Study of Potential for Energy Savings in New Orleans

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Prepared for

by

with

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STUDY CONTEXT AND OBJECTIVES

This study provides an estimate of the potential for energy savings and peak demand reduction through utility run energy efficiency, peak demand, and rate design programs in Entergy New Orleans' (ENO or "Entergy") service territory. Energy efficiency is typically a less expensive way to meet customer load requirements than traditional supply side investments. Furthermore, energy efficiency produces significant additional benefits, such as lower electric bills for ratepayers, lower carbon emissions, and healthier buildings. For these reasons, efficiency has increasingly been used by utilized as an alternative to supply side investments on the electric grid.

This study will be used to inform ENO's future Energy Smart programs; it will also produce inputs for ENO's upcoming Integrated Resource Plan (IRP). An IRP is an analysis that seeks to optimize a utility's supply portfolio to meet its load requirements at lowest cost, subject to fulfilling criteria related to reliability, risk, and other metrics. To this end, Optimal Energy, Inc. (Optimal) will provide ENO with a 20-year forecast of potential energy and demand savings as a demand-side resource in the IRP modeling, which will "compete" with other resources for inclusion in an overall strategy for least-cost planning.

SUMMARY OF RESULTS

High-level results for the three components of this study (i.e., energy efficiency, demand response, and rate design) are presented separately in the sections below. Further detail is provided in the full report that follows.

Energy Efficiency

As discussed in detail in the methodology section, the energy efficiency potential analysis included three levels of potential.

- Economic – All measures that are cost-effective and technically feasible, assuming no market barriers to adoption.
- Maximum Achievable – All cost-effective measures are promoted by aggressive programs, including incentives covering 100% of the total incremental costs of the measure, with the intent of securing the maximum amount of efficiency savings possible given real-world constraints of customer behavior.
- Program Achievable – The amount of available potential assuming "best practice" program design, with incentives covering, on average, 50% of the incremental costs of the measures. An exception is made for income-eligible customers, who still receive 100% incentives, as with ENO's current Energy Smart programs.

Our energy efficiency analysis begins by characterizing hundreds of possible energy efficiency measures as to their costs and energy savings. Savings are expressed as percentage reduction in energy use for the relevant “end-use” (e.g., lighting, cooling, refrigeration). An overall estimate of efficiency potential is generated by first dividing all energy use by ENO’s customers into end-uses and then applying relevant measures and their respective savings percentages to these “buckets” of energy use. This “top-down” approach ensures that energy savings are appropriately scaled to the actual energy consumption of ENO’s customers, and will be described in greater detail later in the report. Overall, we examined 173 different measures over 3 different market types (new construction/renovation, market opportunity, and retrofit/early retirement) and 14 different building types, for 1,491 permutations of unique measures.

Comparisons across potential types are useful for understanding the bounds of achievement. Following the portfolio level results we present more detailed results for the program potential, including disaggregated results for each sector (Residential, Low-Income, and Commercial/Industrial).

Table 1 provides a summary of the economic, maximum achievable, and program potential for electric energy savings relative to the sales forecast after 10 and 20 years. Savings as a percentage of forecast sales is a common metric for comparing efficiency programs and potential estimates, as it provides an understandable scale for those not familiar with energy measurements such as megawatt-hours (MWh). Overall, program potential for electricity is 21% of the forecasted load in 2038. This means that the cumulative result after 20 years of energy efficiency programs with incentives covering 50% of the incremental cost is that New Orleans electric load is 21% lower than it would be with no efficiency programs. The maximum achievable potential for electricity is 30% by 2038, roughly 40% greater than the program potential.

Potential after 20 years is not much greater than after 10 years, particularly for economic and max achievable scenarios, because the majority of equipment has been upgraded after the initial 10 year period. Over the course of the next 10 years, equipment that reaches the end of its useful life provides further opportunities for efficient measures, but savings from measures installed in the earlier years are expiring.

Table 1 shows the cumulative savings in year 10 and year 20. In other words, it represents the total reduction in the given year from all the efficiency measures installed in prior years that have not reached the end of their useful life. However, due to variations in measure lives and baseline adjustments for retrofit, the sum of incremental annual savings (the “new” savings achieved in each year of an efficiency program, independent of what has been achieved in other years) is typically higher than the cumulative savings totals. It is therefore instructive to see the incremental annual savings for each year of the study horizon. This is shown in Table 2.

Table 1 | Cumulative Energy Efficiency Potential as Percent of Sales Forecast

Year	Scenario	Residential Savings	Low Income Savings	C&I Savings	Total
2027	Economic	49%	49%	43%	45%
	Max Achievable	27%	27%	25%	25%
	Program	9%	27%	18%	18%
2037	Economic	49%	49%	45%	46%
	Max Achievable	33%	33%	29%	30%
	Program	9%	33%	21%	21%

Table 2 | Incremental Annual Savings by Year as Percent of Sales Forecast

	Economic Potential			Max Achievable Potential			Program Potential		
Year	Total	Res	C&I	Total	Res	C&I	Total	Res	C&I
2018	5.7%	7.5%	4.6%	0.7%	0.7%	0.6%	0.5%	0.5%	0.5%
2019	5.5%	7.3%	4.4%	1.3%	1.4%	1.2%	1.0%	1.0%	0.9%
2020	5.2%	6.7%	4.4%	2.0%	2.0%	1.9%	1.4%	1.4%	1.4%
2021	4.4%	4.6%	4.3%	2.6%	2.5%	2.7%	1.9%	1.7%	2.0%
2022	4.2%	4.3%	4.2%	2.8%	2.7%	2.8%	2.0%	1.8%	2.1%
2023	4.4%	4.5%	4.3%	3.0%	3.1%	3.0%	2.2%	2.1%	2.2%
2024	4.5%	4.7%	4.4%	3.1%	3.3%	3.0%	2.3%	2.3%	2.3%
2025	4.5%	4.6%	4.4%	3.2%	3.5%	3.1%	2.3%	2.4%	2.3%
2026	4.6%	4.7%	4.5%	3.3%	3.7%	3.1%	2.4%	2.5%	2.3%
2027	4.7%	5.0%	4.5%	3.4%	3.8%	3.1%	2.4%	2.6%	2.3%
2028	2.7%	2.5%	2.8%	1.3%	1.7%	1.1%	0.9%	1.2%	0.8%
2029	3.0%	2.8%	3.1%	1.6%	1.9%	1.5%	1.2%	1.3%	1.1%
2030	3.0%	2.9%	3.1%	1.9%	2.0%	1.8%	1.4%	1.4%	1.4%
2031	3.3%	3.0%	3.6%	2.3%	2.2%	2.4%	1.7%	1.5%	1.8%
2032	3.4%	3.0%	3.6%	2.3%	2.2%	2.4%	1.7%	1.5%	1.8%
2033	3.6%	3.1%	3.9%	2.5%	2.2%	2.6%	1.8%	1.6%	2.0%
2034	3.6%	3.1%	3.9%	2.5%	2.2%	2.6%	1.8%	1.6%	2.0%
2035	3.6%	3.1%	3.9%	2.5%	2.2%	2.6%	1.8%	1.6%	2.0%
2036	3.7%	3.4%	3.9%	2.6%	2.4%	2.6%	1.9%	1.7%	2.0%
2037	3.7%	3.4%	3.9%	2.6%	2.4%	2.6%	1.9%	1.7%	2.0%

Figure 1 shows the historic and forecasted sales of electric energy. As seen, the forecast is expected to be relatively flat over the next 20 years.[1] Total sales could be reduced significantly, however, through energy efficiency.

Figure 1 | Electric Energy Savings Relative to Sales Forecast

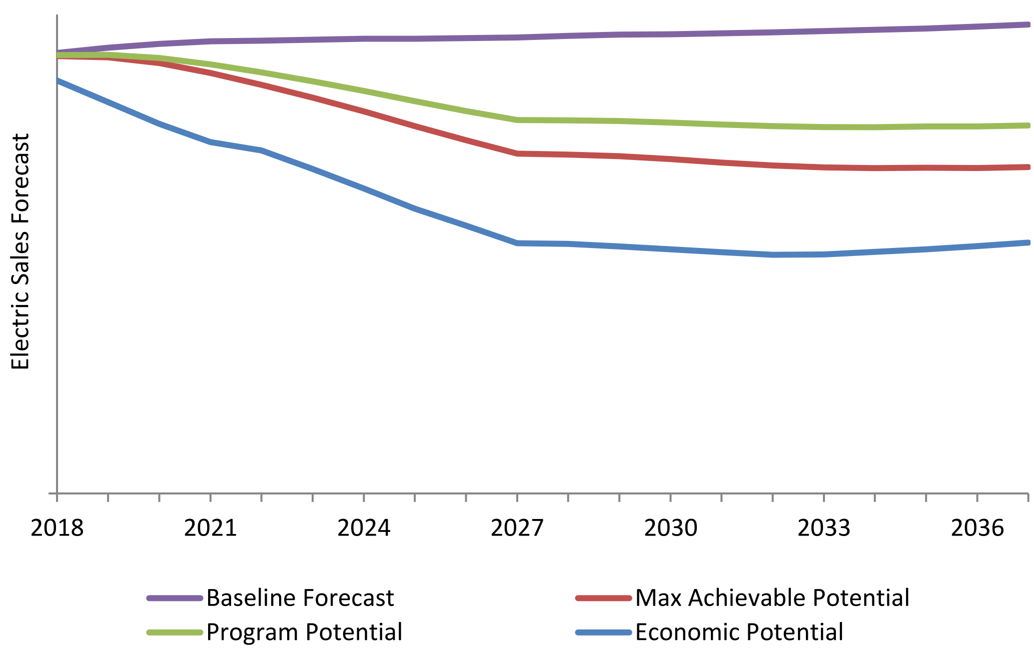


Table 3 shows the peak demand reduction in 2027 and 2037 for the different potential scenarios. These represent the savings associated with efficiency programs only. Savings from demand response programs are discussed separately below. In contrast to the energy savings estimates, these are given in megawatts (MW) instead of percent of total load. This allows for an easier comparison to traditional generation assets, such as the recently approved 150 MW gas turbine plant.

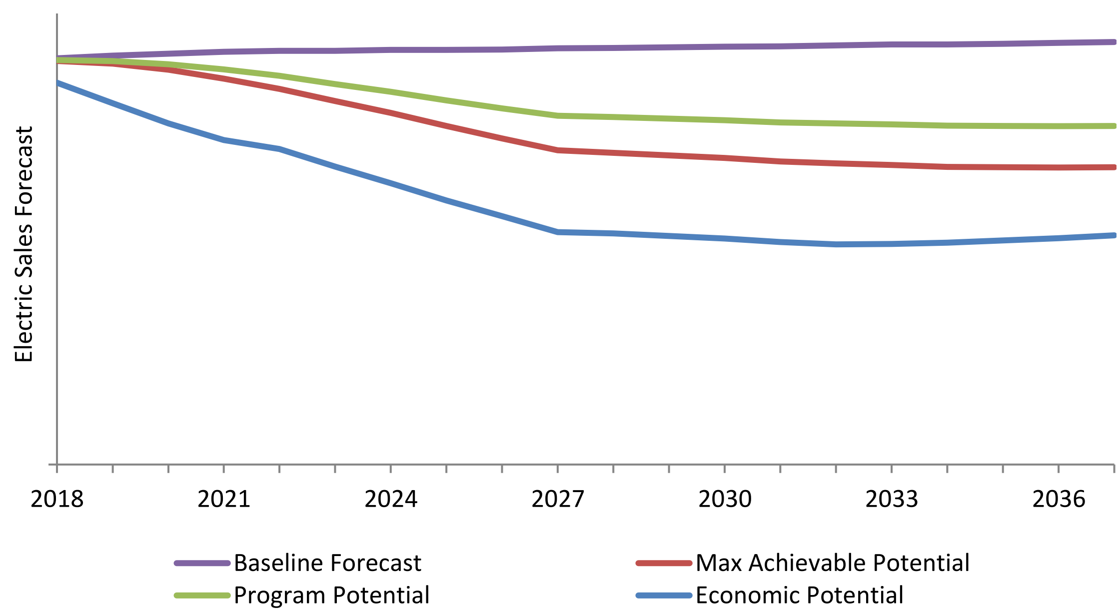
Figure 2 shows the historic and forecasted sales of electric peak demand. The other lines show the reduction in peak demand from each scenario. This graph only shows peak demand reduction from efficiency. Demand response impacts are discussed separately in the next section.

[1] The scale for the y-axis of this figure is omitted to avoid disclosing data considered by ENO as Highly Sensitive Protected Material (HSPM).

Table 3 | Cumulative Demand Savings Potential by Sector and Scenario (MW)

Year	Scenario	Residential Savings	LI Savings	C&I Savings	Total
2027	Economic Potential	137	133	260	530
	Max Achievable Potential	73	71	150	294
	Program Potential	17	71	106	194
2037	Economic Potential	137	134	286	557
	Max Achievable Potential	89	86	186	361
	Program Potential	24	86	133	243

Figure 2 | Electric Peak Demand Savings From Efficiency Relative to Sales Forecast



The next table shows the Total Resource Cost Effectiveness Test results for each scenario. The costs and benefits below represent the net present value of running 20 years of programs. As seen, while the scenarios incur significant costs (i.e., utility administrative costs, incentive costs, and customer contributions), the total benefits are two to four times larger than the costs.

Table 4 | Scenario TRC Cost-Effectiveness by Sector – Full 20 Years

Sector	Scenario	Costs ($MM)	Benefits ($MM)	Net Benefits ($MM)	BCR
Residential	Economic	461	1,216	754	2.6
	Max Achievable	310	716	406	2.3
	Program	207	467	260	2.3
C&I	Economic	516	2,486	1,970	4.8
	Max Achievable	304	1,129	825	3.7
	Program	202	823	621	4.1
Total	Economic	978	3,702	2,724	3.8
	Max Achievable	614	1,845	1,231	3.0
	Program	409	1,290	880	3.2

Table 5 shows the same information, but for the 2018-2027 time frame instead of the full 20-years. As seen, BCRs are very similar, but slightly lower. This is because of a higher share of retrofit measures which, on average, have lower BCRs than market driven measures.

Table 5 | Scenario TRC Cost-Effectiveness by Sector – First 10 Years

Sector	Scenario	Costs ($MM)	Benefits ($MM)	Net Benefits ($MM)	BCR
Residential	Economic	$335	792	$457	2.37
	Max Achievable	$203	$409	$207	2.02
	Program	$134	$267	$133	1.99
C&I	Economic	$333	1,445	$1,112	4.33
	Max Achievable	$185	597	$412	3.23
	Program	$118	$427	$309	3.62
Total	Economic	$668	$ 2,237	$1,569	3.35
	Max Achievable	$388	$ 1,006	$619	2.60
	Program	$252	$694	$442	2.75

The costs presented in the tables above represent the net present value of the total costs of energy efficiency programs and the resulting investment in efficient measures. This includes the administrative costs of running the programs and the full incremental costs of installing the measures, regardless of the amount paid for by the utility vs. paid for by the customer. In the program potential scenario, the utility only covers a portion of the measure costs; the table below shows the utility program budget needed to achieve the savings in the program potential scenario.

Table 6 | Nominal Program Potential Budgets by Year (Millions$)

Year	Non-Incentive	Incentive	Total	Year	Non-Incentive	Incentive	Total
2018	$1.6	$4.8	$6.5	2028	$2.6	$9.9	$12.5
2019	$3.2	$9.7	$12.9	2029	$3.1	$11.2	$14.3
2020	$4.7	$14.4	$19.2	2030	$3.5	$12.4	$15.9
2021	$6.4	$19.4	$25.8	2031	$4.2	$14.3	$18.5
2022	$6.7	$20.6	$27.3	2032	$4.2	$14.3	$18.5
2023	$7.2	$22.4	$29.7	2033	$4.6	$15.4	$20.1
2024	$7.6	$23.6	$31.2	2034	$4.6	$15.5	$20.2
2025	$7.8	$24.4	$32.2	2035	$4.7	$15.6	$20.2
2026	$8.0	$25.2	$33.2	2036	$4.8	$16.0	$20.7
2027	$8.1	$25.8	$34.0	2037	$4.8	$16.0	$20.8

Demand Response

While energy efficiency investments result in “permanent” load reductions (i.e., throughout the useful life of the measure), demand response (DR) strategies aim to reduce usage during peak load conditions. This may mean shifting consumption to off-peak periods or simply reducing consumption without replacing it at another time. Because energy prices are typically highest during peak load conditions, this can substantially reduce total system costs. Furthermore, in areas with constrained generation, transmission, or distribution capacity, it can avoid the need to invest in additional capacity, again typically at lower cost. The DR analysis in this study is based on the demonstrated performance of DR programs in other utility-implemented programs and extrapolating to the ENO service territory.

The DR analysis considered two scenarios, which roughly align with the max achievable and program potential scenarios from the energy efficiency analysis. Scenario One assumes participation on the lower end of the range of what is being achieved in other jurisdictions for residential and large customer direct load control (DLC), residential automated demand response (ADR), and large customer standard offer program (SOP). Scenario Two assumes participation on the upper end for these programs. In addition, Scenario One assumes a residential peak time rebate program (in which customers can receive an incentive payment for reducing usage during times of highest load, e.g., “peak time event”), while Scenario Two assumes residential critical peak pricing (in which customers must pay a much higher rate for usage during peak time events). Studies have been shown that because consumers tend to be more averse to losing money than to missing out on a similar windfall, critical peak pricing can have a somewhat bigger impact on behavior than peak time rebates.

Results for each of the scenarios are presented in the Figures and Tables below.

Table 7 | Demand Response Peak Load Reductions (MW) – Scenario One

Program	2018	2027	2037
Residential DLC and ADR	2.0	16.0	20.2
Residential PTR pricing	4.9	12.6	15.5
Large Customer SOP	1.1	10.9	16.9
Total	**8.0**	**39.5**	**52.5**

Table 8 | Demand Response Peak Load Reductions (MW) – Scenario Two

Program	2018	2027	2037
Residential DLC and ADR	3.9	31.9	40.3
Residential PTR pricing	5.6	14.2	17.5
Large Customer SOP	1.9	13.4	23.2
Total	**11.5**	**59.6**	**81.1**

Figure 3 | Electric Demand Savings—Scenario One

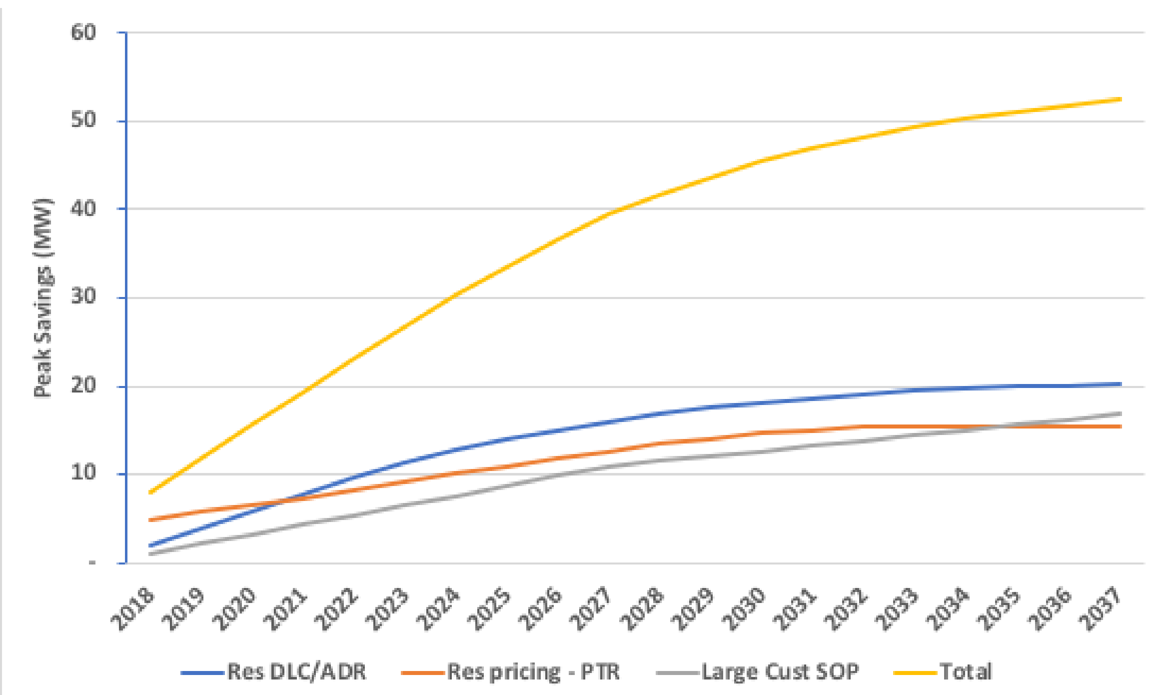
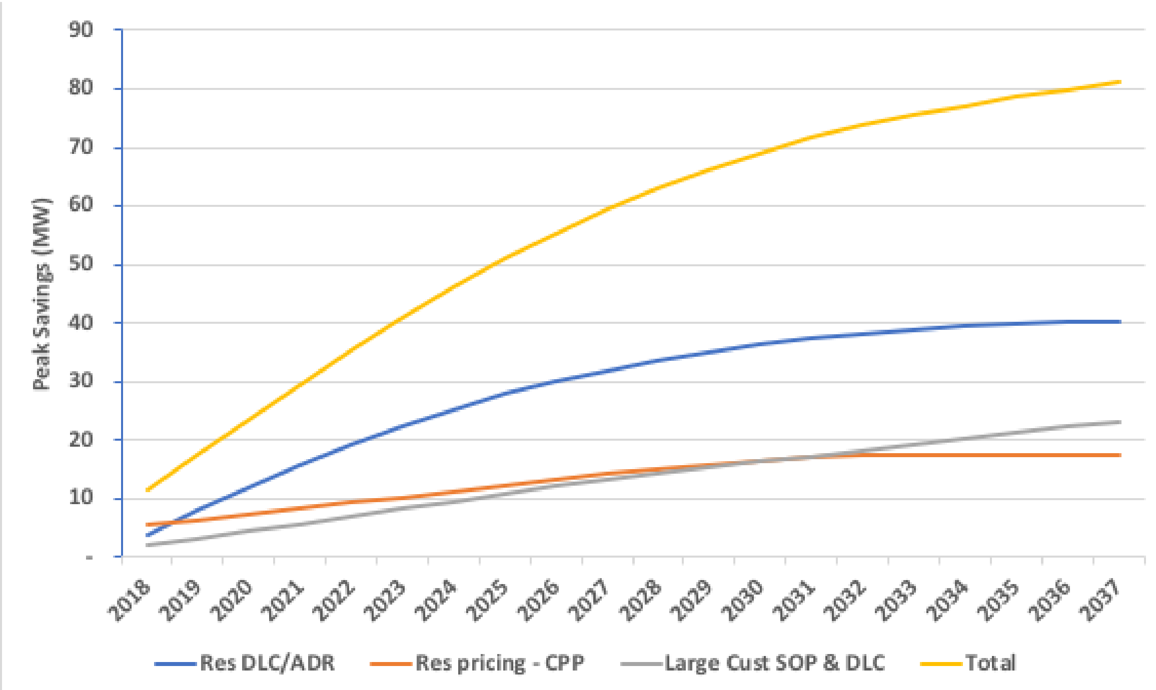


Figure 4 | Electric Demand Savings Relative to Sales Forecast--Scenario Two



Rate Design

The design of rate tariffs can have a significant impact on patterns of electric consumption. For example, inclining block rates (in which the price per unit of energy increases as consumption increases) tend to discourage energy use as the marginal cost of consumption exceeds the average. Declining block rates and large monthly fixed costs may encourage additional electric use for the opposite reason; lower marginal energy costs increase consumption. Now that advanced metering infrastructure (AMI) enables more sophisticated tariffs such as time-of-use (TOU) rates, utilities can better correlate prices with the costs of energy at different times. This can shift usage to off-peak periods, resulting in benefits similar to demand response efforts. Importantly, all of these rate options can be implemented in a way that does not change the total revenue collected from customers, which means neither the customers as a whole or the utility are disadvantaged.

For this study, we use recently published estimates of the price elasticity of electricity to calculate the impact of various revenue neutral rate designs for the residential sector. We considered the following rate structures.

- Higher monthly customer charges – this will decrease the marginal price of electricity, and thus increase the total usage
- Time-of-use rates – we examined both “opt-in” and “opt-out” scenarios
- Seasonal inclining block rate – the cost per unit of electricity increases as consumption increases, thus increasing the incentive to use less electricity at the margin

The table below shows the results from the analysis. Increased customer charges would increase the total electric load, while the inclining block rate would decrease total load. The time-of-use rate would produce a small decrease in total load, but create a fairly significant shift from on-peak to off-peak periods. Note that these impacts are one-time events – they do not accumulate from year-to-year as efficiency savings do.

Table 9 | Cumulative Rate Design Potential Relative to Sales Forecast

Rate Scenario	Change in energy consumption	Change in peak demand
Optional time of use	-0.5%	-4.4%
Default time of use	-0.9%	-7.9%
Inclining block rate	-2.1%	N/A
Seasonal ($25/mo. customer charge)	3.6%	N/A
Seasonal ($50/mo. customer charge)	8.9%	N/A

Total Peak Demand Savings, all DSM

Although this analysis mainly treats the demand response, energy efficiency, and rate design portions as independent and separate, we do provide a high level analysis of the likely total peak demand reduction from all three DSM types (efficiency, demand response, and rate design). The table below shows project total demand reduction by year. We derived these values by assuming a simple "loading order" of the categories: first rate design first, then energy efficiency, and then demand response. In other words, if in a given year the three categories would each produce a 10% reduction in peak separately, we assume that the rate design reduces the forecast by 10%, then the efficiency reduces the new forecast by 10%, and then demand response reduces the remaining peak by another 10%. This way, total demand is reduced by around 27%, instead of the 30% that would result if you simply added the reductions together. Table 10 presents the results of this analysis, assuming an optional time of use rate design, the program potential energy efficiency savings, and scenario two for demand response.

