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December 13, 2024

Via Electronic Delivery
Clerk of Council
Council of the City of New Orleans
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: **In Re: 2024 Triennial Integrated Resource Plan of Entergy New Orleans, LLC**
Docket No. UD-23-01

Dear Clerk of Council:

Entergy New Orleans, LLC ("ENO") respectfully submits the Public Version of its 2024 Integrated Resource Plan for filing in the above-referenced docket.

Appendices B, C, E and H of the 2024 Integrated Resource Plan contain information that is designated as Highly Sensitive Protected Materials ("HSPM"). An HSPM version of these Appendices are being produced only to those representatives who are authorized to review such information under the terms of the provisions of the Official Protective Order adopted pursuant to Resolution No. R-07-432 relative to the disclosure of Protected Materials.

ENO submits this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations or as you direct. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

Should you have any questions regarding this matter, please do not hesitate to contact me.

Sincerely,

Keith D. Wood

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

CERTIFICATE OF SERVICE
UD-23-01

I hereby certify that I have served the required number of copies of the foregoing pleading upon all other known parties of this proceeding individually and/or through their attorney of record or other duly designated individual.

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Keith D. Wood




Entergy New Orleans, LLC

2024 Integrated Resource Plan

December 13, 2024

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Abbreviations & Definitions

AMI	Advanced Metering Infrastructure
ANO	Arkansas Nuclear One
BESS	Battery Energy Storage Systems
BOT	Build-Own-Transfer
BP24	Business Plan 2024
CCCT	Combined Cycle Combustion Turbine
CDD	Cooling Degree Days
CEO	Chief Executive Officer
Council	Council of the City of New Orleans
CT	Combustion Turbine
DER	Distributed Energy Resource
DLC	Direct Load Control
DLOL	Direct Loss of Load
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ENO	Entergy New Orleans, LLC
Entergy	Entergy Corporation
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GPO	Green Power Option program
Grand Gulf	Grand Gulf Nuclear Station
Guidehouse	Guidehouse Consulting, Inc.
GOM	Gulf of Mexico
GW, GWh	Gigawatt, Gigawatt Hour
HDD	Heating Degree Days
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Installed Generation Capacity
IFOM	In Front of the Meter
IRA	Inflation Reduction Act
IRP	Integrated Resource plan
ISAC	Intermediate Seasonal Accredited Capacity
ITC	Investment Tax Credits
kW, kWh	Kilowatt, Kilowatt Hour
LCOE	Levelized Cost of electricity
LCR	Local Clearing Requirement
LMP	Locational Marginal Price
LMR	Load Modifying Resource
LOLE	Loss of Load Expectation
LRZ	Local Resource Zone
LSE	Load Serving Entity
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
MW, MWh	Megawatt, megawatt Hour
NERC	North American Electric Reliability Corporation
NOx	Oxides of Nitrogen
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory Annual Technology Baseline
NTG	Net-to-Gross
OEM	Original Equipment Manufacturer
POV	Point of View
PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credits
PV	Solar Photovoltaic
RBDC	Reliability Based Demand Curve
REC	Renewable Energy Certificate
RICE	Reciprocating Internal Combustion engine
RCPS	Renewable and Clean Portfolio Standard
RTO	Regional Transmission organization
SERC	Southeastern Electric Reliability Council
SLR	Subsequent License Renewal
SO2	Sulfur Dioxide
SWB	Sewerage & Water Board of New Orleans
TRSC	Total Relevant Supply cost
WB	White Bluff Steam Electric Station
UCAP	Unforced Generation Capacity
Union 1	Union Power Block 1
UPC	Use Per Customer
WACC	Weighted Average Cost of Capital
ZRCs	Zonal Resource Credits

Executive Summary

Continued Productive Collaboration

This 2024 Integrated Resource Plan ("IRP") report builds on the collaborative efforts and productive process that characterized the development of the 2021 IRP. Working under the current IRP Rules adopted by the Council of the City of New Orleans ("Council"),[1] as well as the direction and schedule provided by the Council in the 2024 IRP Initiating Resolution, R-23-254, the parties have engaged in constructive discussions over the last 16 months about the inputs and analysis required to develop the 2024 IRP during a stakeholder process that included a series of four technical meetings.[2] The result is a report that meets the goal expressed in the preamble to the IRP Rules: "It is the Council's desire that a comprehensive IRP conducted in accordance with these IRP Rules provide **a full picture** of all **reasonably available resource options** in light of current and expected market conditions and technology trends, and generate an informed understanding of the **economic, reliability, and risk evaluation** of utility resource planning as well as associated **social and environmental impacts.**" Following is some additional context on these key elements:

