040
CO2 Reduction Target (Levelized Real, 2021$/short ton)	Reference	None	High

If necessary, a fourth Stakeholder Scenario will be modeled.

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ENO Planning Strategies—Proposed

	Strategy 1	Strategy 2	Strategy 3
Description	Least Cost Planning	But For RCPS	RCPS Compliance
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources.	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs.	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals.
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes resources that would not be RCPS compliant.

If necessary, a Stakeholder Planning Strategy will be modeled.

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MISO Market Modeling and Total Relevant Supply Cost Calculation

1 Market Model Set-Up

- Develop projection of MISO market outside ENO for each Scenario
  - MISO reserve margin target (based on MISO summer peak load and Resource Adequacy process)
  - Build out MISO resource pool to achieve economic resource mix per Scenario

2 Initial Production Cost Simulation

- Using AURORA production cost model, simulate MISO market to generate market price curve (i.e., LMPs) for each Scenario

3 Development of Portfolios using either AURORA or Manual Process

- Use AURORA capacity expansion model to select demand- and supply-side alternatives to create ENO portfolios for each Scenario/Strategy combination
  - ENO long term planning reserve margin assumption
  - Portfolio addition decisions based on value of supply additions
- If the capacity expansion model is unable to select resources required by a particular Strategy consistent with identified resource needs, develop manual portfolios using defined constraints and professional judgment

4 Final Production Cost Simulations and Total Relevant Supply Cost Calculations

- Compute variable supply costs for each downselected portfolio in each of the Scenarios/Strategies using detailed MISO Zonal Model in AURORA
- Calculate Total Relevant Supply Cost for each downselected portfolio
  - Includes: variable supply costs, cost of DSM programs, incremental non-fuel fixed costs, and capacity purchases

Assessment of Portfolio Performance Across Scenarios

- Portfolios developed for each Scenario/Strategy combination will be tested across all other Scenarios to assess performance in a range of possible outcomes
- The total relevant supply cost of each of the Scenario/Portfolio combinations represents the present value of fixed and variable costs to customers in 2021$

***ILLUSTRATIVE ONLY*—Actual number of Scenario/Portfolio combinations TBD**

Portfolios / Scenarios	Strategy 1 (Least Cost)				Strategy 2 (But For RCPS)				Strategy 3 (RCPS Compliance)			
	Port 1	Port 2	Port 3	Port 4	Port 5	Port 6	Port 7	Port 8	Port 9	Port 10	Port 11	Port 12
Scenario A	R_{A1}	R_{A2}	R_{A3}	R_{A4}	R_{A5}	R_{A6}	R_{A7}	R_{A8}	R_{A9}	R_{A10}	R_{A11}	R_{A12}
Scenario B	R_{B1}	R_{B2}	R_{B3}	R_{B4}	R_{B5}	R_{B6}	R_{B7}	R_{B8}	R_{B9}	R_{B10}	R_{B11}	R_{B12}
Scenario C	R_{C1}	R_{C2}	R_{C3}	R_{C4}	R_{C5}	R_{C6}	R_{C7}	R_{C8}	R_{C9}	R_{C10}	R_{C11}	R_{C12}
Scenario D	R_{D1}	R_{D2}	R_{D3}	R_{D4}	R_{D5}	R_{D6}	R_{D7}	R_{D8}	R_{D9}	R_{D10}	R_{D11}	R_{D12}

Note: “R” = resulting total relevant supply cost

Section 3
Inputs and Assumptions

2021 IRP Inputs and Assumptions

- **The IRP analysis will rely on a variety of inputs, including:**
  - Planning Scenarios and Strategies
  - Gas Price Forecast
  - CO2 Price Forecast
  - Capacity Value Forecast
  - ENO Load Forecast and Long-Term Capacity Need
  - DSM Potential Study Input Cases
- **Several of these inputs will also have sensitivities used in the analysis (e.g., gas price, CO2 price)**
- **IRP will use Business Plan 2021 values once finalized in 1Q2021**

2021 IRP Inputs and Assumptions

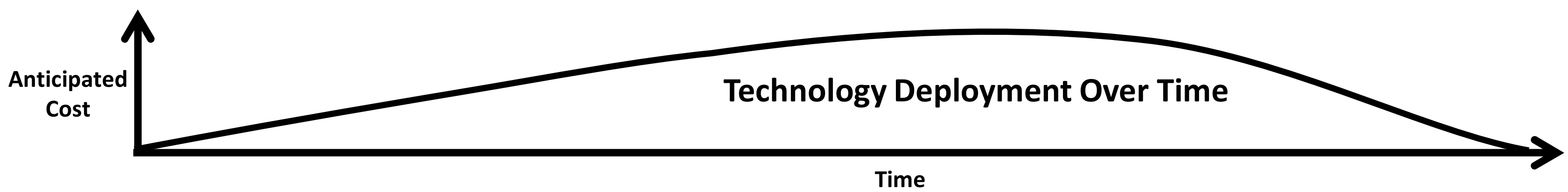
Input/Assumption	MISO Market Modeling	Portfolio Development	Total Relevant Supply Costs
Planning Scenarios	✓	✓	✓
Gas Price Forecast	✓	✓	✓
CO2 Price Forecast	✓	✓	✓
Load Forecast	✓	✓	✓
Planning Strategies		✓	✓
Capacity Value		✓	✓
Supply-Side Resource Alternative Costs		✓	✓
ENO’s Long-Term Capacity Need		✓	✓
DSM Potential Study Results		✓	✓
Input Sensitivities			✓

Section 4
Resource Options

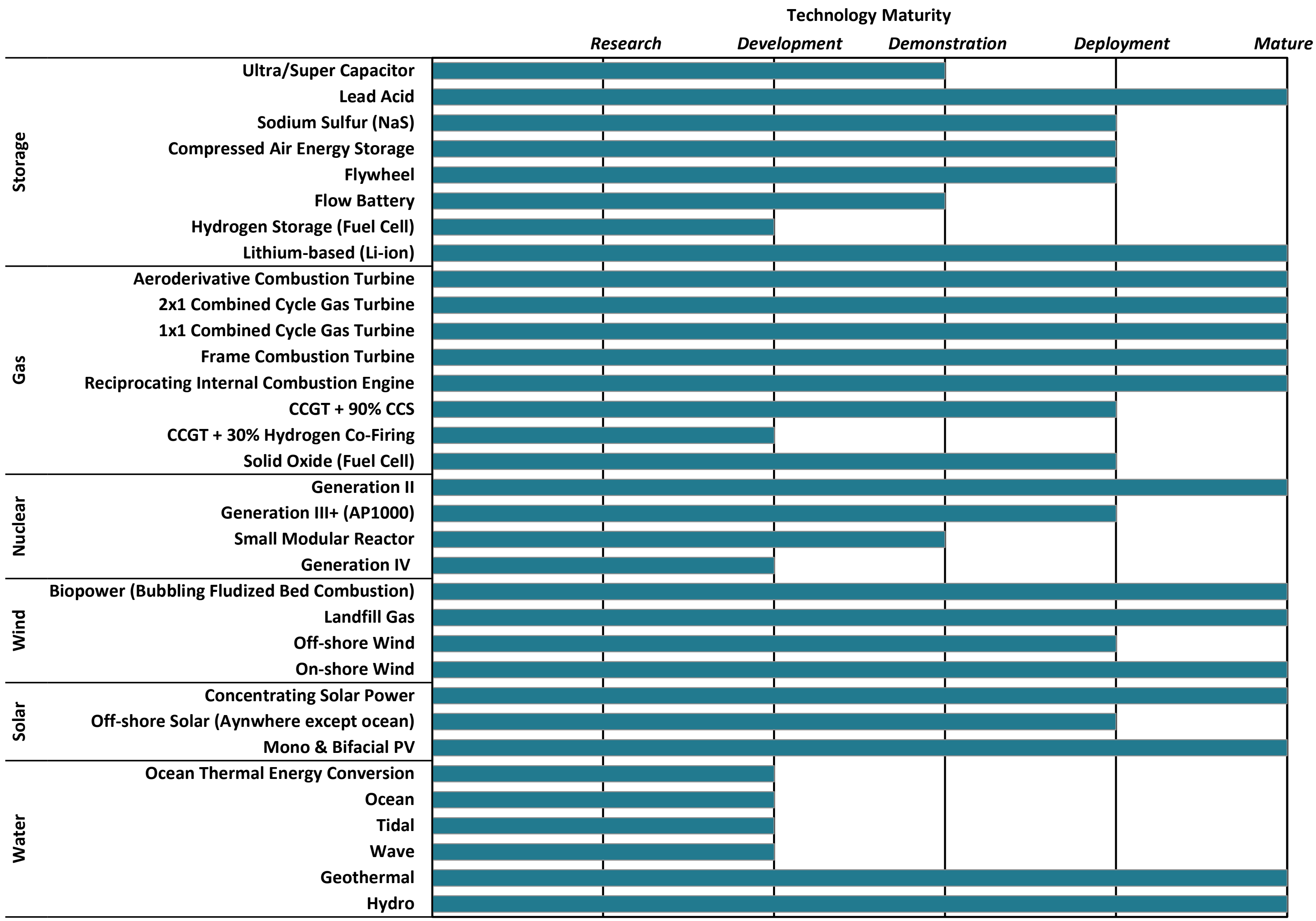
Technology Assessment Purpose & Process

- Generation technology costs and operational characteristics are necessary inputs to resource planning and portfolio development.

- The process to evaluate generation includes surveying supply-side resource alternatives to meet supply needs. A subset of alternatives are retained to further understand costs and operational characteristics to be considered for meeting planning objectives.
  - Alternatives considered within the IRP are typically technologically mature and could reasonably be expected to be operational in or around the Entergy service territory given existing cost and performance factors.
  - This process also identifies technologies that, depending on the evolution of cost and performance factors, show promise for future deployment and may be considered as alternatives later in the IRP evaluation period, or should continue to be further monitored.



Potential Supply-Side Resource Alternatives (Illustrative)



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DSM Potential Studies

- **ENO and Council both having DSM Potential Studies developed**
  - Long term (2021-2040) EE and DR Potential in Orleans Parish
- **Study results to be structured into input cases for use in Aurora**
- **ENO study to produce multiple input cases**
- **DSM Studies will use BP2020 inputs to meet schedule requirements**
- **DSM Studies currently due to be filed by March 1, 2021**
- **Each Planning Strategy will require an assigned DSM Input Case**

Section 5
Timeline

Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2020	✓
Technical Meeting #1 Material Due	November 2020	✓
Technical Meeting #1	December 2020	✓
Technical Meeting #2 Material Due	March 2021	-
Technical Meeting #2	March 2021	-
Technical Meeting #3 Material Due	May 2021	-
Technical Meeting #3	June 2021	-
IRP Inputs Finalized	**June 2021**	-
Optimized Portfolio Results Due	October 2021	-
Technical Meeting #4 Material Due	October 2021	-
Technical Meeting #4	October/November 2021	-
File IRP Report	January 2022	-
Public Meeting #2 Material Due	January/February 2022	-
Public Meeting #2 - Present IRP Results	February 2022	-
Intervenors and Advisors Questions & Comments Due	February 2022	-
ENO Response to Questions and Comments Due	February 2022	-
Public Meeting #3 Material Due	February/March 2022	-
Technical Meeting #5 Material Due	February/March 2022	-
Public Meeting #3 - Public Response	March 2022	-
Technical Meeting #5	March 2022	-
ENO File Reply Comments	May 2022	-
Advisors File Report	June 2022	-

ENO 2021 IRP Technical Meeting #2

Entergy®

April 29, 2021

Goals and Agenda of Technical Meeting #2

Goals

- As described in the Initiating Resolution (R-20-257), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to continue discussions regarding the Scenarios and Strategies with a goal of reaching consensus for inclusion in the IRP modeling.
- If necessary, the parties will discuss the Planning Scenario and/or Strategy that have been prepared by the Intervenors and provided to the parties in advance of this Technical Meeting.
- These discussions will support the finalization of Planning Scenarios and non-DSM inputs by May 24, 2021 as required under the Order issued by Judge Auzenne on April 7, 2021 that modified the procedural schedule.

Agenda

1. Updates to Proposed Planning Scenarios and Strategies
2. Business Plan 2021 (BP21) Supply-Side Alternatives
3. BP21 IRP Inputs and Assumptions
4. Timeline and Next Steps

Technical Meeting #1—Follow Ups

- **Planning Scenarios**
  - Provide additional description of drivers and expected impact
- **Supply-Side Resource Alternatives Selection**
  - Provide more detail on BP21 technology assessment and selected resources
- **Non-DSM inputs**
  - Review final BP21 inputs to be used in IRP modeling
- **Planning Objectives**
  - Further discussion of planning objectives in IRP analysis

Section 1
Updates to Proposed Planning Scenarios and Strategies

Proposed Scenario Purpose and Drivers

IRP analytics rely on macro market Scenarios designed to allow for the assessment of the total production cost and risk of resource portfolios across a reasonable range of possible future outcomes.

Scenarios	Key Drivers
Scenario 1 (Reference)	• Moderate distributed energy resources and demand side management penetration dampen peak load and energy growth • Coal economics continue to face pressure from low natural gas prices • Renewables and gas play balanced roles in replacing retiring capacity
Scenario 2 (Decentralized Focus - DSM & Renewables)	• **CHANGE SINCE TECH MEETING #1:** This Decentralized Focus Scenario replaces the Current Environment Persists Scenario originally proposed (see Appendix for comparison) • Social trends and corporate initiatives adapt to meet evolving technology, demanding high penetration of DERs, DSM, and EE • Moderate carbon mandates (legislatively- and consumer-imposed) drive coal plants to retire earlier than anticipated • The increased levels of energy efficiency, renewables, and DER along with a lower level of demand growth lessen the need for gas-fired generation as compared to Reference, however there is still a considerable need for gas-fired capacity to replace coal generation retirements (and provide flexible capability)
Scenario 3 (Economic Growth with Emphasis on Renewables)	• Economic growth contributes to recovery in peak load and energy projections • Political, environmental, and economic pressure on coal and legacy gas plants accelerates retirements • Market fills load growth needs with renewables due to slow expansion of natural gas pipeline infrastructure, economics and state pressure for fuel diversity

Proposed ENO Planning Scenarios—Updated

	Scenario 1	Scenario 2	Scenario 3
Description	Reference	Decentralized Focus (DSM & renewables) ***CHANGE***	Economic Growth with an Emphasis on Renewables
Peak / Energy Load Growth	Reference	Low	High
Natural Gas Prices (Levelized Real, 2021$/MMBtu)	Reference	Low	High
DR / EE / DER Additions	Medium	High	Medium
Market Coal Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (50 years)
Legacy Gas Fleet Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (50 years)
Magnitude of Coal & Legacy Gas Deactivations	23% by 2030 69% by 2040	49% by 2030 84% by 2040	67% by 2030 89% by 2040
CO2 Tax Assumption (Levelized Real, 2021$/short ton)	Reference	Reference	High

If necessary, a fourth Stakeholder Scenario will be modeled.

ENO Proposed Planning Strategies--Assumptions

	Strategy 1	Strategy 2	Strategy 3
Description	Least Cost Planning	But For RCPS (Reference)	RCPS Compliance
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes resources that would not be RCPS compliant.
DSM Input Case	TBD	TBD	TBD

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Section 2
BP21 Supply-Side Alternatives

Supply-side Technology Resources

- The supply-side technology assessment analyzes potential supply-side generation solutions that could help ENO serve customers' needs reliably and at the most reasonable cost, including renewable, energy storage, and hydrogen-capable conventional generation.
- The technology assessment for the 2021 IRP explores in detail the challenges, opportunities, and costs of generation alternatives to be considered when designing resource portfolios to meet identified capacity needs.
  - Renewable energy resources, especially solar, have emerged as viable economic alternatives.
  - Trend to smaller, more modular resources (such as battery storage) provides opportunity to reduce risk and manage peak demand.
  - Deployment of intermittent generation has increased the need for flexible, diverse supply alternatives. New smaller scale supply alternatives can better address locational, site specific reliability requirements while continuing to support overall grid reliability.
  - Any large-scale future natural gas resources will be hydrogen capable.

Supply-side Alternatives: Screening Approach

Screening approach is designed to evaluate the cost-effectiveness and feasibility of deployment of potential resources, resulting in the selection of technologies to be included in the capacity expansion model.

TECHNICAL SCREENING

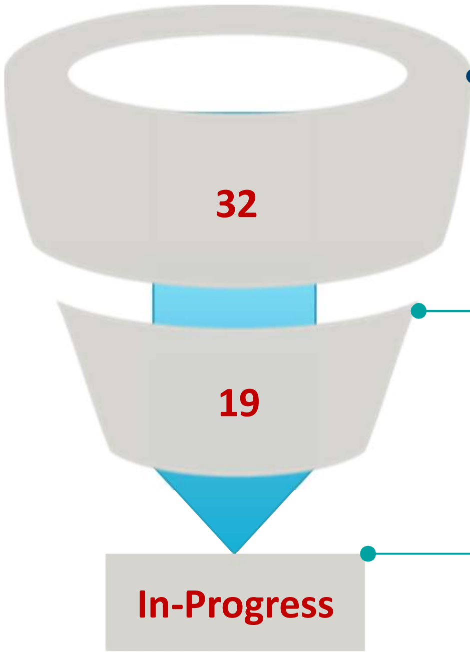
The technical screening process evaluates potential supply side alternatives based on technology maturity, environmental impact, fuel availability, and feasibility to serve ENO's generation needs. From this, generation alternatives are narrowed down for inclusion in the economic screening.

ECONOMIC SCREENING

The economic screening process evaluates levelized cost of electricity metrics and key performance parameters.
From this, generation alternatives are narrowed down for inclusion in the capacity expansion.

TECHNOLOGY SELECTION

The technologies selected for inclusion in the capacity expansion model are those deemed to be most feasible to serve ENO's generation needs based on comparative LCOE and performance parameters, deployment risks (cost / schedule certainty), and emerging commercial, technical, and policy trends.