Table 10 | Cumulative Peak Demand Reduction from EE, DR, and Rate Design

Year	Peak Reduction (MW)	Year	Peak Reduction (MW)
2018	67	2028	297
2019	83	2029	305
2020	104	2030	313
2021	129	2031	321
2022	154	2032	329
2023	181	2033	335
2024	209	2034	340
2025	236	2035	343
2026	262	2036	347
2027	288	2037	350

INTRODUCTION

STUDY OVERVIEW AND SCOPE

This section provides a brief overview of the study scope and approaches, with more detail provided in the sections below. This study was conducted to provide a set of inputs for use in Entergy New Orleans' (ENO or "Entergy") upcoming Integrated Resource Plan (IRP), as well as to inform spending and savings targets for future Energy Smart program years. The study looked at savings opportunities from energy efficiency, demand response, and rate designs independently over a 20-year horizon. Each can serve as a resource for meeting some of ENO's forecast load requirements in the IRP modeling. The study scope was limited in several important respects:

- Except for input from the Delphi panel, no primary data were collected; the study thus relies primarily on existing available data, in some cases from outside of ENO's service territory or Louisiana
- Does not include combined heat and power (CHP) opportunities
- Did not attempt to project future changes in code that are not currently planned, nor changes in costs and savings from current technologies over time

The Methodology section later in this report describes the methods and assumptions used in the analysis in detail. The efficiency, demand response, and rate design analyses are each present in their own section that includes the methodology, data sources, and results.

SUMMARY OF STUDY PROCESS AND TIMELINE

The study was initiated in late March, followed by a kick-off meeting in New Orleans on April 4, attended by Entergy New Orleans, several stakeholders, and representatives of the City Council, the client for the project. At this meeting, the Optimal Energy team (Optimal) presented a preliminary measure list and described the study methodology. Analytical work began in earnest after the stakeholder meeting, including the creation of two Delphi panels to provide key input to the efficiency potential study. Draft results for a "maximum achievable" scenario were distributed to stakeholders on July 9, followed by another stakeholder meeting on July 13. Stakeholders submitted comments and questions on the draft results on July 23, and responses were provided on August 6. A draft final report was circulated on August 16, followed by the receipt of comments from stakeholders and the release of this report on August 31.

DEFINITION OF SCENARIOS

This study evaluated energy efficiency potential for three separate scenarios:

- Economic – Everything that is cost-effective and technically feasible, assuming no market barriers. A measure is considered to be cost-effective if the net present value of the avoided energy and capacity costs over its effective useful life is equal to or greater than the net present value of the measure cost.

- Maximum Achievable – The maximum level of program activity and savings that is possible given the market barriers to adoption of energy efficient technologies, with no limits on incentive payments, but including administrative costs necessary to implement programs.
- Program Achievable – A feasible and practical level of achievable savings given a specific set of programs targeting specific markets, with realistic estimates of incentive payments. Administrative costs are again included.

The analyses of demand response and rate design opportunities proceeded using slightly different methodologies, so the scenario definitions for efficiency are not directly applicable to these resources. The demand response analysis includes two scenarios of greater or lesser "aggressiveness" in assumed customer response and a key programmatic difference. The rate design analysis included five different scenarios with a range of impacts.

ENERGY EFFICIENCY

This section presents the methodology for and detailed results from our analysis of the energy efficiency potential.

SUMMARY OF APPROACH & MAJOR ASSUMPTIONS

The major steps in conducting the energy efficiency potential study were as follows:

- Develop energy use forecasts
- Disaggregate energy forecasts by sector (e.g., residential vs. commercial), and end uses (e.g., lighting, cooling, refrigeration)
- Characterize efficiency measures
- Screen measures and programs for cost-effectiveness
- Develop measure penetrations for "achievable" scenarios
- Determine scenario potential and develop outputs

A key characteristic of our approach to efficiency potential studies is that it proceeds using a "top-down" methodology. This involves beginning with the entirety of ENO's electric sales, then "disaggregating" those sales into many smaller quantities of electricity that represent consumption by various customer types and several building types. From there, energy efficiency measures—in the form of percentage reductions in consumption—are applied to the portion of each quantity of electricity to which they are applicable. This is in contrast to a "bottom-up" methodology that seeks to build up the efficiency potential by estimating the quantity of measures that could be installed and the per-unit energy savings of that measure. The top-down method insures that the energy savings are calibrated to actual energy sales.

METHODOLOGY OVERVIEW

This section gives a short summary of the overall methodology used to perform the efficiency analysis. For much more detail see the later section on methodology.

Energy Use Forecast and Disaggregation

For consistency with the IRP process, we started from Entergy's sales forecast, and adjusted to add back savings from current levels of savings from existing Energy Smart Programs. Energy use was disaggregated using multiple sources. In the commercial sector, data provided by Entergy was used to segment sales by building type based on customer SIC code. In both the residential and commercial sectors, disaggregation by end-use relied on data from the Energy Information Administration[2][3].

Measure Selection and Characterizations

The measure list for the study was initially developed from several sources in combination, including the NOLA TRM and previous potential studies conducted by Optimal Energy. Each measure included in the study must be characterized, which is a process of specifying the costs, savings, effective useful life, and other impacts of the measure. This is at the core of any potential study. To characterize the measures for this study we used data from the NOLA TRM where applicable and practical. This information was supplemented with other regional TRMs and Optimal's existing measure characterization database. In addition, we drew on data from a Residential Appliance Saturation Survey conducted by Entergy, as well as other similar studies conducted more in nearby states. All told, we examined 173 different measures over 3 different market types (New Construction/Renovation, market opportunity, and retrofit) and 14 different building types for 1,491 permutations of unique measure types. See the section on methodology details for more information.

Assessing Economic Potential & Cost-Effectiveness

Once the measure list is complete and fully characterized, we can develop an initial estimate of potential that assumes all cost-effective measures are fully implemented where technically feasible. Although this "economic" potential does not represent an outcome that could reasonably be expected under any conditions, it helps to calibrate the remaining scenarios that take into account customer behavior and the many barriers to efficiency investment.

This study uses a "Total Resource Cost" (TRC) test to evaluate cost-effectiveness, by comparing the economic benefits resulting from the program activity to the costs of efficiency investments. The TRC test is the most commonly used cost-effectiveness test for evaluating energy efficiency programs and measures, and attempts to consider a total, economy-wide vision of the costs and benefits of the program. On the cost side, program administration costs and the full incremental costs of the efficiency measures are included. The precise incentive amount does not impact the TRC, as the total incremental cost is incurred by the economy, regardless of whether it is paid for by the participant or the program administrator. Efficiency measures and programs are considered to be cost-effective if the net present value of benefits exceeds the net present value of costs.

Assessing the cost-effectiveness of efficiency measures means comparing the costs of investing in the measure with the economic benefits realized from that investment. With most efficiency measures, the vast majority of economic benefits are derived from the value of avoiding

[2] US Energy Information Administration. Commercial Building Energy Consumption Survey. https://www.eia.gov/consumption/commercial/reports.php. Used data from 2012 survey in West South Central Census Division.

[3] US Energy Information Administration. Residential Energy Consumption Survey. https://www.eia.gov/consumption/residential/. Used data from 2009 survey in West South Central Census Division

the energy consumption that would otherwise other in the absence of the efficiency measure. These "avoided costs" are therefore a key input to the potential model. The benefits listed below are included. For more detailed descriptions, please refer to the Methodology Section

- Avoided Energy Costs: These represent the variable costs associated with producing the marginal unit of electricity. For this study, we used forecasts of location marginal prices (LMPs) for the relevant zone within the Midcontinent Independent System Operator (MISO) footprint.
- Avoided Capacity Costs: This is the value of avoiding new generation equipment. For this study, we use ENO's forecast cost of a new combustion turbine plant.
- Avoided Fuel Costs: Some measures, such as insulation, result in fossil fuel savings in addition to electric savings. These savings are included in a TRC test.
- Avoided Non-Energy Costs: Some measures produce quantifiable non-energy benefits, such as operation and maintenance savings and water savings. These have been included in the measure TRCs to the extent feasible given current estimates of their magnitude and value.

For this study, we developed avoided energy costs from ENO's forecast of annual energy prices[4] and historical hourly Locational Marginal Price (LMP) data.[5] We simplified these thousands of data points into average costs during four energy periods. The year was first divided in "summer" months (April through October) and "winter" months (November through March) based on observed patterns of energy consumption revealed in. Figure 5, below, shows the average hourly price for each summer month. In each season, on-peak and off-peak periods were determined, again using hourly LMP data. For summer, on-peak hours are weekdays between 11 AM and 9 PM; winter on-peak hours are weekdays between 7 and 10 AM and between 6 and 10 PM. At the beginning of the study period, 2018, avoided energy costs ranged from 2.7 cents/kWh winter off-peak hours to 4.6 cents/kWh for summer on-peak hours.

We also developed loadshapes for each sector and end use. These loadshapes determine what portion of the total annual energy savings coincides with each peak period. This means that cooling measures, for example, will have larger benefits than outdoor lighting measures, where the savings general fall on off-peak hours. As indicated earlier, if the net present value of the future stream of benefits (energy and demand, but also other societal benefits such as gas, water, or maintenance savings) exceeds the costs, then the measure is considered cost-effective.

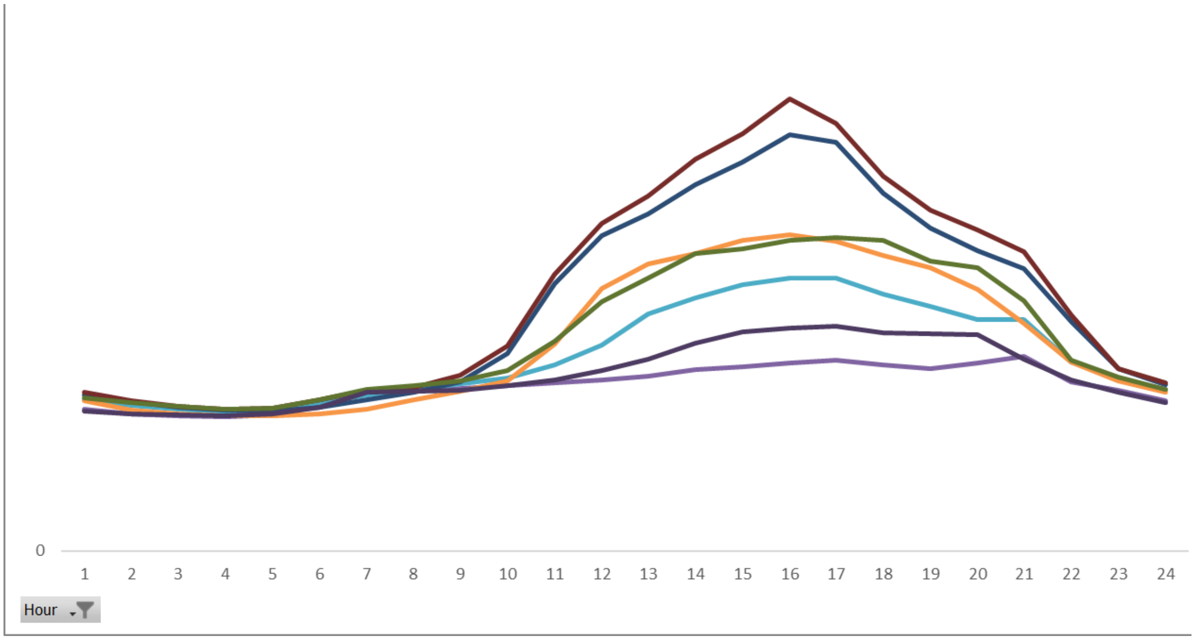
Avoided costs for peak demand reduction were based on ENO's forecast cost of a new combustion turbine plant. No value was placed on avoided transmission and distribution (T&D) costs; ENO did not provide an estimate of these values and we wished to use assumptions consistent with the other aspects of the IRP modeling. Our cost-effectiveness results are therefore likely to be conservative. Line losses were calculated by using ENO's estimates of average losses

[4] Forecast annual LMPs for Zone ENOI were provided by Entergy, and are Highly Sensitive Protected Material (HSPM)

[5] Historical hourly real-time LMP for 2015 for zone EES.NOPLD from MISO

adjusted for the fact that efficiency reduces consumption on the margin and therefore should result in marginal line loss savings, which are higher than average losses. Finally, we use a discount rate of three percent to better reflect the public policy nature of energy efficiency programs. We also include a sensitivity analysis using ENO's weighted average cost of capital (WACC), again for consistency with the IRP.

Figure 5 | Average Hourly Forecast Energy Price – Summer Months



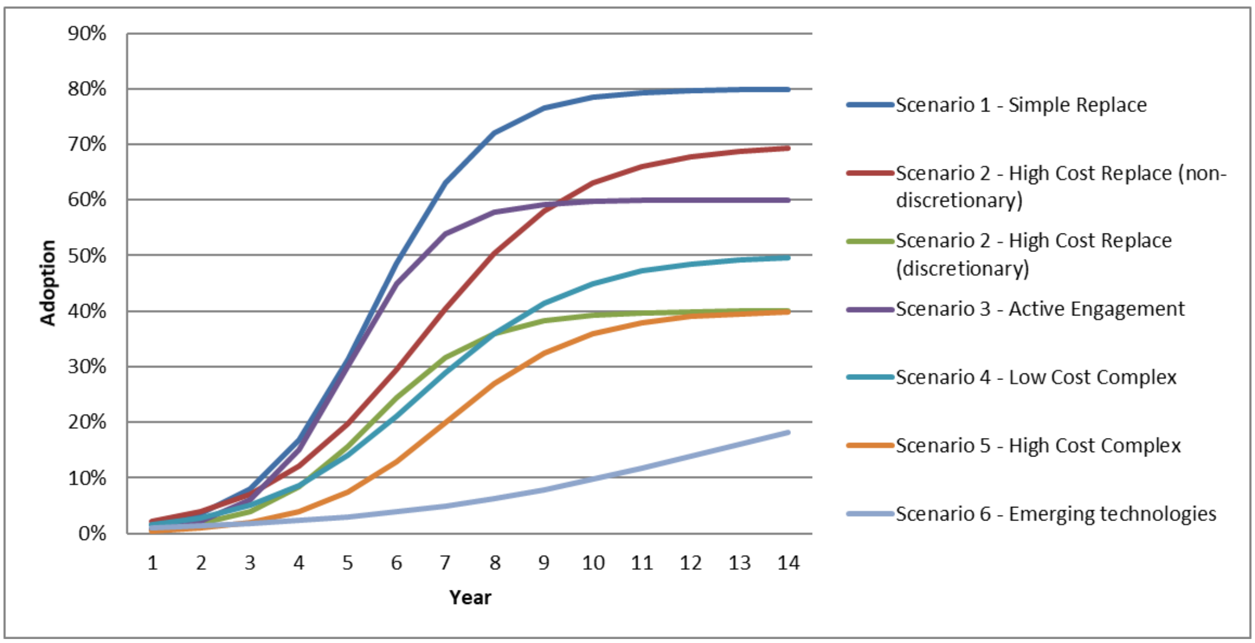
The avoided costs and loadshapes allow us to calculate the net present value of each measure's energy and capacity savings. A measure is considered cost-effective if this value exceeds the measure's cost. For the economic potential estimate, we generally assumed that all cost-effective measures would be immediately installed for market-driven measures such as for new construction, major renovation, and natural replacement ("replace on failure"). For retrofit measures we generally assumed that resource constraints (primarily contractor availability) would limit the rate at which retrofit measures could be installed, depending on the measure, but that all or nearly all efficiency retrofit opportunities would be realized over the 10-year study period. Spreading out the retrofit opportunities results in a more realistic distribution of efficiency investment over time, providing a better basis for the later achievable scenarios.

Estimating Achievable Potential using a Delphi Panel

As noted earlier, one of the key objectives of this study is to provide inputs to ENO's Integrated Resource Plan (IRP). To properly define the efficiency resource that is available as part of the IRP analysis, there must be a high level of confidence that the resource can be "built" in the required timeframe using tested programmatic and policy approaches. In short, the level of efficiency must be "achievable." From an analytical perspective, this means that we developed a set of assumptions about the rate at which efficiency measures will be adopted by customers if promoted by an energy efficiency program. Typically, this means that the utility provides a monetary incentive to offset the increased capital cost of high efficiency equipment or retrofit activity (e.g., adding insulation). An achievable efficiency scenario therefore assumes some level of incentive and attempts to model customer response. This can be done either quantitatively or qualitatively. The former models customers' willingness to participate as a function of the financial impacts of each measure, usually in terms of a measure called simple payback. Simple payback is the ratio of the required investment to the annual cost savings from the investment. It is a measure of the length of time required for the savings to repay the initial investment. A qualitative approach relies on data from existing programs to estimate program participation as function of incentive levels and various program approaches. That is, if a particular program type succeeded in convincing 10% of customers to invest in an efficiency measure, this value could be used as an estimate for the participation of a similar measure under similar conditions.

We developed two estimates of achievable potential using a combination of these methods. First, we developed an estimate of "maximum achievable" potential. Maximum achievable potential assumes that efficiency programs cover 100% of the incremental cost of efficiency measures. As a result, the simple payback is undefined, because there is no investment to repay from bill savings. Therefore, we used a set of qualitative estimates developed by a panel of experts. Please refer to Appendix A for more information on the Delphi panel process. These estimates indicate, for several prototypical efficiency measures, the likely maximum adoption rate by customers and the time required to reach that maximum. See the figure below for the residential adoption curves that resulted from the Delphi Panel.

Figure 6 | Delphi Panel Adoption Curves – Residential Sector



Although the maximum achievable potential is theoretical possible, it is usually considered an extreme upper-bound. As with any product, at any given price there are those who will purchase the product and those who will not. But within those who would purchase the product, some would have purchased it at an even higher cost. With energy efficiency programs, it is difficult to provide different incentive levels for the same product to different customers.

Therefore, if incentives are raised to increase participation, all participants must receive the higher payment, even those who would have participated at the lower incentive lever. As a result, increasing incentive levels results in diminishing returns, and programs rarely provide full or nearly full coverage of measure costs (with the exception of low-income programs). Therefore, we developed a "program achievable" potential that is based on incentive levels that are more in keeping with actual program practice.

For this study, we assumed an average incentive of 50% of measure costs for the program achievable potential. The Delphi panel provided estimates of how measure adoption would change based on changes in customer simple payback. Therefore, this step in the process used a quantitative approach that adjusted the maximum achievable potential based on the calculated simple payback for measure. The Delphi Panel developed consensus on the amount by which the maximum adoption curve would be reduced given certain simple paybacks in the residential and C&I sectors. See Appendix A for more details.

Hourly Efficiency Savings ("8760" Outputs)

Because the results of this report will be used as inputs for ENO's IRP, we will provide an efficiency savings potential estimate for each hour of the year for the next 20-years. In order to produce this "8760" output (so-called because there are 8,760 hours in a non-leap year), we use the same efficiency loadshapes provided by ENO in their 2015 potential study. Note that since these loadshapes are not identical to those we use to model cost-effectiveness, the resulting peak demand impacts implied by the 8760 output may be slightly different than those reported in our study.

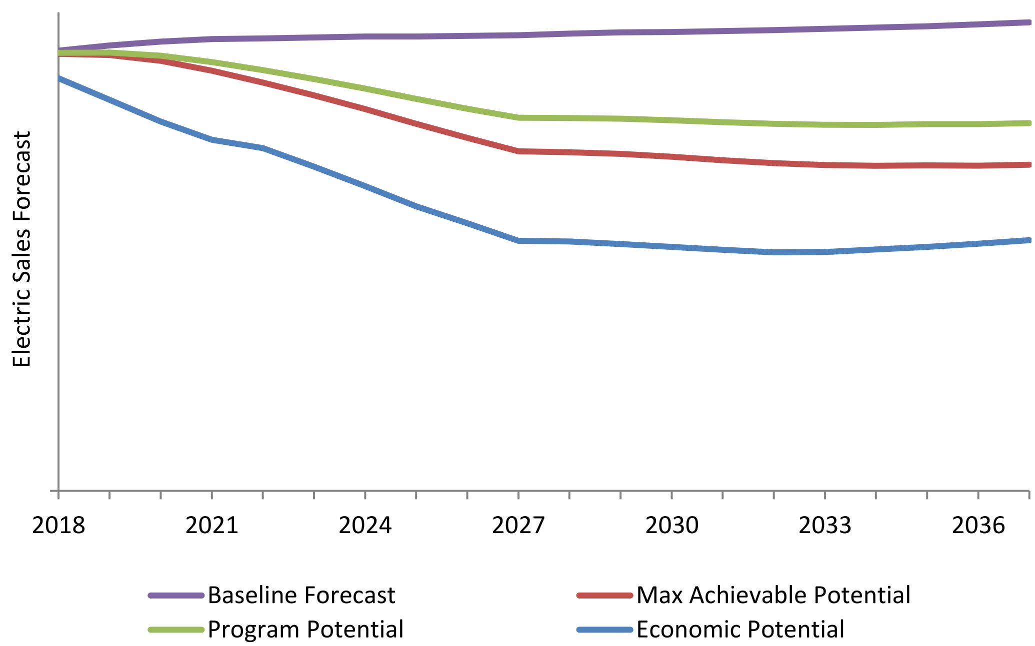
RESULTS

Overall Results

This section presents the overall results of the three scenarios examined. The results are given at the sector level – residential and C&I. Low-income results, where measures with a TRC above 0.8 were counted as economic, are separated from residential further below. Further, note that the cumulative potential does not significantly change between year 10 and year 20. This is because all the adoption curves, as defined by the Delphi Panels, reach full or nearly-full adoption by year 10. Thus most of the market is addressed in the first 10 years, and the additional potential in the last 10 years is largely due to equipment turnover. We also want to emphasize that, due to inherent uncertainties in predicting the future, the results get less and less certain the further out in time. We therefore would recommend placing a focus on the first 10 years when evaluating the results of this study.

The figure below shows the baseline forecasted electric usage (purple line) over the 20-year study horizon, and compares to what sales would be under the three scenarios examined for the study. As expected, sales decline significantly under the efficiency scenarios. This represents electricity that will not be sold if the given scenario is followed.

Figure 7 | Electric Energy Savings Relative to Sales Forecast



The table below gives the specific figures. There is economic potential of 49% in the residential sector, and 45% in the C&I sector. This drops of to 22% and 21% in the program potential scenario.

Table 11 | Cumulative Energy Savings As Percent of Sales by Sector and Scenario (MWh)

Year	Scenario	Residential Savings	Low Income Savings	C&I Savings	Total
	Economic Potential	49%	49%	43%	45%
2027	Max Achievable Potential	27%	27%	25%	25%
	Program Potential	9%	27%	18%	18%
	Economic Potential	49%	49%	45%	46%
2037	Max Achievable Potential	33%	33%	29%	30%
	Program Potential	9%	33%	21%	21%

Note that the above values represent cumulative savings. Due to many measures having a useful life of less than 20 years, a cumulative savings value of, for example, 20% in year 20 does not mean that incremental annual savings will be 1% in each year (i.e., 20% / 20 years). Our modeling tool provides the incremental savings in each year, from which we calculate the average incremental annual savings for the first and second 10 years show in the table below.

Table 12 | Average Incremental Annual Savings

Scenario	2018-2027	2028-2037
Economic	4.8%	3.4%
Max Achievable	2.5%	2.2%
Program	1.8%	1.6%

The average savings above still masks some granularity, for example in the early years while the program is ramping up. The table below shows the incremental annual savings for every year of the analysis period.

Table 33 | Incremental Annual Savings by Year as Percent of Sales

	Economic Potential			Max Achievable Potential			Program Potential		
Year	Total	Res	C&I	Total	Res	C&I	Total	Res	C&I
2018	5.7%	7.5%	4.6%	0.7%	0.7%	0.6%	0.5%	0.5%	0.5%
2019	5.5%	7.3%	4.4%	1.3%	1.4%	1.2%	1.0%	1.0%	0.9%
2020	5.2%	6.7%	4.4%	2.0%	2.0%	1.9%	1.4%	1.4%	1.4%
2021	4.4%	4.6%	4.3%	2.6%	2.5%	2.7%	1.9%	1.7%	2.0%
2022	4.2%	4.3%	4.2%	2.8%	2.7%	2.8%	2.0%	1.8%	2.1%
2023	4.4%	4.5%	4.3%	3.0%	3.1%	3.0%	2.2%	2.1%	2.2%
2024	4.5%	4.7%	4.4%	3.1%	3.3%	3.0%	2.3%	2.3%	2.3%
2025	4.5%	4.6%	4.4%	3.2%	3.5%	3.1%	2.3%	2.4%	2.3%
2026	4.6%	4.7%	4.5%	3.3%	3.7%	3.1%	2.4%	2.5%	2.3%
2027	4.7%	5.0%	4.5%	3.4%	3.8%	3.1%	2.4%	2.6%	2.3%
2028	2.7%	2.5%	2.8%	1.3%	1.7%	1.1%	0.9%	1.2%	0.8%
2029	3.0%	2.8%	3.1%	1.6%	1.9%	1.5%	1.2%	1.3%	1.1%
2030	3.0%	2.9%	3.1%	1.9%	2.0%	1.8%	1.4%	1.4%	1.4%
2031	3.3%	3.0%	3.6%	2.3%	2.2%	2.4%	1.7%	1.5%	1.8%
2032	3.4%	3.0%	3.6%	2.3%	2.2%	2.4%	1.7%	1.5%	1.8%

Peak demand reduction for each scenario in 2027 and 2037 are reported in megawatts, rather than percent of forecast peak load, in order to make it more easily comparable to power generation that may be avoided through efficiency. See Table 14.

Table 14 | Cumulative Demand Savings Potential by Sector and Scenario (MW)

Year	Scenario	Residential Savings	LI Savings	C&I Savings	Total
2027	Economic Potential	137	133	260	530
	Max Achievable Potential	73	71	150	294
	Program Potential	17	71	106	194
2037	Economic Potential	137	134	286	557
	Max Achievable Potential	89	86	186	361
	Program Potential	24	86	133	243

Figure 8 shows the demand under each scenario compared to the baseline peak demand forecast. As seen, similar to the chart for energy, peak demand quickly starts to diverge from the forecast. Note that this figure includes peak demand reduction from efficiency only. Demand response programs will provide additional savings and are discussed fully below.

Figure 9 shows the cumulative avoided CO_2 emissions achieved through the efficiency programs. By the end of the study horizon, the program potential scenario would avoid almost 800 thousand metric tons of CO_2, the equivalent to the emissions from over 160,000 cars. This represents a reduction of emissions of over 26% compared to the baseline forecast.

Figure 8 | Electric Peak Demand Savings From Efficiency Relative to Sales Forecast

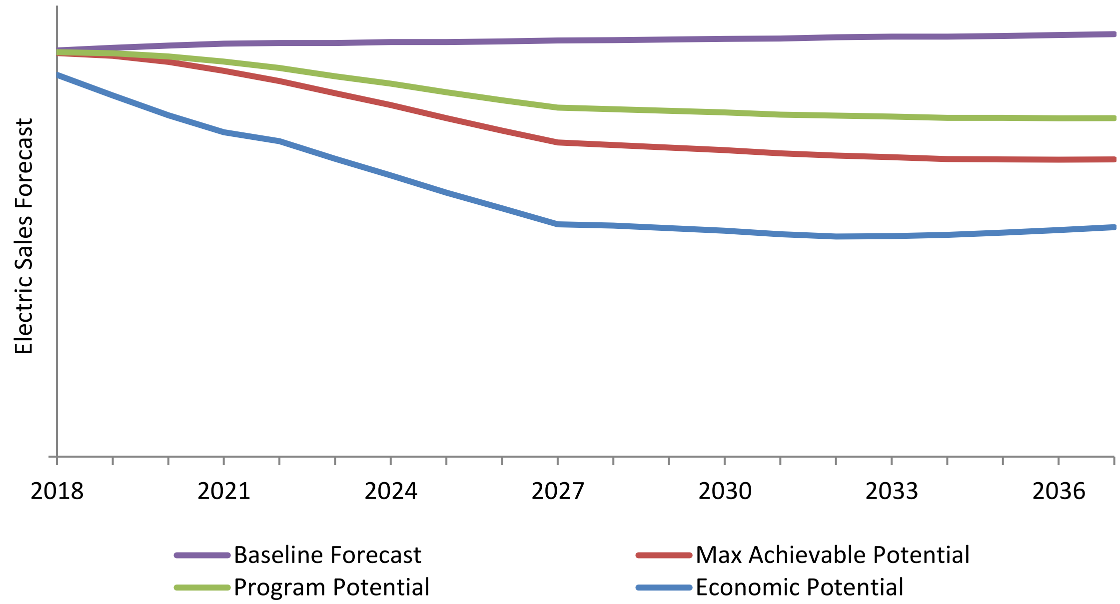
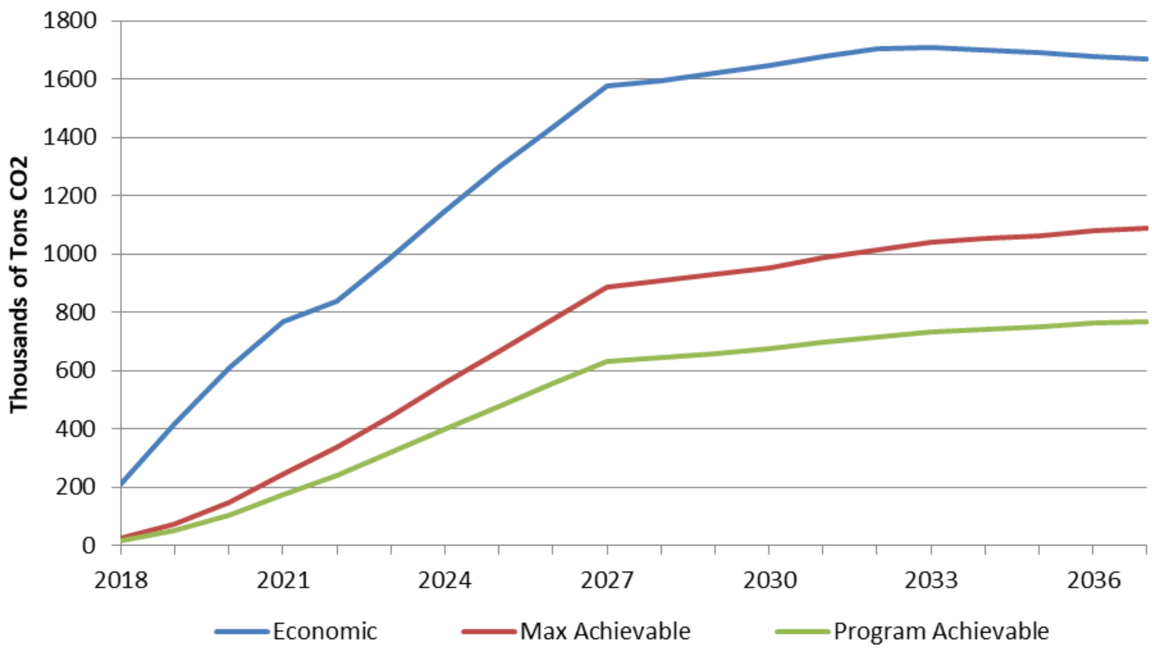


Figure 9 | Cumulative Avoided CO_2 Emissions (Thousands of Metric Tons)



The next table shows the Total Resource Cost Effectiveness Test results in each scenario. The costs and benefits below represent the net present value of running 20 years of programs. As seen, while the scenarios incur significant costs (i.e., utility administrative costs, incentive costs, and customer contributions), there societal benefits are 2-4 times larger.

Table 15 | Scenario TRC Cost-Effectiveness by Sector – Full 20 Years

Sector	Scenario	Costs ($MM)	Benefits ($MM)	Net Benefits ($MM)	BCR
Residential	Economic	461	1,216	754	2.6
	Max Achievable	310	716	406	2.3
	Program	207	467	260	2.3
C&I	Economic	516	2,486	1,970	4.8
	Max Achievable	304	1,129	825	3.7
	Program	202	823	621	4.1
Total	Economic	978	3,702	2,724	3.8
	Max Achievable	614	1,845	1,231	3.0
	Program	409	1,290	880	3.2

Table 16 shows the same information, but for the 2018-2027 time frame instead of the full 20 years. As seen, BCRs are very similar, but slightly lower. This is because of a higher share of retrofit measures during this period which, on average, have lower BCRs than market driven measures.

Finally, tables 17 and 18 show the utility budgets, by year, for the max achievable and program potential scenarios. As seen, the year 1 budget would be $6.5 million, a slight increase from the current Energy Smart Program budgets of $6.2 million.[6] From there, budgets would continue to increase until reaching $58.5 million in 2027. After 2027, budgets begin to decline as retrofit opportunities decline. Achieving the program potential would represent a significant investment. However, it would also avoid significant electricity generation need and produce benefits of three to four times greater than the cost (as seen in the TRC ratios above)..

[6] Entergy New Orleans. Program Year Six Annual Report.

Table 16 | Scenario TRC Cost-Effectiveness by Sector – First 10 years

Sector	Scenario	Costs ($MM)	Benefits ($MM)	Net Benefits ($MM)	BCR
Residential	Economic	$335	792	$457	2.37
	Max Achievable	$203	$409	$207	2.02
	Program	$134	$267	$133	1.99
C&I	Economic	$333	1,445	$1,112	4.33
	Max Achievable	$185	597	$412	3.23
	Program	$118	$427	$309	3.62
Total	Economic	$668	$ 2,237	$1,569	3.35
	Max Achievable	$388	$ 1,006	$619	2.60
	Program	$252	$694	$442	2.75

Table 17 | Program Potential Nominal Budgets ($MM)

Year	Non-Incentive	Incentive	Total	Year	Non-Incentive	Incentive	Total
2018	$1.6	$4.8	$6.5	2028	$2.6	$9.9	$12.5
2019	$3.2	$9.7	$12.9	2029	$3.1	$11.2	$14.3
2020	$4.7	$14.4	$19.2	2030	$3.5	$12.4	$15.9
2021	$6.4	$19.4	$25.8	2031	$4.2	$14.3	$18.5
2022	$6.7	$20.6	$27.3	2032	$4.2	$14.3	$18.5
2023	$7.2	$22.4	$29.7	2033	$4.6	$15.4	$20.1
2024	$7.6	$23.6	$31.2	2034	$4.6	$15.5	$20.2
2025	$7.8	$24.4	$32.2	2035	$4.7	$15.6	$20.2
2026	$8.0	$25.2	$33.2	2036	$4.8	$16.0	$20.7
2027	$8.1	$25.8	$34.0	2037	$4.8	$16.0	$20.8

Table 18 | Maximum Achievable Potential Nominal Budgets ($MM)

Year	Non-Incentive	Incentive	Total	Year	Non-Incentive	Incentive	Total
2018	$1.9	$10.8	$12.8	2028	$2.7	$21.2	$23.9
2019	$3.7	$21.7	$25.5	2029	$3.2	$24.3	$27.5
2020	$5.6	$33.0	$38.5	2030	$3.6	$26.9	$30.5
2021	$7.5	$44.9	$52.4	2031	$4.5	$32.2	$36.7
2022	$7.8	$47.5	$55.3	2032	$4.5	$32.3	$36.8
2023	$8.3	$51.4	$59.8	2033	$5.0	$35.3	$40.2
2024	$8.7	$53.7	$62.4	2034	$5.0	$35.4	$40.4
2025	$8.9	$55.4	$64.3	2035	$5.0	$35.5	$40.5
2026	$9.1	$57.1	$66.2	2036	$5.1	$36.2	$41.3
2027	$9.3	$58.5	$67.9	2037	$5.1	$36.3	$41.4

Detailed Results

Overview

This section drills down into the results in more detail. We focus on the Program Potential Scenario, since that is the scenario most likely to be implemented in New Orleans. For each sector (Residential, Low-Income, and Commercial and Industrial), we show the savings by end use, as well as the top 10 saving measures. Note that the percentages in the tables showing the top savings measures represent the portion of total 2037 savings by that measure. A few items to note:

- There are very little residential lighting savings remaining in 2037. This is due to federal regulations that essentially eliminate the opportunity in that sector.
- The "ElecTotal" end-use represents measures that reduce full building electric use. This includes measures such as Conservation Voltage Reduction, Commissioning, and integrated New Construction.
- There are significant space heating savings in the residential sector. This is due to a high saturation of electric resistance heat – a prime candidate for significant savings from replacing with an air source heat pump.
- Residential demand savings are dominated by cooling, while C&I demand reduction is due to a broader combination of measures.

Residential Non Low-Income

Figure 10 | Residential Electric Energy Savings by End Use (2037)

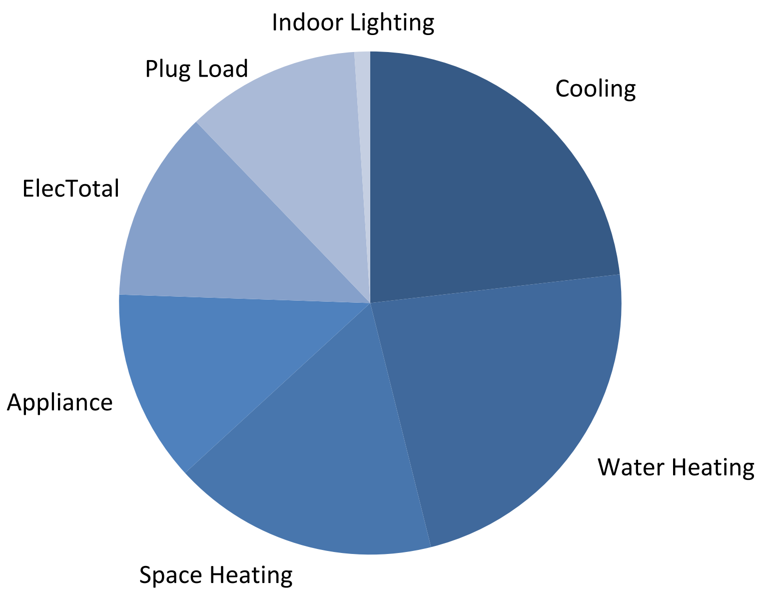


Table 19 | Residential Electric Energy Top Saving Measures (2037)

Measure Name	Percent of Total Savings
Low Flow Showerhead	14.2%
Conservation Voltage Reduction	8.0%
Duct Sealing	7.0%
Ductless Mini-split Heat Pump	5.5%
Faucet Aerator	4.9%
Quality Install Air Source Heat Pump	4.1%
Air Source Heat Pump	3.5%
Learning Thermostat	3.5%
Desktop Computer	2.9%
Fridge and Freezer Removal	2.9%
SubTotal	*56.5%*

Figure 11 | Residential Electric Demand Savings by End Use (2037)

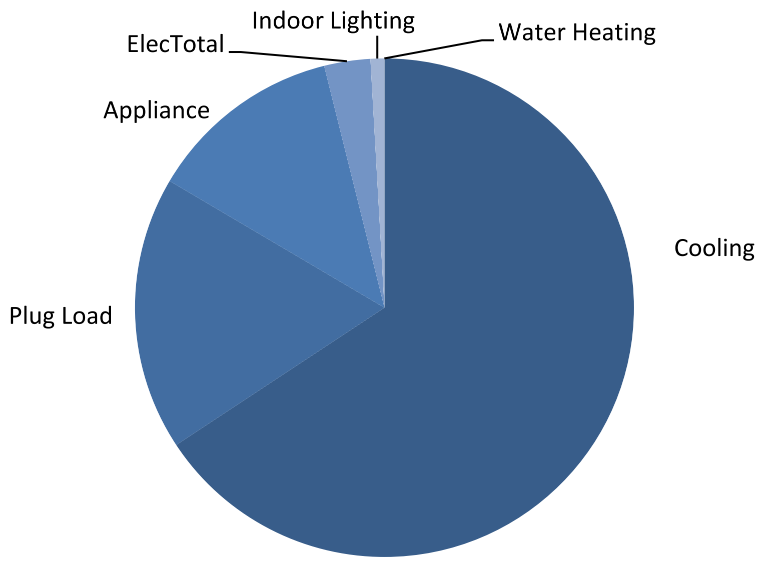


Table 20 | Residential Electric Demand Top Saving Measures (2037)

Measure Name	Cumulative MW
Duct Sealing, Electric Heat	1.56
Duct Sealing, Gas Heat	1.56
Learning Thermostat, Gas Heat	1.48
Learning Thermostat, Electric Heat	1.48
Central AC	1.44
Energy Star Ceiling Fan	1.37
Energy Star Room AC	1.33
Ductless Mini-Split HP	1.30
Quality Install ASHP	1.20
Tier 2 Power Strip	0.97
SubTotal	*13.68*
Total	**24**

Residential Low-Income

Figure 12 | LI Residential Electric Energy Savings by End Use (2037)

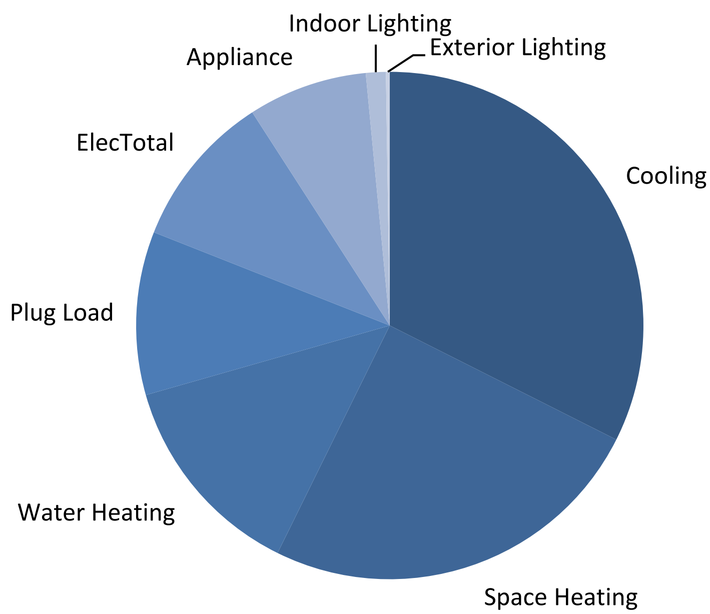


Table 21 | LI Residential Electric Energy Top Saving Measures (2037)

Measure Name	Percent of Total Savings
Air Source Heat Pump	9.6%
Ductless Mini-split Heat Pump	7.3%
Low Flow Showerhead	6.6%
Quality Install Air Source Heat Pump	5.9%
Learning Thermostat	5.8%
Attic Insulation	4.1%
Central AC	3.8%
Duct Sealing	3.8%
ES Ceiling Fan	3.8%
Conservation Voltage Reduction	3.8%
SubTotal	54.5%

Figure 13 | LI Residential Electric Demand Savings by End Use (2037)

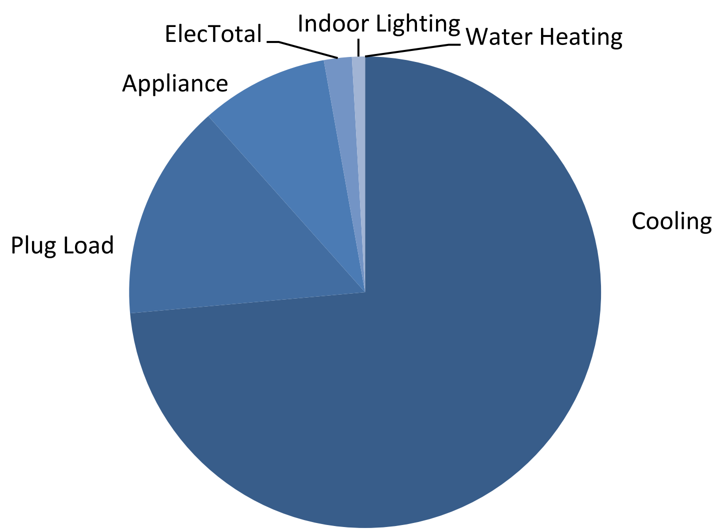


Table 22 | LI Residential Electric Demand Top Saving Measures (2037)

Measure Name	Cumulative MW
Air Source Heat Pump	7.43
Learning Thermostat, Elec Heat	7.16
Learning Thermostat, Gas Heat	7.16
Central AC	6.97
ES Ceiling Fan	6.65
Quality Install Air Source Heat Pump	5.20
Ductless Mini Split Heat Pump	5.09
Quality Install Central AC	3.33
Efficient Windows	3.32
Window Attachments	2.78
SubTotal	55.08
Total	**86.36**

Commercial and Industrial

Figure 14 | C&I Electric Energy Savings by End Use (2037)

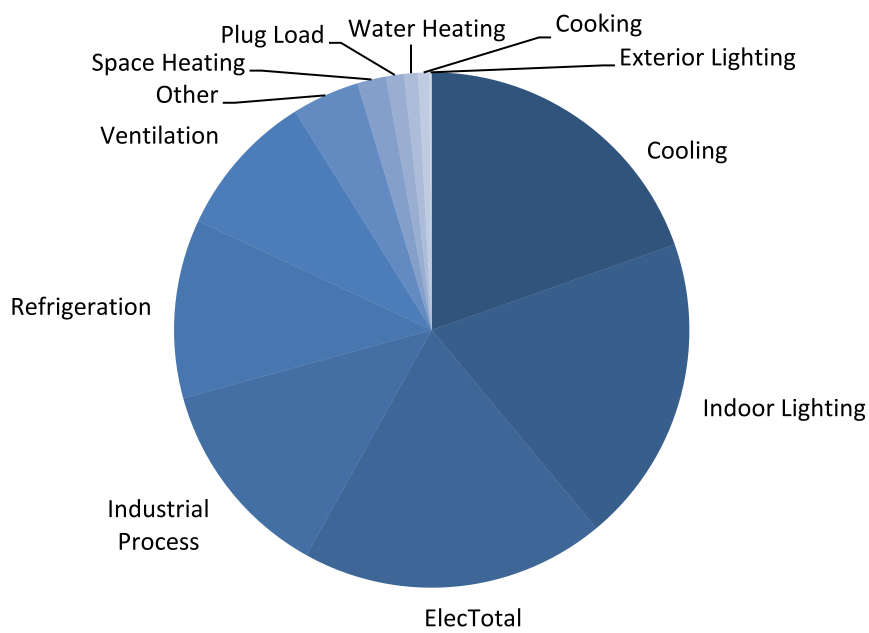


Table 234 | C&I Electric Energy Top Saving Measures (2037)

Measure Name	Percent of Total Savings
Retrocommissioning/Calibrate Sensors - Elec Heat	10.5%
Com LED Tube Replacement Lamps	8.9%
Interior Lighting Controls	7.9%
Compressed Air	6.9%
Industrial Process	5.8%
VSD, HVAC Fan	5.0%
Conservation Voltage Reduction	4.6%
Heat Pump Tune Up	4.5%
Refrigeration Retrofit	3.9%
High Efficiency Heat Pump	3.6%
SubTotal	*61.5%*

Figure 15 | C&I Electric Demand Savings by End Use (2037)

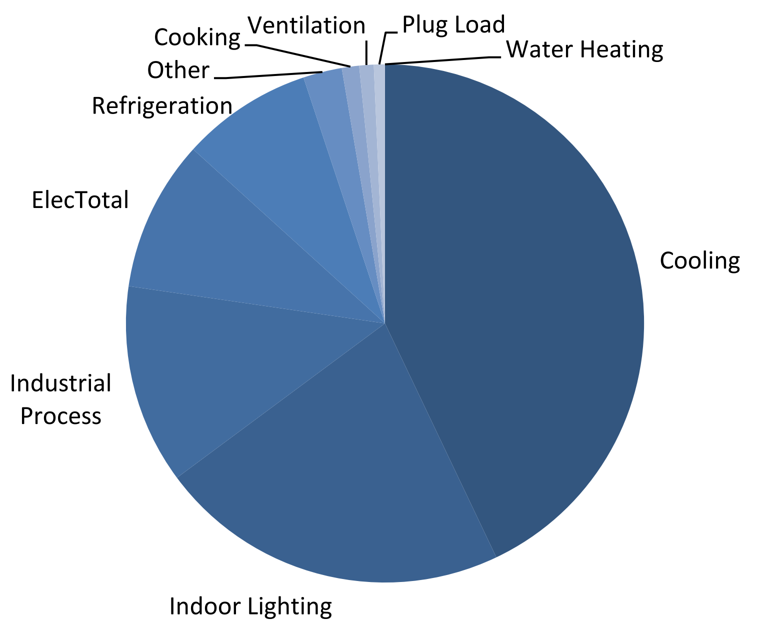


Table 24 | C&I Electric Demand Top Saving Measures (2037)

Measure Name	Cumulative MW
Com LED Tube Replacement Lamps	13
HP Tune Up	13
Int Lighting Controls	12
Mini Split Ductless HP-Cool	10
High Efficiency AC	9
Compressed Air	9
High Efficiency HP	8
Industrial Process	8
Retrocommissioning/Calibrate Sensors - Electric Heat	6
Cool Roof	4
SubTotal	92
Total	**133**

Rate and Bill Impacts

Although cost-effective energy efficiency lowers overall utility bills and the utility's revenue requirement, it also affects customer rates. A utility that promotes efficiency will see a reduction in revenue from the reduced sales volume. Because a portion of the variable rate that customers pay compensates the utility for their fixed costs, the utility will under-recover their fixed costs as a result. In the absence of a rate case that resets rates to meet the revenue requirement with the new, lower volume of sales, the utility will suffer lost fixed cost revenues (sometime referred to as lost base revenues). When rates are reset, they will be higher than they were in absence of energy efficiency, but total customer bills will still be reduced, because the variable costs of efficiency are lower than the variable costs of traditional supply.

Some jurisdictions rely on the Ratepayer Impact Measure (RIM) test to assess whether or not rates will increase as a result of efficiency. The RIM test is a poor measure of this, though, as it provides no information about the magnitude of the rate increase, nor how changes in total utility bills will be distributed among the customer population. Furthermore, nearly every efficiency program will fail the RIM test, precisely because it reduces consumption. It is not a sign that an efficiency measure or program is a bad investment for the utility or their customers.