Technical Screening
Technology Maturity
Environmental Impact
Fuel Availability
Service Territory Feasibility

Economic Screening
Levelized Cost of Electricity
Capital Cost
Fixed and Variable O&M Cost
Emission Costs
Performance

Technology Selection
Levelized Cost of Electricity
Performance
Deployment Risk
Emerging Trends

Technical Screening

Evaluated 32 generation alternatives with 19 selected for economic screening

STORAGE
- Sodium Sulphur (4-hr)
- Compressed Air Energy (16-hr)
- Fly Wheel
- Flow -Vanadium Redox (4-hr)
- Lithium-Ion (4-hr)
- Lead Acid
- Ultra/Super Capacitor

CONVENTIONAL GENERATION*
- Aeroderivative CT
- CCGT (2x1 w/DF)
- CCGT (1x1 w/DF)
- CCGT (2x1 w/o DF)
- CCGT (1x1 w/o DF)
- Frame CT
- RICE

NUCLEAR
- Generation III+ (AP 1000)
- Small Modular Reactor
- Generation IV

WIND
- On-shore
- Off-shore, Fixed
- Off-shore, Floating
- On-Shore, Off System

SOLAR
- Mono & Bifacial
- Off System
- Concentrating Solar Power
- Off-shore (Anywhere except ocean)

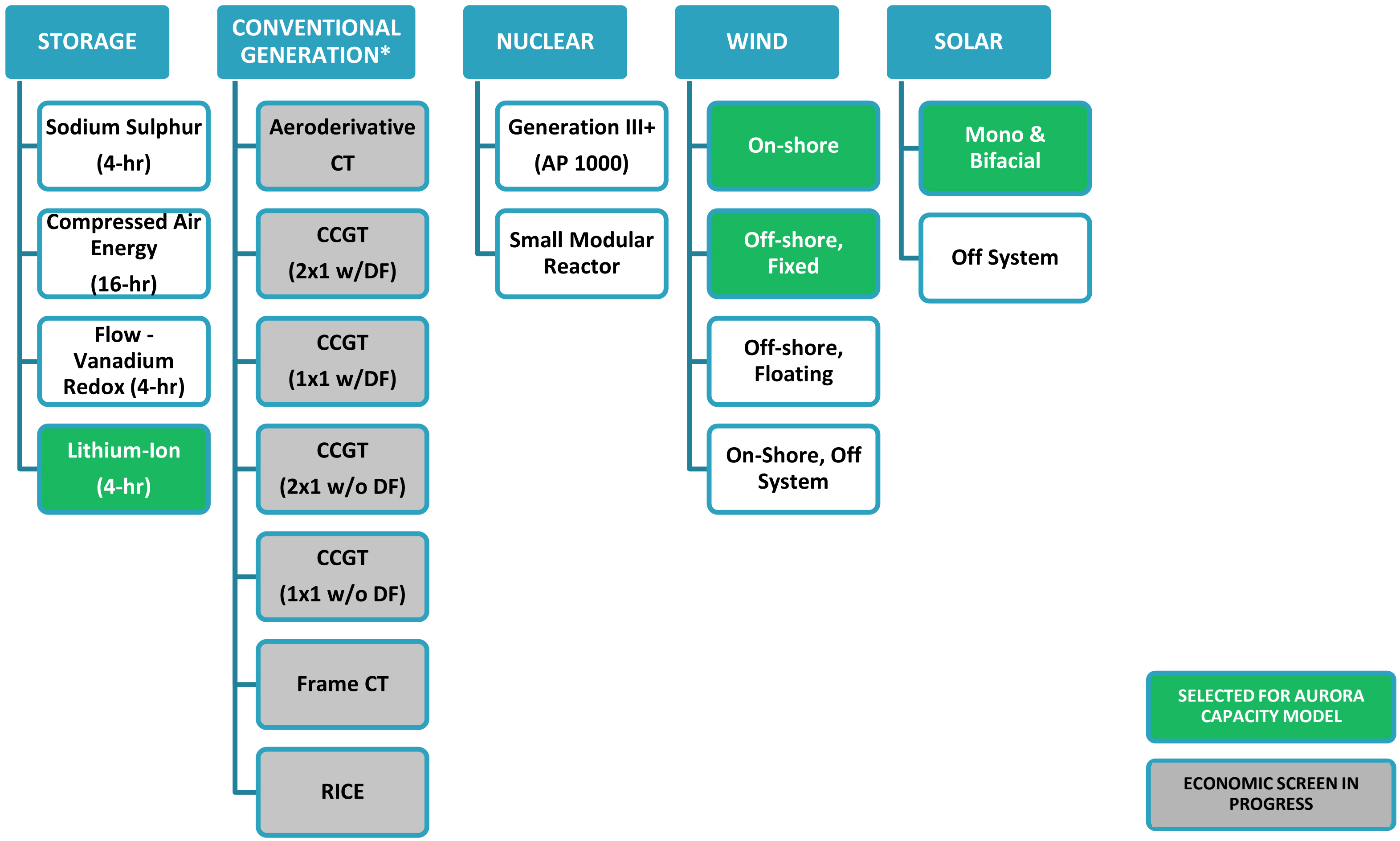
WATER
- Hydroelectric, New Stream
- Hydroelectric, non-powered dam
- Ocean Thermal Energy Conversation
- Ocean
- Tidal
- Wave
- Geothermal

SELECTED FOR ECONOMIC SCREENING

Notes:
* Any large-scale future gas resources will be hydrogen capable. Cost data for hydrogen capable generation resources are under-development.

Economic Screening

4 renewable/storage generation technologies have been selected for inclusion in the capacity expansion model. The economic screen for conventional generation technologies is in progress.



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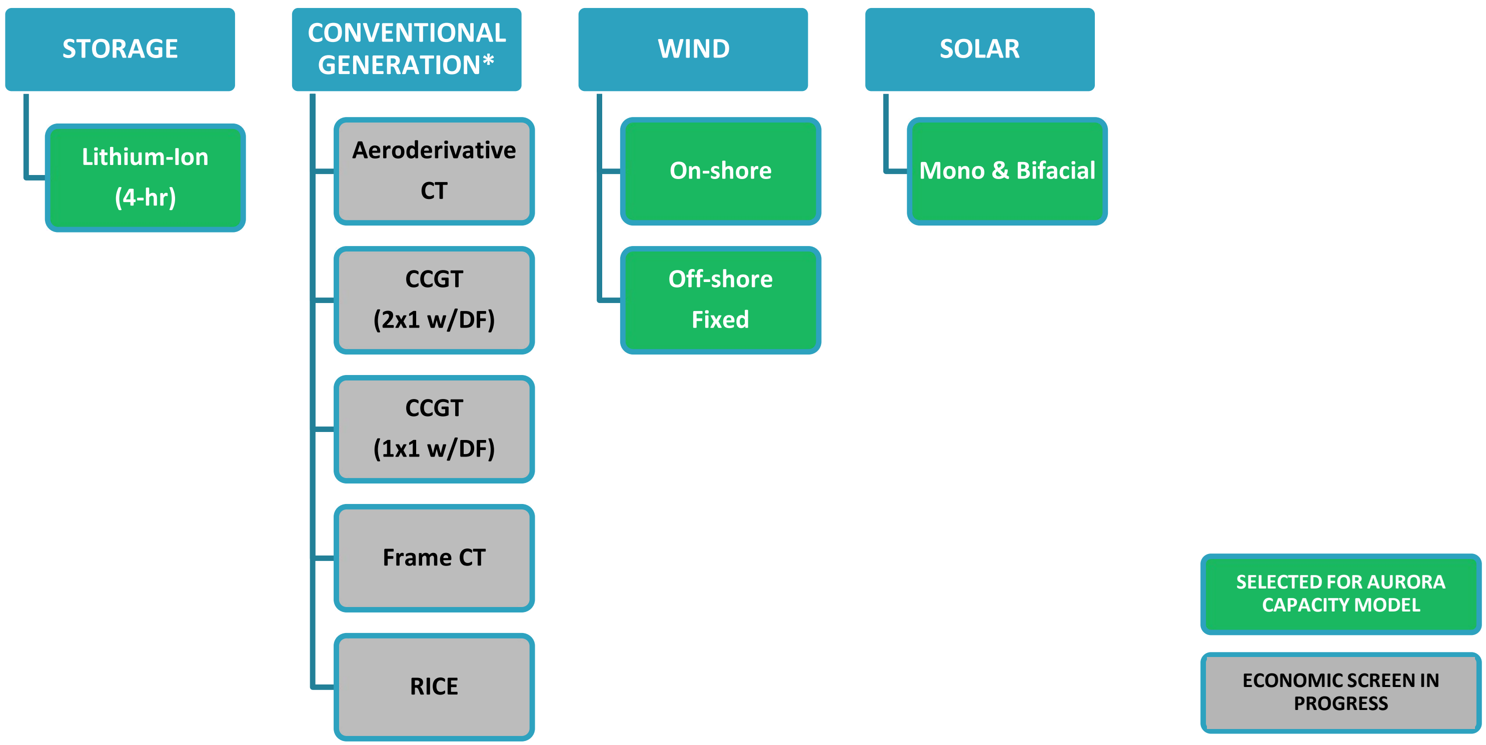
Technology Selection

4 renewable/storage generation technologies have been selected for inclusion in the capacity expansion model. The economic screen for conventional generation technologies is in progress.



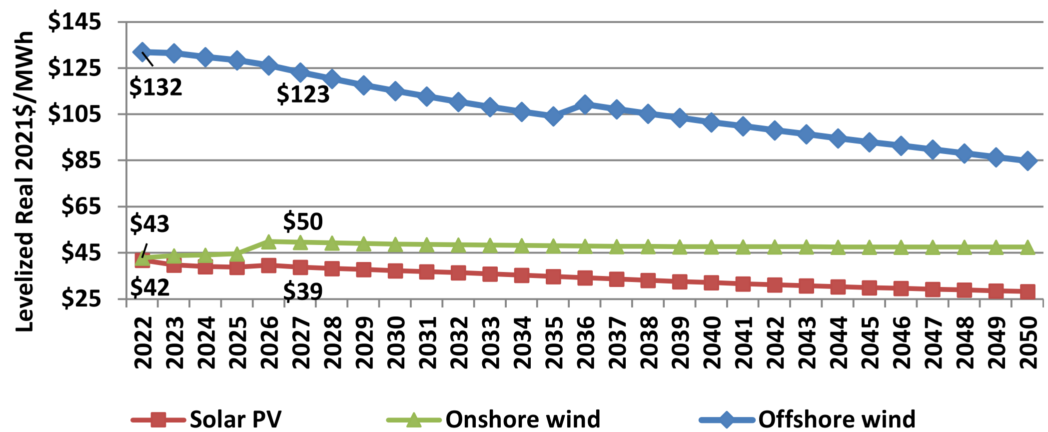
Notes:
*Cost data for hydrogen capable generation resources are under-development

Renewable Resource Assumptions (Solar PV & Wind – MISO S.)

Other Modeling Assumptions

	Solar	On-shore Wind	Off-shore Wind
Size (MW)	100MW	200MW	600MW
Fixed O&M (Levelized R. 2021$/KWac-yr)[1]	$10.31	$37.59	$88.71
Useful Life (yr)	30	30	25
MACRS Depreciation (yr)	5	5	5
Capacity Factor	24.8%	29.6%	37.1%
DC:AC	1.30	N/A	N/A
Hourly Profile Modeling Software	PlantPredict	NREL SAM	NREL SAM

LCOE [2,3]



Notes:
1. Solar and Wind Fixed O&M excludes property tax and insurance; Solar includes inverter replacement in year 16.
2. LCOE is calculated as levelized total cost over the book life divided by the levelized energy output over the book life. (based on 12.2020 ENO WACC)
3. ITC normalized over useful life and assumes an extended ITC for Solar, PTC for On-shore Wind, and ITC for Off-shore Wind.
   - Assumes solar projects online between 2021 and 2023 receive 30% ITC. Assumes solar projects online between 2024 and 2025 receive 26% ITC. Solar projects online beginning 2026 and beyond receive 10% ITC.
   - Assumes on-shore wind projects online in 2021 receive 80% PTC. Assumes on-shore wind projects online between 2022 and 2025 receive 60% PTC. On-shore wind projects online in 2026 or beyond are not eligible for tax credits.
   - Assumes off-shore wind projects online between 2021 and 2035 receive 30% ITC.

Source:
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Grid-Scale Battery Storage Alternatives

- As battery storage technology continues to improve it is important to assess the costs and benefits associated with its deployment to meet long-term needs in the proper context.

- Battery storage includes a range of unique attributes that should be considered, such as:
  - ➢ The ability to store energy for later commitment and dispatch (energy and capacity value)
  - ➢ Ability to discharge in milliseconds and fast ramping capability (ancillary services)
  - ➢ Potential deferral of transmission and distribution upgrades
  - ➢ Rapid construction (on the order of months)
  - ➢ Modular deployment provides potential scalability
  - ➢ Portability and capability to be redeployed in different areas
  - ➢ Small footprint (typically less than an acre), allowing for flexible siting
  - ➢ Low round-trip losses compared to other storage technologies (such as compressed air)

- These attributes should be considered in light of possible limitations and impacts:
  - ➢ Batteries are not a source of electric generation
  - ➢ Useful life can be much shorter than other grid-scale investments (replacement cost)
  - ➢ Market rules not yet established to govern participation in wholesale markets
  - ➢ Discharge less electricity than required to charge due to losses
  - ➢ Cost of environmentally sound disposal

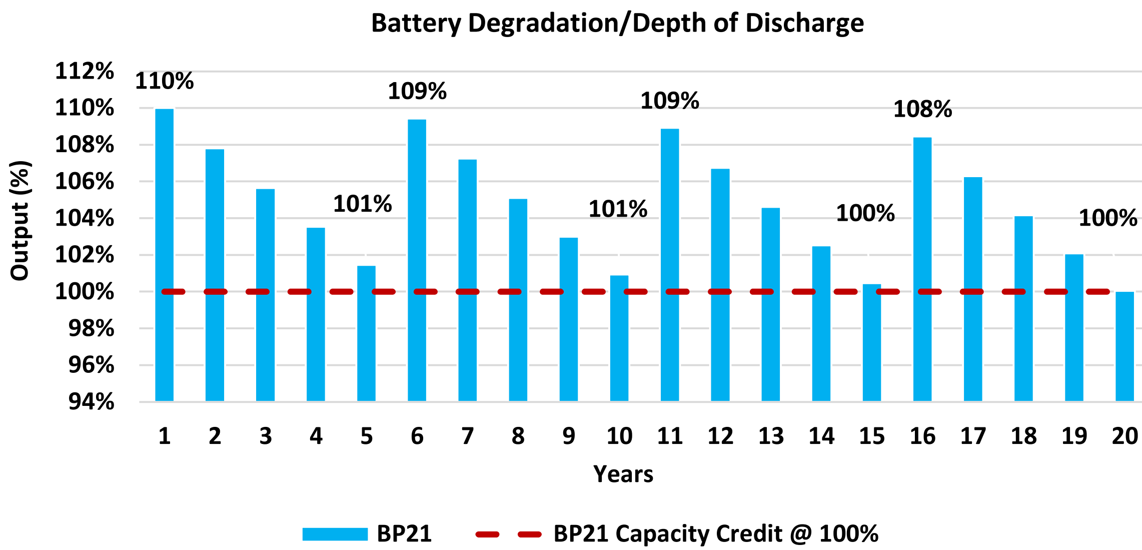
Storage Assumptions (4hr BESS – U.S. Generic)

Installed Capital Cost w/ Augmentation (Nominal, $/KWac) [1]

	2022	2023	2026	2029	2032	2035	2038	2041
Battery Storage	$1,380	$1,327	$1,183	$1,142	$1,123	$1,121	1,126	$1,138

Other Modeling Assumptions

	Battery Storage
Energy Capacity : Power [2]	4:1
Size (MW/MWh)	50MW/200MWh
Fixed O&M (Levelized R. 2021$/KWac-yr) [3]	$13.17
Useful Life (yr)	20
MACRS Depreciation (yr)	7
Round-trip efficiency	86%
Hourly Profile Modeling Software	Aurora



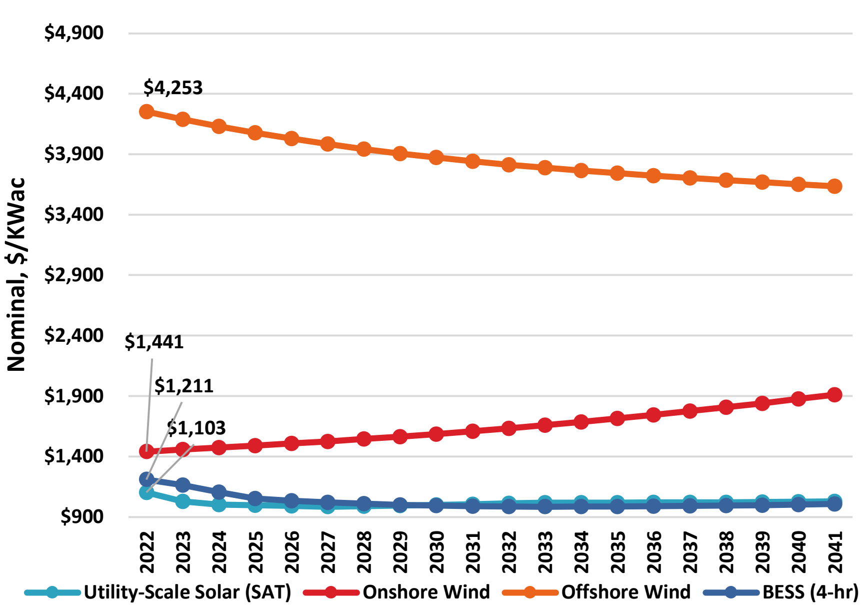
Notes:

1. BESS Installed Capital Cost includes 10% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by an additional 10% augmentation every five years (year 6, 11, & 16). This corresponds to a degradation rate of 2% of BESS capacity per year.
2. Current MISO Tariff requirement for capacity credit
3. Battery Fixed O&M excludes property tax and insurance cost; includes recycling cost of $1.00 (2021$) in year 20.

Source:

Renewable & Storage Installed Capital Forecast

Installed Capital Cost Forecast (Nominal $/KWac, 2022 to 2041) [1,2]



Notes:
1. Utility-scale Solar PV is an average between mono and bi-facial with Single Axis Tracking.
2. Battery Installed Capital Cost does not include augmentation.

Source:
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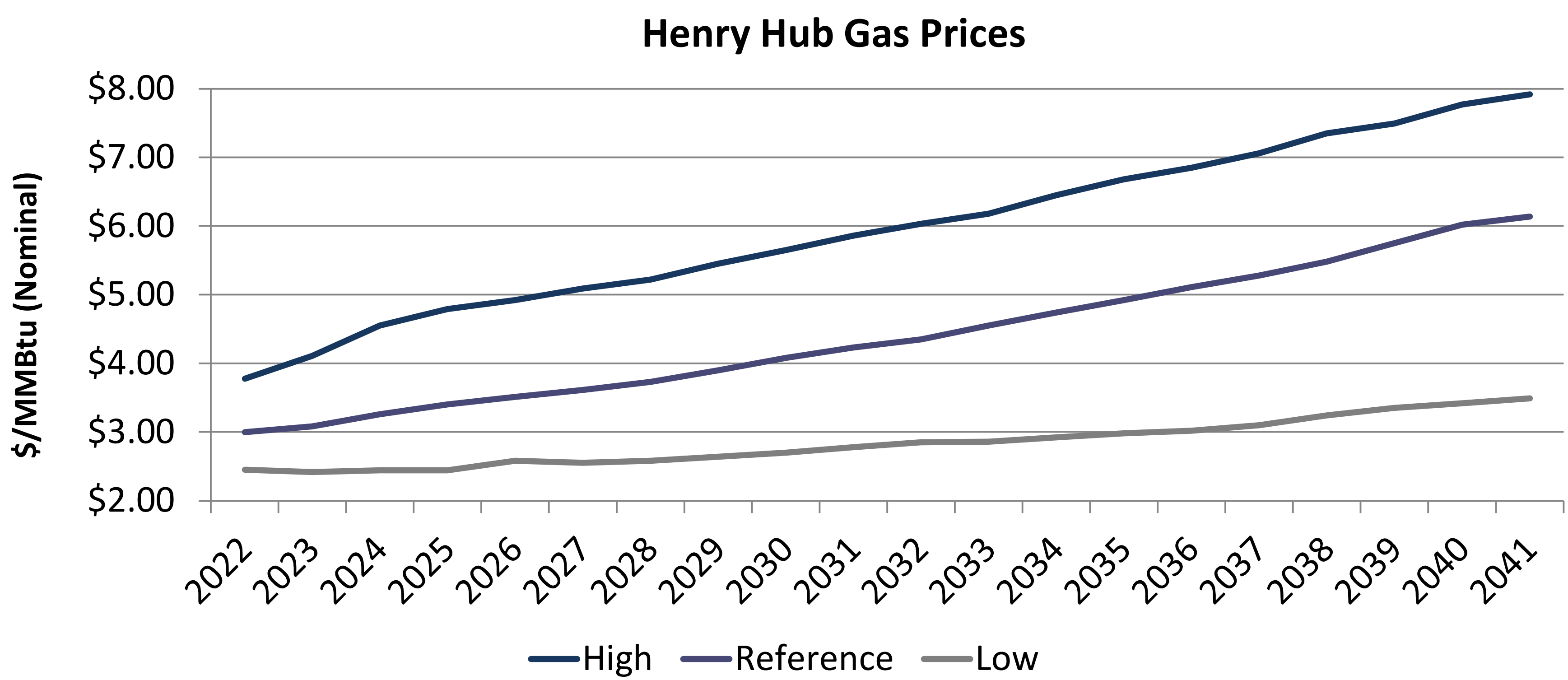
	Utility-Scale Solar (SAT)	On-shore Wind	Off-shore Wind	BESS (4-Hr)
2022	$1,103	$1,441	$4,253	$1,211
2023	$1,028	$1,458	$4,189	$1,163
2024	$1,001	$1,474	$4,130	$1,106
2025	$996	$1,490	$4,077	$1,053
2026	$991	$1,507	$4,028	$1,034
2027	$986	$1,525	$3,983	$1,020
2028	$990	$1,545	$3,943	$1,009
2029	$995	$1,565	$3,906	$1,001
2030	$1,000	$1,586	$3,872	$994
2031	$1,006	$1,609	$3,841	$989
2032	$1,012	$1,634	$3,813	$987
2033	$1,018	$1,660	$3,787	$986
2034	$1,018	$1,687	$3,764	$986
2035	$1,019	$1,715	$3,742	$987
2036	$1,020	$1,745	$ 3,722	$989
2037	$1,020	$1,775	$3,703	$991
2038	$1,022	$1,806	$3,685	$994
2039	$1,023	$1,838	$3,668	$997
2040	$1,025	$1,876	$3,651	$1,001
2041	$1,028	$1,911	$3,635	$1,007