Not surprisingly, the program achievable scenario fails the RIM test, with a benefit-cost ratio of 0.6. More relevant information can be gleaned from assessing the size of the rate increase and the change in overall utility revenue requirement from efficiency programs. For the program potential scenario, the rate impacts in the short term are minor. Through the first five years of the program, the cumulative reduction of roughly 7% of sales results in a 4% increase in rates. The utility's revenue requirement decreases by nearly $16 million, which indicates that overall customer bills are also reduced by this amount. As efficiency savings accumulate, the rate impacts and the customer bill savings both grow. In 2027, the cumulative sales reduction is approximately 18%, while rates will have increased by approximately 13%. The results in total annual bill savings of over $41 million.

Sensitivity Analysis

As discussed earlier, we used a discount rate of three percent to evaluate the measures for cost-effectiveness. However, Entergy has normally used a higher discount rate reflecting their weighted average cost of capital (WACC) of seven to eight percent in screening measures for cost-effectiveness. A higher discount rate has the effect of placing a lower value on future costs and benefits. The costs of efficiency measures are generally incurred at the time of installation while the benefits of energy savings occur over the life of the measure. A higher discount rate thus lowers the value of the future energy savings relative to the costs, which lowers the cost-effectiveness of measures and programs. In this case, it is possible that some measures that pass the TRC with a three percent discount rate would not be cost-effective using a higher rate such as WACC. In order to estimate how large an impact this may have, we performed a sensitivity analysis looking at the TRCs of each measure using both the societal discount rate and the WACC.

The table below shows the measures that passed the TRC using the societal discount rate but not with the WACC. Only 12 measures of the over 190 examined in the study meet this criterion.

The table also shows the Year 2037 savings from each of these measures in the Max Achievable Scenario. The cumulative savings from these 12 measures represents 8% of the total potential. Looking at program potential, these measures also consist of about 8% of the total. However, this does not necessarily mean that the potential would be 8% lower using the WACC; some measures could be replaced with similar measures with the same or higher savings. For example, even though air source heat pumps do not pass using the WACC, air source heat pumps with quality install still do pass, as do ductless mini-split heat pumps. In a scenario where air source heat pumps do not pass the TRC, these other measures could be promoted in their place.

Table 255 | Measures not Cost-Effective with Higher WACC Discount Rate

Measure Name	Sector	TRC (3%)	TRC (WACC)	Savings in Max Achievable Scenario (MWh, 2037)
Central AC RET	Res	1.09	0.72	8,441
Quality Install Central AC RET	Res	1.30	0.84	6,357
Air Source Heat Pump	Res	1.38	0.99	60,992
Water Heater Jacket RET	Res	1.06	0.80	1,121
Window Attachments RET	Res	1.14	0.92	22,040
LED DI (2018) RET*	Res	1.01	0.92	-
Occupancy Sensors RET	Res	1.00	0.82	10,006
Energy Efficient New Home - Multi Family MD	Res	1.59	0.87	16,661
Retrofit duct sealing	C&I	1.16	0.85	16,356
Integrated bldg design -Elec MD	C&I	1.76	0.98	10,107
Advanced RTU Control - Gas Heat MD	C&I	1.15	0.84	7,458
Integrated bldg design -Gas MD	C&I	1.59	0.88	2,074

BENCHMARKING THE RESULTS

In addition to conducting this New Orleans-specific potential study, we examined how our results compare to the results from other recent potential studies in the region. Table 26 shows the results of both economic and achievable potential scenarios from these studies.

Our New Orleans study generated results that are higher than these other studies, sometimes by a substantial amount. While it is hard to know the specific reasons other studies generated lower results, some of the reasons may include the following.

- Lower penetration rate assumptions, based solely on customer “willingness-to-accept” studies
- Fewer measures included
- Failure to include early retirement measures
- Lower avoided costs and/or higher discount rates
- Different assumptions regarding free-ridership and spillover

- Limited inclusion of potential savings from "custom" projects (i.e., projects involving efforts beyond narrowly-defined "prescriptive" measures)

Table 26 | Potential Study Benchmarking

State	Study Year	Study Period	Analysis Period	Economic Potential	Achievable Potential	Scenario Description
Arkansas	2015	2016-2025	10	17%	8%	Funding set at levels comparable to levels in the past
Georgia (Georgia Power)	2015	2015-2026	12	19%	14%	Max achievable
Mississippi	2013	2014-2025	12	N/A	13%	Reflects other programs in the region, does not attempt to examine maximum
Missouri (Ameren)	2013	2016-2030	15	23%	16%	Max achievable
Austin, Texas	2012	2011-2020	10	26%		Economic only
Tennessee	2011	2012-2030	20	25%	20%	Incentives cover "a substantial portion of the incremental cost"
Oklahoma	2015	2015-2024	10	15%		Economic only
Penn.	2015	2016-2024	10		13%	Max achievable
New Orleans	**2018**	**2018-2037**	**20**	**46%**	**21%/30%**	**Program/Max achievable**

It is also instructive to consider actual program experience in leading efficiency states. The program potential scenario in this study indicates average incremental annual savings of 1.7%. Table 27 shows the 10 states with the highest actual achieved savings in 2016. The average savings is 1.82% of sales, slightly higher than our result. We also note that these top states represent a wide variety of climates and demographics; they are not limited to a particular set of circumstances that are not applicable to Louisiana or New Orleans. In fact, there are many good reasons to believe that New Orleans can at least match the performance of these other jurisdictions with high levels of savings. For example:

- New Orleans does not have a long a history of aggressive efficiency programs, and the existing stock of equipment and buildings is likely of lower efficiency than in areas where efficiency savings have been pursued for many years
- New Orleans has a high cooling load, due to its hot, humid climate
- New Orleans has a high heating load, due to a preponderance of electric resistance heating in the residential sector and relatively low levels of insulation and air sealing.

Table 27 | Efficiency 2016 Top Savers

State	% of 2016 retail sales
Massachusetts	3.0%
Rhode Island	2.8%
Vermont	2.5%
Washington	1.5%
California	1.5%
Connecticut	1.5%
Arizona	1.4%
Maine	1.4%
Hawaii	1.3%
Minnesota	1.1%
Average	**1.82%**

OTHER BENEFITS OF EFFICIENCY

Our assessment of the efficiency potential assessed cost-effectiveness using a set of benefits limited largely to directly avoided supply costs and readily quantifiable resource impacts. Yet efficiency produces many other benefits that are difficult to quantify and often excluded from benefit-cost analysis. This can result in an underestimate of efficiency potential, the net benefits of efficiency, or both. This section briefly describes several benefit categories not quantified in our analysis.

Risk Reduction

Because the largest portion of the marginal costs of producing electricity are related to fuel expenses, electric prices are highly correlated to the underyling commodity. Commodity prices can be highly volatile and cyclical, and thus leave ratepayers exposed to the risk of price shocks. The costs related to energy efficiency, by contrast, are largely related to local labor and expenses, can be ramped up and down much more easily, and are thus much less exposed to the ups and downs of the global commodity markets.

Another type of risk relates to the construction of new generation facilities. These facilities may take 10 years or longer to begin producing power, while demand side investments start saving energy right away. Generation facilities are therefore far more exposed to unexpected capital cost overruns (such as from rising labor and/or material costs), as well as lower than projected load requirements. Some states have begun to quantify the value of reduced risk from efficiency and include it as a benefit in the TRC test. Vermont, for example, adds 10% to the benefits of avoided energy and capacity as a proxy for this risk reduction. However, this practice is still fairly rare.

Transmission and Distribution Avoidance

In addition to peak demand savings from avoided generation, there is often additional savings from lowering the load on the Transmission and Distribution System. These savings can be significant, but they are highly variable from jurisdiction to jurisdiction and difficult to estimate without a dedicated study. We do include these benefits in the analysis of this study due to lack of ENO specific data, but they likely do exist and are possibly significant.

Demand Reduction Induced Price Effects

Many states, especially in New England, are beginning to recognize Demand Reduction Induced Price Effects (DRIPE) as a quantifiable benefit of energy efficiency and demand response. DRIPE is a measurement of the value of efficiency provides by reducing the wholesale energy prices borne by all retail customers. The reduced energy demand due to efficiency programs removes the most expensive marginal generating resources and lowers the overall costs of energy. This reduces the wholesale prices of energy and demand, and this reduction, in a relatively deregulated market, is in theory passed on to retail customers. The effects on energy prices are small in terms of percentages, but the absolute dollar impacts are significant because the price reduction applies to all energy usage on the system.

Originally, it was thought that DRIPE would only be significant in the short-term. In the long run, market actors would react to lower energy consumption and peak demand by retiring inefficient generators. With lower available supply, wholesale prices would begin to increase again, assuming no other changes in demand. However, the most recent study on avoided costs in New England concluded that DRIPE impacts persist far longer than had been assumed. DRIPE effects in New England are now estimated to last 11 years for peak capacity reductions and 13 years for energy reductions. The value of DRIPE varies based on energy period and region, but for New England range from $0.001/kWh to $0.032/kWh and from $2.23/kW to $59.07/kW for peak demand.

Economic Benefits

There is a large and growing body of evidence that money spent on energy efficiency creates more jobs and provides a greater stimulus to local economies than equivalent money spent on supply-side resources. Efficiency investments are far more labor intensive than supply-side resources and require significant effort from contractors, design professionals, and suppliers/distributors. Academic research and interviews with business owners from process evaluations both confirm that utility-run efficiency programs can be an enormous boon for small businesses. According to 2009 study done by the University of Massachusetts, Amherst, a $1 million investment in supply-side resources will create 5.3 jobs, while an equivalent investment in efficiency can be expected to create 16.7 jobs.[7] The table below shows estimates of the jobs effect of efficiency spending.[8] The multipliers are based on modeling by ACEEE, with multipliers adapted from a regional economic modeling tool. Typically, studies have found that around 10-20 net jobs are created per million dollars spent on efficiency.

[7] Throughout the report, one "job" represents one full time job for one year.

[8] ACEEE. *Potential for Energy Efficiency, Demand Response, And Onsite Solar Energy in Pennsylvania. April, 2009.*

Table 28 | Effect of Efficiency Spending on Jobs[9]

Spending Category	Impact	Amount (Millions)	Job Multiplier	Job Impact (job-years)
Installation	Upfront payment for efficiency measures	$100	13	1,300
Consumer Spending	Because of efficiency spending, consumers spend less in the short term	-$100	12	-1,200
Consumer Savings	Because of energy savings, consumers spend more in the long term	$200	12	2,400
Lost Utility Revenues	Utility revenues decrease because of energy savings	-$200	5	-1,000
Net effect of a $100 million investment in efficiency measures				**1,500**

In addition to direct job benefits, one dollar of efficiency spending creates more than one dollar of economic activity. In economics, this is known as the multiplier effect. While every economic activity has some multiplier, the multiplier for efficiency spending is larger than that of many other activities, particularly compared with supply-side spending. The efficiency multiplier occurs as 1) people who are employed due to the efficiency program re-spend their new income into the economy; 2) increased demand for efficient products causes increased demand for upstream suppliers; and, 3) money saved by ratepayers from lower energy bills is spent on other goods and services.

These estimates have been validated by economic studies of specific investment decisions. For example, a 2009 study in East Kentucky found that efficiency investment of $634.2 million would create $1.2 billion of local economic activity and over 5,400 jobs, not including the effect of energy savings being reinvested into the local economy. A coal plant to produce the equivalent amount of energy would not only be more expensive, but would create only 700 jobs during the 3-year construction phase and 60 positions once operational.[10]

Health Benefits

Air pollution such as sulfur dioxide, nitrogen oxides, and particulate matter emitted during electricity generation causes health effects that damage both public well-being and the economy. Additionally, there is mounting evidence that weatherization programs can have significant health benefits in low-income households. Adverse effects include increased incidences of asthma, respiratory, and cardiac diseases; higher mortality rates, and increased medical and hospitalization spending. In fact, there is reason to believe that increased health costs due to air emissions effectively double the price of coal-fired electricity. For example, a recent study from Harvard University finds that adverse health impacts from coal generation cost the public an

[9] This study uses the same job multiplier as was found in the PA ACEEE study, or 15 jobs per million dollars spent. This number is actually on the low side of multipliers found in the economic literature. When this paper references jobs created, it is referring to a job as one full time job for one year.

[10] http://www.ochscenter.org/documents/EKPC_report.pdf

average of 9.3 cents per kWh of power generated.[11,12] A study for the European Union estimates direct externalities at between 4 and 15 euro cents per kWh for coal generation, between 3 and 11 euro cents per kWh for oil, and between 1 and 3 cents per kWh for gas, consistent with the Harvard study.[13] Another study found that Ontario's electric generation produces 668 premature deaths, 928 extra hospital admissions, 1,100 extra emergency room visits, and 333,600 minor illnesses. The financial impact of these health effects is estimated to be over $3 billion per year. The study estimates total Ontario consumption at 26.6 TWh/year, implying health costs for Ontario of over $0.11 per kWh.

Environmental Benefits

In addition to the health effects discussed above, emissions from electricity generation carry significant environmental costs. Although environmental damage can be very difficult to quantify, they can be avoided by investing in efficiency rather than traditional supply-side resources.

- Surface water and soil acidification
- Damage to vegetation and forests
- Contributions to coastal eutrophication, causing algal blooms, depletion of dissolved oxygen, changes in biodiversity, and losses in the tourism/fishing industry
- Faster weathering of buildings
- Reduced visibility from smog and haze
- Mercury accumulation in fish

Other Benefits

Efficient buildings tend to have smaller temperature swings, better lighting levels, less glare, lower temperature gradients, and better indoor air quality than standard buildings. These additional benefits partly improve participant comfort and quality of life, but may also manifest as decreased illnesses and increased worker productivity which can translate into additional economic benefits. The links between buildings and occupant health and productivity are very complex and difficult to generalize. However, the Center for Building Performance Diagnostics at Carnegie Mellon University has created a database of studies that have attempted to quantify this link. Overall, it finds that building environments that are associated with efficiency, such as increased outside air circulation, individual control of lights, moisture control, and pollutant source controls reduce symptoms of illnesses such as flu, asthma, sick building syndrome, and headaches by an average of 43%. Other measures, such as window views, natural ventilation, and increased day-lighting reduce symptoms by an average of 36%. Further, the studies find that lighting measures in offices increase worker productivity by a median of 3.2%. These estimates

[11] This is an average. The actual value varies widely from plant to plant based on its age, type of pollution controls, and downwind population.

[12] Epstein et al. Page 86. http://solar.gwu.edu/index_files/Resources_files/epstein_full%20cost%20of%20coal.pdf

[13] Page 13. http://www.externe.info/externpr.pdf

are highly uncertain, and the past efforts to quantify the benefits have found a range of from less than $10 to $50 per square foot over 20 years. Since the energy savings over 20 years for a typical LEED-certified building are about $10 per square foot, even the low range of this estimate would mean that health and productivity benefits equal the energy saving benefits of green buildings.[14]

[14] Kats, Greg. *Greening Our Built World.*

DEMAND RESPONSE

SUMMARY OF APPROACH & MAJOR ASSUMPTIONS

Demand response (DR) is defined by the Federal Energy Regulatory Commission (FERC) as changes in electric usage by end-use customers from their normal consumption patterns in response to either short-term changes in the price of electricity or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[15]

We estimate the potential and costs for demand reductions from DR in New Orleans based on a review of DR programs by other utilities, with an emphasis on Southern states. We collected data on participation rates, average savings per participating customer, and cost of reduced demand ($/kW). We apply these representative values, adjusted to an ENO context, to estimate the savings and costs for various DR program strategies in the appropriate customer groups in the ENO service territory, and estimate benefits based on the avoided cost of capacity in New Orleans.

ENO customers have had limited experience with DR offerings, in particular those strategies that rely upon advanced metering infrastructure (AMI), which ENO is just beginning to implement in its service territory. Program marketing will be important to build customer awareness and encourage participation. As AMI becomes available to more customers, the range of program offerings can diversify to take advantage of these new technology opportunities.

METHODOLOGY

This section provides an overview of our approach to the DR portion of the potential study analysis. The subsequent sections provide more detailed descriptions of the analysis methodology and assumptions for each program area.

The DR potential analysis involved several steps. We began by conducting a literature review of previous DR potential studies, including at the national, state, and utility-territory levels. We reviewed DR program evaluations from utilities and their evaluators, as well as available meta-studies of demand response. We reviewed relevant literature throughout the study and used previous studies and program results to compare and check the general scale and validity of our own data.

Following the initial literature review, we compiled a database of utility demand response program evaluations and results. These evaluations are typically publicly available on utility websites and public utility commission docketing systems. We spoke with evaluators and program administrators to collect further documentation or to clarify methodology and results where necessary. We collected program evaluations from programs run in the same or similar climate regions to Entergy New Orleans in order to have data that would be comparative. To supplement the somewhat limited in-region data, we also collected data for programs run in

[15] https://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp

different climate zones in order to build out a more robust data set. For each program, we collected data points including:

- Program title and utility administrator
- Year of program
- Location or state of program
- Program description
- Target sector including customer demand level cutoffs when applicable
- Key demand response technique(s) used
- Measures, appliances, or technologies targeted, including use of AMI
- Season and time period of demand response events called
- Participation rates
- Number of events called
- Incentive amount
- Program spending
- Demand savings
- Energy savings

In order to build the savings models, we used data from Entergy New Orleans as well as other publicly available data sources. The latter included assessments of peak demand, penetration of central air conditioning, and load growth projections. Entergy New Orleans provided data including number of customers in each class and avoided capacity costs. To calculate cost-effectiveness, we assume a discount rate of 3%.

Subsequent to our analysis we were able to obtain monthly peak demand for 2017 disaggregated by residential, small commercial, and large commercial customers. Annual peaks occurred during the three summer months (June, July, and August) with residential and non-residential each contributing about half of the total peak. This distribution of the annual peak confirms our assumptions based on power sales to these customers used in our analysis. The review of the monthly peaks also revealed a winter peak primarily driven by residential load, assumed to result from resistance heating load. While our residential demand response measures will also ameliorate these peaks, an increased use of heat pumps in residential sector would also provide an important contribution to managing this peak in the future, as is mentioned in the residential energy efficiency discussion.

From the data points we collected, we created a taxonomy of major demand response program types.[16] We determined major programs to be based on sector (residential, small, medium, and large commercial and industrial), program type (e.g., direct control, automated response, or use of rates), and the targeted energy end-use (e.g., lighting, heating, air conditioning). For each program, we developed two achievable scenarios, as described below.

Data on demand by disaggregated customer types was not available from ENO. We therefore use various strategies to estimate the share of demand attributable to these customers.

[16] We relied upon Peters and Cappers 2017 to inform the general taxonomy of DR programs.

Availability of Data

With limited current presence of DR programs from Louisiana utilities, we have had to rely upon data from a larger geographic area. For some program models the available data are limited or incomplete, creating uncertainty in our estimates of performance, costs and participation, particularly for large customers. The available program data limits our ability to project the likely participation by specific target audiences, limiting our ability to reflect unique demographic characteristics for ENO with a greater share of some customer classes such as hospitality and healthcare. Additionally, residential rate demand response programs vary widely in design, including number and magnitude of peak prices or rebates. This creates variability in program costs and achieved savings. We used estimates for costs and savings consistent with levels we observed in the programs we reviewed, although the utility could choose to spend more to achieve deeper savings, such as through increased recruitment and marketing efforts.

MEASURE CHARATERIZATIONS

Residential Direct Load Control (DLC) and Automated Demand Response (ADR)

The objective of both residential direct load control (DLC) and automated demand response (ADR) programs is to reduce residential peak demand (as measured in kW) during load control events, which typically occur during the summer months. In the case of DLC programs, for example program participants have a load control receiver installed typically on their central air conditioners (CAC) that allows the program administrator to remotely shut down or reduce the amount of time the unit is running. Water heaters and pool pumps are other common technology applications. Participants typically have an option of 50% or 75% cycling of their CAC during the events and receive an incentive based on the level of cycling. Participants may also receive a one-time bill credit for installation and successful testing of the load control device.

An example of an ADR program is the Bring Your Own Thermostat (BYOT) program, which has recently emerged as a residential demand response program opportunity. Through the program, consumers purchase Wi-Fi-enabled smart thermostats and participate in this cloud-based demand response programs. The DR implementer provides a software solution to coordinate and communicate with the thermostat to cycle air conditioning use during called-upon event days.

To estimate demand reductions and costs for residential DLC and ADR programs, we first estimated local penetration of residential central air conditioning (CAC) from the American Housing Survey (Census 2015). We assume that the presence of CAC would determine the households that would be the target of such a program. The Census survey identified that an estimated 89% of housing units in the NOLA metro area have CAC. We use this estimate because it is more recent than the Residential Appliance Saturation Survey (RASS) data from Entergy, which found that 83% of customers had CAC in 2006 (Entergy 2006)[17]. Next, we estimated participation levels based on data from other utility demand response programs in the region.

[17] Full citations for this and other in-text references are forthcoming.

For example, Entergy Arkansas' DLC program reached a participation rate of about 6.5% of eligible customers after about six years.[18] Participants in that program received an installation incentive of $25 or $40 as well as an annual incentive of up to $25 or $40 (depending on the cycling level with higher incentives for the higher level of cycling). Another example is Duke Energy, which had achieved 13% customer participation over five years. Yet another example is PNM in New Mexico, which has reached an estimated 22% of eligible customers.[19]

Similarly, we estimated energy and demand savings and costs assumptions based on DLC and ADR program data from other programs in the region. Savings are based on portfolio results from programs in our review, which may include multiple measures such as HVAC, hotwater, and pool pumps. In addition to Entergy Arkansas, Duke Energy Carolinas and PNM New Mexico, we also used DR program data from utilities in Texas, including Centerpoint Energy Houston, AEP Texas Central, and Oncor.

Table 29 | Residential DLC/ADR Model Inputs

Program Measure	Peak Reduction per Participant (kW)	Participation Rate (% residential customers)[1]	Cost per kW Saved[2]
Residential DLC/ADR (Scenario 1)	1.25 (DLC) and 1.2 (ADR)	1%-9%	$48-$160
Residential DLC/ADR (Scenario 2)	1.25 (DLC) and 1.2 (ADR)	2%-18%	$48-$160

[1]Assumes total starting participation of 1% for both DLC and ADR programs combined ramping up to total participation of 9% by 2037 in scenario one.In scenario two, participation starts at 2% combined for DLC and ADR programs ramping up to total participation of 18% by 2037.

[2]Assumes costs range from $48/kW for ADR to $160/kW for new DLC customers.

Residential Time-Varying Rates Demand Response Programs

The objective of residential time-varying rates in demand response portfolios is to use price signals to reduce residential peak loads during load control events. Residential demand response rate programs vary in design. Some offer customers a rebate for reducing load during peak times, while others increase prices during peak load events. Programs vary in the number of pricing blocks used throughout the day and in the magnitude of the rebate or price increase. These price blocks can range from "real-time pricing" where prices may vary by the hour or even smaller intervals, to programs with a few or even just two different price blocks (off-peak and peak/critical peak). Peak times typically cover a span of a few hours in the afternoon/evening and are also influenced by the weather. The magnitude of the price signal influences the savings achieved. Time-varying rates are "carrot and stick" approaches. Rewards can include very low

[18] This assumes 55% saturation of CAC in Arkansas per FERC 2009 and a total number of residential customers in the service area in 2016 per EIA 2017.

[19] This estimate again uses statewide penetration of CAC per FERC 2009 and total number of residential customers in the service area per EIA 2017.

prices for energy usage in off-peak periods or rebates for demand reductions in peak periods. Penalties can include very high prices for usage in on-peak times.

For this analysis, we consider two common residential rate options: Residential Peak Time Rebates (PTR) and Residential Critical Peak Pricing (CPP). We consider these two programs because they aim to specifically reduce demand during peak times (load control events), rather than during multiple time periods throughout the day. Additionally, these programs are commonly included in utility demand response portfolios, meaning that there are adequate data available for conducting analysis. We explain each program in further detail below. The use of advanced metering technology (such as programmable communicating thermostats or Wi-Fi thermostats) in conjunction with these programs influences the level of savings achieved. For that reason, we model savings potential with and without these technologies for both program types ("without tech." or "with tech.").

Rate programs can be designed as "opt-in" or "opt-out" programs. For opt-out programs, the time-varying rate is the default, and customers can decide not to participate, and for opt-in programs, customers must actively sign up for the time-varying rate. We consider only opt-in programs in this analysis, as these are typically pursued prior to implementing opt-out or default time-varying rates. For opt-in programs, spending on marketing and outreach to recruit customers influences participation and savings rates. Some utilities administer these programs as they would any other rate option, meaning that their only costs are program evaluations. Other utilities invest in marketing and outreach to increase rate subscriptions. Programs that use high on-peak prices to penalize energy use during certain times attract customers by focusing on low off-peak prices that they can take advantage of.

There are limited data available to determine a direct ratio between spending and savings for time-varying rate programs, and utility spending on time-varying rate programs varies widely. For this reason, we use a median cost estimate of $50/kW-saved based on utility evaluations we reviewed and keep this estimate consistent over time. We use the same cost estimate for both rate programs in this analysis because utilities often market their time-varying rate options together and evaluation or other costs are similar for both types of programs. For example, in 2015 Arizona Public Service reports spending $2.24/kW-saved on marketing and outreach for their time-varying rates with low participation, while BGE reports spending $154.58/kW-saved in total for their opt-out program, which achieved high participation (APS 2016; BG&E 2016).