Section 3
Inputs and Assumptions

2021 IRP Inputs and Assumptions

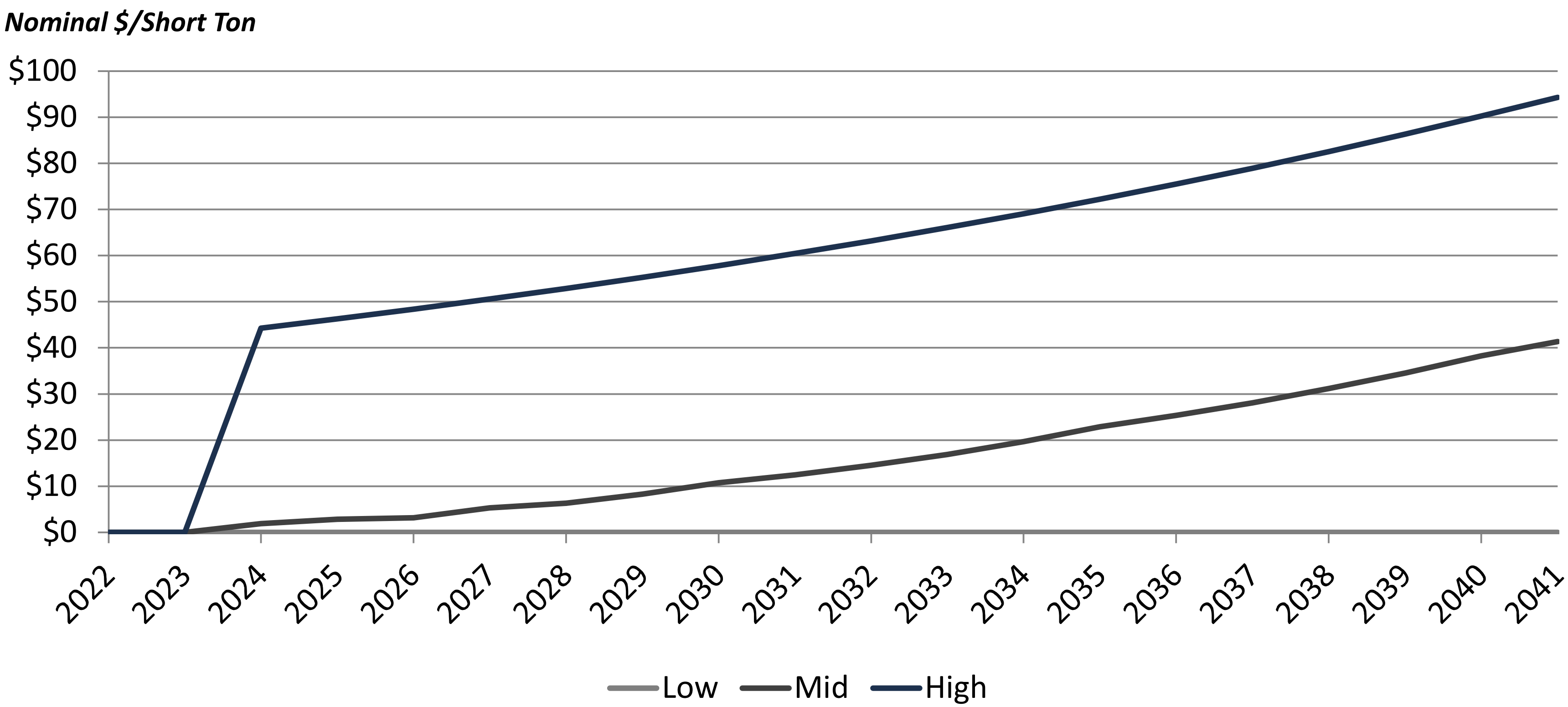
Input/Assumption	MISO Market Modeling	Portfolio Development	Total Relevant Supply Costs
Planning Scenarios	✓	✓	✓
Gas Price Forecast	✓	✓	✓
CO2 Price Forecast	✓	✓	✓
Load Forecast	✓	✓	✓
Planning Strategies		✓	✓
Capacity Value		✓	✓
Supply-Side Resource Alternative Costs		✓	✓
ENO’s Long-Term Capacity Need		✓	✓
DSM Potential Study Results		✓	✓
Input Sensitivities			✓

Gas Price Forecast (BP21)



Case	2022	2029	2034	2041
Low	$2.45	$2.64	$2.92	$3.49
Reference	$3.00	$3.90	$4.74	$6.14
High	$3.78	$5.45	$6.45	$7.92

CO2 Price Forecast (BP21)



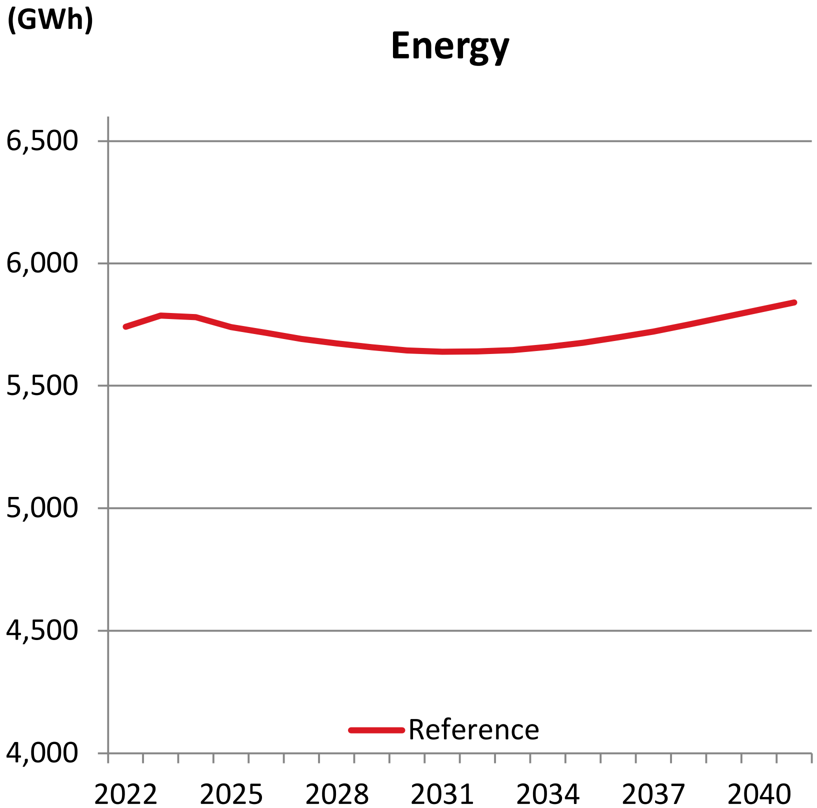
Case	2024	2030	2035	2041
Low	$0.00	$0.00	$0.00	$0.00
Reference	$1.87	$10.72	$22.86	$41.39
High	$44.26	$57.81	$72.21	$94.31

Load Forecast Levers

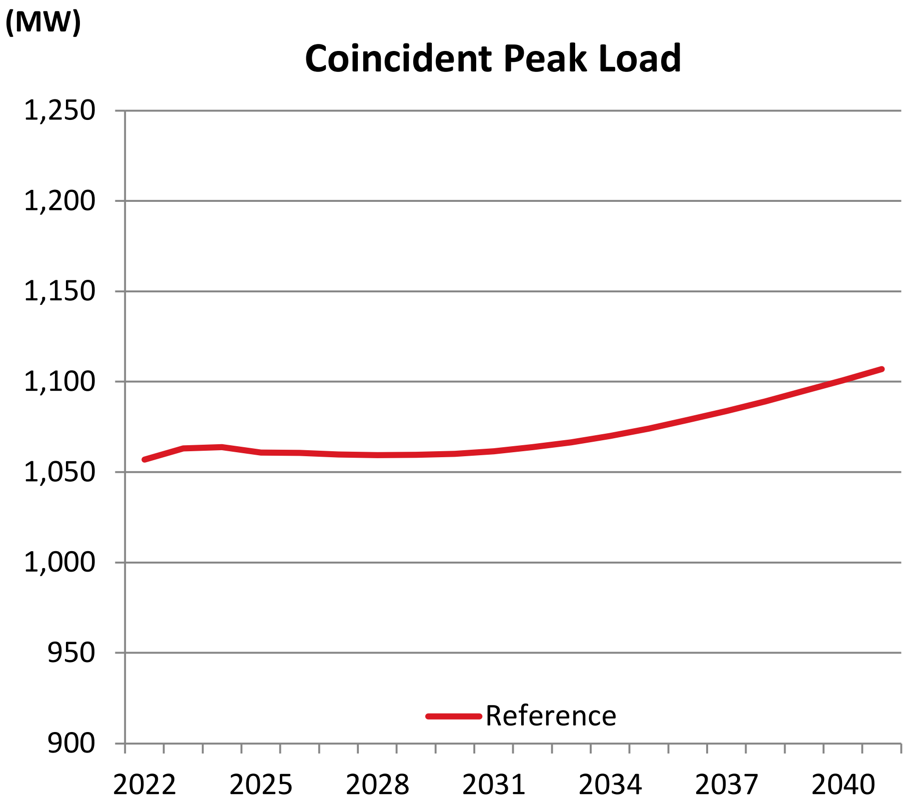
Item	*Scenario 1* Reference Case	*Scenario 2* Decentralized Focus (DSM and Renewables)	*Scenario 3* Economic and Renewables Growth
Policy Traits		More utility DSM; More BTM solar; Lower battery costs due to incentives; Increased EV adoption	More utility DSM; Utility-scale solar favored over BTM solar; Higher EV and non-EV electrification
Other Traits		Healthy economic conditions; Res & Com growth	Higher economic growth; High CO2 costs and power prices
Peaks	Reference	Lower: Increased EV adoption is offset by increases in BTM solar and increased OpCo DSM	Higher: High EV adoption, higher building electrification, higher growth in Res/Com/Ind offset increased BTM solar adoption
Energy	Reference		
Load Shapes	Reference	Intra-day shifts due to higher EV and higher BTM solar	Higher with intra-day shifts due to higher EV and higher BTM solar
BTM Solar	Reference	High	High
Electric Vehicles (EVs)	Reference (2100)	Higher (2055)	High (2040)
Building Electrification	Reference	Reference	High
Organic EE and OpCo DSM	Reference	Higher	Higher
Res. & Com. Growth	Reference	Reference	Higher
Refinery Utilization due to EVs	Reference	Lower (opposite of EVs)	Lower (opposite of EVs)
Industrial Growth	Reference	Reference	Higher

Peak Load & Energy Forecast (BP21)

Reference (Scenario 1) case forecast for ENO. Low (Scenario 2) and High (Scenario 3) load forecasts are being developed.



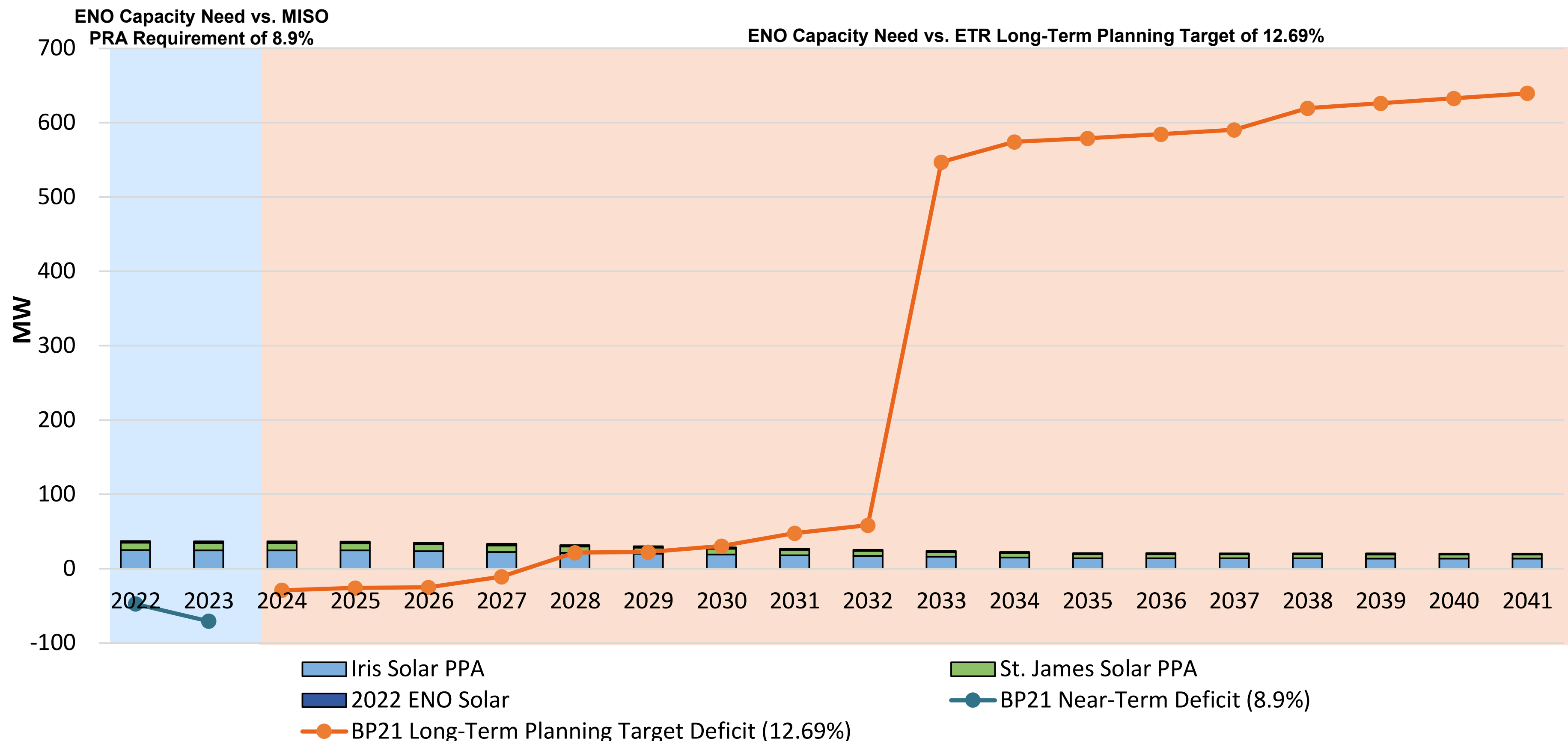
10 Year CAGR (%)	2022-2031	2032-2041
Reference	-0.20%	0.39%



Peak Load (MW)	2022	2026	2031	2036	2041
Reference	1,057	1,061	1,062	1,079	1,107

ENO's Long-Term Capacity Need (BP21) - Updated

To maintain long-term system reliability, ENO uses a long-term planning reserve margin applied to ENO's coincident peak with MISO



Assumptions:

- *Requirements are based on ENO's peak coincident w/ MISO and resources are represented by UCAP accreditation ratings*
- *Chart assumes a 50% capacity credit for solar resources through 2025, then decreases 2% each year beginning in 2026 until 30% minimum is reached to align with MISO MTEP 2021 futures*

Section 4
Timeline and Next Steps

Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2020	✓
Technical Meeting #1 Material Due	November 2020	✓
Technical Meeting #1	December 2020	✓
Technical Meeting #2 Material Due	April 2021	-
Technical Meeting #2	April 2021	-
Planning Scenarios and Non-DSM Inputs Finalized	**May 2021**	-
DSM Potential Studies Due	**July 2021**	-
Technical Meeting #3 Material Due	July/August 2021	-
Technical Meeting #3	August 2021	-
IRP Inputs Finalized	**August 2021**	-
Optimized Portfolio Results Due	December 2021	-
Technical Meeting #4 Material Due	January 2022	-
Technical Meeting #4	January 2022	-
Final IRP Report due	**March 2022**	-
Public Meeting #2 Material Due	April 2022	-
Public Meeting #2 - Present IRP Results	April 2022	-
Public Meeting #3 Material Due	April 2022	-
Public Meeting #3 - Public Response	April/May 2022	-
Technical Meeting #5 Material Due	April 2022	-
Technical Meeting #5	April/May 2022	-
Intervenors and Advisors Questions & Comments Due	May 2022	-
ENO Response to Questions and Comments Due	June 2022	-
ENO File Reply Comments	June 2022	-
Advisors File Report	July 2022	-

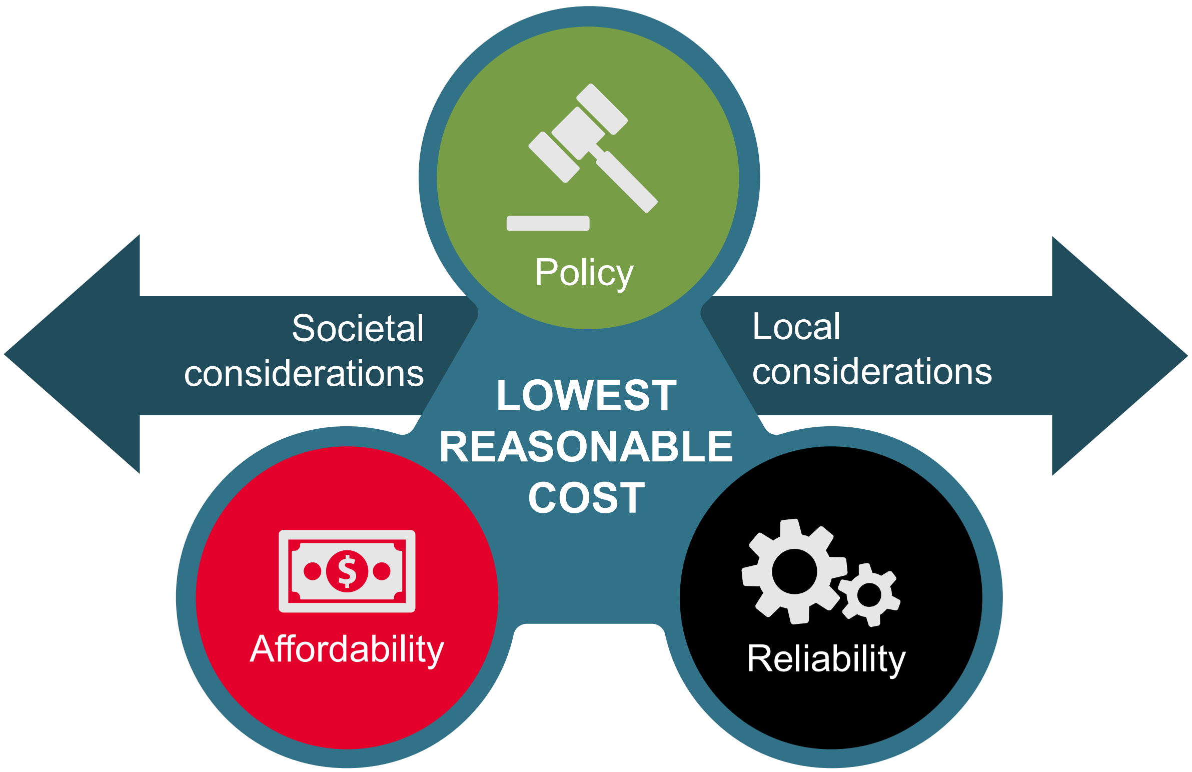
Appendix

Comparison of Old Scenario 2 to New Scenario 2

	Old Scenario 2	New Scenario 2
Description	Current Environment Persists (gas centric)	Decentralized Focus (DSM & renewables)
Peak / Energy Load Growth	Reference	Low
Natural Gas Prices (Levelized Real, 2021$/MMBtu)	Low	Low
DR / EE / DER Additions	Low	High
Market Coal Retirements	Reference (60 years)	Accelerated (55 years)
Legacy Gas Fleet Retirements	Reference (60 years)	Accelerated (55 years)
Magnitude of Coal & Legacy Gas Deactivations	23% by 2030 69% by 2040	49% by 2030 84% by 2040
CO2 Reduction Target (Levelized Real, 2021$/short ton)	None	Reference

ENO Planning Objectives

The 2021 IRP process seeks to identify a range of possible approaches to serving the electricity needs of ENO customers over the period 2022-2041 while addressing three main planning objectives: **reliability, affordability, and policy considerations**

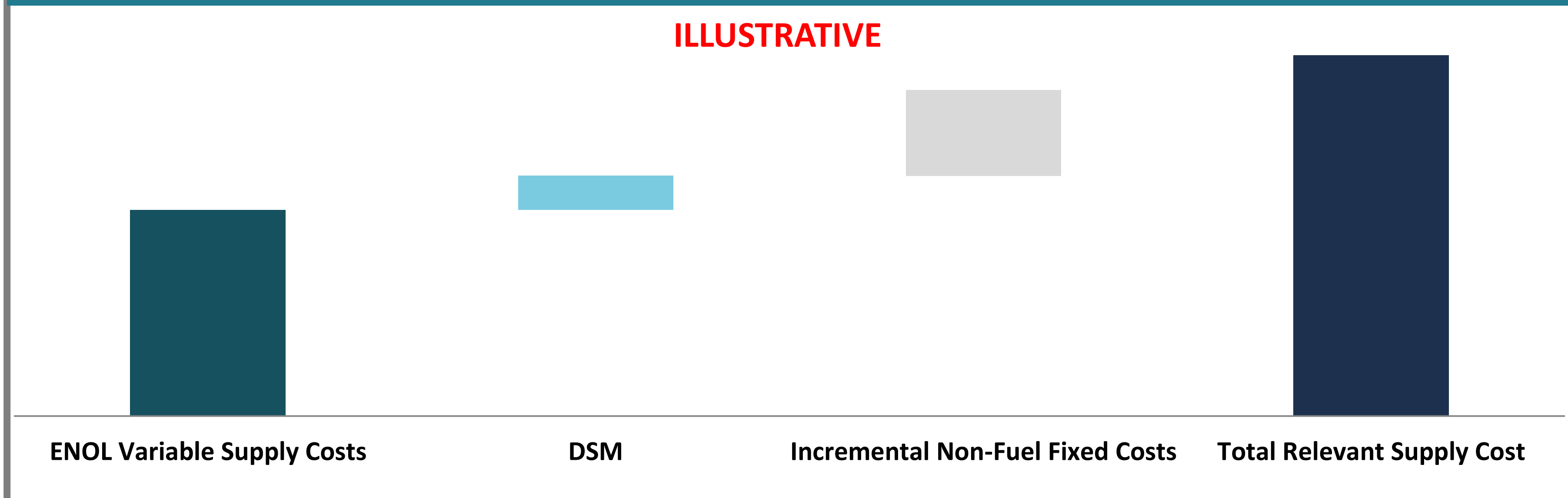


Measuring Customer Economics & Affordability

ENO Total Relevant Supply Cost results consist of 3 major components:

ENO Variable Supply Costs
+ Demand Side Management (DSM) Costs
+ Non-Fuel Fixed Costs[1]
Total Relevant Supply Cost ("TRSC")

Components of ENO Total Relevant Supply Cost



[1] Non-fuel Fixed Costs include an adjustment for applicable tax credits and capacity purchases/sales

Entergy

ENO 2021 IRP
Technical Meeting #3

August 12, 2021

Goals and Agenda of Technical Meeting #3

Goals

- As described in the Initiating Resolution (R-20-257), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to discuss and finalize the Planning Strategies and engage in an initial discussion regarding scorecard metrics.
- Address questions as necessary to finalize the IRP inputs by August 15, 2021, as required by the procedural schedule.

Agenda

1. Planning Strategies—Discussion of ENO Proposed Strategies and Proposed Stakeholder Strategy (if applicable)
2. Initial Discussion of Scorecard Metrics—Initial discussion, starting from 2018 IRP Scorecard
3. IRP Inputs and DSM Studies—Discussion of any outstanding questions

Technical Meeting #2 (4/29/21)—Follow Ups

- BP21 Macro Inputs Workbook
  - Circulated HSPM workbook on 5/10/21
- Planning Scenarios
  - Worked out parameters for Stakeholder Scenario #3 through series of calls and emails in May and June
  - Finalized Scenario #3 on 6/29/21
  - EPG working on MISO market modeling for all three Scenarios
- DSM Studies
  - Call w/ GDS and EPG to discuss required IRP inputs on 6/4/21
  - Circulated description of achievable cases from Guidehouse study on 6/15/21
  - GDS achievable cases circulated 6/17/21
    - Call to discuss GDS cases on 7/16/21
  - Call w/ Guidehouse and GDS to confirm alignment on study inputs on 7/21/21
- Union 1 Deactivation Sensitivity
  - Based on discussion at TM#2, developed approach for manual portfolio to assess early deactivation of Union 1

Section 1
Planning Strategies

ENO Proposed Planning Strategies--Assumptions

	Strategy 1	Strategy 2	Strategy 3	Strategy 4	Strategy 5
Description	Least Cost Planning	But For RCPS (Reference)	RCPS Compliance	TBD, Stakeholder Strategy	TBD, If applicable
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals		
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes resources that would not be RCPS compliant.		
DSM Input Case	Reference Case (Guidehouse)	2% Program Case (Guidehouse)	2% Program Case (Guidehouse)		
Manual Portfolio*	Alternative Deactivation – Union Power Station	N/A	N/A		

*An additional portfolio informed by the portfolio developed under Strategy 1 and Scenario 1 ("Strategy 1a") will be developed to assess the accelerated deactivation of Union, as discussed at Technical Meeting #2.

Anticipated Resulting Portfolios

- Below is a table of the anticipated 13 portfolios to be developed from capacity expansion* assuming four Strategies and the three established Scenarios.

Strategies / Scenarios	Strategy 1 (Least Cost)	Strategy 1a (Least Cost- Union Sensitivity)	Strategy 2 (But For RCPS)	Strategy 3 (RCPS Compliance)	Strategy 4 (TBD, Stakeholder Strategy)	Strategy 5 (TBD, if applicable)
Scenario 1	P1&1	MP1a&1	P2&1	P3&1	P4&1	
Scenario 2	P1&2	N/A	P2&2	P3&2	P4&2	
Scenario 3	P1&3	N/A	P2&3	P3&3	P4&3	

*The one exception is that the Union Sensitivity will be developed manually and informed by the portfolio resulting from Strategy 1/Scenario 1 (“P1&1”) as discussed at Technical Meeting #2

Section 2

Scorecard Metrics

(Separate Excel File with Draft Scorecard Format)

Section 3
IRP Inputs and DSM Studies

Section 4
Timeline and Next Steps

Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2020	✓
Technical Meeting #1 Material Due	November 2020	✓
Technical Meeting #1	December 2020	✓
Technical Meeting #2 Material Due	April 2021	✓
Technical Meeting #2	April 2021	✓
Planning Scenarios and Non-DSM Inputs Finalized	May 2021	✓
DSM Potential Studies Due	July 2021	✓
Technical Meeting #3 Material Due	July/August 2021	-
Technical Meeting #3	August 2021	-
IRP Inputs Finalized	August 15, 2021	-
Optimized Portfolio Results Due	December 2021	-
Technical Meeting #4 Material Due	January 2022	-
Technical Meeting #4	January 2022	-
Final IRP Report due	March 2022	-
Public Meeting #2 Material Due	April 2022	-
Public Meeting #2 - Present IRP Results	April 2022	-
Public Meeting #3 Material Due	April 2022	-
Public Meeting #3 - Public Response	April/May 2022	-
Technical Meeting #5 Material Due	April 2022	-
Technical Meeting #5	April/May 2022	-
Intervenors and Advisors Questions & Comments Due	May 2022	-
ENO Response to Questions and Comments Due	June 2022	-
ENO File Reply Comments	June 2022	-
Advisors File Report	July 2022	-

Appendix

2021 IRP Planning Scenarios—Finalized 6/29/21

	Scenario 1	Scenario 2	Scenario 3
Description	Reference	Decentralized Focus (DSM & renewables)	Stakeholder
Peak / Energy Load Growth	Reference	Low	High
Basis of DR / EE / DER Additions (Adjustment to Load)	Entergy (Medium)	Entergy (High)	Entergy (High)
Natural Gas Prices (Levelized Real, 2021$/MMBtu)	Reference	Low	High
Market Coal Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (30 Years)
Legacy Gas Fleet Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (30 Years)
CO2 Tax Assumption (Levelized Real, 2021$/short ton)	Reference	Reference	High
New-Build Resource Alignment with MTEP Future #3	No, Aurora capacity expansion tool will be used	No, Aurora capacity expansion tool will be used	Yes, via a manual MISO market portfolio buildout
Renewable Resource Costs	Entergy Technology Assessment	Entergy Technology Assessment	NREL 2020 ATB

Entergy

ENO 2021 IRP
Technical Meeting #4

January 19, 2022

WE POWER LIFE℠

Goals and Agenda of Technical Meeting #4

Goals

- The Initiating Resolution (R-20-257) contemplates several goals for this Technical Meeting:
  - Review and discuss the Optimized Resource Portfolios selected through the Aurora capacity expansion modeling, and reach consensus on the subset of portfolios to be carried through the total supply cost analysis and cross testing;
  - Finalize the Scorecard Metrics initially presented at Technical Meeting #3;
  - Engage in an initial discussion regarding Energy Smart Program Years 13-15 (2023-2025).

Agenda

1. Optimized Resource Portfolio Discussion and Downselection
2. Risk Assessment Discussion
3. Scorecard Metrics Discussion
4. Energy Smart PY 13-15 Program Discussion
5. Timeline and Next Steps

Technical Meeting #3 (8/12/21)—Follow Ups

- Planning Scenarios and Strategies
  - Parties had further discussions regarding Planning Strategies to be analyzed under the Planning Scenarios finalized on 6/29/21.
  - The Parties reached consensus on 8/16/21 regarding four Planning Strategies to be modeled, two of which would include additional manual portfolios and one of which would include a sensitivity case.
  - The Stakeholders agreed to provide the Renewable LCOE values to be used in modeling the Stakeholder Strategy #4 and its associated sensitivity.
    - The final Excel file containing LCOE values was received from Simon Mahan on 9/13/21 and submitted to EPG for review.
    - On 10/4/21, EPG provided an Excel file converting the LCOE values to the $/MW-week metric required for inputting the renewables costs into Aurora.

- DSM Inputs
  - After follow up discussions, GDS provided the necessary EE and DR input files for EPG to use in modeling Stakeholder Strategy #4 on 9/13 and 9/15/21, respectively.

- Scorecard Draft Template
  - ENO presented a draft Scorecard modeled on the 2018 IRP for review and comment. There was discussion regarding updates to account for the RCPS and the Advisors indicated they would review further and consider proposed edits.

Section 1
Optimized Resource Portfolios

Analytic Process to Create and Value Portfolios

Development of Planning Scenarios and Strategies

Development of assumptions and inputs for Scenarios and Strategies

Reviewed & finalized inputs, Strategies and Scenarios at previous Technical Meetings

Market Modeling

Projection of MISO market **outside of ENOL** for each Scenario

Developed and executed market modeling based upon agreed upon Scenarios & Strategies

Portfolio Development

Construction of resource portfolios for each Scenario/Strategy combination

Produced Optimized Portfolios through Aurora's capacity expansion based on agreed upon Strategies & Scenarios. Results summarized within the following slides

Total Relevant Supply Cost

Production costs and fixed costs are determined for each downselected portfolio under each Scenario/Strategy combination (Recommendations included on following slides)

Recommendations for Total Supply Cost analysis included within the following slides

Action Plan

Identify action plan that balances reliability, cost, and risk

Review of Scorecard is included within the following slides

2021 IRP Planning Scenarios—Finalized 6/29/21

	Scenario 1	Scenario 2	Scenario 3
Description	**Reference**	**Decentralized Focus (DSM & renewables)**	**Stakeholder**
Peak / Energy Load Growth	Reference	Low	High
Basis of DR / EE / DER Additions (Adjustment to Load)	Entergy (Medium)	Entergy (High)	Entergy (High)
Natural Gas Prices (Levelized Real, 2021$/MMBtu)	Reference	Low	High
Market Coal Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (30 Years)
Legacy Gas Fleet Retirements	Reference (60 years)	Accelerated (55 years)	Accelerated (30 Years)
CO2 Tax Assumption (Levelized Real, 2021$/short ton)	Reference	Reference	High
New-Build Resource Alignment with MTEP Future #3	No, Aurora capacity expansion tool will be used	No, Aurora capacity expansion tool will be used	Yes, via a manual MISO market portfolio buildout
Renewable Resource Costs	Entergy Technology Assessment	Entergy Technology Assessment	NREL 2020 ATB

2021 IRP Planning Strategies—Finalized 8/16/21

	Strategy 1	Strategy 2	Strategy 3	Strategy 4
Description	Least Cost Planning	But For RCPS (Reference)	RCPS Compliance	Stakeholder Strategy
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals; NREL 2020 ATB LCOE values for renewables costs provided by Stakeholders
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.
DSM Input Case	Reference Case (Guidehouse)	2% Program Case (Guidehouse)	2% Program Case (Guidehouse)	High Case (GDS)
Manual Portfolio	Alternative Deactivation – Union Power Station (2025)[1] (Manual Portfolio 1a)	N/A	N/A	Alternative Deactivation – Union Power Station (2025)[2] (Manual Portfolio 4a)
Sensitivity	N/A	N/A	N/A	Lower renewables costs provided by Stakeholders[3] (Sensitivity 4b)

[1] An additional manual portfolio informed by the optimized portfolio developed under Strategy 1 and Scenario 1 ("Manual Portfolio 1a") will be developed.
[2] An additional manual portfolio informed by the optimized portfolio developed under Strategy 4 and Scenario 3 ("Manual Portfolio 4a") will be developed.
[3] A sensitivity using the alternative cost assumptions provided by the Stakeholders on the resources identified in the optimized portfolio developed under Strategy 4 and Scenario 3 ("Sensitivity 4b").

Optimized Portfolios – Process and Observations

Process

- For each Scenario and Strategy combination, portfolios are optimized in Aurora capacity expansion using constraints and assumptions
- Three Scenarios and four Strategies produced twelve optimized portfolios
- Stakeholders work together to narrow down the twelve portfolios created in capacity expansion to no more than five to be cross-tested across the three Scenarios
- Limiting to five necessary to maintain the IRP schedule
- The objective of portfolio downselection for cross-testing is to identify a diverse, representative range of potential portfolios, which when tested across each of the Scenarios will provide more information regarding how portfolios' total supply costs change under the different assumptions of the three Scenarios

Observations

- No fossil-fired resources selected in any of the twelve portfolios
- Each portfolio is composed of renewable and storage resources in differing amounts and timing
- Each 150 MW Hybrid resource equals 100 MW Solar and 50 MW Storage resulting in resource components that are similar to standalone solar and storage additions

Capacity Expansion Portfolios

	Strategy 1 Guidehouse Low DSM – Optimized (TA - All Resource)	Strategy 2 Guidehouse 2% Program DSM – Forced In (TA - All Resource)	Strategy 3 Guidehouse 2% Program DSM – Forced In (TA - Renewable Only)	Strategy 4 GDS High DSM – Forced In (NREL costs provided by Stakeholders, Solar & wind only)
Scenario 1: (Ref) Reference Gas Reference Demand Reference CO2	400MW 36% 600MW 55% 100MW 9%	350MW 28% 700MW 56% 200MW 16%	300MW 26% 600MW 52% 100MW 9% 150M…	700MW 37% 1,200MW 63%
Scenario 2: (Low) Low Gas Low Demand Reference CO2	350MW 41% 500MW 59%	250MW 39% 100MW 15% 300MW 46%	300MW 46% 200MW 31% 150MW 23%	400MW 25% 1,200MW 75%
Scenario 3: (High) High Gas High Demand High CO2	550MW 15% 1,100MW 31% 1,900MW 54%	500MW 14% 1,300MW 36% 1,800MW 50%	450MW 13% 1,500MW 42% 1,600MW 45%	1,700MW 33% 3,500MW 67%

TA=Technology Assessment

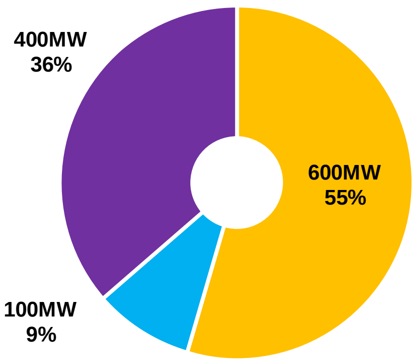
Solar Hybrid Wind Battery

***All capacity stated in ICAP**

"Hybrid" resources include solar + storage

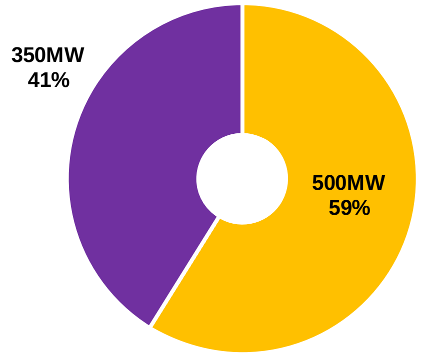
Strategy 1 – Capacity Expansion Portfolios

Scenario 1



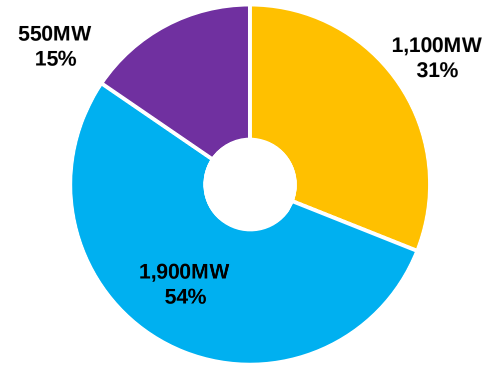
Resource	Year	Installed Cap (MW)
Solar/Battery	2033	400/350
Solar	2034	100
Solar	2035	100
Wind/Battery	2041	100/50

Scenario 2



Resource	Year	Installed Cap (MW)
Solar/Battery	2033	300/350
Solar	2038	100
Solar	2041	100