In coordination with the mid-range spending value used, we also used conservative estimates for participation rates. For the PTR program, we assume participation rates begin at 5% based on utility evaluations and recruitment rates, and end with just over 15% participation in 2037. We use similar estimates for the CPP program, starting at 4% participation based on utility evaluations and recruitment rates, and end with just over 12.5% participation in 2037. These are reasonable estimates using a mid-range spending value over time, as other utilities have achieved similar or higher participation for opt-in time-varying rates. For example the Salt River Project achieved over 30% participation in the opt-in time-of-use rate program in 2015, and OG&E achieved about 15% participation in their time-varying rate program in 2016 (Relf, Baatz, and Nowak 2017; OG&E 2017). We split participation rates between those with and without technology, based on technology adoption rates of past utility programs. For example, OG&E has achieved between 45% and 65% technology adoption rates in past program years. This is consistent with other utility technology adoption rates.

Residential Peak Time Rebates (PTR)

Peak time rebates (PTR) are pay-for-performance incentive programs that pay participants to reduce energy use during certain hours of selected days when a peak event is called. The number of events called varies by year based on weather and system needs. Our methodology does not attempt to assume a certain number of events, but rather uses the percent of peak energy saved based on the median data point from a meta-analysis of PTR programs with and without AMI technologies. The incentive payment is calculated based on the difference between actual metered electricity use and estimated participant use in the absence of a called event (i.e. baseline electricity use). PTR programs provide only "carrots," or rewards, for reducing energy during peak times, rather than using a "stick," or penalties, in the rate structure. Examples of PTR programs include Baltimore Gas & Electric's (BG&E) PTR program and Oklahoma Gas & Electric's (OG&E) PeakTime Rewards program. PTR has also been offered as a default rate with the option to opt-out in Southern California, Maryland, and Washington, D.C. (Brattle 2014).

The price ratio for a peak rebate to off peak price typically falls in a range of about 4 to 9, meaning that the peak rebate is 4 to 9 times the off-peak price. Examples include (Fenrick et. al 2014):

- SDG&E's PTR program that provides incentives of $0.75/kWh for manual reduction and $1.25/kWh for automated demand response
- AEP Central Power and Light's PTR program that provided incentives ranging from $0.65-$1.60/kWh
- Pepco's PTR that provided an incentive of $0.75/kWh

Residential PTR Model Inputs

For the PTR potential savings model, we used residential customer and peak demand load forecast data from ENO. We used ENO 2017 residential peak demand data and estimated savings using the median data point of percent of peak energy saved from a meta-analysis of PTR programs with and without AMI technologies. These estimates are consistent with peak savings percentage data from additional utility program evaluations we reviewed. Participation rates and costs per kW saved data are based on utility program evaluations. Table 30 shows the major assumptions and inputs to the PTR models.

Table 30 | Residential PTR Model Inputs

Program Measure	Baseline Demand (average peak kW per customer)[1]	Peak Reduction per Participant	Participation Rate (% residential customers)[2]	Cost per kW Saved
Residential PTR w/o tech.	3.35	12%	2.3%	$50
Residential PTR with tech.	3.35	20%	2.7%	$50

[2]Asummes total starting participation of 5% for both programs combined (without tech at 2.3% and with tech at 2.7%). Analysis assumes an annual participation growth rate of 15% that declines by 1% annually. We assume no growth in participation after 2032 to be conservative. . Total participation reaches a maximum of 15.7% in 2033. [2]We use a median cost estimate of $50/kW-saved for PTR and CPP programs, based on utility evaluations we reviewed; this estimate remains constant over time.

Residential Critical Peak Pricing (CPP)

Residential Critical Peak Pricing (CPP) programs charge customers a higher peak price during certain hours of selected days when events are called. The number of events called varies by year based on weather and system needs. Our methodology does not attempt to assume a certain number of events, but rather uses the percent of peak energy saved based on the median data point from a meta-analysis of CPP programs with and without AMI technologies. CPP programs provide "carrots", or incentives of very low energy prices, for using energy during peak times. They also use a "stick", or penalty of very high prices for energy use during peak times in the rate structure. Opt-in CPP programs attract customers by focusing on the ability of participants to manage their consumption and to take advantage of very low off-peak prices. The ratio of the peak price to off-peak prices typically falls around 8 or 9, meaning that the critical peak price is 8 or 9 times the off-peak price. Examples include (Fenrick et. al 2014):

- OG&E's critical peak price of $0.42/kWh
- PSE&G's critical peak price added to the off-peak price in a range from $0.23/kWh (non-summer) to $1.37/kWh (summer)
- Pacific Gas & Electric's critical peak price adder of $0.60/kWh
- DTE's critical peak price of $1.00/kWh (DTE 2014)

Examples of CPP programs include OG&E's SmartHours program and Arizona Public Service's residential Super Peak CPP program.

Residential CPP Model Inputs

For the CPP savings potential model, we used residential customer and peak demand load forecast data from ENO. We used ENO 2017 residential peak demand data and estimated savings using the median data point of percent of peak energy saved from a meta-analysis of CPP programs with and without AMI technologies. This estimate is consistent with peak savings data from additional utility program evaluations we reviewed. Participation rates and estimated costs per kilowatt saved are based on averages of utility evaluation program data. Table 31 shows the major assumptions and inputs to the CPP models.

Table 31 | Residential CPP Model Inputs

Program Measure	Baseline Demand (average peak kW per customer)[1]	Peak Reduction per Participant	Participation Rate (% residential customers)[2]	Cost per kW Saved
Residential CPP w/o tech.	3.35	20%	1.6%	$50
Residential CPP with tech.	3.35	25%	2.4%	$50

[2]Asummes total starting participation of 4% for both programs combined (without tech at 1.6% and with tech at 2.4%). Analysis assumes an annual participation growth rate of 15% that declines by 1% annually. We assume no growth in participation after 2032 to be conservative. Total participation reaches a maximum of 12.5% in 2033. [2]We use a median cost estimate of $50/kW-saved for PTR and CPP programs, based on utility evaluations we reviewed; this estimate remains constant over time.

Large Customer Programs

The only current large customer demand response offering from ENO is a curtailment tariff that is used by Air Products for their air separation plant. Expanded participation will likely come with the implementation of advanced metering infrastructure (AMI) that would enable bidirectional communications between the customer and the utility, which should be available for large customers in the early to mid-2020s.

Reviewing the literature, we chose to research three program models for the large customers:

- Standard offer program (SOP), where the customer is paid to allow the utility to curtail load for a maximum number of times during a set period, usually with 24 hours advance notice.
- Direct load control (DLC), where the utility installs equipment on large energy using equipment, predominately HVAC, that allows the utility to remotely control the equipment during certain prescribed periods of time.
- Automated demand response (ADR), which makes use of AMI system bi-directional communications to provide information to the customer that allows their intelligent building management system to take steps, such as precooling of the facility, to anticipate future grid needs that would allow the facility to reduce energy consumption during peak periods. In exchange, the customer is compensated for their reductions. In some cases, the customer is also incented to install necessary equipment to participate in the program.

In general, these programs are made available to all larger customers.

Looking at the examples of these programs from across the country for which data was available, with a particular focus on programs in the south, we found multiple examples of SOP that showed a consistent pattern of cost and performance. Data on large customer DLC and ADR programs are more limited, with significant variation in cost of avoided capacity despite similarities in the programs. In particular, the data for ADR showed a wide variation in cost and in many cases lacked other performance indicators.

Because of this limited data for the large customer ADR, and its dependence on availability of AMI, we opted to collapse these two categories (i.e., DLC and ADR) into a single load control measure. We anticipate that initially the load control would make use of DLC technologies, but as the technologies continue evolve and AMI becomes available that the program would likely transition to next generation ADR in those applications where it is more cost effective than traditional DLC. We would anticipate that the cost per kW would likely remain the same, but that the reductions per customer would increase. Because there is significant uncertainty in projecting this results into future years, we elected to make a conservative assumption of holding per-customer savings and costs constant for the study period.

We propose two large customer DR program bundles: 1) a standard offer that would be available initially to about half of the commercial, industrial, and government load, with modest participation increases during the study period, and 2) the standard offer combined with a direct load control offering that would initially be available to about 20% of the load, increasing to 40% of load by the end of the study period as the program transitions from DLC to next generation ADR system that can control a larger range of loads. In the second scenario we assume that the SOP and DLC/ADR programs are complementary and additive.

As noted above, ENO does not have a history of DR programs for the majority of their C&I customers, which means that it will take several years of marketing and customer experience to build participation in the program. As a result, we project a relatively modest trajectory of increasing program participation. In addition, the ENO commercial base has a higher share of hospitality customers than we see in most customer bases. The large national chains are likely to participate in DR programs, but we might anticipate that locally-owned customers would be less likely to participate in DR programs because they have limited familiarity with DR programs and concerned about customer comfort in a hot and humid climate, and therefore less willing to participate in any program that might interrupt cooling and negatively affect customer comfort. For both of these reasons we feel that a lower ultimate participation of the large customer DR program is reasonable.

We estimate that the non-residential customers account for about half of the peak for the study period, as reflected in data from 2017.

Table 32 | Large Customer Program Assumptions

Program Measure	Savings per Customer (kW)	Spending per kW Saved
Standard Offer Program (SOP)[1]	5.1	$37.26
Large Customer Direct Load Control (DLC)[2]	1.7	$33.50

Notes: 1) Assumes an average 10% reduction for participating customers; 2) assumes an average 3% reduction for participating custom

RESULTS

This section presents results including total costs, peak demand savings, and cost-effectiveness for the demand response programs evaluated. We present findings from two scenarios for years 2018-2037. Both scenarios are achievable and are based on participation rates that have been achieved in other jurisdictions. In Scenario One, we assume participation rates at the lower end the range that we see from other jurisdictions. In Scenario Two, we assume participation rates at the upper end of the range that we see from other jurisdictions. Scenario Two therefore assumes more aggressive program participation and marketing and as a result higher levels of demand reduction. Another important distinction between the two scenarios is for the residential pricing programs. In Scenario One we model a residential PTR program and in Scenario Two we model a residential CPP program that would achieve higher levels of demand reduction.

Scenario One includes the following measures:

- Residential DLC and ADR
- Residential PTR pricing with and without AMI technology
- Large customer standard offer program (SOP)

Scenario Two includes the following measures:

- Residential DLC and ADR
- Residential CPP pricing with and without AMI technology
- Large customer SOP plus a DLC/ADR offering

Peak Demand Savings

Results for each of the scenarios are presented in the Figures and Tables below.

Figure 16 | Electric Demand Savings - Scenario One

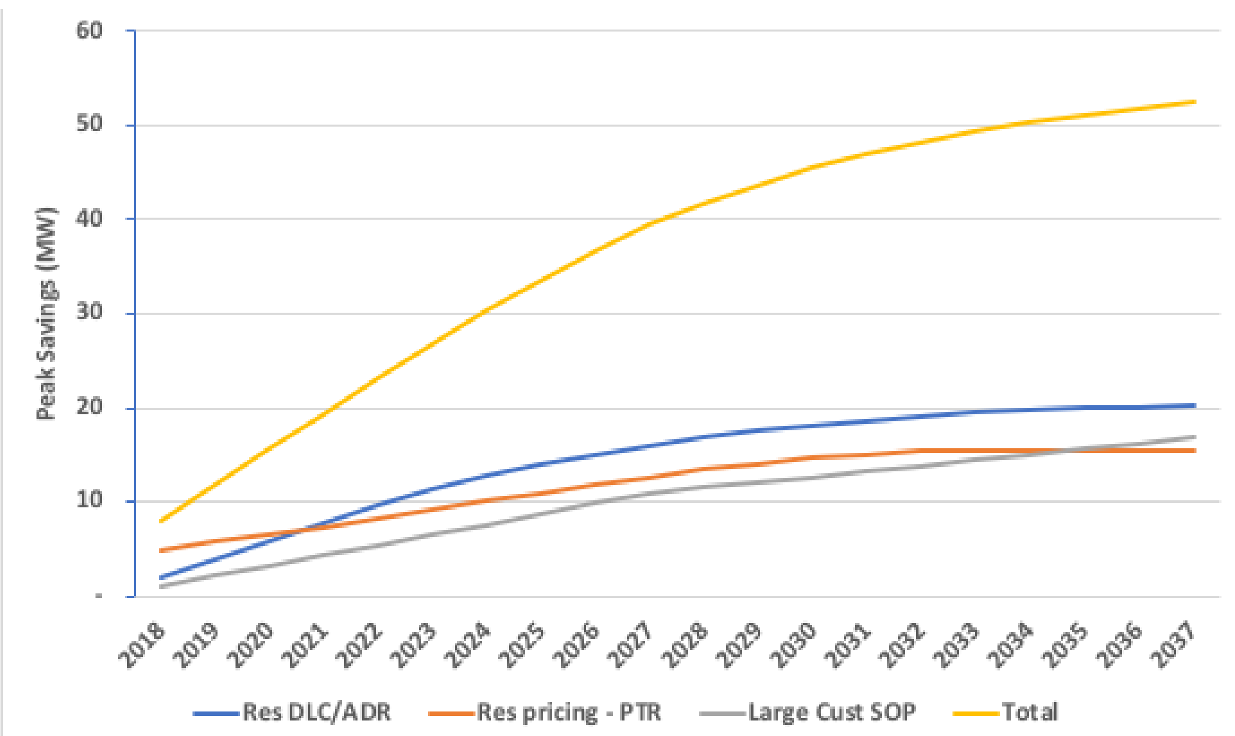


Figure 17 | Electric Demand Savings - Scenario Two

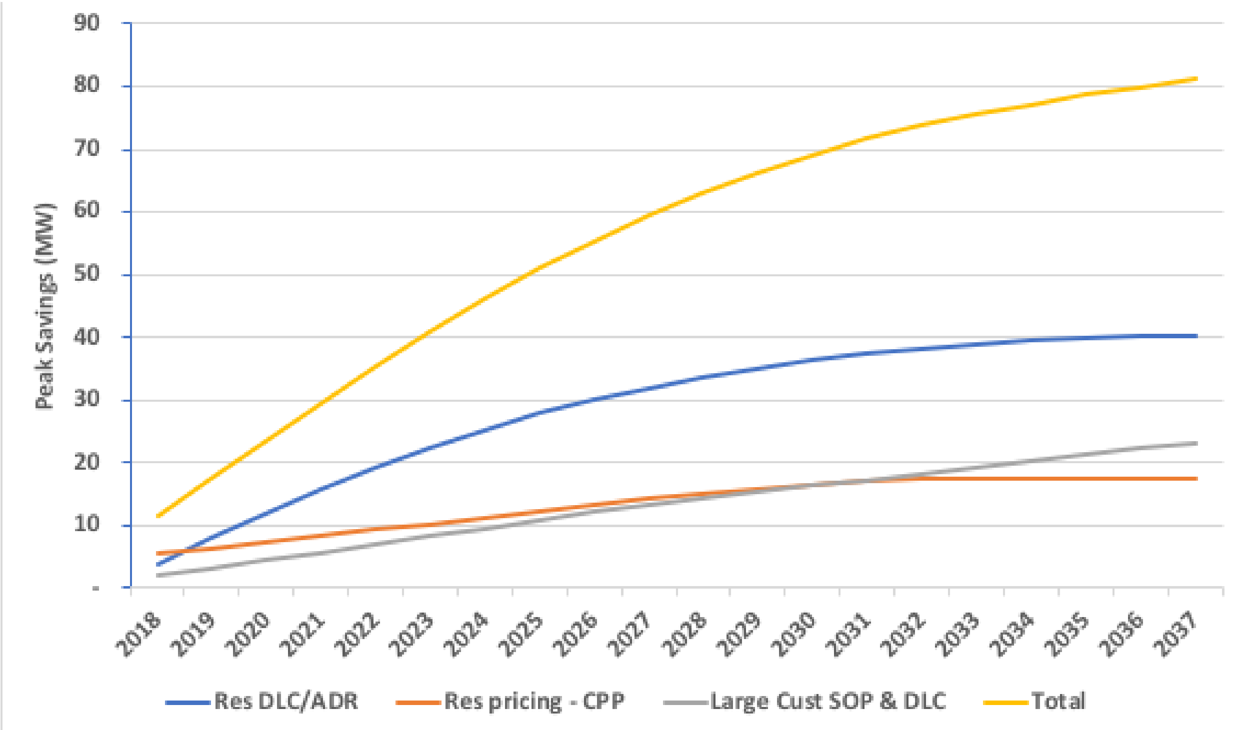


Table 33 | Demand Response Peak Load Reductions Summary – Scenario One

Program	2018	2027	2037
Residential DLC and ADR	2.0	16.0	20.2
Residential PTR pricing	4.9	12.6	15.5
Large Customer SOP	1.1	10.9	16.9
Total	8.0	39.5	52.5

Table 34 | Demand Response Peak Load Reductions Summary– Scenario Two

Program	2018	2027	2037
Residential DLC and ADR	3.9	31.9	40.3
Residential CPP pricing	5.6	14.2	17.5
Large Customer SOP	1.9	13.4	23.2
Total	11.5	59.6	81.1

Scenario One reached peak reductions from these programs equivalent to 2.7% of total system forecast peak in 2027 and 3.6% in 2037. In Scenario Two, peak reductions from these programs are equivalent to 4.5% of forecasted system peak in 2027 and 5.9% in 2037. The tables below gives a more detailed breakout of savings by year for every year of the study horizon for each scenario.

Table 35 | Demand Response Peak Load Reductions By Year – Scenario One

	Res DLC/ADR	Res Pricing - PTR	Large Cust SOP	Total
2018	2	5	1	**8**
2019	4	6	2	**12**
2020	6	6	3	**16**
2021	8	7	4	**19**
2022	10	8	5	**23**
2023	11	9	6	**27**
2024	13	10	8	**30**
2025	14	11	9	**34**
2026	15	12	10	**37**
2027	16	13	11	**39**
2028	17	13	11	**42**
2029	18	14	12	**44**
2030	18	15	13	**45**
2031	19	15	13	**47**
2032	19	15	14	**48**
2033	19	16	14	**49**
2034	20	16	15	**50**
2035	20	16	16	**51**
2036	20	16	16	**52**
2037	20	16	17	**53**

Table 36 | Demand Response Peak Load Reductions By Year – Scenario Two

	Res DLC/ADR	Res Pricing - PTR	Large Cust SOP	Total
2018	4	6	2	**11**
2019	8	6	3	**18**
2020	12	7	4	**24**
2021	16	8	6	**30**
2022	19	9	7	**35**
2023	23	10	8	**41**
2024	25	11	10	**46**
2025	28	12	11	**51**
2026	30	13	12	**55**
2027	32	14	13	**60**
2028	34	15	14	**63**
2029	35	16	15	**66**
2030	36	16	16	**69**
2031	37	17	17	**72**
2032	38	17	18	**74**
2033	39	17	19	**76**
2034	39	17	20	**77**
2035	40	17	21	**79**
2036	40	17	22	**80**
2037	40	17	23	**81**

Budgets and Cost-Effectiveness

Program budgets are presented in the figures below and overall cost-effectiveness results for each program, scenario, and the overall DR portfolio are presented in the table below.

Figure 18 | Annual Program Costs—Scenario One

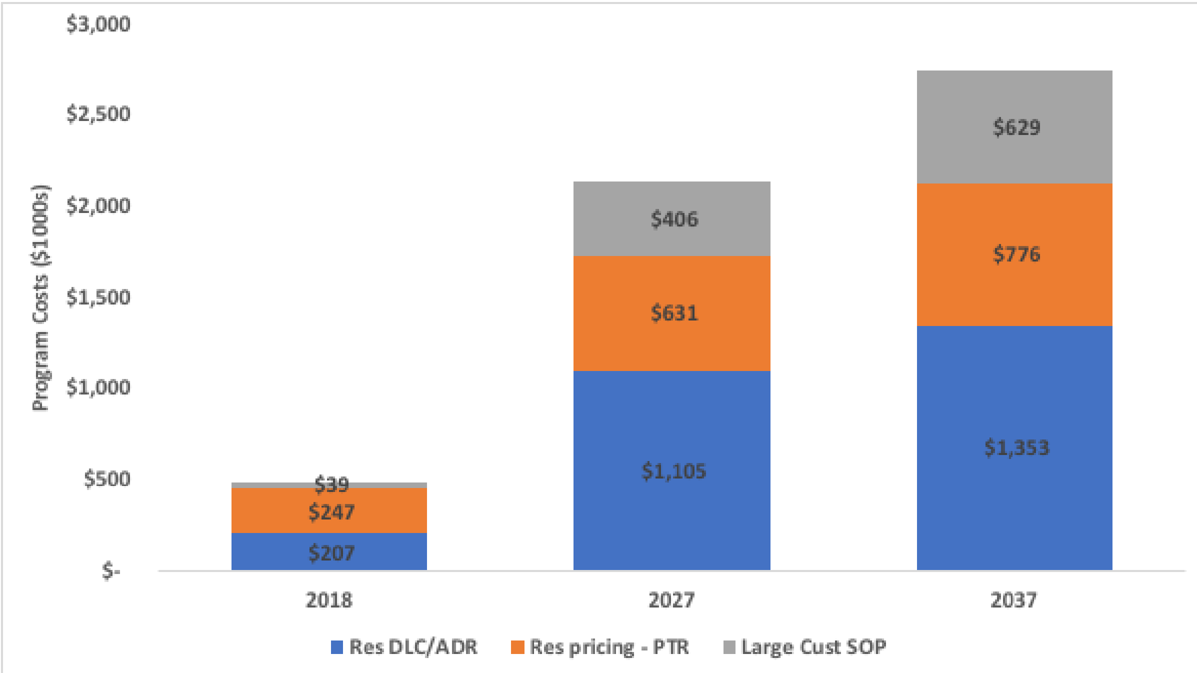


Figure 19 | Annual Program Costs—Scenario Two

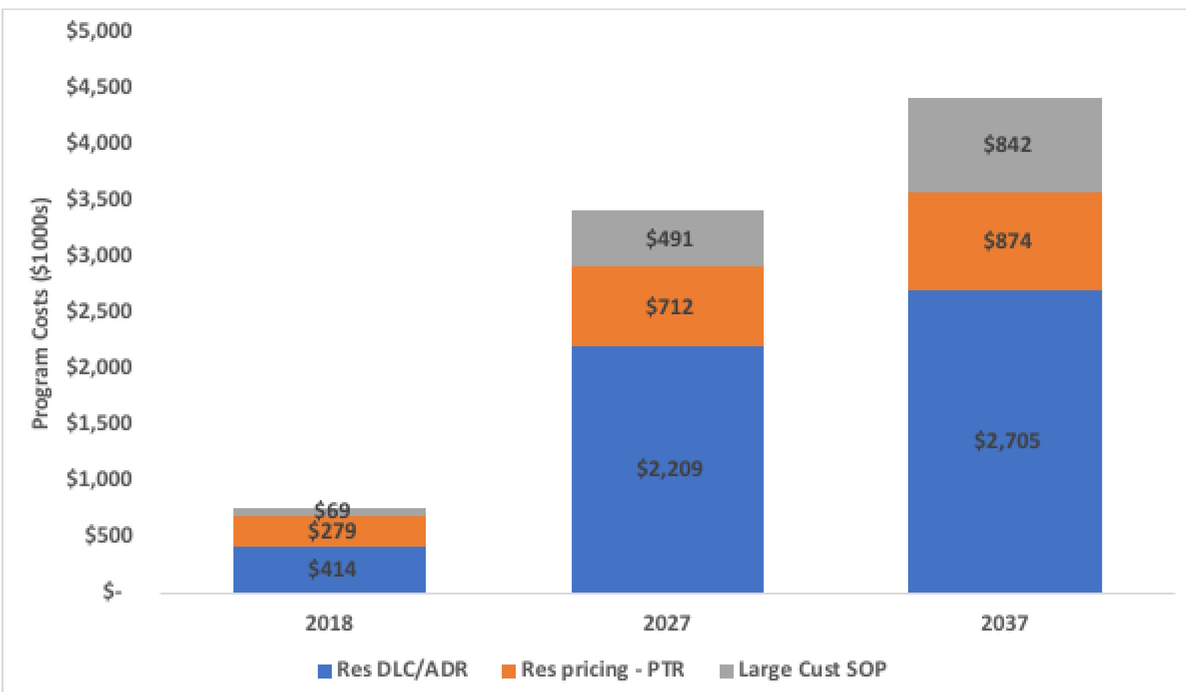


Table 376 | Net Costs and Benefits of DR Potential in Scenarios One and Two

Program	Scenario One			Scenario Two		
	Costs (Million$)	**Benefits (Million$)**	**BCR**	**Costs (Million$)**	**Benefits (Million$)**	**BCR**
Residential DLC and ADR	$14.0	$19.8	1.4	$18.3	$25.2	1.4
Residential pricing	$8.4	$16.4	2.0	$9.4	$18.5	2.0
Large Customer SOP	$1.87	$4.99	2.7	$6.6	$18.1	2.8
Total	$27.5	$50.1	1.8	$34.3	$61.9	1.8

COMBINED RESULTS

Total Peak Demand Savings, all DSM

Although this analysis mainly treats the demand response, energy efficiency, and rate design portions as independent and separate, we do provide a high level analysis of the likely total peak demand reduction from all three DSM types (efficiency, demand response, and rate design). The table below shows project total demand reduction by year. We derived these values by assuming a simple "loading order" of the categories: first rate design first, then energy efficiency, and then demand response. In other words, if in a given year the three categories would each produce a 10% reduction in peak separately, we assume that the rate design reduces the forecast by 10%, then the efficiency reduces the new forecast by 10%, and then demand response reduces the remaining peak by another 10%. This way, total demand is reduced by around 27%, instead of the 30% that would result if you simply added the reductions together. Table 10 presents the results of this analysis, assuming an optional time of use rate design, the program potential energy efficiency savings, and scenario two for demand response.