Scenario 3

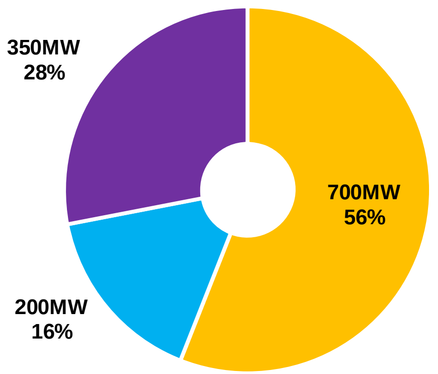


Resource	Year	Installed Cap (MW)
Solar/Battery	2031	200/50
Battery	2032	50
Wind/Solar/ Battery	2033	200/700/250
Battery	2034	100
Solar/Battery	2035	100/50
Wind	2036	300
Wind	2037	100
Wind/Battery	2038	300/50
Wind/Solar	2039	100/100
Wind	2040	300
Wind	2041	600

Solar Hybrid Wind Battery

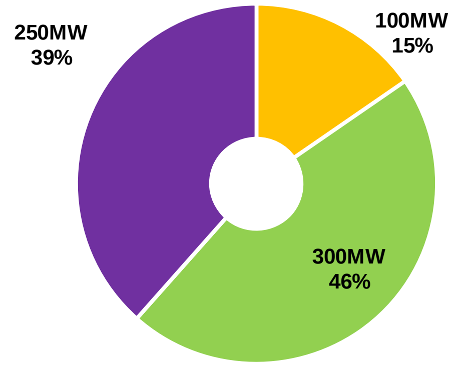
Strategy 2 – Capacity Expansion Portfolios

Scenario 1



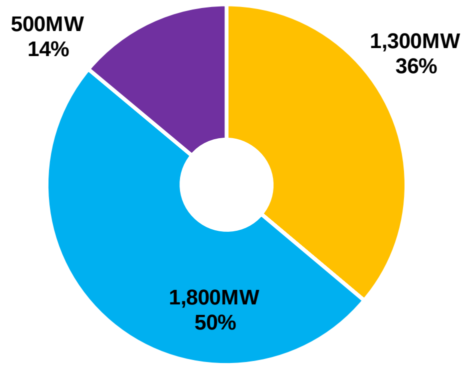
Resource	Year	Installed Cap (MW)
Solar/Battery	2033	500/300
Solar	2034	100
Battery	2035	50
Wind	2038	200
Solar	2041	100

Scenario 2



Resource	Year	Installed Cap (MW)
Hybrid/ Battery	2033	300/250
Solar	2038	100

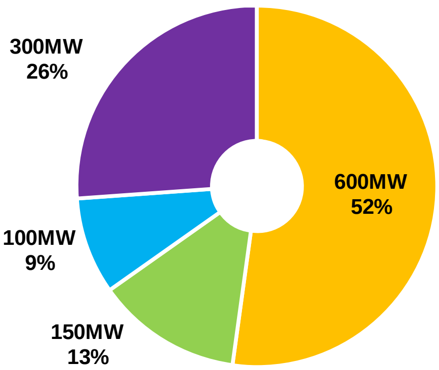
Scenario 3



Resource	Year	Installed Cap (MW)
Solar/Battery	2031	100/50
Battery	2032	50
Wind/Solar/ Battery	2033	200/500/350
Solar	2034	300
Wind	2035	300
Battery	2036	50
Wind	2037	200
Wind	2038	300
Wind/Solar	2039	200/100
Wind	2040	300
Wind/Solar	2041	300/300

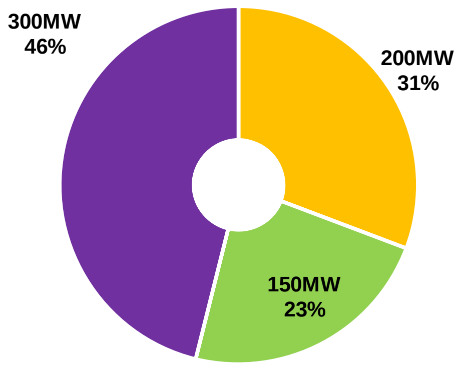
Strategy 3 – Capacity Expansion Portfolios

Scenario 1



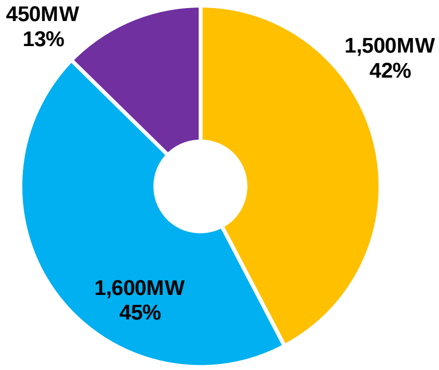
Resource	Year	Installed Cap (MW)
Solar/Battery/ Hybrid	2033	400/250/150
Battery	2034	50
Solar	2038	100
Wind/Solar	2041	100/100

Scenario 2



Resource	Year	Installed Cap (MW)
Solar/Battery/ Hybrid	2033	100/300/150
Solar	2034	100

Scenario 3

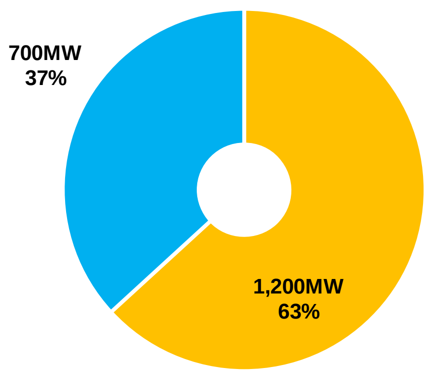


Resource	Year	Installed Cap (MW)
Wind/Solar	2031	100/300
Solar	2032	100
Wind/Solar/Battery	2033	200/400/350
Solar/Battery	2034	100/50
Solar	2035	200
Wind	2036	200
Wind/Battery	2037	100/50
Wind/Solar	2038	200/100
Wind	2039	300
Wind	2040	300
Wind/Solar	2041	200/300

Solar Hybrid Wind Battery

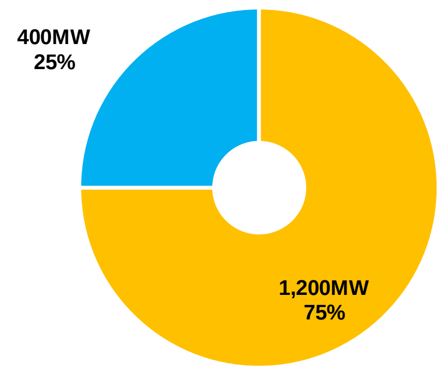
Strategy 4 – Capacity Expansion Portfolios

Scenario 1



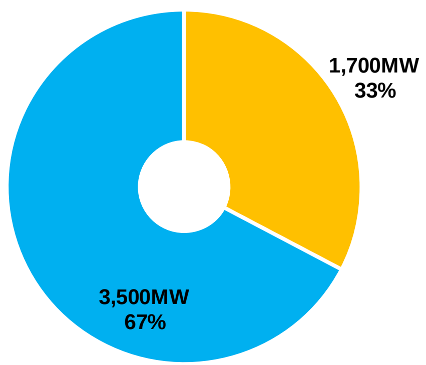
Resource	Year	Installed Cap (MW)
Wind/Solar	2033	300/1100
Wind/Solar	2034	100/100
Wind	2035	100
Wind	2038	200

Scenario 2



Resource	Year	Installed Cap (MW)
Wind/Solar	2033	100/1100
Wind/Solar	2034	100/100
Wind	2035	100
Wind	2038	100

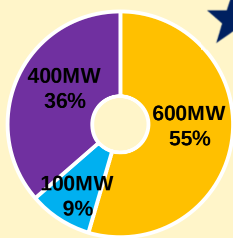
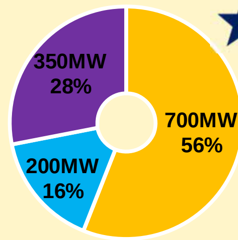
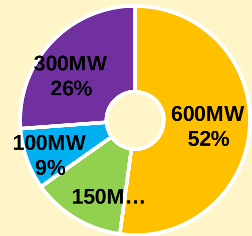
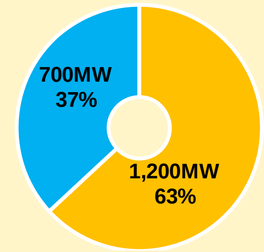
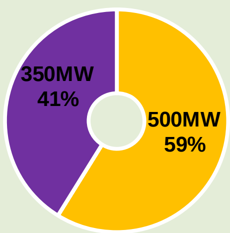
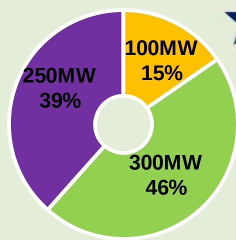
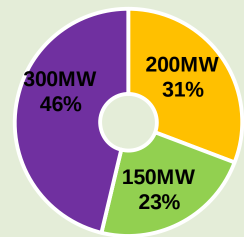
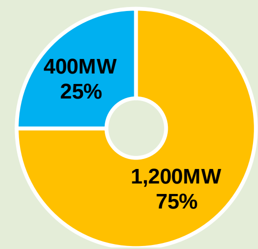
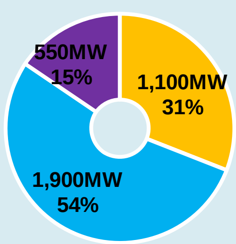
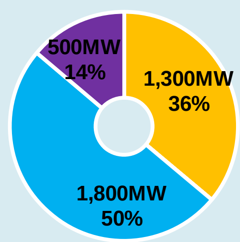
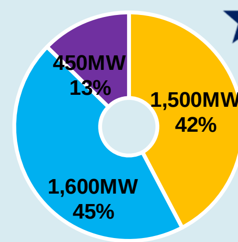
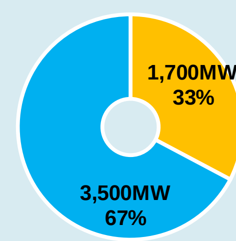
Scenario 3



Resource	Year	Installed Cap (MW)
Wind	2031	400
Wind	2032	200
Wind/Solar	2033	100/1500
Wind/Solar	2034	200/200
Wind	2035	500
Wind	2036	300
Wind	2037	300
Wind	2038	400
Wind	2039	300
Wind	2040	300
Wind	2041	500

Solar   Hybrid   Wind   Battery

Capacity Expansion Portfolios and Proposed Downselections

	Strategy 1 Guidehouse Low DSM – Optimized (TA - All Resource)	Strategy 2 Guidehouse 2% Program DSM – Forced In (TA - All Resource)	Strategy 3 Guidehouse 2% Program DSM – Forced In (TA - Renewable Only)	Strategy 4 GDS High DSM – Forced In (NREL costs provided by Stakeholders, Solar & wind only)
Scenario 1: (Ref) Reference Gas Reference Demand Reference CO2	★ 	★ 		
Scenario 2: (Low) Low Gas Low Demand Reference CO2		★ 		
Scenario 3: (High) High Gas High Demand High CO2			★ 	★ 

★ **Proposed portfolios for cross testing**
TA=Technology Assessment

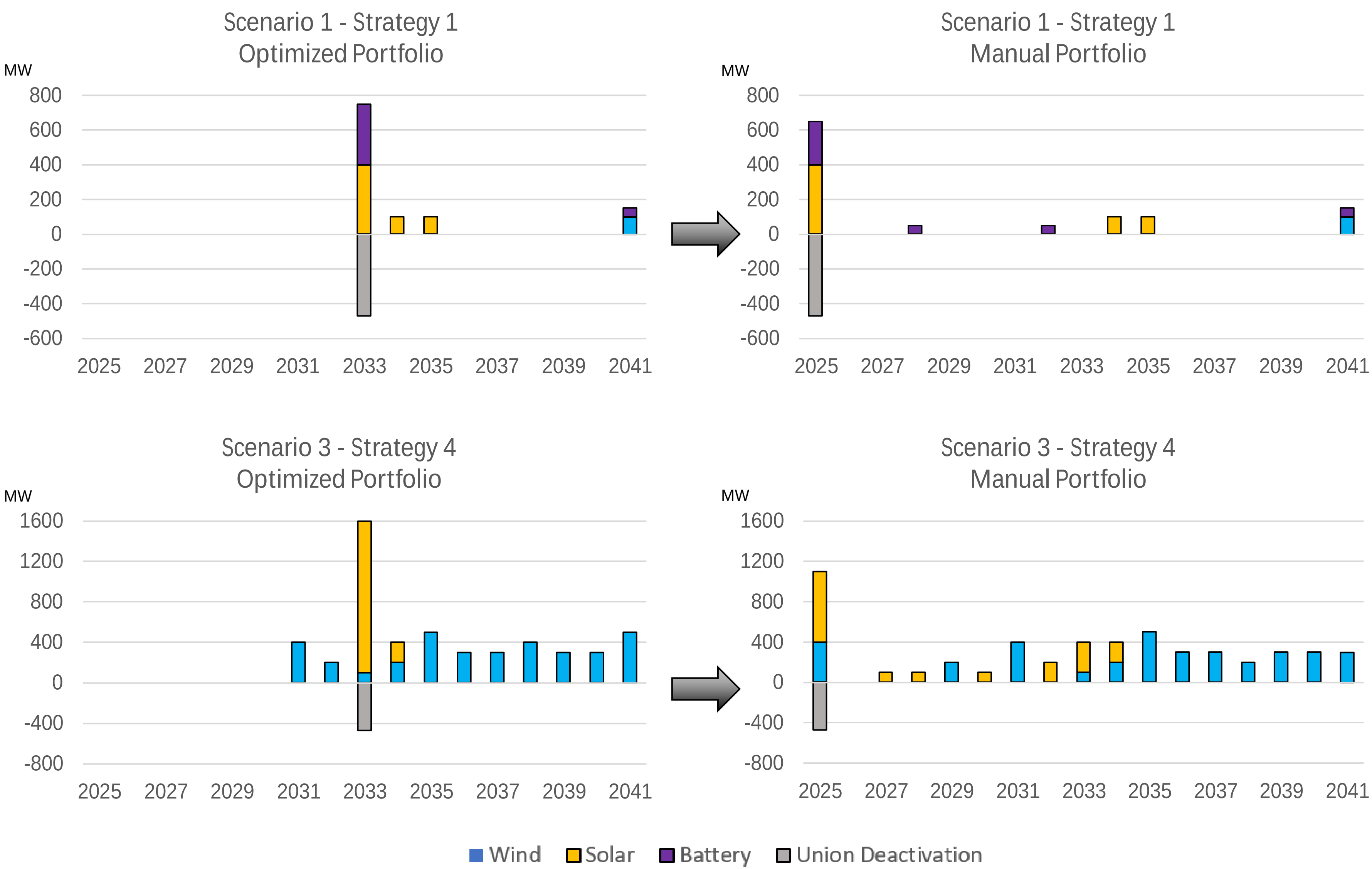
Solar **Hybrid** **Wind** **Battery**

***All capacity stated in ICAP**
"Hybrid" resources include solar + storage

Manual Portfolios and Stakeholder Sensitivity

- Manual Portfolio 1a and 4a—Objective and Assumptions
  - Accelerate Union deactivation assumption from 2033 to 2025 and pull forward resources identified in the optimized portfolios developed under Scenario 1/Strategy 1 (Manual Portfolio 1a) and Scenario 3/Strategy 4 (Manual Portfolio 4a), respectively, to maintain target reserve margin.
  - Each manual portfolio will only be tested under the Scenario in which the associated optimized portfolio was created in order to produce Total Relevant Supply Costs.
- Sensitivity 4b—Objective and Assumptions
  - A sensitivity using the alternative renewables cost assumptions provided by the Stakeholders on the resources identified in the optimized portfolio developed under Scenario 3/Strategy 4 (Sensitivity 4b).
  - The sensitivity will only be tested under the Scenario in which the associated optimized portfolio was created (i.e., Scenario 3) in order to produce Total Relevant Supply Costs.

Manual Portfolios



Section 2
Risk Assessment

Stochastic Analysis

- The stochastic risk assessment gives an indication of the variability of a Portfolio's costs as underlying assumptions change. For the 2018 IRP, the parties agreed during Technical Meeting #4 to run the stochastic assessment on four of the five downselected Portfolios given procedural schedule deadlines.

- The sensitivity of a Portfolio's performance for the 2018 IRP was assessed relative to changes in assumptions for natural gas prices and CO_2 emission prices through stochastic analysis. ENO proposes to evaluate the same variables for the 2021 IRP.

- Of the five portfolios proposed for downselection on slide 15, the Company proposes performing the stochastic analysis on the following four portfolios (Scenario-Strategy):
  - 1-1
  - 1-2
  - 2-2
  - 3-4

Section 3
Scorecard Metrics

Scorecard Proposed at Technical Meeting #3

Scoring Parameters / Descriptions	A	B	C	D
	Grading Scale (from A to D)[1]			
Utility Cost (Portfolio optimization in Aurora model)				
Expected Value	>7.50	7.50 - 5.01	5.00 - 2.51	≤ 2.50
Utility Costs Impact on ENO's Revenue Requirements				
Net present value of revenue requirements	>7.50	7.50 - 5.01	5.00 - 2.51	≤ 2.50
Nominal Portfolio Value (residential/ other customer classes) - initial 5 years of planning period	>7.50	7.50 - 5.01	5.00 - 2.51	≤ 2.50
Risk/Uncertainty				
Distribution of potential utility costs	>7.50	7.50 - 5.01	5.00 - 2.51	≤ 2.50
Range of potential utility costs	>7.50	7.50 - 5.01	5.00 - 2.51	≤ 2.50
Probability of high CO2 intensity - initial 5 years of planning period	< 33%	> 33%	>66%	= 100%
Probability of high groundwater usage - initial 5 years of planning period	< 33%	> 33%	>66%	= 100%
Operational Flexibility				
Flexible Resources (MW of ramp)	>7.50	7.50 - 5.01	5.00 - 2.51	≤ 2.50
Quick Start Resources (MW of Quick-Start)[2]	>7.50	7.50 - 5.01	5.00 - 2.51	≤ 2.50
Environmental Impact				
CO2 intensity (tons CO2/GWh)	>7.50	7.50 - 5.01	5.00 - 2.51	≤ 2.50
Groudwater usage (% of energy generated using Groundwater)	< 33%	> 33%	>66%	= 100%
Consistency with City Policies/ Goals				
Climate Action Plan -- 100% Low Carbon (% of Carbon Free Energy from New Resource)[3]	100% Low Carbon	>66% Low Carbon	> 33% Low Carbon	< 33% Low Carbon
Climate Action Plan -- 255 MW Solar added (Total Solar MW in Portfolio)	≥ 255 MW	>225 MW	> 150 MW	< 150 MW
Climate Action Plan -- 3.3% Annual Energy Savings (CAGR over 20 years)	≥ 3.3%	>2.0%	> 1.0%	< 1.0%
Macroeconomic Impact to CNO				
Macroeconomic Factor (Jobs, local economy impacts)	N/A	N/A	N/A	N/A

Update Pending Advisors Input

Notes:

1. Except as otherwise noted, A is top quartile of Portfolios, B is second, C is third, and D is the bottom quartile
2. Quick-Start includes supply and demand side dispatchable resources
3. Carbon-free resource include Energy Efficiency

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Section 4

Energy Smart Program PY13-15

Energy Smart PY 13-15—Implementation Plan Timeline

IRP Technical Meeting #4	January 19, 2022
2021 IRP Report Filed	March 25, 2022
IRP Technical Meeting #5	April 29 - May 6, 2022
Intervenor Comments on Final IRP	May 9, 2022
Draft of Implementation Plan	June 30, 2022
Proposed Technical Conference	July 11, 2022
Advisors' Report	July 12, 2022
Implementation Plan Filing	July 19, 2022

Energy Smart PY 13-15—RFP Timeline

Task Name	Completion Date
RFP Issued	December 21, 2021
Proposal Submission Deadline	February 11, 2022
Contractors selected	March 12, 2022
Submission of ENO's choice of TPA and TPE to Council	March 25, 2022

Energy Smart PY 13-15—DSM Program Matrix

<table>
<tr><th>Current Programs</th><th>Guidehouse</th><th>GDS</th></tr>
<tr><td colspan="3">Energy Efficiency</td></tr>
<tr><td>Home Performance w Energy Star</td><td>Home Performance w Energy Star</td><td>Home Performance</td></tr>
<tr><td>A/C Solutions</td><td>HVAC</td><td>High Efficiency Tune-Ups</td></tr>
<tr><td>Retail Lighting and Appliances</td><td>Retail</td><td>Residential Lighting and Appliances</td></tr>
<tr><td>Residential Behavioral</td><td>Residential Behavioral</td><td>Scorecard</td></tr>
<tr><td>Income Qualified Weatherization</td><td rowspan="2">Low Income_Multifamily</td><td>Low Income</td></tr>
<tr><td>Multifamily Solutions</td><td>Multifamily</td></tr>
<tr><td>School Kits</td><td>School Kits</td><td></td></tr>
<tr><td>Small C&I Solutions</td><td>Small C&I</td><td></td></tr>
<tr><td>Large C&I Solutions</td><td rowspan="3">Large C&I</td><td rowspan="3">Large C&I</td></tr>
<tr><td>New Construction</td></tr>
<tr><td>Publicly Funded Institutions</td></tr>
</table>

Energy Smart PY 13-15—Potential New DR Programs

1. Residential
   A. Electric Vehicle Charging (Pilot)
   B. Battery Storage (Pilot)
   C. Critical Peak/ Dynamic Pricing (Pilot)

2. Small C&I
   A. Smart Thermostats
   B. Alternative Small C&I curtailment options offering two-way control
   C. Electric Vehicle Charging (Fleet Electrification) (Pilot)
   D. Battery Storage (Pilot)
   E. Critical Peak/ Dynamic Pricing (Pilot)

3. Large C&I
   A. Electric Vehicle Charging (Fleet Electrification) (Pilot)
   B. Battery Storage (Pilot)
   C. Critical Peak/ Dynamic Pricing (Pilot)

Section 5
Timeline and Next Steps

Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2020	✓
Technical Meeting #1 Material Due	November 2020	✓
Technical Meeting #1	December 2020	✓
Technical Meeting #2 Material Due	April 2021	✓
Technical Meeting #2	April 2021	✓
Planning Scenarios and Non-DSM Inputs Finalized	May 2021	✓
DSM Potential Studies Due	July 2021	✓
Technical Meeting #3 Material Due	July/August 2021	✓
Technical Meeting #3	August 2021	✓
IRP Inputs Finalized	August 15, 2021	✓
Optimized Portfolio Results Due	December 2021	✓
Technical Meeting #4 Material Due	January 2022	-
Technical Meeting #4	January 2022	-
Final IRP Report due	March 25, 2022	-
Public Meeting #2 Material Due	April 2022	-
Public Meeting #2 - Present IRP Results	April 2022	-
Public Meeting #3 Material Due	April 2022	-
Public Meeting #3 - Public Response	April/May 2022	-
Technical Meeting #5 Material Due	April 2022	-
Technical Meeting #5	April/May 2022	-
Intervenors and Advisors Questions & Comments Due	May 2022	-
ENO Response to Questions and Comments Due	June 2022	-
ENO File Reply Comments	June 2022	-
Advisors File Report	July 2022	-

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX H

ANNUAL DSM VALUES

MARCH 2022

Annual Program Costs (All values reflected in $MM, Nominal)

Scenario 1: Strategy 1 - Low Case (Guidehouse)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Residential EE																				
HPwES	2.06	1.14	1.26	1.43	1.53	1.60	1.66	1.67	1.67	1.67	1.66	1.62	1.56	1.51	1.52	1.46	1.40	1.34	1.51	-
Retail	1.72	0.95	1.05	1.20	1.28	1.34	1.39	1.40	1.40	1.40	1.39	1.35	1.31	1.26	1.27	1.22	1.18	1.12	1.26	-
LI_MF	2.20	1.21	1.34	1.53	1.63	1.71	1.77	1.79	1.79	1.78	1.77	1.73	1.67	1.61	1.63	1.56	1.50	1.44	1.61	-
HVAC	0.74	0.41	0.45	0.52	0.55	0.58	0.60	0.60	0.60	0.60	0.60	0.58	0.57	0.54	0.55	0.53	0.51	0.49	0.54	-
School Kits 2029	-	-	-	-	-	-	-	0.45	0.45	0.45	0.45	0.44	0.42	0.41	0.41	0.40	0.38	0.36	0.41	-
School Kits 2033	-	-	-	-	-	-	-	-	-	-	-	0.44	0.42	0.41	0.41	0.40	0.38	0.36	0.41	-
Res Behavior	0.44	0.25	0.27	0.31	0.33	0.34	0.36	0.36	0.36	0.36	0.36	0.35	0.34	0.33	0.33	0.32	0.30	0.29	0.33	-
Recycling	0.50	0.28	0.31	0.35	0.37	0.39	0.41	0.41	0.41	0.41	0.41	0.40	0.38	0.37	0.37	0.36	0.34	0.33	0.37	-
C&I EE																				
Com Behavior	2.89	1.67	1.79	1.86	1.97	1.96	1.93	1.95	1.88	1.75	1.60	1.45	1.31	1.17	1.06	0.96	0.89	0.80	0.80	-
Large C&I	13.68	7.92	8.48	8.80	9.33	9.31	9.15	9.25	8.92	8.30	7.59	6.88	6.19	5.56	5.00	4.54	4.22	3.81	3.78	-
Small C&I	0.55	0.32	0.34	0.35	0.37	0.37	0.37	0.37	0.36	0.33	0.30	0.28	0.25	0.22	0.20	0.18	0.17	0.15	0.15	-
Demand Response																				
Dynamic Pricing with enabling tech.	-	0.14	0.12	0.17	0.20	0.16	0.13	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18
DLC-Thermostat-HVAC	0.06	0.10	0.13	0.16	0.19	0.22	0.26	0.29	0.45	0.36	0.39	0.43	0.45	0.46	0.48	0.50	0.52	0.54	0.56	0.58
C&I Curtailment- Auto-DR HVAC Control	0.16	0.20	0.22	0.23	0.24	0.24	0.25	0.26	0.38	0.27	0.28	0.29	0.29	0.30	0.31	0.31	0.32	0.33	0.33	0.34
Dynamic Pricing w/o enabling tech.	-	0.31	0.31	0.40	0.39	0.19	0.10	0.10	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09
DLC-Termostat-Res	0.18	0.20	0.23	0.24	0.26	0.28	0.30	0.33	0.51	0.40	0.44	0.47	0.51	0.54	0.58	0.62	0.65	0.69	0.73	0.77
C&I Curtailment- Standard Lighting Control	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.12	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
DLC-Switch-Centrail Air Conditioning	0.11	0.09	0.08	0.08	0.07	0.07	0.07	0.07	0.60	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
C&I Curtailment-Industrial	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
C&I Curtailment-Other	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Water Heating Control	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Advanced Lighting Control	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	0.00	0.00	0.00	0.01	0.01	0.01
C&I Curtailment-Refrigeration Control	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total																				
Total EE	24.78	14.14	15.29	16.35	17.36	17.60	17.63	18.25	17.84	17.05	16.12	15.51	14.42	13.40	12.76	11.92	11.28	10.50	11.16	-
Total DR	0.61	1.17	1.21	1.39	1.47	1.29	1.24	1.31	2.36	1.44	1.53	1.61	1.68	1.74	1.81	1.89	1.95	2.02	2.10	2.17

Scenario 1: Strategy 2 - 2% Program Case (Guidehouse)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Residential EE																				
HPwES	2.69	1.52	1.70	1.94	2.08	2.18	2.24	2.26	2.24	2.22	2.19	2.10	2.00	1.93	1.99	1.96	1.95	1.89	2.04	-
Retail	2.25	1.28	1.42	1.63	1.74	1.82	1.88	1.89	1.87	1.86	1.83	1.75	1.67	1.62	1.67	1.64	1.63	1.59	1.71	-
LI_MF	2.88	1.63	1.82	2.08	2.22	2.33	2.40	2.41	2.39	2.38	2.34	2.24	2.14	2.07	2.13	2.10	2.08	2.03	2.18	-
HVAC	0.97	0.55	0.61	0.70	0.75	0.79	0.81	0.82	0.81	0.80	0.79	0.76	0.72	0.70	0.72	0.71	0.70	0.68	0.74	-
School Kits	0.73	0.41	0.46	0.53	0.56	0.59	0.61	0.61	0.60	0.60	0.59	0.57	0.54	0.52	0.54	0.53	0.53	0.51	0.55	-
Res Behavior	0.58	0.33	0.37	0.42	0.45	0.47	0.48	0.49	0.48	0.48	0.47	0.45	0.43	0.42	0.43	0.42	0.42	0.41	0.44	-
Recycling	0.66	0.37	0.42	0.48	0.51	0.53	0.55	0.55	0.55	0.54	0.53	0.51	0.49	0.47	0.49	0.48	0.48	0.46	0.50	-
C&I EE																				
Com Behavior	0.62	0.36	0.38	0.39	0.42	0.41	0.40	0.41	0.39	0.36	0.33	0.30	0.27	0.24	0.21	0.19	0.18	0.16	0.16	-
Large C&I	15.57	8.94	9.52	9.83	10.38	10.30	10.08	10.15	9.71	8.99	8.19	7.40	6.63	5.94	5.32	4.80	4.46	4.01	3.97	-
Small C&I	3.29	1.89	2.01	2.08	2.19	2.17	2.13	2.14	2.05	1.90	1.73	1.56	1.40	1.25	1.12	1.01	0.94	0.85	0.84	-
Demand Response																				
Dynamic Pricing with enabling tech.	-	0.14	0.12	0.17	0.20	0.16	0.13	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18
DLC-Thermostat-HVAC	0.07	0.13	0.18	0.22	0.26	0.31	0.37	0.42	0.59	0.52	0.57	0.62	0.65	0.68	0.71	0.74	0.77	0.80	0.83	0.86
C&I Curtailment- Auto-DR HVAC Control	0.25	0.34	0.37	0.39	0.40	0.41	0.42	0.43	0.56	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.55	0.56
Dynamic Pricing w/o enabling tech.	-	0.31	0.30	0.39	0.38	0.19	0.10	0.10	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09
DLC-Termostat-Res	0.27	0.30	0.34	0.36	0.39	0.43	0.47	0.51	0.72	0.62	0.67	0.72	0.78	0.83	0.90	0.96	1.02	1.08	1.14	1.20
C&I Curtailment- Standard Lighting Control	0.09	0.12	0.14	0.14	0.14	0.14	0.14	0.14	0.17	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.15
DLC-Switch-Centrail Air Conditioning	0.15	0.13	0.12	0.12	0.12	0.11	0.11	0.11	0.70	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10
C&I Curtailment-Industrial	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06
C&I Curtailment-Other	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Water Heating Control	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Advanced Lighting Control	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Refrigeration Control	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total																				
Total EE	30.25	17.28	18.70	20.08	21.28	21.59	21.58	21.73	21.10	20.15	18.99	17.64	16.30	15.15	14.63	13.85	13.36	12.59	13.12	-
Total DR	0.88	1.54	1.64	1.85	1.96	1.82	1.81	1.92	3.07	2.13	2.25	2.37	2.48	2.58	2.69	2.80	2.91	3.02	3.13	3.24

Manual Portfolio 1a - Low Case (Guidehouse)

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	2.06	1.14	1.26	1.43	1.53	1.60	1.66	1.67	1.67	1.67	1.66	1.62	1.56	1.51	1.52	1.46	1.40	1.34	1.51	-
Retail	1.72	0.95	1.05	1.20	1.28	1.34	1.39	1.40	1.40	1.40	1.39	1.35	1.31	1.26	1.27	1.22	1.18	1.12	1.26	-
LI_MF	2.20	1.21	1.34	1.53	1.63	1.71	1.77	1.79	1.79	1.78	1.77	1.73	1.67	1.61	1.63	1.56	1.50	1.44	1.61	-
HVAC	0.74	0.41	0.45	0.52	0.55	0.58	0.60	0.60	0.60	0.60	0.60	0.58	0.57	0.54	0.55	0.53	0.51	0.49	0.54	-
School Kits 2029	-	-	-	-	-	-	-	0.45	0.45	0.45	0.45	0.44	0.42	0.41	0.41	0.40	0.38	0.36	0.41	-
School Kits 2033	-	-	-	-	-	-	-	-	-	-	-	0.44	0.42	0.41	0.41	0.40	0.38	0.36	0.41	-
Res Behavior	0.44	0.25	0.27	0.31	0.33	0.34	0.36	0.36	0.36	0.36	0.36	0.35	0.34	0.33	0.33	0.32	0.30	0.29	0.33	-
Recycling	0.50	0.28	0.31	0.35	0.37	0.39	0.41	0.41	0.41	0.41	0.41	0.40	0.38	0.37	0.37	0.36	0.34	0.33	0.37	-
C&I EE																				
Com Behavior	2.89	1.67	1.79	1.86	1.97	1.96	1.93	1.95	1.88	1.75	1.60	1.45	1.31	1.17	1.06	0.96	0.89	0.80	0.80	-
Large C&I	13.68	7.92	8.48	8.80	9.33	9.31	9.15	9.25	8.92	8.30	7.59	6.88	6.19	5.56	5.00	4.54	4.22	3.81	3.78	-
Small C&I	0.55	0.32	0.34	0.35	0.37	0.37	0.37	0.37	0.36	0.33	0.30	0.28	0.25	0.22	0.20	0.18	0.17	0.15	0.15	-
Demand Response																				
Dynamic Pricing with enabling tech.	-	0.14	0.12	0.17	0.20	0.16	0.13	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18
DLC-Thermostat-HVAC	0.06	0.10	0.13	0.16	0.19	0.22	0.26	0.29	0.45	0.36	0.39	0.43	0.45	0.46	0.48	0.50	0.52	0.54	0.56	0.58
C&I Curtailment- Auto-DR HVAC Control	0.16	0.20	0.22	0.23	0.24	0.24	0.25	0.26	0.38	0.27	0.28	0.29	0.29	0.30	0.31	0.31	0.32	0.33	0.33	0.34
Dynamic Pricing w/o enabling tech.	-	0.31	0.31	0.40	0.39	0.19	0.10	0.10	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09
DLC-Termostat-Res	0.18	0.20	0.23	0.24	0.26	0.28	0.30	0.33	0.51	0.40	0.44	0.47	0.51	0.54	0.58	0.62	0.65	0.69	0.73	0.77
C&I Curtailment- Standard Lighting Control	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.12	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
DLC-Switch-Centrail Air Conditioning	0.11	0.09	0.08	0.08	0.07	0.07	0.07	0.07	0.60	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
C&I Curtailment-Industrial	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
C&I Curtailment-Other	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Water Heating Control	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Advanced Lighting Control	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	0.00	0.00	0.00	0.01	0.01	0.01
C&I Curtailment-Refrigeration Control	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total																				
Total EE	24.78	14.14	15.29	16.35	17.36	17.60	17.63	18.25	17.84	17.05	16.12	15.51	14.42	13.40	12.76	11.92	11.28	10.50	11.16	-
Total DR	0.61	1.17	1.21	1.39	1.47	1.29	1.24	1.31	2.36	1.44	1.53	1.61	1.68	1.74	1.81	1.89	1.95	2.02	2.10	2.17

Manual Portfolio 3a - 2% Program Case (Guidehouse)

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	2.69	1.52	1.70	1.94	2.08	2.18	2.24	2.26	2.24	2.22	2.19	2.10	2.00	1.93	1.99	1.96	1.95	1.89	2.04	-
Retail	2.25	1.28	1.42	1.63	1.74	1.82	1.88	1.89	1.87	1.86	1.83	1.75	1.67	1.62	1.67	1.64	1.63	1.59	1.71	-
LI_MF	2.88	1.63	1.82	2.08	2.22	2.33	2.40	2.41	2.39	2.38	2.34	2.24	2.14	2.07	2.13	2.10	2.08	2.03	2.18	-
HVAC	0.97	0.55	0.61	0.70	0.75	0.79	0.81	0.82	0.81	0.80	0.79	0.76	0.72	0.70	0.72	0.71	0.70	0.68	0.74	-
School Kits	0.73	0.41	0.46	0.53	0.56	0.59	0.61	0.61	0.60	0.60	0.59	0.57	0.54	0.52	0.54	0.53	0.53	0.51	0.55	-
Res Behavior	0.58	0.33	0.37	0.42	0.45	0.47	0.48	0.49	0.48	0.48	0.47	0.45	0.43	0.42	0.43	0.42	0.42	0.41	0.44	-
Recycling	0.66	0.37	0.42	0.48	0.51	0.53	0.55	0.55	0.55	0.54	0.53	0.51	0.49	0.47	0.49	0.48	0.48	0.46	0.50	-
C&I EE																				
Com Behavior	0.62	0.36	0.38	0.39	0.42	0.41	0.40	0.41	0.39	0.36	0.33	0.30	0.27	0.24	0.21	0.19	0.18	0.16	0.16	-
Large C&I	15.57	8.94	9.52	9.83	10.38	10.30	10.08	10.15	9.71	8.99	8.19	7.40	6.63	5.94	5.32	4.80	4.46	4.01	3.97	-
Small C&I	3.29	1.89	2.01	2.08	2.19	2.17	2.13	2.14	2.05	1.90	1.73	1.56	1.40	1.25	1.12	1.01	0.94	0.85	0.84	-
Demand Response																				
Dynamic Pricing with enabling tech.	-	0.14	0.12	0.17	0.20	0.16	0.13	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18
DLC-Thermostat-HVAC	0.07	0.13	0.18	0.22	0.26	0.31	0.37	0.42	0.59	0.52	0.57	0.62	0.65	0.68	0.71	0.74	0.77	0.80	0.83	0.86
C&I Curtailment- Auto-DR HVAC Control	0.25	0.34	0.37	0.39	0.40	0.41	0.42	0.43	0.56	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.54	0.55	0.56
Dynamic Pricing w/o enabling tech.	-	0.31	0.30	0.39	0.38	0.19	0.10	0.10	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09
DLC-Termostat-Res	0.27	0.30	0.34	0.36	0.39	0.43	0.47	0.51	0.72	0.62	0.67	0.72	0.78	0.83	0.90	0.96	1.02	1.08	1.14	1.20
C&I Curtailment- Standard Lighting Control	0.09	0.12	0.14	0.14	0.14	0.14	0.14	0.14	0.17	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.15
DLC-Switch-Centrail Air Conditioning	0.15	0.13	0.12	0.12	0.12	0.11	0.11	0.11	0.70	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10
C&I Curtailment-Industrial	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06
C&I Curtailment-Other	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Water Heating Control	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Advanced Lighting Control	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
C&I Curtailment-Refrigeration Control	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total																				
Total EE	30.25	17.28	18.70	20.08	21.28	21.59	21.58	21.73	21.10	20.15	18.99	17.64	16.30	15.15	14.63	13.85	13.36	12.59	13.12	-
Total DR	0.88	1.54	1.64	1.85	1.96	1.82	1.81	1.92	3.07	2.13	2.25	2.37	2.48	2.58	2.69	2.80	2.91	3.02	3.13	3.24

Manual Portfolio 4a - High Case (GDS)