Table 38 | Cumulative Peak Demand Reduction from EE, DR, and Rate Design

Year	Peak Reduction (MW)	Year	Peak Reduction (MW)
2018	67	2028	297
2019	83	2029	305
2020	104	2030	313
2021	129	2031	321
2022	154	2032	329
2023	181	2033	335
2024	209	2034	340
2025	236	2035	343
2026	262	2036	347
2027	288	2037	350

RATE DESIGN

SUMMARY OF APPROACH & MAJOR ASSUMPTIONS

Electric rate design holds promise as a tool to incent specific behavior or consumption pattern changes from customers. In the assessment of demand response potential, we considered rate design approaches that focus on short-duration price signals for specific events (i.e., critical peak pricing and peak time rebates). This section of the analysis describes other rate design options (such as a time of use rates) that apply to all hours of the year and therefore can result in larger shifts in customer energy consumption patterns. Decades of study has demonstrated positive customer response to changes in marginal prices or electric rates.[20] In this section we present results of our analysis of how Entergy New Orleans residential customers may respond to different rate design alternatives.

Rate design refers to the process of translating utility revenue requirements into the prices paid by customers.[21] Rates for residential customers are typically composed of two parts, a fixed customer charge and a volumetric energy rate. The fixed customer charge is a flat fee paid by customers regardless of how much energy they use in a given month. This is often intended to recover specific costs of utility service, including billing, metering, and customer service. The volumetric energy component bills customers for each unit of energy consumed. While the majority of residential customers in the United States are subject to a flat energy charge, meaning they pay the same price for each unit of energy regardless of what time of day it is used or the total level of consumption, many utilities also offer time varying volumetric energy rates, charging customers different prices for energy consumed based on the time of day or year. Finally, some utilities also offer tiered rates, charging customers a higher or lower rate for each unit of consumption based on the total usage for the month. Entergy New Orleans currently relies on a rate structure with a flat energy charge in the summer and a declining block rate in the winter. Table 39 shows the current residential rate design.

Table 39 | ENO Existing Residential Rates

Component	Summer	Winter
Customer charge (monthly)	$8.07	$8.07
Energy Charge per kWh		
Tier 1 (0-800 kWh)	$0.06002	$0.06002
Tier 2 (over 800 kWh)	$0.06002	$0.04766

To estimate potential changes in consumption for the Entergy New Orleans service territory we relied on existing evidence from prior pricing studies regarding customer price response and participation. We developed five revenue neutral rate design scenarios to understand consumer

[20] Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis.* epri.com/#/pages/product/1016264/?lang=en.

[21] National Association of Regulatory Utility Commissioners. 2016. *Distributed Energy Resources Rate Design and Compensation.* pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

price response using the current rate structure as a baseline. Revenue neutral rate approaches are designed to recover the same level of revenue in the analysis period, which is one year for this analysis. The various rate design scenarios are based on commonly used and industry-accepted approaches to residential rate design. Table 40 shows the five rate scenarios, with customer charge and volumetric rate values for each scenario. The table also shows the participation assumption for the analysis, which is described in greater detail below.

Table 40 | Summary of Rate Design Scenarios

Description	Customer charge ($/month)	Season	Period or block	Volumetric rate ($/kWh)	Participation Assumption
Seasonal with higher customer charge	$25	Summer	all	$0.0508	100% (mandatory)
		Winter	all	$0.0351	
Seasonal with higher customer charge	$50	Summer	all	$0.0278	100% (mandatory)
		Winter	all	$0.0168	
Time of use (opt in)	$8.07	summer	on peak	$0.1231	25% (opt in)
		summer	off peak	$0.0424	
		winter	on peak	$0.0925	
		winter	off peak	$0.0463	
Time of use (opt-out)	$8.07	summer	on peak	$0.1231	90% (opt-out)
		summer	off peak	$0.0424	
		winter	on peak	$0.0925	
		winter	off peak	$0.0463	
Seasonal inclining block rate	$8.07	summer	tier 1	$0.0550	100% (mandatory)
		summer	tier 2	$0.0850	
		winter	tier 1	$0.0343	
		winter	tier 2	$0.0548	

The first two scenarios are both seasonal rates with higher customer charges. The volumetric price varies from summer to winter to reflect the higher cost of energy production in the summer. The customer charge for the first scenario is $25 per month and $50 per month for the second scenario. The time of use rate relies on the same customer charge as the current residential offering, but uses on- and off-peak periods in both summer and winter for the volumetric charge. This structure more accurately reflects the cost to serve residential customers throughout the day.

Finally, the seasonal inclining block rate relies on the existing customer charge and an inclining block structure for volumetric prices. As with the other scenarios, the seasonal price varies to reflect the higher cost to serve customers in the summer months. The inclining tier structure assesses a higher cost per unit of energy consumed based on higher levels of consumption. In this analysis, the first tier includes consumption from 0-500 kWh per month. The second tier captures all consumption in excess of 500 kWh per month. The current ENO residential rate uses a declining block rate in the winter months, meaning customers are billed a lower cost per unit of energy in the second tier (800 kWh or greater).

For all seasonal rates we assumed a summer period of May through October and a winter period of November through April. For the time of use rate, we assume a peak period between 3 and 8 pm in summer and 6 to 9 am in the winter. These periods are based on consumption patterns presented in the load research sample data from Entergy.

These scenarios represent a range of potential rate designs for Entergy New Orleans. The time-of-use scenario relies on an on-peak to off-peak ratio of 3:1 in the summer. Prior research demonstrates that this ratio is a critical factor in how customers respond and modify their energy consumption.[22]

METHODOLOGY

We took several steps to estimate changes in consumption and peak demand for various rate designs. First, we created revenue neutral rate designs using a load research sample provided by Entergy New Orleans. We determined revenue targets using revenues per customer provided in the most recent Federal Energy Regulatory Commission (FERC) Form 1, an industry data reporting form required for all investor-owned utilities. We then applied applicable price elasticities from relevant, recent pricing studies to usage in specific periods to measure changes in consumption.

According to EPRI, the price elasticity of demand is a measure of how price changes influence electricity use.[23] Price elasticities for electricity, as with nearly all consumer products and services, are generally negative, meaning that as prices increase, consumption declines. The EPRI study surveyed prior literature on price elasticity and concluded that residential short-run price elasticity ranges between -0.2 and -0.6, with a mean value of -0.3. The long-run elasticities were estimated between -0.7 and -1.4, with a mean value of -0.9. Short run is considered 1-5 years, while long run is anything beyond five years. The value represents the ratio of a percentage change in quantity demanded and the percentage change in price. For example, a 10% increase in residential electricity prices would result in a 3% decline in short term consumption, relying on the mean estimate from the EPRI study. These values allow us to estimate how residential customers may adjust their electric consumption in responses to changes in prices.

Entergy New Orleans has not conducted any recent pricing studies which would offer primary data for this purpose. Instead, we reviewed several recent pricing studies to source applicable elasticities for the Entergy New Orleans service territory. Table 29 shows the elasticities used for this analysis. For the seasonal two-part rate, we relied on the first tier elasticity for the summer period consumption. All elasticities are short run, meaning they only capture changes in consumption in the near term. . We did not estimate customer response in the long

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[22] Faruqui, A. et al. 2017. *Arcturus 2.0: A Meta-Analysis Of Time Varying Rates For Electricity.* The Electricity Journal. Vol 30, Issue 10, December 2017, pages 64-72.

[23] Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis.* *epri.com/#/pages/product/1016264/?lang=en*.

run because the results are less certain than the short run customer response. However, we would expect greater price response in the long run as customers have more options to reduce or shift consumption over time..

Table 41 | Price Elasticity Assumptions[24]

Rate	Elasticity
IBR first tier	-0.130
IBR second tier	-0.260
TOU on peak	-0.083
TOU off peak	-0.0265

Our analysis applies these elasticities to consumption data for a sample population of 319 residential ENO customers. The sample is intended to represent the larger population of residential customers. However, Entergy New Orleans has approximately 178,000 residential customers. The sample, if properly drawn, should represent the larger population of residential customers.[25] To estimate changes for the entire customer class, we extrapolate the results from the price response analysis of the sample population to the entire residential customer class. This allows us to understand the potential impacts of implementation of a given rate design to all residential customers.

For this exercise, we must also make assumptions on uptake or participation of specific rates by the customer class. This is primarily important because customers have demonstrated greater changes in consumption when opting-in or subscribing to a specific rate on a voluntary basis.[26] Customers as a whole show a lower response when placed on a rate on a nonvoluntary basis. For the optional time-of-use (TOU) rate, we assumed 25% of customers would enroll, with the remaining customers staying on the existing rate. Under the default TOU rate, we assumed 90% of customers stayed on the rate, while the other 10% opted back to the existing two part seasonal rate. The inclining block and seasonal two part iterations were assumed to be mandatory, with 100% of customers subject to the rate.

RESULTS

High-level results include:

- Under an optional time-of-use rate with on and off-peak pricing for both summer and winter periods, overall consumption declined by 0.5% for the entire class, with a summer peak period reduction of 4.4%.

[24] The tier rate elasticities are sourced from Faruqui, A. 2008. *Inclining Towards Efficiency.* Public Utilities Fortnightly. August. The time-of-use rate elasticities are sourced from Faruqui et al. 2016. *Analysis of Ontario's Full Scale Roll-out of TOU Rates.*

[25] We did not conduct a review of the accuracy of the sample of residential customers and assume it accurately matches the rest of the customer class.

[26] George, S. et al. 2014. SMUD SmartPricing Options Pilot Evaluation. August 6. smartgrid.gov/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf.

- If the time-of-use rate were default instead of optional, we estimate a decrease in overall consumption of 0.9%, with a summer peak period reduction of 7.9%.
- If all customers were moved to an inclining block rate, we estimate a decrease in overall consumption of 2.1%.
- If the customer charge was increased to $25 a month (from the current $8.07 per month) and the second tier in the winter rate were eliminated, we estimate overall consumption would increase by 3.6%. If it were increased to $50, we estimate overall consumption could increase by 8.9%.

Table 42 presents a summary of these results.

Table 42 | Summary of Results

Rate Scenario	Change in Energy Consumption	Change in Peak Demand
Optional time of use	-0.5%	-4.4%
Default time of use	-0.9%	-7.9%
Inclining block rate	-2.1%	N/A
Seasonal ($25/mo. customer charge)	3.6%	N/A
Seasonal ($50/mo. customer charge)	8.9%	N/A

Our analysis shows that time-of-use and inclining block rates would marginally reduce consumption, while also providing a price signal to customers to engage in energy efficiency programs and behavior. The reductions of peak demand are driven by higher rates in those time periods. These results also suggest not all consumption in the peak period is reduced, but some is shifted to off peak periods. The seasonal rate options with higher customer charges would lead to higher consumption overall and provide a poor price signal to conserve electricity and engage in energy efficiency programs.

Peak Demand Savings

The analysis showed a summer peak period demand savings of 7.9% under the default time-of-use rate, but only a 4.4% reduction under an optional time-of-use rate. The inclining and seasonal rate options with higher customer charge are not intended to drive changes in the timing of consumption or reductions in peak demand.

Effect on System Costs

There are several categories of utility system costs that may be affected through the changes in overall consumption and peak demand presented in table 4. Reducing peak demand allows a utility to reduce production during peak periods, which lowers overall energy costs and the need for increased peaking production capacity. Energy and other variable costs are also avoided through consumption reductions during off peak periods. Conversely, increasing consumption and peak demand would likely increase system costs. At a minimum, variable energy and maintenance costs would increase. However, generation and distribution system capacity cost increases will depend on current system conditions and needs. Future rate increases because of investment in new assets may be avoided through the reduction in peak demand and localized demand reductions.

The cost associated with rolling out new rate design approaches varies significantly based on the level of marketing and customer outreach employed by the utility. There are also many other considerations for a utility or regulator in any new rate design approach. Not all customers will respond and some will face higher bills as a result of the new rates. Before implementing any new rate design, the effect on vulnerable customers should be assessed and attempts made to mitigate any negative outcomes they may face. Discussion of methods for doing so are beyond the scope of this study.

METHODOLOGY DETAILS

OVERVIEW

This section provides a brief overview of our approach to the study analysis. The subsequent sections provide more detailed descriptions of the analysis methodology and assumptions.

The energy efficiency potential analysis involves several steps. The first several are required regardless of the scenario being analyzed, and were first performed in order to build the base model used to run each scenario. These steps include:

- Assess and adjust energy forecast. In this case, we used the forecast from Entergy New Orleans, and added back the projected savings from current Energy Smart Programs.
- Disaggregate adjusted energy forecasts by sector (residential, low-income, commercial and industrial), by market segment (e.g., building types), and end uses (e.g., lighting, cooling, etc.)
- Characterize efficiency measures, including estimating costs, savings, lifetimes, and share of end use level forecasted usage for each market segment

To develop each scenario (economic, maximum achievable, and program potential) required additional steps specific to the assumptions in each scenario. These steps are listed below.

- Build up savings by measure/segment based on measure characterizations calibrated to total energy usage
- Account for interactions between measures, including savings adjustments based on other measures as well as ranking and allocating measures when more than one measure can apply to a particular situation
- Run the stock adjustment model to track existing stock and new equipment purchases to capture the eligible market for each measure in each year
- Run the efficiency potential model to estimate the total potential for each measure/segment/market combination to produce potential results
- Screen each measure/segment/market combination for cost-effectiveness. Remove failing measures from the analysis and rerun the model to re-adjust for measure interactions

Annual energy sales forecasts were for each sector (residential, low income, commercial/industrial), for the 20-year study period. The electric forecasts was provided by Entergy, and adjusted to add back in the Energy Smart savings. The sales forecasts was then disaggregated by end use and building type in order to apply each efficiency measure to the appropriate segment of energy use. This study applied a top-down analysis of efficiency potential relative to the energy sales disaggregation for each sector, merged with a bottom-up measure level analysis of costs and savings for each applicable technology.

The study applied a Total Resource Cost (TRC) Test to determine measure cost-effectiveness. The TRC test considers the costs and benefits of efficiency measures from the perspective of society as a whole. Efficiency measure costs for market-driven measures represent the incremental cost from a standard baseline (non-efficient) piece of equipment or practice to the high efficiency measure. For retrofit markets the full cost of equipment and labor was used because the base case assumes no action on the part of the building owner. Measure benefits are driven primarily by energy savings over the measure lifetime, but also may include other easily quantifiable benefits associated with the measures, including water savings, and operation and maintenance savings. The energy impacts may include multiple fuels and end uses. For example, efficient lighting reduces waste heat, which in turn reduces the cooling load, but increases the heating load. All of these impacts are accounted for in the estimation of the measure's costs and benefits over its lifetime.

There are two aspects of electric efficiency savings: annual energy and coincident peak demand. The former refers to the reductions in actual energy usage, which typically drive the greatest share of electric economic benefits as well as emissions reductions. However, because it is difficult to store electricity the total reduction in the system peak load is also an important impact. Power producers need to ensure adequate capacity to meet system peak demand, even if that peak is only reached a few hours each year. As a result, substantial economic benefits can accrue from reducing the system peak demand, even if little energy and emissions are saved during other hours. The electric benefits reported in this study reflect both electric energy savings (MWh) and peak demand reductions (MW) from efficiency measures.

The primary scenario for the study was the program potential, which best reflects what could actually be accomplished by efficiency programs given real-world constraints, and assumes incentive amounts of 50% of the incremental cost for residential and C&I sectors, and 100% for the low-income sector. We have also estimated the economic and maximum achievable potentials. The general approach for these three scenarios differed as follows:

- **Economic potential scenario:** We generally assumed that all cost-effective measures would be immediately installed for market-driven measures such as for new construction, major renovation, and natural replacement ("replace on failure"). For retrofit measures we generally assumed that resource constraints (primarily contractor availability) would limit the rate at which retrofit measures could be installed, depending on the measure, but that all or nearly all efficiency retrofit opportunities would be realized over the 10-year study period. Spreading out the retrofit opportunities results in a more realistic ramp up, providing a better basis of comparison for the achievable scenarios. In years 11-20 the retrofit activity significantly declines as the entire market has been reached, and any new retrofits are just replacing another technology that has failed (such as re-commissioning a building that was commissioned 10 years earlier).
- **Maximum achievable scenario:** This scenario is based on the economic potential but accounts for real-world market barriers. We assumed that efficiency programs would provide incentives to cover 100% of the incremental costs of efficiency measures, so that program participants would have no out-of-pocket costs relative to standard baseline equipment. Measure

participation was estimated using the Delphi Process, described earlier in the report.

- **Program potential scenario:** For this scenario, we assume that most incentives are set to 50% of the incremental cost. Penetration rates are based on the simple payback of the measure, as defined by the Delphi Panels. The one exception is that, for low income, we assume that programs will still provide 100% incentives. These programs therefore achieve the same participation as in the Max Achievable scenario.

ENERGY FORECASTS

Electric Forecast

The electric usage forecast was developed primarily from the information provided by Entergy New Orleans. Reported sales categories aligned with traditional utility categories, which closely mirror the three customer sectors that were analyzed. In some cases, energy loads were aggregated to the sector level using standard conventions (e.g., street lighting energy use is included in the commercial sector). Assumed savings from the Energy Smart Programs running at constant savings into the future were added back into the provided forecast. Current programs save about 0.4% of total sales, at a cost of $6.2 million. By adding these savings back to the forecast, the results of the study reflect a base case where no utility run efficiency programs exist.

Forecast Disaggregation by Segment and End Use

The commercial and residential sales disaggregations draw upon many sources. The commercial and industrial disaggregation relies on a number of sources. First, total forecasted energy sales are divided across building types using data from Entergy showing usage by SIC code, supplemented with data from EIA. Low-income buildings were separated from non-LI residential based on the statistical atlas[27]. Next, energy use was disaggregated into end use using the data from the EIA, and especially the Commercial Building Energy Consumption Survey (CBECS) and the Residential Energy Consumption Survey (RECS) .

Sales were further disaggregated into sales for new construction and renovated spaces and those for existing facilities. New construction activity was based on Entergy's projection of customer count growth, compared with EIA data on the consumption of new versus existing facilities.

MEASURE CHARACTERIZATION

The first step for developing measure characterizations is to define a list of measures to be considered. This list was developed and qualitatively screened for appropriateness in consultation with stakeholders to the study process. The final list of measures considered in the

[27] https://statisticalatlas.com/place/Louisiana/New-Orleans/Household-Income

analysis is shown with their characterizations in Appendix I, which also shows the markets for which each measure was considered.

A total of 173 measures were included and characterized for up to three applicable markets (new construction/renovation, natural replacement, and retrofit). This is important because the costs and savings of a given measure can vary depending on the market to which it is applied. For example, a retrofit or early retirement of operating but inefficient equipment entails covering the costs of entirely new equipment and the labor to install it and dispose of the old equipment. For new construction or other market-driven opportunities, installing new high efficiency equipment may entail only the incremental cost difference between a standard efficiency piece of equipment and the high efficiency one, as other labor and capital costs would be incurred in either case. Similarly, on the savings side, retrofit measures can initially save more when compared to older existing equipment, while market-driven measure savings reflect only the incremental savings over current standard efficiency purchases. For retrofit measures, often we model a baseline efficiency shift at the time when the retrofit measure being replaced is assumed to have needed to be replaced anyway.

For each measure, in addition to separately characterizing them by market, we also separately analyze each measure/market combination for each building segment (e.g., small office, large office, industrial, restaurant, etc.). The result is that we modeled 1,591 distinct measure/market/segment permutations for each year of the analysis.

The overall potential model relies on a top-down approach that begins with the forecast and disaggregates it into loads attributable to each possible measure, as described in the following section. In general, measure characterizations include defining the following characteristics for each combination of measure, market, and segment:

- Measure lifetime (both baseline and high efficiency options if different)
- Measure savings (relative to baseline equipment)
- Measure cost (incremental or full installed depending on market)
- O&M impacts (relative to baseline equipment)
- Water impacts (relative to baseline equipment).

Energy Savings

For each technology, we estimate the energy usage of baseline and high efficiency measures based primarily on engineering analysis. We rely heavily on the New Orleans Technical Resource Manual (TRM), as well as other TRMs from other jurisdictions, and Optimal's existing database of measure characteristics. For more complex measures not addressed by the TRMs engineering calculations are used based on the best available data about current baselines in New Orleans and the performance of high efficiency equipment or practices. The New Orleans Appliance Saturation Survey, done in 2006, was used to determine they type of equipment and fuel used, but was too old to use to determine the efficiencies. Due to budget and time constraints we did not include any building simulation modeling or other sophisticated engineering approaches to establishing detailed, weather normalized savings.

Costs

Measure costs were drawn from Optimal Energy's measure characterization database when no specific Louisiana costs were available. These costs have been developed over time, and are continually updated with the latest information, including a recent update for an ongoing potential study in Minnesota. Major sources include the New Orleans TRM and Mid-Atlantic TRMs, baseline studies, incremental cost studies, direct research into incremental costs, and other analyses and databases that are publicly available.

Lifetimes

As with measure costs, lifetimes are drawn from Optimal's measure characterization database. These have been developed over time, and were revised for this study based on the New Orleans TRM.

Operations and Maintenance Impacts

Operation and maintenance (O&M) impacts are those other than the energy costs of operations. They represent, for example, things like replacement lamp purchases for new high efficiency fixtures, or changes in labor for servicing high-efficiency vs. standard-efficiency measures. High efficiency equipment can often reduce O&M costs because of higher quality components that require less-frequent servicing. On the other hand, some high efficiency technologies require enhanced servicing, or have expensive components that need to be replaced prior to the end of the measure's lifetimes. For most measures, O&M impacts are very minimal, as many efficient and baseline technologies have the same O&M costs over time. Where they are significant, we estimate them based on our engineering and cost analyses, the New Orleans TRM, and other available data.

Additional aspects of measure characterization are more fully described below in the potential analysis section, along with other factors that merge the measure level engineering data with the top-down forecast of applicable loads to each measure.

TOP-DOWN METHODOLOGY

The general approach for this study, for all sectors, is "top-down" in that the starting point is the actual forecasted loads for each sector. As described above, we then break these down into loads attributable to individual building equipment. In general terms, the top-down approach starts with the energy sales forecast and disaggregation and determines the percentage of the applicable end use energy that may be offset by the installation of a given efficiency measure in each year. This contrasts with a "bottom-up" approach in which a specific number of measures are assumed installed each year.

Various measure-specific factors are applied to the forecasted building-type and end use sales by year to derive the potential for each measure for each year in the analysis period. This is shown below in the following central equation:

Measure Savings	=	Segment/ End use /year kWh Sales	x	Applicability Factor	x	Feasibility Factor	x	Turnover Factor (replace-ment only)	x	Not Complete Factor (retrofit only)	x	Savings Fraction	x	Net Penetration Rate

Where:

- **Applicability** is the fraction of the end use energy sales (from the sales disaggregation) for each building type and year that is attributable to equipment that could be replaced by the high-efficiency measure. For example, for replacing office interior linear fluorescent lighting with a higher efficiency LED technology, we would use the portion of total office building interior lighting electrical load consumed by linear fluorescent lighting.
- **Feasibility** is the fraction of end use sales for which it is technically feasible to install the efficiency measure. Numbers less than 100% reflect engineering or other technical barriers that would preclude adoption of the measure. Feasibility is not reduced for economic or behavioral barriers that would reduce penetration estimates. Rather, it reflects technical or physical constraints that would make measure adoption impossible or ill advised. An example might be an efficient lighting technology that cannot be used in certain low temperature applications.
- **Turnover** is the percentage of existing equipment that will be naturally replaced each year due to failure, remodeling, or renovation. This applies to the natural replacement (“replace on failure”) and renovation markets only. In general, turnover factors are assumed to be 1 divided by the baseline equipment measure life (e.g., assuming that 5% or 1/20th of existing stock of equipment is replaced each year for a measure with a 20-year estimated life).
- **Not Complete** is the percentage of existing equipment that already represents the high-efficiency option. This only applies to retrofit markets. For example, if 30% of current single family homes already have learning thermostats, then the not complete factor for residential thermostats would be 70% (1.0-0.3), reflecting that only 70% of the total potential from thermostats remains.
- **Savings Fraction** represents the percent savings (as compared to either existing stock or new baseline equipment for retrofit and non-retrofit markets, respectively) of the high efficiency technology. Savings fractions are calculated based on individual measure data and assumptions about existing stock efficiency, standard practice for new purchases, and high efficiency options.
  - **Baseline Adjustments** adjust the savings fractions downward in future years for early-retirement retrofit measures to account for the fact that newer, standard equipment efficiencies are higher than older, existing

stock efficiencies. We assume average existing equipment being replaced for retrofit measures is at 60% of its estimated useful life. The baseline adjustment also comes with a cost credit to reflect the standard equipment that the participant would have had to install to replace the failed unit.

- **Annual Net Penetrations** are the difference between the base case measure penetrations and the measure penetrations that are assumed for an economic potential. For the economic potential, it is assumed that 100% penetration is captured for all markets, with retirement measures generally being phased in and spread out over time to reflect resource constraints such as contractor availability. The product of all these factors results in the total potential for each measure permutation. Costs are then developed by using the "cost per energy saved" for each measure applied to the total savings produced by the measure. The same approach is used for other measure impacts, e.g., operation and maintenance savings.