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Home Performance	5.39	3.41	3.58	3.86	4.70	5.60	6.47	7.12	7.48	7.82	7.53	6.84	5.94	5.00	4.19	3.46	2.92	2.41	2.01	-
Residential Lighting & Appliance	3.50	1.99	2.16	2.35	2.57	2.75	3.01	3.12	3.21	3.34	3.30	3.23	3.13	3.06	3.02	2.92	2.73	2.60	2.49	-
Low Income	2.66	1.72	1.91	2.15	2.60	3.05	3.45	3.73	3.85	3.82	3.67	3.33	2.91	2.48	2.09	1.76	1.46	1.21	1.06	-
Multifamily	1.89	1.13	1.17	1.25	1.52	1.76	2.05	2.27	2.40	2.47	2.35	2.12	1.83	1.52	1.23	0.97	0.77	0.63	0.52	-
High Efficiency Tune Ups	3.42	2.38	2.79	3.25	3.88	4.50	5.13	5.59	5.93	6.16	6.23	6.16	5.99	5.81	5.65	5.44	5.26	5.55	5.25	-
Scorecard	3.01	1.57	1.60	1.61	1.61	1.62	1.63	1.64	1.65	1.65	1.66	1.67	1.67	1.68	1.69	1.70	1.70	1.71	1.71	-
No Program	3.75	1.79	1.69	1.60	1.53	1.47	1.42	1.37	1.31	1.11	1.10	0.94	0.98	0.92	1.42	1.34	1.23	1.12	0.96	-
C&I EE																				
EE - C&I (MW)	40.90	22.32	24.03	25.76	27.42	29.52	30.67	31.21	30.31	28.22	25.78	22.96	20.02	17.22	18.80	16.56	13.88	12.27	11.81	-
Demand Response																				
Residential - Peak Time Rebate	1.07	1.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Residential - Direct Load Control - Smart Thermostat	0.91	1.43	2.17	1.88	1.38	1.21	1.19	1.23	1.25	1.28	1.34	1.76	2.23	2.71	2.34	1.87	1.72	1.72	1.77	1.80
Residential - Direct Load Control - Pool Pump	0.30	0.37	0.61	0.51	0.34	0.28	0.27	0.27	0.27	0.27	0.29	0.27	0.27	0.28	0.28	0.39	0.53	0.68	0.54	0.38
Residential - Critical Peak Pricing	3.39	6.57	8.24	4.46	1.31	0.21	0.03	0.03	0.04	0.04	0.04	1.73	3.84	5.64	3.35	1.00	0.18	0.05	0.05	0.05
Residential - PEV Chargin	0.12	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04
Non Residential - Smart Thermostat	0.17	0.10	0.16	0.14	0.12	0.11	0.11	0.11	0.12	0.12	0.14	0.15	0.17	0.20	0.18	0.16	0.16	0.16	0.16	0.17
Non Residential - Interruptible/Curtailable	0.28	0.32	0.28	0.22	0.27	0.31	0.35	0.40	0.44	0.49	0.53	0.58	0.63	0.67	0.72	0.77	0.81	0.86	0.90	0.95
Non Residential - Capacity Bidding	0.29	0.22	0.37	0.35	0.28	0.25	0.25	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23
Non Residential - Demand Bidding	0.30	0.22	0.32	0.21	0.08	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Non Residential - Critical Peak Pricing	0.49	0.57	0.69	0.35	0.12	0.05	0.03	0.03	0.04	0.04	0.04	0.17	0.33	0.44	0.26	0.11	0.05	0.04	0.04	0.04
Total																				
Total EE	64.53	36.32	38.93	41.82	45.83	50.26	53.83	56.06	56.14	54.60	51.62	47.25	42.48	37.68	38.09	34.14	29.95	27.50	25.81	-
Total DR	7.32	10.86	12.88	8.17	3.93	2.49	2.29	2.38	2.45	2.54	2.68	4.98	7.78	10.25	7.44	4.60	3.76	3.81	3.77	3.70

Note:
The two DSM studies provided program costs in a nominal format for the DSM study period of 2021-2040. These costs were then levelized over the 20-year IRP evaluation period of 2022 - 2041 for use in the IRP.
Nominal costs that were attributable to 2021 were included in the 2022 spending year prior to levelization over the IRP evaluation period.

Annual Peak MW Reductions (All values reflected in MWs)

Scenario 1: Strategy 1

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	2.56	3.93	5.41	7.03	8.71	10.42	12.13	13.80	15.40	16.93	18.37	19.70	20.94	22.08	23.17	24.17	25.09	25.93	26.90	27.88
Retail	0.62	0.92	1.26	1.63	2.01	2.41	2.84	3.26	3.69	4.11	4.57	5.02	5.46	5.89	6.32	6.74	7.14	7.52	7.89	8.25
LI_MF	2.74	4.22	5.79	7.48	9.23	11.00	12.76	14.47	16.11	17.66	19.10	20.45	21.68	22.80	23.87	24.85	25.74	26.55	27.51	28.46
HVAC	1.24	1.94	2.68	3.44	4.21	4.96	5.69	6.37	6.99	7.54	8.03	8.45	8.80	9.10	9.34	9.54	9.70	9.83	9.93	10.04
School Kits	0.05	0.07	0.10	0.12	0.15	0.17	0.20	0.22	0.24	0.26	0.27	0.29	0.30	0.32	0.33	0.34	0.34	0.35	0.36	0.37
Res Behavior	1.71	1.90	2.09	2.28	2.47	2.55	2.64	2.73	2.82	2.91	3.00	3.08	3.17	3.26	3.34	3.36	3.37	3.38	3.39	3.40
Recycling	0.15	0.24	0.32	0.41	0.49	0.59	0.68	0.77	0.87	0.97	1.06	1.16	1.26	1.36	1.46	1.56	1.66	1.76	1.86	1.95
C&I EE																				
Com Behavior	3.35	5.33	7.45	9.62	11.89	14.12	16.27	18.40	20.39	22.16	23.72	25.08	26.24	27.23	28.07	28.80	29.44	29.99	30.54	31.00
Large C&I	6.02	9.46	13.04	16.65	20.39	24.01	27.47	30.99	34.27	37.22	39.84	42.15	44.17	45.94	47.47	48.82	50.04	51.10	52.14	51.44
Small C&I	2.27	3.65	5.15	6.78	8.45	10.08	11.72	13.29	14.73	16.03	17.15	18.10	18.89	19.53	20.04	20.44	20.76	21.00	21.18	21.37
Demand Response																				
Dynamic Pricing with enabling tech.	-	0.09	0.86	3.66	8.77	11.48	12.13	12.74	13.30	13.81	14.29	14.72	15.11	15.47	15.81	16.13	16.50	16.84	17.18	17.52
DLC-Thermostat-HVAC	1.35	2.79	4.03	5.02	6.04	7.07	8.09	9.04	9.91	10.68	11.34	11.89	12.34	12.71	13.00	13.23	13.63	13.91	14.21	14.52
C&I Curtailment- Auto-DR HVAC Control	5.69	8.64	9.71	9.80	9.89	9.98	10.08	10.18	10.25	10.31	10.37	10.43	10.48	10.52	10.56	10.58	10.63	10.66	10.69	10.73
Dynamic Pricing w/o enabling tech.	-	0.15	1.29	5.02	11.02	13.27	12.96	12.65	12.33	12.03	11.73	11.44	11.17	10.91	10.66	10.41	10.14	9.89	9.64	9.38
DLC-Thermostat-Res	2.52	2.91	3.33	3.60	3.88	4.17	4.48	4.81	5.13	5.48	5.83	6.19	6.57	6.95	7.36	7.78	8.15	8.56	8.97	9.36
C&I Curtailment- Standard Lighting Control	2.16	3.20	3.51	3.45	3.38	3.32	3.26	3.20	3.12	3.06	3.00	2.96	2.92	2.89	2.87	2.85	2.82	2.80	2.77	2.75
DLC-Switch-Central Air Conditioning	3.45	3.37	3.29	3.22	3.15	3.08	3.02	2.95	2.89	2.82	2.76	2.70	2.64	2.58	2.53	2.47	2.41	2.35	2.29	2.24
C&I Curtailment- Industrial	0.67	1.00	1.10	1.09	1.09	1.08	1.08	1.07	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.07	1.07	1.07
C&I Curtailment- Other	0.44	0.65	0.71	0.70	0.69	0.68	0.67	0.65	0.64	0.63	0.62	0.62	0.61	0.61	0.60	0.60	0.59	0.59	0.58	0.58
C&I Curtailment- Water Heating Control	0.15	0.23	0.25	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
C&I Curtailment- Advanced Lighting Control	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.09	0.12	0.13	0.14	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
C&I Curtailment- Refrigeration Control	0.10	0.14	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Total																				
Total EE	20.72	31.66	43.28	55.44	68.01	80.32	92.41	104.30	115.50	125.78	135.12	143.48	150.92	157.50	163.42	168.61	173.27	177.41	181.69	184.15
Total DR	16.56	23.21	28.30	36.02	48.36	54.59	56.21	57.73	59.11	60.38	61.51	62.52	63.42	64.22	64.96	65.62	66.47	67.19	67.93	68.68

Scenario 1: Strategy 2

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	2.79	4.32	5.98	7.79	9.66	11.54	13.41	15.21	16.91	18.50	19.97	21.32	22.54	23.65	24.72	25.71	26.63	27.47	28.44	29.42
Retail	0.62	0.92	1.27	1.64	2.03	2.44	2.88	3.33	3.77	4.22	4.71	5.20	5.68	6.15	6.62	7.09	7.56	8.01	8.43	8.86
LI_MF	3.00	4.64	6.39	8.28	10.22	12.17	14.08	15.90	17.62	19.21	20.66	21.98	23.16	24.23	25.24	26.17	27.03	27.80	28.73	29.65
HVAC	1.40	2.20	3.04	3.91	4.78	5.62	6.40	7.11	7.73	8.26	8.70	9.06	9.35	9.57	9.75	9.89	10.00	10.09	10.15	10.22
School Kits	0.05	0.07	0.10	0.13	0.15	0.18	0.21	0.23	0.25	0.27	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.36	0.37
Res Behavior	3.43	3.80	4.18	4.55	4.94	5.11	5.29	5.46	5.64	5.81	5.99	6.17	6.34	6.51	6.69	6.72	6.74	6.77	6.78	6.80
Recycling	0.15	0.24	0.32	0.41	0.49	0.59	0.68	0.77	0.87	0.97	1.06	1.16	1.26	1.36	1.46	1.56	1.66	1.76	1.86	1.95
C&I EE																				
Com Behavior	3.39	5.40	7.54	9.73	12.02	14.26	16.42	18.55	20.54	22.31	23.86	25.21	26.36	27.35	28.18	28.90	29.54	30.08	30.62	31.07
Large C&I	6.15	9.64	13.28	16.94	20.71	24.36	27.83	31.38	34.65	37.60	40.20	42.49	44.50	46.25	47.77	49.10	50.30	51.34	52.37	51.65
Small C&I	2.29	3.71	5.24	6.92	8.63	10.24	11.89	13.46	14.90	16.19	17.31	18.26	19.04	19.67	20.17	20.56	20.87	21.10	21.28	21.46
Demand Response																				
Dynamic Pricing with enabling tech.	-	0.09	0.84	3.58	8.56	11.19	11.82	12.40	12.93	13.41	13.85	14.24	14.60	14.92	15.23	15.51	15.85	16.15	16.46	16.77
DLC-Thermostat-HVAC	1.47	3.04	4.39	5.46	6.58	7.70	8.81	9.85	10.79	11.63	12.34	12.94	13.43	13.83	14.15	14.39	14.83	15.13	15.45	15.80
C&I Curtailment- Auto-DR HVAC Control	6.44	9.77	10.98	11.07	11.17	11.27	11.38	11.47	11.54	11.60	11.65	11.69	11.72	11.74	11.75	11.76	11.78	11.79	11.81	11.82
Dynamic Pricing w/o enabling tech.	-	0.15	1.26	4.88	10.71	12.89	12.57	12.26	11.93	11.63	11.33	11.05	10.78	10.52	10.27	10.03	9.76	9.52	9.26	9.01
DLC-Thermostat-Res	2.79	3.22	3.68	3.98	4.29	4.61	4.96	5.32	5.68	6.06	6.45	6.85	7.26	7.69	8.14	8.60	9.02	9.47	9.91	10.35
C&I Curtailment- Standard Lighting Control	2.44	3.62	3.96	3.90	3.82	3.75	3.68	3.61	3.52	3.44	3.37	3.32	3.27	3.23	3.20	3.17	3.13	3.09	3.06	3.03
DLC-Switch-Central Air Conditioning	3.85	3.76	3.67	3.59	3.51	3.44	3.36	3.29	3.22	3.14	3.07	3.01	2.94	2.87	2.81	2.74	2.68	2.61	2.55	2.48
C&I Curtailment- Industrial	0.76	1.13	1.25	1.24	1.23	1.22	1.21	1.21	1.20	1.19	1.19	1.19	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18
C&I Curtailment- Other	0.49	0.73	0.81	0.79	0.78	0.76	0.75	0.74	0.72	0.71	0.70	0.69	0.68	0.67	0.67	0.66	0.65	0.65	0.64	0.63
C&I Curtailment- Water Heating Control	0.18	0.26	0.29	0.28	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.25	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24
C&I Curtailment- Advanced Lighting Control	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.10	0.13	0.15	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19
C&I Curtailment- Refrigeration Control	0.11	0.16	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.15	0.15	0.15
Total																				
Total EE	23.28	34.95	47.33	60.31	73.64	86.50	99.09	111.40	122.87	133.33	142.76	151.14	158.53	165.06	170.95	176.06	180.67	184.77	189.03	191.44
Total DR	18.56	25.98	31.37	39.01	51.16	57.34	59.04	60.62	62.06	63.37	64.52	65.55	66.44	67.23	67.96	68.62	69.46	70.18	70.91	71.66

Manual Portfolio 1a

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	2.56	3.93	5.41	7.03	8.71	10.42	12.13	13.80	15.40	16.93	18.37	19.70	20.94	22.08	23.17	24.17	25.09	25.93	26.90	27.88
Retail	0.62	0.92	1.26	1.63	2.01	2.41	2.84	3.26	3.69	4.11	4.57	5.02	5.46	5.89	6.32	6.74	7.14	7.52	7.89	8.25
LI_MF	2.74	4.22	5.79	7.48	9.23	11.00	12.76	14.47	16.11	17.66	19.10	20.45	21.68	22.80	23.87	24.85	25.74	26.55	27.51	28.46
HVAC	1.24	1.94	2.68	3.44	4.21	4.96	5.69	6.37	6.99	7.54	8.03	8.45	8.80	9.10	9.34	9.54	9.70	9.83	9.93	10.04
School Kits	0.05	0.07	0.10	0.12	0.15	0.17	0.20	0.22	0.24	0.26	0.27	0.29	0.30	0.32	0.33	0.34	0.34	0.35	0.36	0.37
Res Behavior	1.71	1.90	2.09	2.28	2.47	2.55	2.64	2.73	2.82	2.91	3.00	3.08	3.17	3.26	3.34	3.36	3.37	3.38	3.39	3.40
Recycling	0.15	0.24	0.32	0.41	0.49	0.59	0.68	0.77	0.87	0.97	1.06	1.16	1.26	1.36	1.46	1.56	1.66	1.76	1.86	1.95
C&I EE																				
Com Behavior	3.35	5.33	7.45	9.62	11.89	14.12	16.27	18.40	20.39	22.16	23.72	25.08	26.24	27.23	28.07	28.80	29.44	29.99	30.54	31.00
Large C&I	6.02	9.46	13.04	16.65	20.39	24.01	27.47	30.99	34.27	37.22	39.84	42.15	44.17	45.94	47.47	48.82	50.04	51.10	52.14	51.44
Small C&I	2.27	3.65	5.15	6.78	8.45	10.08	11.72	13.29	14.73	16.03	17.15	18.10	18.89	19.53	20.04	20.44	20.76	21.00	21.18	21.37
Demand Response																				
Dynamic Pricing with enabling tech.	-	0.09	0.86	3.66	8.77	11.48	12.13	12.74	13.30	13.81	14.29	14.72	15.11	15.47	15.81	16.13	16.50	16.84	17.18	17.52
DLC-Thermostat-HVAC	1.35	2.79	4.03	5.02	6.04	7.07	8.09	9.04	9.91	10.68	11.34	11.89	12.34	12.71	13.00	13.23	13.63	13.91	14.21	14.52
C&I Curtailment- Auto-DR HVAC Control	5.69	8.64	9.71	9.80	9.89	9.98	10.08	10.18	10.25	10.31	10.37	10.43	10.48	10.52	10.56	10.58	10.63	10.66	10.69	10.73
Dynamic Pricing w/o enabling tech.	-	0.15	1.29	5.02	11.02	13.27	12.96	12.65	12.33	12.03	11.73	11.44	11.17	10.91	10.66	10.41	10.14	9.89	9.64	9.38
DLC-Thermostat-Res	2.52	2.91	3.33	3.60	3.88	4.17	4.48	4.81	5.13	5.48	5.83	6.19	6.57	6.95	7.36	7.78	8.15	8.56	8.97	9.36
C&I Curtailment- Standard Lighting Control	2.16	3.20	3.51	3.45	3.38	3.32	3.26	3.20	3.12	3.06	3.00	2.96	2.92	2.89	2.87	2.85	2.82	2.80	2.77	2.75
DLC-Switch-Central Air Conditioning	3.45	3.37	3.29	3.22	3.15	3.08	3.02	2.95	2.89	2.82	2.76	2.70	2.64	2.58	2.53	2.47	2.41	2.35	2.29	2.24
C&I Curtailment- Industrial	0.67	1.00	1.10	1.09	1.09	1.08	1.08	1.07	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.06	1.07	1.07	1.07
C&I Curtailment- Other	0.44	0.65	0.71	0.70	0.69	0.68	0.67	0.65	0.64	0.63	0.62	0.62	0.61	0.61	0.60	0.60	0.59	0.59	0.58	0.58
C&I Curtailment- Water Heating Control	0.15	0.23	0.25	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
C&I Curtailment- Advanced Lighting Control	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.09	0.12	0.13	0.14	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
C&I Curtailment- Refrigeration Control	0.10	0.14	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Total																				
Total EE	20.72	31.66	43.28	55.44	68.01	80.32	92.41	104.30	115.50	125.78	135.12	143.48	150.92	157.50	163.42	168.61	173.27	177.41	181.69	184.15
Total DR	16.56	23.21	28.30	36.02	48.36	54.59	56.21	57.73	59.11	60.38	61.51	62.52	63.42	64.22	64.96	65.62	66.47	67.19	67.93	68.68