COST-EFFECTIVENESS ANALYSIS

Cost-Effectiveness Tests

This study applies the Total Resource Cost (TRC) Test as the basis for excluding non-cost-effective measures from the potential. The TRC test considers the costs and benefits of efficiency measures from the perspective of society as a whole. In addition, for the program potential scenario we report the cost-effectiveness of the efficiency programs using the Program Administrator Cost Test and the Participant Cost Test. The principles of these cost tests are described in the *California Standard Practice Manual*.[28]

Table 43 provides the costs and benefits from the perspective of each of the cost-effectiveness tests.

Discounting the Future Value of Money

Future costs and benefits are discounted to the present using a real discount rate of 3%. The U.S. Department of Energy recommends a real discount rate of 3% for projects related to energy conservation, renewable energy, and water conservation, which is consistent with the Federal Energy Management Program (FEMP).[29] For discounting purposes we assume that initial measure costs are incurred at the beginning of the year, whereas annual energy savings are incurred half way through the year. As described further above, we also performed a sensitivity analysis on the cost-effectiveness of each measure using a higher discount rate representing Entergy's Weighted Average Cost of Capital (WACC).

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[28] California Standard Practice Manual: Economic Analysis Of Demand-Side Programs And Projects, July 2002; Governor's Office of Planning and Research, State of California; http://www.calmac.org/events/SPM_9_20_02.pdf

[29] See page 1 in http://www1.eere.energy.gov/femp/pdfs/ashb10.pdf.

Table 43 | Overview of Cost-Effectiveness Tests

Monetized Benefits / Costs	Total Resource Cost (TRC)	Program Administrator Cost Test	Participant Cost Test
Measure cost (incremental over baseline)	Cost		Cost
Program Administrator incentive costs		Cost	Benefit
Program Administrator non-incentive program costs	Cost	Cost	
Energy & electric demand savings*	Benefit	Benefit	Benefit
Fossil fuel increased usage	Cost	Cost	Cost
Operations & Maintenance savings	Benefit		Benefit
Water savings	Benefit		Benefit
Deferred replacement credit**	Benefit		Benefit

*For the TRC and PACT, energy and electric demand savings are valued using avoided cost values that represent wholesale marginal costs, varying by time of day and season. For the Participant Cost Test, energy savings are valued at average retail costs for each customer sector.

**For early-retirement retrofit measures, the Deferred Replacement Credit is a credit for when the existing equipment would have needed replacement. The equipment's replacement cycle has been deferred due to the early replacement.

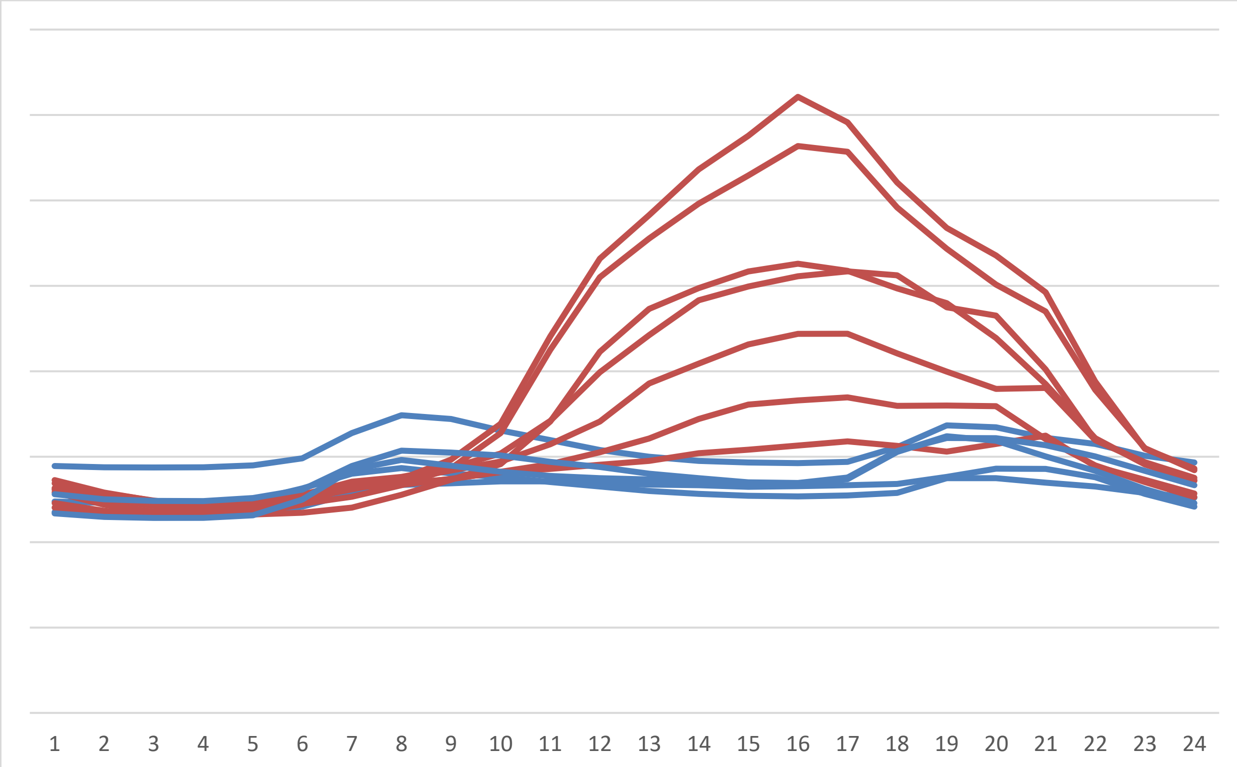
AVOIDED ENERGY SUPPLY COSTS

Avoided energy supply costs are used to assess the economic value of energy savings (or the costs of increased consumption). Developing a set of avoided costs specific to energy efficiency in New Orleans was outside the scope of the project; we relied on the best available data to prepare a set of values that represent reasonable estimates without a substantial investment of time and resources.

We developed electric energy avoided costs using a set of forecast hourly marginal energy prices in the relevant load zone operated by the Midcontinent Independent System Operator (MISO). We reduced this detailed information into forecast energy prices in four energy costing periods for use in our modeling software. We had previously determined that using four distinct energy periods would produce a more accurate estimate of avoided energy benefits than would a single annual average value, particularly for cooling measures that save energy during expensive summer on-peak hours.

To develop the energy costing periods we reviewed and plotted the daily average hourly marginal energy prices for each month. This is shown in the figure below, with summer months in orange and winter months in blue.

Figure 20 | Average Hourly Forecast Energy Price – Summer Months



As seen, there is a clear difference in price between peak and off peak periods, as well as between summer and winter periods. Based on this review, we defined four energy periods: Summer On-Peak, Summer Off-Peak, Winter On-Peak, and Winter Off-Peak.

- Summer is April through October; peak hours are 11 AM – 9 PM weekdays (1,683 hours)
- Off-peak Summer is the rest of the summer months (3,453 hours)
- Winter November through March; peak hours are 7 AM – 10 AM and 6 PM – 10PM weekdays (972 hours)
- Off-peak Winter is the rest of the winter months (2,652 hours)

In addition to avoided electric energy costs, we develop avoided capacity costs to value reductions in peak demand. For this study, these costs are based on Entergy's projected cost to build a new gas turbine plant. Gas avoided costs are based on the long-term Henry Hub price forecast. Entergy did not provide any information on the value of avoided capacity on the transmission and distribution network, the result of which is that our analysis is likely to understate the cost-effectiveness of efficiency savings.

ENERGY RETAIL RATES

Retail rates are not used in the TRC, and so do not impact the net benefits of efficiency from those perspectives. However, they were used in this study to determine the simple payback of each efficiency measure, which in turn determined the penetration rates for the program potential based on the outcome of the Delphi Panel. Retail rates were developed from Entergy New Orleans' published rate tariffs. For purposes of the simple payback analysis, only the variable portion of rates was included. For residential customers, we estimated a price of 8.5 cents/kWh. For commercial customers whose rates also depend on billing demand, we converted projected demand savings into a per kWh rate to simplify the analysis. Taking an average of both small and large commercial rates, we estimate an avoidable retail price of 9 cents/kWh.

ELECTRIC LOAD SHAPES

Electric energy load shapes are used to distribute annual efficiency measure energy savings into the energy costing periods of the avoided costs. Although previous potential studies conducted by Entergy included detailed hourly loadshapes, these were specific to particular efficiency programs (e.g., commercial new construction, residential consumer products, etc.). Our analysis applies load-shapes by energy end-use (e.g., residential lighting, commercial refrigeration, etc) and therefore could not make use of these loadshapes, because the efficiency programs each include measures of several end-uses. Instead, we relied on end-use load shapes information developed by the Electric Power Research Institute (EPRI)[30]. These end-use loadshapes are region-specific; we relied on the Southeast Reliability Council region (excluding Florida). At the level of precision in this study, any differences in the distribution of energy reductions across the four energy costing periods between this regional average and New Orleans are not expected to be significant.

For each end-use, the EPRI data include hourly loadshapes for average weekdays, peak weekdays, and average weekend days, for both summer and winter seasons. From these data, we developed a loadshape for each end-use that defines the percentage of annual energy consumption occurring in each period.

ECONOMIC POTENTIAL ANALYSIS

The top-down analysis, along with all the data inputs, produces the measure-level potential, with the economic potential being limited to installation of cost-effective measures. However, the total economic potential is less than the sum of each separate measure potential. This is because of interactions between measures and competition between measures. Interactions result from installation of multiple measures in the same facility. For example, if one insulates a building, the heating load is reduced. As a result, if one then installs a high efficiency furnace, savings from the furnace will be lower because the overall heating needs of the building have been lowered. As a result, interactions between measures should be taken into account to avoid over-estimating savings potential. Because the economic potential assumes all possible measures are adopted, interactions assume every building does all applicable measures. Interactions are accounted for by ranking each set of interacting measures by total savings, and assuming the greatest savings measure is installed first, and then the next highest savings measure.

[30] Electric Power Research Institute (EPRI). Loadshape Library. http://loadshape.epri.com/

Measures that compete also need to be adjusted for. These are two or more efficiency measures that can both be applied to the same application, but only one can be chosen. An example is choosing between installing an air source heat pump or an efficient central air conditioner, but not both. In this case, the total penetration for all competing measures is 100%, with priority given to the measures based on ranking them from highest savings to lowest savings. If the first measure is applicable in all situations, it would have 100% penetration and all other competing measures would show no potential. If on the other hand, the first measure could only be installed in 50% of opportunities, then the second measure would capture the remaining opportunities.

To estimate the economic potential we generally assumed 100% installation of market-driven measures (natural replacement, new construction/renovation) constrained by measure cost-effectiveness and other limitations as appropriate, such as to account for mutually exclusive measures.

Implementation of retrofit measures was considered to be resource-constrained, i.e., it would not be possible to install all cost-effective retrofit measures all at once. The retrofit penetrations rates are assumed to be 10% of the market for the first 10 years. After this, the entire retrofit market has been adjusted, and any additional retrofits only occur after the life of the original retrofit expires, and there is no market driven measure that addresses the same energy use. For example, since retro-commissioning has a measure life shorter than the analysis period, the same building my become eligible for a second retro-commissioning once the first one has expired.

PROGRAM POTENTIAL SCENARIO

For the achievable potential scenarios (both max achievable and program achievable), we did not attempt to develop detailed program designs to group each measure into. Instead, we make the simplifying assumption that the programs will be well designed and able to capture the amount of market adoption as determined by the local experts on the Delphi Panel. Thus, this study can help determine the amount of efficiency available, and which measures may offer the most opportunity, but is not a detailed roadmap on how to group these measures into programs or how to best promote and market the programs to customers.

Measure Incentives and Penetration Rates

Measure penetration rates, or adoption rates, are affected by a broad variety of factors depending on the measure: the market barriers that apply and to what degree, the program delivery strategy, incentive levels, marketing and outreach, technical assistance to installers, etc. While penetration rates will generally increase with increased spending, how the spending is applied can have a huge impact on actual participation rates. There is large uncertainty inherent in developing penetration rates, and self-reported surveys are often not a reliable indicator of eventual adoption. Further, these rates have an outsized impact on the final efficiency available in the max achievable and program potential scenarios. For this study, we avoided these issues by convening a group of local experts to determine the penetrations rate. We asked these panels for penetrations both at 100% incentives, and as a function of simple payback. See the Appendix on the Delphi Panel for more information.

Non-Incentive Program Budgets

The costs of implementing efficiency programs include both the cost of the efficiency measures themselves and the associated administrative costs for marketing, customer interactions, incentive and rebate processing, evaluation activities, etc. To estimate these costs for inclusion in both program budgets and cost-effectiveness testing, we relied on actual program data from a number of efficiency portfolios. We previously developed these estimates for another potential study and believe them to be reasonable for use in this study. The estimates are specific to our major program categories (e.g., residential new construction, commercial equipment replacement), because different program types and delivery models can have different administrative needs.

Data were sourced from recent program performance in New England, the Mid-Atlantic states, and Minnesota, totaling 8 individual utility or state-wide portfolios. All of these portfolios are generating savings substantially greater than Entergy New Orleans' current programs, and are likely to be a better predicted of the administrative costs needed to achieve the level of savings found by our maximum achievable and program potential analyses. The average administrative costs for the various program types range from 25 percent to 37 percent of total program costs.

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APPENDIX A: DELPHI PROCESS

As described in the report, this report used Delphi Panels in order to estimate the penetration rates for the max achievable and program potential scenarios. There were two separate panels convened – one panel for residential measures with 9 participants, and a panel for commercial and industrial measures, with 8 participants. Each participant is a local expert with appropriate knowledge to allow them to be a good judge on potential measure adoption. Each panel contained representation from each of the following categories:

- Trade Allies/Contractors
- Academics
- Program Implementers
- Program Planner/Managers
- Distributor/Manufacturing Representatives
- Government Officials
- Real Estate Developers
- Building/Facility Managers

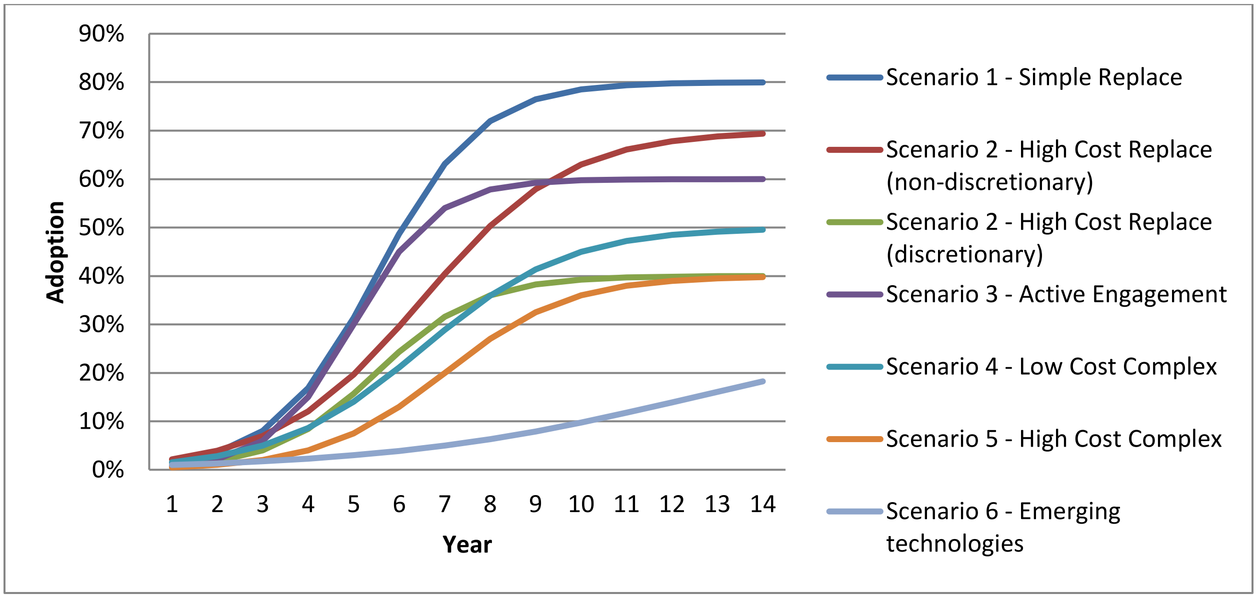
The Delphi Process is used to develop a consensus estimate for uncertain or contentious values. It involves sending the same survey to each participant on the panel. The participant then fills out their best estimates for each survey question and gives some indication of their reasoning. We then compile all answers together and send the survey back for a second round. In this round, each participant will have the opportunity to adjust their responses based on the responses and reasonings of the other participants. The survey is done anonymously, so that the loudest voices do not have disproportionate influence on the other members of the panel. The idea is that, after two or three rounds, the answers from each participant will converge on a consensus estimate. In this case, consensus was already largely achieved after two rounds.

For this study, two Delphi Panels were formed, one focusing on the residential sector and one on the C&I sector. For each sector, the survey asked for measure adoption rates assuming 100% incentives (instantaneous payback) for five different types of measures with different levels of first costs, complexities, and other market barriers. The survey asks for three different datapoints to develop this curve – the percent adoption at program maturity, the number of years to reach 10% of full adoption, and the number of years to reach 90% of full adoption. We then assume a typical “S” curve using these three datapoints, where there is fairly slow adoption until 10% adoption is reached, a steeper ramp up until 90% adoption is reached, and then slower growth until the full adoption is reached. For retrofit measures, we converted these curves to cumulative numbers, so that, for example, instead of achieving 80% penetration per year by year 12, the retrofits would reach a total of 80% market share by year 12 (in other words the sum of adoption in years 1-12 would be 80%).

In addition to the above questions, which apply to the max achievable scenario, the survey also developed estimates of adoption for the program potential scenario, which only provides incentives at 50% of the full incremental cost. In order to derive these numbers, we asked the Delphi participants by what percent the penetrations in the max achievable scenario would be reduced under numerous simple payback scenarios. This number will be applied to every year of the max achievable curve to derive the curve used for the program potential scenarios

The table below shows the curve for each scenario for the Residential sector. As seen, simple measures that are easy to install quickly achieve a fairly high adoption. Other measures types with higher market barriers tend to take longer to ramp up and achieve a lower maximum adoption.

Figure 21 | Residential Adoption Curves



The next table shows the percent that the above curve would be reduced by, if instead of paying the full incremental cost, the incentive just buys the measure down to a specified payback. For example, if an LED screw-in bulb (scenario 1) achieved a simple payback of 2-years after the incentive is applied, every datapoint in the "Scenario 1" curve from the above table would be multiplied by 0.4 to derive the new adoption curve.

Table 44 | Delphi Panel Residential Program Potential Multipliers

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
1-year payback	70%	70%	60%	60%	60%
2-year payback	40%	30%	30%	30%	30%
4-year payback	20%	20%	10%	10%	20%
8-year payback	5%	5%	10%	5%	10%

The next two charts give the same information for the Commercial and Industrial Sector.

Figure 22 | Delphi Panel C&I Responses

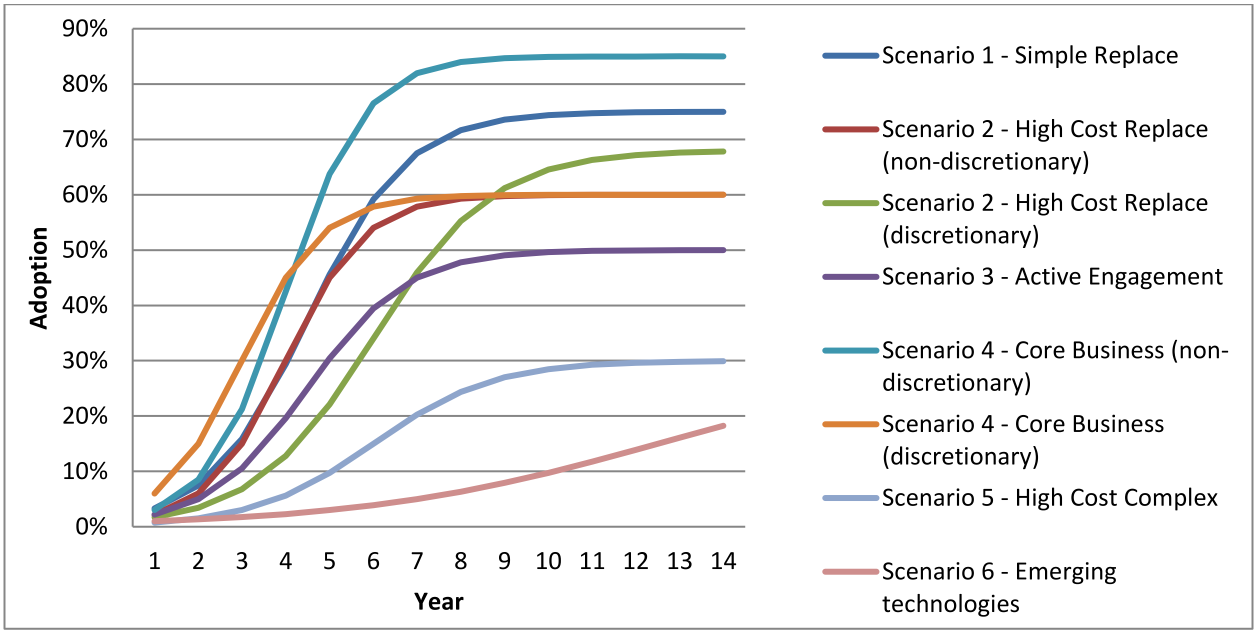


Table 45 | Delphi Panel C&I Program Potential Multipliers

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
1-year payback	83%	78%	78%	78%	85%
2-year payback	43%	48%	45%	65%	60%
4-year payback	23%	25%	28%	48%	38%
8-year payback	11%	10%	13%	15%	20%

Finally, we mapped each of the curves from the Delphi Panel to specific measures. The next table shows this mapping for each measure, for both market driven transactions (e.g., new construction, replace-on-failure) and retrofit transactions. If no curve number is given, that market is not applicable for that measure.

Table 46 | Delphi Panel Measure Mapping

Measure Name	Sector	Curve (market driven)	Curve (Retrofit)
ESTAR Room AC	C&I	1	1
Exterior Canopy/Soffit LED	C&I	1	1
Exterior Wall Pack LED	C&I	1	1
Improved Ext Lgt Design	C&I	1	
Heat Pump Water Heater	C&I	2	2
High Volume Low Speed Fans	C&I	2	
Mini Split Ductless HP-Cool	C&I	2	2
Mini Split Ductless HP-Heat	C&I	2	2
Optimized unitary HVAC distribution/control system	C&I	5	5
Optimized chiller distribution/control system	C&I	5	5
Int Ltg Controls	C&I		1

Exit Sign Retrofit	C&I		1
High Bay LED	C&I		1
Incand. Over 100W Ret, Fixt.	C&I		1
Incand. Over 100W Ret, Lamp	C&I		1
Incand. Up to 100W Ret, Fixt.	C&I		1
Incand. Up to 100W Ret, Lamp	C&I		1
LED Troffers	C&I		1
Com LED Tube Replacement Lamps	C&I		1
Refrigerated Case LED	C&I		2
Stairwell Occupancy Sensors	C&I		2
LED Street Lighting	C&I		1
Pre-Rinse Sprayers	C&I		1
Chiller Tune-Up	C&I		3
VSD, Chilled Water Pump	C&I		2
VSD, Heating Hot Water Pump	C&I		2
VSD, Condenser Water Pump	C&I		2
VSD, HVAC Fan	C&I		2
VSD, Cooling Tower Fan	C&I		2
Demand Control Ventilation-Cool	C&I		3
Demand Control Ventilation-Heat	C&I		3
Demand Control Ventilation-Vent	C&I		3
Screw-Based LED	C&I		1
Retrofit duct sealing fan energy	C&I		5
Retrofit duct sealing cool	C&I		5
Retrofit duct sealing HS fan	C&I		5
Retrofit duct sealing HS cool	C&I		5
Ground Source HP (Heating)	C&I	6	6
Ground Source HP (Cooling)	C&I	6	6
HE Clothes Washer, elec DHW	C&I	1	1
Ozone Laundry System	C&I		6
Office Equipment Controls	C&I		3
Window Film	C&I		3
Cool Roof	C&I	2	5
LED Ped Light (Sign Lighting)	C&I		
HE Kitchen Equipment	C&I	5	
HP Window Glaze (Cooling)	C&I	2	
HP Window Glaze (Heating)	C&I	2	
Compressed Air	C&I	4	4
Industrial Process	C&I		4
High Efficiency HP (Heating)	C&I	2	2
High Efficiency HP (Cooling)	C&I	2	2
High Efficiency AC	C&I	2	2
HP Tune Up (Heating)	C&I		1
HP Tune Up (Cooling)	C&I		1

AC Tune Up	C&I		1
Cooler Night Cover	C&I		1
Commercial Faucet Aerator (Elec WH)	C&I		1
High Efficiency Chiller	C&I	4	5
ECM Blower Motors	C&I		1
Conservation Voltage Reduction	C&I		1
Building Management System - Elec Heat	C&I		1
Control System for Hopitality	C&I	5	5
Retrocommissioning/Calibrate Sensors - Electric Heat	C&I		2
Integrated bldg design -Elec	C&I	5	
Replace Cooler and Freezer Door Gaskets	C&I		4
Reach-in Storage Refrigerator	C&I	2	
HE Small Walk-In	C&I	2	
Refrigeration Retrofit	C&I		4
Strip Curtains	C&I		4
Advanced RTU Control - Elec Heat	C&I	3	3
Advanced RTU Control - Gas Heat	C&I	3	3
Network Connected LEDs	C&I		6
High Efficiency Chiller vs DX System	C&I	5	
Replace Pneumatic contols with DDC - Elec Heat	C&I		2
Replace Pneumatic contols with DDC - Gas Heat	C&I		2
Central AC	Res	2	2
QI Central AC	Res	2	2
ASHP (Cooling)	Res	2	2
ASHP (Heating)	Res	2	2
QI ASHP (Cooling)	Res	4	2
QI ASHP (Heating)	Res	4	2
CAC Tune-Up	Res		3
ASHP Tune-Up (Cooling)	Res		3
ASHP Tune-Up (Heating)	Res		3
ES Room AC	Res	1	1
GSHP (Cooling)	Res	5	
GSHP (Heating)	Res	5	
DMSAC	Res	3	
DMSHP (Cooling)	Res	3	2
DMSHP (Heating)	Res	3	2
Duct Sealing, E (Cooling)	Res		3
Duct Sealing, E (Heating)	Res		3
Duct Sealing, G	Res		3
Smart Tstat, E (Cooling)	Res	2	1
Smart Tstat, E (Heating)	Res	2	1
Smart Tstat, G	Res	2	1
Learning Tstat, E (Cooling)	Res	2	1

Learning Tstat, E (Heating)	Res	2	1
Learning Tstat, G	Res	2	1
ES Ceiling Fan	Res	1	
ES Bathroom Ventilation Fan	Res	1	
ECM Blower Motor	Res	4	
ECM Circulators, DHW	Res		4
ECM Circulators, CW	Res		4
ECM Circulators, HW	Res		4
HEMS	Res	3	3
ES Solar Water Heater	Res	5	5
Heat Pump Water Heater	Res	2	2
Faucet Aerator	Res	1	1
Low Flow Showerhead	Res	1	1
Water Heater Pipe Insulation	Res		3
Water Heater Jacket	Res	1	1
WH Drainpipe Heat Exchange	Res	4	4
Water Heater Setback	Res		3
Therm Restriction Valve	Res	5	5
ES SF Clothes Washer (App)	Res	1	2
ES SF Clothes Washer (WH)	Res	1	2
ES MF Clothes Washer (App)	Res	1	2
ES MF Clothes Washer (WH)	Res	1	2
ES SF Clothes Dryer	Res	1	2
ES MF Clothes Dryer	Res	1	2
ES Dehumidifier	Res	1	
ES Dishwasher (App)	Res	1	
ES Dishwasher, WH	Res	1	
ES Refrigerator	Res	1	
ES Freezer	Res	1	
Fridge and Freezer Removal	Res		1
ES Air Purifier	Res	1	
ENERGY STAR Pool Pump	Res	2	2
Tier 2 Power Strip	Res		1
ES Desktop Computer	Res	1	
Efficient Windows (Cooling)	Res	2	
Efficient Windows (Heating)	Res	2	
Window Attachments (Cooling)	Res		5
Window Attachments (Heating)	Res		5
Attic Insulation, E (Cooling)	Res		3
Attic Insulation, E (Heating)	Res		3
Attic Insulation, G	Res		3
Air Sealing, E (Cooling)	Res		3
Air Sealing, E (Heating)	Res		3
Air Sealing, G	Res		3

LED Screw-in Lamp (18)	Res	1	
LED Screw-in Lamp (19)	Res	1	
LED Screw-in Lamp (20)	Res	1	
LED Screw-in Lamp (21)	Res	1	
ES LED Downlight Fixture (18)	Res	1	
ES LED Downlight Fixture (19)	Res	1	
ES LED Downlight Fixture (20)	Res	1	
ES LED Downlight Fixture (21)	Res	1	
LED DI (18)	Res		1
LED DI (19)	Res		1
LED DI (20)	Res		1
LED DI (21)	Res		1
Occupancy Sensors	Res		2
Smart LED Screw-in Lamp	Res	3	
Ext Motion Sensor	Res		2
Net Zero Energy Home	Res	5	
Energy Efficient New Home - Single Family	Res	3	
ENERGY STAR Manufactured Home	Res	3	
Energy Efficient New Home - Multi Family	Res	3	
Home Energy Reports Q3, Electric	Res		1
Conservation Voltage Reduction	Res		1
Integrated bldg design -Gas	C&I	3	
Retrocommissioning/Calibrate Sensors - Gas Heat	C&I		4
Building Management System - Gas Heat	C&I		4
HP Window Glaze Gas	C&I	2	
ES LED PAR/Flood Lamp, Ext (18)	Res		1
ES LED PAR/Flood Lamp, Ext (19)	Res		1
ES LED PAR/Flood Lamp, Ext (20)	Res		1
ES LED PAR/Flood Lamp, Ext (21)	Res		1
ENERGY STAR Pool Pump	C&I	4	4
Data Center Retrofit	C&I		5

APPENDIX B: SALES DISSAGGREGTION

Table 47 | Residential Sales Disaggregation

End Use	Non Low-Income	Low-Income
Space Heating	9%	9%
Cooling	16%	16%
Water Heating	7%	7%
Indoor Lighting	4%	4%
Exterior Lighting	1%	1%
Plug Load	6%	6%
Appliance	7%	6%
Total	**51%**	**49%**

Table 48 | Commercial and Industrial Sales Disaggregation

End Use	Small Office	Large Office	Small Retail	Large Retail	Wareh ouse	Educa-tion	Food Sales	Health	Lodg-ing	Rest-aurant	Indus-trial	Other
Space Heating	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.2%	0.1%	0.0%	0.1%
Cooling	1.7%	1.1%	1.8%	1.2%	0.4%	3.1%	0.2%	2.1%	3.0%	1.1%	0.5%	3.5%
Ventilation	1.8%	1.2%	1.4%	0.9%	0.1%	1.4%	0.2%	1.4%	2.2%	0.7%	0.5%	1.0%
Water Heating	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.2%	0.1%	0.0%	0.0%
Indoor Lighting	1.3%	0.9%	1.7%	1.1%	0.7%	1.7%	0.3%	1.1%	2.0%	0.4%	0.4%	1.9%
Exterior Lighting	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.2%	0.0%	0.0%	0.2%
Cooking	0.0%	0.0%	0.1%	0.1%	0.0%	0.1%	0.2%	0.1%	0.6%	1.2%	0.0%	0.0%
Refrigeration	0.2%	0.2%	2.1%	1.4%	0.3%	0.8%	2.4%	0.3%	1.6%	2.4%	0.1%	0.6%
Plug Load	1.6%	1.0%	0.4%	0.3%	0.2%	1.8%	0.1%	0.8%	2.3%	0.2%	0.5%	1.1%
Other	1.2%	0.8%	1.2%	0.8%	0.6%	1.4%	0.2%	1.3%	3.8%	0.5%	0.4%	3.0%
Industrial Process	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.7%	0.0%
ElecTotal	8.0%	5.4%	9.0%	6.0%	2.4%	10.5%	3.9%	7.4%	16.3%	6.8%	13.1%	11.3%

APPENDIX C: LOADSHAPES

See below for the loadshapes used to distribute the savings to the four avoided costs periods. As described above, these periods are:

- Summer on-peak is April – October, 9 AM – 9 PM Weekdays
- Summer off-peak is the rest of the time in April-October
- Winter on-peak is Nov- Mar, 7 AM – 10 AM and 6 PM – 10PM Weekdays
- Winter off-peak is the rest of the time in Nov-Mar

Table 49 | Residential Loadshapes

End Use	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Space Heating	0.4%	0.8%	27.6%	71.2%
Cooling	44.5%	49.1%	1.9%	4.5%
Ventilation	22.4%	25.0%	14.8%	37.9%
Water Heating	18.2%	33.7%	15.3%	32.8%
Indoor Lighting	28.7%	30.6%	13.9%	26.8%
Outdoor Lighting	11.2%	47.4%	8.8%	32.6%
Refrigeration	20.2%	41.5%	10.0%	28.2%
Plug Load	24.2%	34.9%	12.8%	28.1%
Other	23.0%	32.0%	13.4%	31.6%
Appliance	22.7%	34.8%	12.2%	30.3%
Total Building	23.0%	32.0%	13.4%	31.6%

Table 50 | C&I Loadshapes

End Use	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Space Heating	0.6%	3.5%	28.5%	67.4%
Cooling	41.8%	47.2%	3.0%	8.0%
Ventilation	19.1%	38.9%	10.6%	31.4%
Water Heating	22.7%	28.4%	13.8%	35.1%
Indoor Lighting	26.6%	32.2%	11.9%	29.2%
Outdoor Lighting	11.2%	47.4%	8.8%	32.6%
Cooking	20.8%	34.4%	12.1%	32.6%
Refrigeration	21.6%	42.0%	9.5%	27.0%
Plug Load	23.0%	35.7%	11.1%	30.2%
Other	20.8%	34.4%	12.1%	32.6%
Industrial Process	23.0%	35.9%	12.4%	28.7%
Total Building	20.8%	34.4%	12.1%	32.6%

APPENDIX D: MEASURE CHARACTERIZATIONS

This appendix shows the measure characterizations used for the study. Each measure characterization may have two different characterizations, one for market driven (MD) transactions and one for retrofit (RET) situations. Measures that show "N/A" for the TRC are one part of a linked measure. Linked measures are measures that produce savings for more than end use. For example, a heat pump produces different savings percentages for cooling and heating savings. Our analysis allocates all of the costs to just one of the end uses, but savings are kept separate because they have different loadshapes. In order to calculate TRC, costs and benefits are summed across all parts of the linked measures.

Table 51 | Residential Measure Level Information

Measure Name	Market	TRC	% Savings	$/kWh (annual)	Measure Life
Central AC	MD	2.65	26%	$0.44	19
Central AC	RET	1.09	38%	$1.39	19
QI Central AC	MD	2.12	28%	$0.55	19
QI Central AC	RET	1.30	45%	$1.25	19
ASHP (Cooling)	MD	1.38	28%	$1.18	16
ASHP (Heating)	MD	1.57	72%	$-	16
ASHP (Cooling)	RET	N/A	45%	$1.26	16
ASHP (Heating)	RET	N/A	72%	$-	16
QI ASHP (Cooling)	MD	4.51	36%	$-	16
QI ASHP (Heating)	MD	1.71	75%	$0.28	16
QI ASHP (Cooling)	RET	N/A	51%	$1.17	16
QI ASHP (Heating)	RET	N/A	75%	$-	16
CAC Tune-Up	RET	0.30	5%	$0.54	2
ASHP Tune-Up (Cooling)	RET	0.63	8%	$0.31	2
ASHP Tune-Up (Heating)	RET	N/A	8%	$-	2
ES Room AC	MD	2.96	9%	$0.20	9
ES Room AC	RET	1.58	9%	$1.23	9
GSHP (Cooling)	MD	N/A	36%	$-	18
GSHP (Heating)	MD	0.24	76%	$2.01	18
DMSAC	MD	0.43	43%	$2.61	18
DMSHP (Cooling)	MD	6.79	50%	$0.28	18
DMSHP (Heating)	MD	2.00	81%	$-	18
DMSHP (Cooling)	RET	N/A	50%	$0.95	18
DMSHP (Heating)	RET	N/A	81%	$-	18
Duct Sealing, E (Cooling)	RET	9.60	21%	$0.23	18
Duct Sealing, E (Heating)	RET	N/A	21%	$-	18
Duct Sealing, G	RET	6.84	21%	$0.23	18
Smart Tstat, E (Cooling)	RET	0.65	5%	$1.26	10
Smart Tstat, E (Heating)	RET	0.79	5%	$-	10
Smart Tstat, G	RET	N/A	5%	$1.26	10

Smart Tstat, E (Cooling)	MD	N/A	5%	$1.26	10
Smart Tstat, E (Heating)	MD	0.68	2%	$-	10
Smart Tstat, G	MD	0.68	5%	$1.26	10
Learning Tstat, E (Cooling)	RET	1.71	9%	$0.69	10
Learning Tstat, E (Heating)	RET	1.66	9%	$-	10
Learning Tstat, G	RET	N/A	9%	$0.69	10
Learning Tstat, E (Cooling)	MD	N/A	9%	$0.69	10
Learning Tstat, E (Heating)	MD	1.32	9%	$-	10
Learning Tstat, G	MD	1.46	9%	$0.76	10
ES Ceiling Fan	MD	2.09	44%	$0.62	20
ES Bathroom Ventilation Fan	MD	0.26	72%	$2.56	19
ECM Blower Motor	MD	4.64	50%	$0.22	18
ECM Circulators, DHW	RET	2.50	90%	$0.30	15
ECM Circulators, CW	RET	2.05	82%	$0.34	15
ECM Circulators, HW	RET	0.42	82%	$2.88	15
HEMS	MD	0.53	15%	$1.02	15
HEMS	RET	0.53	15%	$1.02	15
ES Solar Water Heater	RET	0.08	90%	$4.34	15
ES Solar Water Heater	MD	0.12	85%	$5.86	15
Heat Pump Water Heater	RET	0.18	64%	$7.71	10
Heat Pump Water Heater	MD	0.04	59%	$0.99	10
Faucet Aerator	RET	1.29	26%	$0.25	10
Faucet Aerator	MD	1.27	26%	$0.25	10
Low Flow Showerhead	RET	3.44	37%	$0.09	10
Low Flow Showerhead	MD	3.61	37%	$0.09	10
Water Heater Pipe Insulation	RET	2.36	60%	$0.16	12
Water Heater Jacket	RET	1.06	28%	$0.38	13
WH Drainpipe Heat Exchange	RET	0.50	25%	$1.36	20
WH Drainpipe Heat Exchange	MD	0.48	25%	$1.36	20
Water Heater Setback	RET	1.39	4%	$0.05	2
Therm Restriction Valve	RET	0.47	12%	$0.40	10
Therm Restriction Valve	MD	0.76	12%	$0.67	10
ES SF Clothes Washer (App)	MD	2.49	34%	$1.15	14
ES SF Clothes Washer (WH)	MD	0.22	37%	$-	14
ES SF Clothes Washer (App)	RET	N/A	40%	$11.48	14
ES SF Clothes Washer (WH)	RET	N/A	43%	$-	14
ES MF Clothes Washer (App)	MD	9.63	34%	$0.29	14
ES MF Clothes Washer (WH)	MD	N/A	37%	$-	14
ES SF Clothes Dryer	MD	5.07	21%	$0.26	12
ES MF Clothes Dryer	MD	18.98	21%	$0.07	12
ES Dehumidifier	MD	1.66	21%	$0.27	12
ES Dishwasher (App)	MD	N/A	12%	$-	15
ES Dishwasher, WH	MD	4.91	12%	$0.48	15
ES Refrigerator	MD	2.10	12%	$0.25	15

ES Freezer	MD	1.32	10%	$0.29	11
Fridge and Freezer Removal	RET	3.17	100%	$0.09	8
ES Air Purifier	MD	13.90	73%	$0.02	9
ENERGY STAR Pool Pump	MD	0.40	69%	$0.17	10
ENERGY STAR Pool Pump	RET	0.30	79%	$1.15	10
Tier 2 Power Strip	RET	1.68	51%	$0.32	10
ES Desktop Computer	MD	3.23	50%	$0.06	4
Efficient Windows (Cooling)	MD	4.19	10%	$0.51	25
Efficient Windows (Heating)	MD	N/A	10%	$-	25
Window Attachments (Cooling)	RET	1.14	9%	$0.81	10
Window Attachments (Heating)	RET	N/A	11%	$-	10
Attic Insulation, E (Cooling)	RET	2.48	21%	$0.95	20
Attic Insulation, E (Heating)	RET	N/A	21%	$-	20
Attic Insulation, G	RET	1.84	21%	$0.95	20
Air Sealing, E (Cooling)	RET	2.23	8%	$0.53	11
Air Sealing, E (Heating)	RET	N/A	8%	$-	11
Air Sealing, G	RET	1.87	8%	$0.53	11
LED Screw-in Lamp (18)	MD	1.88	82%	$0.10	4
LED Screw-in Lamp (19)	MD	1.42	82%	$0.10	3
LED Screw-in Lamp (20)	MD	0.96	82%	$0.10	2
LED Screw-in Lamp (21)	MD	0.48	82%	$0.10	1
ES LED Downlight Fixture (18)	MD	2.27	88%	$0.09	4
ES LED Downlight Fixture (19)	MD	1.72	88%	$0.09	3
ES LED Downlight Fixture (20)	MD	1.16	88%	$0.09	2
ES LED Downlight Fixture (21)	MD	0.58	88%	$0.09	1
LED DI (18)	RET	1.01	82%	$0.16	15
LED DI (19)	RET	0.76	82%	$0.16	15
LED DI (20)	RET	0.52	82%	$0.16	15
LED DI (21)	RET	0.26	82%	$0.16	15
Occupancy Sensors	RET	1.00	40%	$0.44	10
Smart LED Screw-in Lamp	MD	0.14	10%	$5.16	16
Ext Motion Sensor	RET	0.99	40%	$0.30	10
Net Zero Energy Home	MD	0.70	100%	$1.62	30
Energy Efficient New Home - Single Family	MD	3.37	35%	$0.34	30
ENERGY STAR Manufactured Home	MD	2.17	27%	$0.52	30
Energy Efficient New Home - Multi Family	MD	1.59	37%	$0.71	30
Home Energy Reports Q3, Electric	RET	0.98	2%	$0.04	1
Conservation Voltage Reduction	RET	56.53	2%	$0.02	30
ES LED PAR/Flood Lamp, Ext (18)	RET	1.79	82%	$0.07	4
ES LED PAR/Flood Lamp, Ext (19)	RET	1.35	82%	$0.07	3
ES LED PAR/Flood Lamp, Ext (20)	RET	0.92	82%	$0.07	2
ES LED PAR/Flood Lamp, Ext (21)	RET	0.46	82%	$0.07	1

Table 52 | Commercial Measure Level Information

Measure	Market	TRC	% Savings	$/kWh (annual)	Measure Life
ESTAR Room AC	MD	2.24	9%	$0.23	9
Exterior Canopy/Soffit LED	RET	0.64	78%	$0.34	10.2
Exterior Canopy/Soffit LED	MD	0.94	77%	$0.51	10.2
Exterior Wall Pack LED	RET	0.39	78%	$0.19	10.2
Exterior Wall Pack LED	MD	1.74	76%	$0.84	10.2
Improved Ext Lgt Design	MD	2.13	42%	$0.23	15
Heat Pump Water Heater	MD	0.22	35%	$0.86	10
Heat Pump Water Heater	RET	0.04	40%	$8.62	10
High Volume Low Speed Fans	MD	1.57	82%	$0.22	15
Mini Split Ductless HP-Cool	MD	0.93	47%	$0.24	15
Mini Split Ductless HP-Heat	MD	3.16	72%	$-	15
Mini Split Ductless HP-Cool	RET	N/A	47%	$0.83	15
Mini Split Ductless HP-Heat	RET	N/A	72%	$-	15
Optimized unitary HVAC distribution/control system	MD	0.87	30%	$1.02	15
Optimized chiller distribution/control system	MD	0.55	20%	$1.02	15
Int Ltg Controls	RET	4.55	34%	$0.06	8
Exit Sign Retrofit	RET	2.61	97%	$0.25	16
High Bay LED	RET	0.36	43%	$0.71	11.3
Incand. Over 100W Ret, Fixt.	RET	0.84	74%	$0.51	11.3
Incand. Over 100W Ret, Lamp	RET	2.50	76%	$0.04	3.4
Incand. Up to 100W Ret, Fixt.	RET	0.80	71%	$0.48	11.3
Incand. Up to 100W Ret, Lamp	RET	2.30	72%	$0.05	3.4
LED Troffers	RET	0.49	52%	$0.81	11.3
Com LED Tube Replacement Lamps	RET	3.85	58%	$0.07	11.3
Refrigerated Case LED	RET	2.03	73%	$0.22	10
Stairwell Occupancy Sensors	RET	0.81	92%	$0.77	14.4
LED Street Lighting	RET	2.25	65%	$0.20	15
VSD, Chilled Water Pump	RET	0.84	43%	$0.54	15
VSD, Heating Hot Water Pump	RET	2.14	48%	$0.21	15
VSD, Condenser Water Pump	RET	0.84	43%	$0.54	15
VSD, HVAC Fan	RET	1.86	26%	$0.24	15
VSD, Cooling Tower Fan	RET	0.35	25%	$1.27	15
Demand Control Ventilation-Cool	RET	38.02	10%	$0.18	15
Demand Control Ventilation-Heat	RET	N/A	18%	$-	15
Demand Control Ventilation-Vent	RET	N/A	10%	$-	15
Screw-Based LED	RET	1.18	13%	$0.15	3.4
Retrofit duct sealing fan energy	RET	2.53	13%	$1.49	15
Retrofit duct sealing cool	RET	N/A	7%	$-	15
Retrofit duct sealing HS fan	RET	1.16	51%	$0.89	15
Retrofit duct sealing HS cool	RET	N/A	23%	$-	15

Ground Source HP (Heating)	MD	N/A	33%	$-	20
Ground Source HP (Cooling)	MD	N/A	49%	$1.69	20
Ground Source HP (Heating)	RET	0.48	38%	$-	20
Ground Source HP (Cooling)	RET	0.06	56%	$11.23	20
HE Clothes Washer, elec DHW	MD	7.57	28%	$0.47	11
HE Clothes Washer, elec DHW	RET	1.81	20%	$3.18	11
Ozone Laundry System	RET	2.95	91%	$21.95	20
Office Equipment Controls	RET	1.11	29%	$0.11	3.2
Window Film	RET	0.80	5%	$0.46	10
Cool Roof	MD	2.37	32%	$0.31	20
Cool Roof	RET	0.22	32%	$3.50	20
HE Kitchen Equipment	MD	208.42	27%	$0.12	12
HP Window Glaze (Cooling)	MD	16.13	6%	$0.05	20
HP Window Glaze (Heating)	MD	N/A	24%	$-	20
High Efficiency HP (Heating)	MD	N/A	55%	$-	15
High Efficiency HP (Cooling)	MD	N/A	32%	$0.14	15
High Efficiency HP (Heating)	RET	6.76	59%	$-	15
High Efficiency HP (Cooling)	RET	0.81	42%	$0.87	15
High Efficiency AC	MD	4.18	30%	$0.20	15
High Efficiency AC	RET	0.50	40%	$1.25	15
HP Tune Up (Heating)	RET	N/A	18%	$-	10
HP Tune Up (Cooling)	RET	4.07	10%	$0.13	10
AC Tune Up	RET	4.16	10%	$0.14	10
Commercial Faucet Aerator (Elec WH)	RET	20.15	55%	$0.01	10
ECM Blower Motors	RET	2.31	61%	$0.50	15
Conservation Voltage Reduction	RET	57.53	2%	$0.02	30
Building Management System - Elec Heat	RET	0.39	18%	$1.27	15
Retrocommissioning/Calibrate Sensors - Electric Heat	RET	1.79	16%	$0.17	8
Integrated bldg design -Elec	MD	1.76	31%	$0.50	30
Advanced RTU Control - Elec Heat	MD	1.09	9%	$0.48	15
Advanced RTU Control - Gas Heat	MD	0.98	9%	$0.50	15
Advanced RTU Control - Elec Heat	RET	1.28	9%	$0.48	15
Advanced RTU Control - Gas Heat	RET	1.15	9%	$0.50	15
Network Connected LEDs	RET	0.44	47%	$1.31	15
High Efficiency Chiller vs DX System	MD	0.28	35%	$2.72	20
Replace Pneumatic contols with DDC - Elec Heat	RET	0.48	15%	$1.02	15
Replace Pneumatic contols with DDC - Gas Heat	RET	2.90	15%	$1.24	15
Integrated bldg design -Gas	MD	1.59	31%	$0.56	30
Retrocommissioning/Calibrate Sensors - Gas Heat	RET	1.85	16%	$0.18	8
Building Management System - Gas Heat	RET	0.35	18%	$1.34	15
HP Window Glaze Gas	MD	13.63	6%	$0.05	20
Data Center Retrofit	RET	6.17	22%	$0.12	20
Chiller Tune-Up	RET	2.00	5%	$0.11	5

Cooler Night Cover	RET	0.51	7%	$0.32	5
High Efficiency Chiller	MD	1.10	14%	$0.56	10
High Efficiency Chiller	RET	0.15	22%	$3.44	10
Replace Cooler and Freezer Door Gaskets	RET	0.76	3%	$0.18	5
Reach-in Storage Refrigerator	MD	1.55	37%	$0.31	12
HE Small Walk-In	MD	5.47	40%	$0.10	13
Refrigeration Retrofit	RET	1.36	32%	$0.36	13
Strip Curtains	RET	2.45	15%	$0.05	4
Pre-Rinse Sprayers	RET	4.80	32%	$0.12	10
Control System for Hospitality	RET	6.17	19%	$0.08	8
Control System for Hospitality	MD	5.65	19%	$0.08	8
ENERGY STAR Pool Pump	MD	2.24	69%	$0.17	10
ENERGY STAR Pool Pump	RET	0.33	69%	$0.17	10
Compressed Air	MD	1.90	22%	$0.23	10
Compressed Air	RET	1.74	22%	$0.23	10