Manual Portfolio 3a

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	2.79	4.32	5.98	7.79	9.66	11.54	13.41	15.21	16.91	18.50	19.97	21.32	22.54	23.65	24.72	25.71	26.63	27.47	28.44	29.42
Retail	0.62	0.92	1.27	1.64	2.03	2.44	2.88	3.33	3.77	4.22	4.71	5.20	5.68	6.15	6.62	7.09	7.56	8.01	8.43	8.86
LI_MF	3.00	4.64	6.39	8.28	10.22	12.17	14.08	15.90	17.62	19.21	20.66	21.98	23.16	24.23	25.24	26.17	27.03	27.80	28.73	29.65
HVAC	1.40	2.20	3.04	3.91	4.78	5.62	6.40	7.11	7.73	8.26	8.70	9.06	9.35	9.57	9.75	9.89	10.00	10.09	10.15	10.22
School Kits	0.05	0.07	0.10	0.13	0.15	0.18	0.21	0.23	0.25	0.27	0.29	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.36	0.37
Res Behavior	3.43	3.80	4.18	4.55	4.94	5.11	5.29	5.46	5.64	5.81	5.99	6.17	6.34	6.51	6.69	6.72	6.74	6.77	6.78	6.80
Recycling	0.15	0.24	0.32	0.41	0.49	0.59	0.68	0.77	0.87	0.97	1.06	1.16	1.26	1.36	1.46	1.56	1.66	1.76	1.86	1.95
C&I EE																				
Com Behavior	3.39	5.40	7.54	9.73	12.02	14.26	16.42	18.55	20.54	22.31	23.86	25.21	26.36	27.35	28.18	28.90	29.54	30.08	30.62	31.07
Large C&I	6.15	9.64	13.28	16.94	20.71	24.36	27.83	31.38	34.65	37.60	40.20	42.49	44.50	46.25	47.77	49.10	50.30	51.34	52.37	51.65
Small C&I	2.29	3.71	5.24	6.92	8.63	10.24	11.89	13.46	14.90	16.19	17.31	18.26	19.04	19.67	20.17	20.56	20.87	21.10	21.28	21.46
Demand Response																				
Dynamic Pricing with enabling tech.	-	0.09	0.84	3.58	8.56	11.19	11.82	12.40	12.93	13.41	13.85	14.24	14.60	14.92	15.23	15.51	15.85	16.15	16.46	16.77
DLC-Thermostat-HVAC	1.47	3.04	4.39	5.46	6.58	7.70	8.81	9.85	10.79	11.63	12.34	12.94	13.43	13.83	14.15	14.39	14.83	15.13	15.45	15.80
C&I Curtailment- Auto-DR HVAC Control	6.44	9.77	10.98	11.07	11.17	11.27	11.38	11.47	11.54	11.60	11.65	11.69	11.72	11.74	11.75	11.76	11.78	11.79	11.81	11.82
Dynamic Pricing w/o enabling tech.	-	0.15	1.26	4.88	10.71	12.89	12.57	12.26	11.93	11.63	11.33	11.05	10.78	10.52	10.27	10.03	9.76	9.52	9.26	9.01
DLC-Thermostat-Res	2.79	3.22	3.68	3.98	4.29	4.61	4.96	5.32	5.68	6.06	6.45	6.85	7.26	7.69	8.14	8.60	9.02	9.47	9.91	10.35
C&I Curtailment- Standard Lighting Control	2.44	3.62	3.96	3.90	3.82	3.75	3.68	3.61	3.52	3.44	3.37	3.32	3.27	3.23	3.20	3.17	3.13	3.09	3.06	3.03
DLC-Switch-Central Air Conditioning	3.85	3.76	3.67	3.59	3.51	3.44	3.36	3.29	3.22	3.14	3.07	3.01	2.94	2.87	2.81	2.74	2.68	2.61	2.55	2.48
C&I Curtailment- Industrial	0.76	1.13	1.25	1.24	1.23	1.22	1.21	1.21	1.20	1.19	1.19	1.19	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18
C&I Curtailment- Other	0.49	0.73	0.81	0.79	0.78	0.76	0.75	0.74	0.72	0.71	0.70	0.69	0.68	0.67	0.67	0.66	0.65	0.65	0.64	0.63
C&I Curtailment- Water Heating Control	0.18	0.26	0.29	0.28	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.25	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24
C&I Curtailment- Advanced Lighting Control	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.10	0.13	0.15	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19
C&I Curtailment- Refrigeration Control	0.11	0.16	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.15	0.15	0.15
Total																				
Total DSM	23.28	34.95	47.33	60.31	73.64	86.50	99.09	111.40	122.87	133.33	142.76	151.14	158.53	165.06	170.95	176.06	180.67	184.77	189.03	191.44
Total DR	18.56	25.98	31.37	39.01	51.16	57.34	59.04	60.62	62.06	63.37	64.52	65.55	66.44	67.23	67.96	68.62	69.46	70.18	70.91	71.66

Manual Portfolio 4a

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Home Performance	0.82	1.96	3.18	4.45	5.79	7.40	9.24	11.34	13.58	14.89	16.93	18.79	20.41	21.69	22.70	23.52	24.10	24.45	24.69	24.88
Residential Lighting & Appliance	0.97	1.97	2.98	4.06	5.18	6.38	7.57	8.91	10.27	11.69	12.85	13.99	15.12	16.13	17.09	18.10	19.01	19.38	19.70	19.74
Low Income	0.51	1.22	2.02	2.89	3.84	5.00	6.32	7.84	9.46	10.13	11.55	12.87	14.06	15.05	15.88	16.58	17.13	17.49	17.76	17.94
Multifamily	0.36	0.84	1.35	1.88	2.44	3.11	3.88	4.77	5.73	6.26	7.14	7.94	8.65	9.23	9.69	10.05	10.31	10.47	10.58	10.67
High Efficiency Tune Ups	0.82	1.96	3.31	4.87	6.64	8.80	11.26	14.16	17.31	16.43	19.12	21.79	24.37	26.75	28.94	31.05	32.96	34.61	36.12	37.55
Scorecard	1.51	1.56	1.60	1.64	1.64	1.65	1.65	1.67	1.68	1.67	1.67	1.68	1.69	1.69	1.70	1.71	1.72	1.72	1.72	1.74
No Program	1.05	2.11	3.13	4.13	5.11	6.07	6.97	7.90	8.78	8.39	9.06	9.71	10.08	10.37	10.61	10.86	11.06	11.19	11.31	11.43
C&I EE																				
EE - C&I (MW)	9.99	20.17	30.41	41.20	52.27	63.39	74.38	85.79	96.76	103.03	111.49	119.01	125.68	131.09	135.75	140.02	143.33	145.06	146.44	147.84
Demand Response																				
Residential - Peak Time Rebate	5.51	11.50	9.06	4.51	3.04	2.69	2.61	2.60	-	2.59	2.59	2.59	2.59	2.60	2.60	2.60	2.60	2.61	2.61	2.62
Residential - Direct Load Control - Smart Thermostat	4.99	9.03	15.00	19.04	20.79	21.71	22.43	23.17	18.08	15.99	15.08	12.37	11.54	9.69	8.19	6.02	3.11	-	-	-
Residential - Direct Load Control - Pool Pump	0.73	2.39	4.98	6.64	7.19	7.34	7.39	7.43	7.45	7.47	7.50	7.53	7.56	7.59	7.61	7.65	7.69	7.72	7.76	7.79
Residential - Critical Peak Pricing	17.80	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Residential - PEV Chargin	0.01	0.05	0.12	0.19	0.23	0.26	0.29	0.32	0.35	0.39	0.44	0.49	0.54	0.61	0.68	0.75	0.84	0.93	1.03	1.13
Non Residential - Smart Thermostat	0.37	0.89	1.67	2.21	2.46	2.60	2.71	2.82	2.92	3.02	3.13	3.24	3.34	3.45	3.56	3.67	3.78	3.89	4.00	4.11
Non Residential - Interruptible/Curtailable	9.63	11.32	9.51	7.28	9.02	10.74	12.48	14.30	16.12	17.94	19.76	21.62	19.59	14.97	10.69	5.85	0.31	-	-	-
Non Residential - Capacity Bidding	2.82	9.13	18.79	24.75	26.43	25.01	21.14	17.17	12.72	12.90	14.33	13.96	15.47	16.08	17.06	17.50	17.23	15.16	15.50	16.17
Non Residential - Demand Bidding	0.21	0.66	1.34	1.76	1.89	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.92	1.92	1.92	1.92	1.92	1.92	1.92
Non Residential - Critical Peak Pricing	7.39	22.54	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total																				
Total EE	16.02	31.81	47.97	65.12	82.92	101.80	121.27	142.37	163.55	172.50	189.80	205.79	220.06	232.01	242.34	251.88	259.61	264.38	268.33	271.79
Total DR	49.47	67.52	60.48	66.37	71.05	72.28	70.98	69.73	59.58	62.23	64.76	63.72	62.57	56.90	52.30	45.95	37.47	32.22	32.81	33.73

Note:

Values included for DR and EE are not including gross up for Transmission Losses and/or Reserve Margin

Guidehouse and GDS EE programs are calculated to be the difference between the gross and net peaks for an individual program

Guidehouse and GDS DR program capacity contributions are based on the individual program maximum reductions and do not reflect alignment with the load forecast or the combined effects of multiple programs.

Annual MWh Reductions (All values reflected in MWhs)

Scenario 1: Strategy 1

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	11,483	17,197	23,468	30,490	37,819	45,254	52,867	60,045	67,104	73,882	80,415	86,174	91,658	96,696	102,015	106,444	110,753	114,701	119,236	123,397
Retail	6,526	9,700	13,210	16,879	20,761	24,708	28,935	32,931	36,932	40,909	45,055	48,827	52,594	56,239	60,006	63,289	66,600	69,754	72,979	75,784
LI_MF	12,259	18,358	24,837	31,959	39,324	46,737	54,222	61,223	68,057	74,549	80,736	86,118	91,192	95,784	100,628	104,584	108,395	111,838	115,892	119,624
HVAC	4,477	6,993	9,663	12,398	15,164	17,886	20,522	22,913	25,158	27,181	28,986	30,439	31,706	32,739	33,716	34,376	34,962	35,421	35,811	36,142
School Kits	516	792	1,079	1,362	1,649	1,927	2,207	2,452	2,681	2,888	3,084	3,237	3,380	3,506	3,631	3,721	3,811	3,891	3,977	4,037
Res Behavior	10,486	11,631	12,809	13,937	15,125	15,629	16,214	16,716	17,243	17,793	18,377	18,871	19,405	19,929	20,524	20,567	20,641	20,712	20,802	20,801
Recycling	1,288	1,964	2,668	3,378	4,113	4,865	5,648	6,417	7,213	8,020	8,860	9,658	10,486	11,317	12,182	12,977	13,801	14,617	15,470	16,238
C&I EE																				
Com Behavior	17,244	27,703	39,164	51,416	64,069	76,443	89,114	100,727	111,721	121,562	130,450	137,231	143,186	148,035	152,451	155,035	157,379	159,183	160,996	162,032
Large C&I	49,021	76,512	105,145	133,062	161,968	189,467	215,985	241,704	266,192	288,065	308,228	324,060	338,685	351,442	363,861	372,577	381,373	389,031	397,666	404,351
Small C&I	25,383	40,215	56,056	71,875	88,329	104,316	119,915	134,741	148,900	161,522	172,970	181,778	189,855	196,792	203,542	207,938	212,344	216,108	220,533	223,953
Total																				
Total EE	138,683	211,065	288,098	366,755	448,321	527,231	605,631	679,868	751,200	816,371	877,160	926,393	972,149	1,012,480	1,052,556	1,081,507	1,110,057	1,135,256	1,163,361	1,186,358

Scenario 1: Strategy 2

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	12,369	18,653	25,598	33,397	41,520	49,740	58,065	65,846	73,406	80,600	87,447	93,376	98,951	104,028	109,458	113,968	118,397	122,458	127,124	131,382
Retail	6,562	9,756	13,320	17,062	21,032	25,081	29,429	33,559	37,713	41,870	46,246	50,250	54,253	58,161	62,258	65,908	69,648	73,254	76,911	80,125
LI_MF	13,210	19,922	27,080	34,961	43,079	51,209	59,303	66,771	73,936	80,629	86,877	92,164	97,055	101,412	106,085	109,858	113,528	116,831	120,760	124,356
HVAC	5,050	7,924	10,980	14,101	17,224	20,246	23,091	25,575	27,816	29,748	31,395	32,634	33,665	34,458	35,210	35,657	36,055	36,350	36,599	36,787
School Kits	536	826	1,128	1,427	1,729	2,023	2,314	2,567	2,800	3,006	3,197	3,342	3,476	3,591	3,705	3,784	3,865	3,936	4,015	4,067
Res Behavior	20,969	23,260	25,616	27,872	30,248	31,254	32,426	33,428	34,483	35,584	36,751	37,740	38,807	39,854	41,045	41,131	41,278	41,421	41,601	41,599
Recycling	1,288	1,964	2,668	3,378	4,113	4,865	5,648	6,417	7,213	8,020	8,860	9,658	10,486	11,317	12,182	12,977	13,801	14,617	15,470	16,238
C&I EE																				
Com Behavior	17,390	28,151	39,826	52,517	65,426	77,607	90,355	102,009	113,015	122,839	131,687	138,403	144,288	149,063	153,411	155,926	158,213	159,967	161,740	162,734
Large C&I	50,093	78,099	107,191	135,470	164,667	192,361	218,990	244,880	269,317	291,099	311,152	326,837	341,313	353,916	366,191	374,756	383,420	390,955	399,490	406,067
Small C&I	25,788	40,820	56,842	72,808	89,381	105,450	121,097	135,987	150,126	162,708	174,105	182,847	190,856	197,722	204,407	208,736	213,083	216,793	221,178	224,555
Total																				
Total EE	153,255	229,375	310,249	392,991	478,418	559,835	640,717	717,039	789,826	856,103	917,718	967,251	1,013,149	1,053,522	1,093,951	1,122,701	1,151,288	1,176,583	1,204,888	1,227,909

Manual Portfolio 1a

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	11,483	17,197	23,468	30,490	37,819	45,254	52,867	60,045	67,104	73,882	80,415	86,174	91,658	96,696	102,015	106,444	110,753	114,701	119,236	123,397
Retail	6,526	9,700	13,210	16,879	20,761	24,708	28,935	32,931	36,932	40,909	45,055	48,827	52,594	56,239	60,006	63,289	66,600	69,754	72,979	75,784
LI_MF	12,259	18,358	24,837	31,959	39,324	46,737	54,222	61,223	68,057	74,549	80,736	86,118	91,192	95,784	100,628	104,584	108,395	111,838	115,892	119,624
HVAC	4,477	6,993	9,663	12,398	15,164	17,886	20,522	22,913	25,158	27,181	28,986	30,439	31,706	32,739	33,716	34,376	34,962	35,421	35,811	36,142
School Kits	516	792	1,079	1,362	1,649	1,927	2,207	2,452	2,681	2,888	3,084	3,237	3,380	3,506	3,631	3,721	3,811	3,891	3,977	4,037
Res Behavior	10,486	11,631	12,809	13,937	15,125	15,629	16,214	16,716	17,243	17,793	18,377	18,871	19,405	19,929	20,524	20,567	20,641	20,712	20,802	20,801
Recycling	1,288	1,964	2,668	3,378	4,113	4,865	5,648	6,417	7,213	8,020	8,860	9,658	10,486	11,317	12,182	12,977	13,801	14,617	15,470	16,238
C&I EE																				
Com Behavior	17,244	27,703	39,164	51,416	64,069	76,443	89,114	100,727	111,721	121,562	130,450	137,231	143,186	148,035	152,451	155,035	157,379	159,183	160,996	162,032
Large C&I	49,021	76,512	105,145	133,062	161,968	189,467	215,985	241,704	266,192	288,065	308,228	324,060	338,685	351,442	363,861	372,577	381,373	389,031	397,666	404,351
Small C&I	25,383	40,215	56,056	71,875	88,329	104,316	119,915	134,741	148,900	161,522	172,970	181,778	189,855	196,792	203,542	207,938	212,344	216,108	220,533	223,953
Total																				
Total EE	138,683	211,065	288,098	366,755	448,321	527,231	605,631	679,868	751,200	816,371	877,160	926,393	972,149	1,012,480	1,052,556	1,081,507	1,110,057	1,135,256	1,163,361	1,186,358

Manual Portfolio 3a

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
HPwES	12,369	18,653	25,598	33,397	41,520	49,740	58,065	65,846	73,406	80,600	87,447	93,376	98,951	104,028	109,458	113,968	118,397	122,458	127,124	131,382
Retail	6,562	9,756	13,320	17,062	21,032	25,081	29,429	33,559	37,713	41,870	46,246	50,250	54,253	58,161	62,258	65,908	69,648	73,254	76,911	80,125
LI_MF	13,210	19,922	27,080	34,961	43,079	51,209	59,303	66,771	73,936	80,629	86,877	92,164	97,055	101,412	106,085	109,858	113,528	116,831	120,760	124,356
HVAC	5,050	7,924	10,980	14,101	17,224	20,246	23,091	25,575	27,816	29,748	31,395	32,634	33,665	34,458	35,210	35,657	36,055	36,350	36,599	36,787
School Kits	536	826	1,128	1,427	1,729	2,023	2,314	2,567	2,800	3,006	3,197	3,342	3,476	3,591	3,705	3,784	3,865	3,936	4,015	4,067
Res Behavior	20,969	23,260	25,616	27,872	30,248	31,254	32,426	33,428	34,483	35,584	36,751	37,740	38,807	39,854	41,045	41,131	41,278	41,421	41,601	41,599
Recycling	1,288	1,964	2,668	3,378	4,113	4,865	5,648	6,417	7,213	8,020	8,860	9,658	10,486	11,317	12,182	12,977	13,801	14,617	15,470	16,238
C&I EE																				
Com Behavior	17,390	28,151	39,826	52,517	65,426	77,607	90,355	102,009	113,015	122,839	131,687	138,403	144,288	149,063	153,411	155,926	158,213	159,967	161,740	162,734
Large C&I	50,093	78,099	107,191	135,470	164,667	192,361	218,990	244,880	269,317	291,099	311,152	326,837	341,313	353,916	366,191	374,756	383,420	390,955	399,490	406,067
Small C&I	25,788	40,820	56,842	72,808	89,381	105,450	121,097	135,987	150,126	162,708	174,105	182,847	190,856	197,722	204,407	208,736	213,083	216,793	221,178	224,555
Total																				
Total EE	153,255	229,375	310,249	392,991	478,418	559,835	640,717	717,039	789,826	856,103	917,718	967,251	1,013,149	1,053,522	1,093,951	1,122,701	1,151,288	1,176,583	1,204,888	1,227,909

Manual Portfolio 4a

Residential EE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Home Performance	4,814	11,311	18,212	25,287	32,712	41,510	51,660	63,038	75,138	87,310	99,307	110,224	119,624	127,304	133,341	138,028	141,457	143,972	145,698	146,706
Residential Lighting & Appliance	6,013	12,322	18,945	25,903	33,306	41,245	49,618	58,695	68,019	76,654	84,774	92,502	99,857	106,788	113,239	119,312	124,850	127,798	130,207	130,457
Low Income	2,649	6,358	10,486	14,969	19,909	25,842	32,738	40,453	48,716	56,983	65,003	72,416	78,989	84,623	89,262	93,037	96,065	98,292	99,968	100,797
Multifamily	2,082	4,744	7,506	10,308	13,245	16,748	20,715	25,231	30,119	35,113	39,998	44,475	48,368	51,590	54,140	56,096	57,527	58,537	59,233	59,650
High Efficiency Tune Ups	3,696	8,938	15,051	21,970	29,863	39,444	50,714	63,660	77,861	92,876	108,221	123,348	137,813	151,319	163,795	175,297	185,848	195,587	204,306	211,881
Scorecard	12,860	13,306	13,649	13,906	13,962	14,025	14,081	14,170	14,244	14,307	14,375	14,441	14,505	14,561	14,615	14,682	14,746	14,806	14,861	14,912
No Program	5,274	10,633	15,919	21,064	26,151	31,191	36,181	41,125	45,951	50,512	54,590	58,550	60,655	62,508	64,097	65,463	66,655	67,689	68,601	69,320
C&I EE																				
EE - C&I (MW)	60,673	122,985	187,400	254,806	325,668	397,565	472,000	546,673	619,274	687,323	747,896	801,429	847,180	886,448	919,853	946,769	968,045	982,344	992,305	999,467
Total																				
Total EE	98,061	190,596	287,169	388,213	494,815	607,570	727,706	853,045	979,322	1,101,079	1,214,165	1,317,386	1,406,990	1,485,138	1,552,342	1,608,685	1,655,193	1,689,025	1,715,180	1,733,190

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2021 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-20-02**

APPENDIX I

HIGHLY SENSITIVE PROTECTED MATERIALS

INTENTIONALLY OMITTED

MARCH 2022