1. **A full picture** - This IRP provides a broad view of options for meeting customers' electrical needs across the 20-year planning period from 2025-44 in light of current and expected market conditions and technology trends. Starting with assumptions and inputs developed for ENO's Business Plan 2024 ("BP24"), analysis was performed on three different Planning Scenarios that varied a number of key assumptions about future market conditions outside New Orleans and four different Planning Strategies that assessed policy and planning objectives within the city. The parameters of these Scenarios and Strategies were discussed and agreed upon by the parties during the stakeholder process mentioned above. Important variables among the four Strategies included the assumed potential savings from, and costs of, Demand Side Management ("DSM") programs over the 20-year period and local policy drivers. DSM assumptions came from a DSM Potential Study prepared by Guidehouse which presented projections of future DSM achievable potential. Renewables cost inputs came from the Entergy Technology Assessment. A discussion of the Scenarios and Strategies can be found in Chapter 3.1.
2. **All reasonably available resource options** - As required by the IRP Rules, each Strategy was analyzed in the context of each Scenario to identify an optimized Portfolio of resources to serve customers' needs under that combination of assumptions. Given the combination of three Scenarios times four Strategies, this resulted in an initial set of 12 Optimized Portfolios. These Portfolios included different combinations of renewables, battery storage, and DSM programs depending on their particular assumptions. Additionally, two manual portfolios were produced that assumed alternative deactivation dates for Union 1 of 2032 and 2035. The parties reviewed all the portfolios and agreed on a representative subset of five Portfolios to carry through the remainder of the detailed total relevant supply cost analysis. A discussion of the results of the optimized and downselected Portfolios can be found in further detail in Chapter 3.4.

[1] See, Council Resolution No. R-17-429.

[2] Technical Meeting #1 was held November 9, 2023, Technical Meeting #2 was held February 29, 2024, Technical Meeting #3 was held May 7, 2024, and Technical Meeting #4 was held October 2, 2024.

3. **Economic, reliability, and risk evaluation** - The analysis of total relevant supply cost, which represents the incremental fixed costs and total variable supply costs to serve customers' resource needs reliably under the assumptions of a particular Portfolio through the planning horizon, used cross-testing to identify a 20-year revenue requirement for each of the five downselected Portfolios in all three Scenarios. Additionally, stochastic analysis was conducted on the five downselected Portfolios to evaluate their sensitivity to changes in two main input assumptions—natural gas price and CO2 price. Information on the total relevant supply costs and risk analysis can be found in Chapters 3.5–3.7.
4. **Social and environmental impacts** - The IRP Rules require the development of a Scorecard to assist the Council in assessing the IRP based on several aspects of the Resource Portfolios, including social and environmental impacts, some of which are only able to be evaluated on a subjective basis. Starting from the Scorecard developed for the 2021 IRP, the parties affirmed the continued use of several metrics and agreed on additional metrics through the Stakeholder process. More discussion of the Scorecard can be found in Chapter 3.8.

Key Takeaways

The analysis performed on the various downselected portfolios in the 2024 IRP indicates that the optimal mix of resources to serve ENO's electric customers will depend heavily on ENO's capacity need and the market conditions and policies in place at the time. The timing of capacity needs, as well as the amounts and types of resources best suited to fill those needs, varied significantly in the IRP analysis based on the constraints imposed on the Scenario and Strategy under which portfolios were developed.

In the 2024 IRP, the Least Cost Planning portfolio developed under Strategy 1/Scenario 1 included the current 2041 deactivation assumption for Union 1, while Manual Portfolio 1b, also developed under Strategy 1/Scenario 1 but with an assumed deactivation of Union 1 in 2035, showed a Total Relevant Supply Cost approximately 2% lower over 20 years. For comparison, the manual portfolios in the 2021 IRP that accelerated the deactivation of Union 1 resulted in TRSC values about 8% higher than the Least Cost Planning portfolio over the 20 year planning horizon. The results of the manual portfolio analysis over the last two IRPs underscore the sensitivity of the TRSC results to Scenario and Strategy input assumptions and the value of further analysis in future IRPs.

The IRP will serve as a near-term source to inform the implementation of Energy Smart DSM programs in the city over the next few years. The programs identified in the 20 year potential study will be valuable inputs to the Program Year 16-18 implementation plan for 2026-2028 that will be filed in 2025 for review by the Council.

This IRP will inform the Company's compliance efforts under the Council's RCPS adopted in Docket UD-19-01. The Company is required under the RCPS rules to develop its three year prospective Compliance Plan for 2026-2028 based on this IRP report. The Scenario 1 total relevant supply cost for the optimized portfolio produced for Strategy 2/Scenario 1 (designated as the "But For RCPS" portfolio) will be used as the baseline for calculating incremental costs associated with the three-year RCPS compliance plan for 2026-2028 in accordance with Section 4.d.1 of the RCPS rules. ENO's generation portfolio already emits far less CO2 than the national average for investor-owned utilities, with an estimated 2023 CO2 emission rate of 372 lbs/MWh.[3] This IRP analysis will support our efforts to continue reducing our CO2 emissions and comply with the Council's RCPS goals.

[3] See: https://cdn.entergy-neworleans.com/userfiles/your_business/Entergy-New-Orleans-2023-Emission-Rate-Information.pdf

ENO has made progress in developing tools and processes to support the interconnection and planning of distributed energy resources (such as solar generation and battery storage) on its distribution grid. As required by the Council, the IRP report describes the improvements ENO has made in its ability to evaluate locational and reliability benefits and impacts of distributed energy resources.

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

Action Plan

There are numerous ongoing and planned activities that are important to supporting Council goals and Company initiatives in the near term. Some of these include filing the Energy Smart PY 16-18 Implementation Plan for 2026-28 and the RCPS Compliance Plan for 2026-28 discussed above. Additional efforts include active participation in the ongoing Community Solar and DER Programs dockets, developing and submitting proposals for further resilience and storm hardening projects, and identifying and pursuing available sources of federal funding in connection with infrastructure projects. The Action Plan for pursuing these efforts is found in Chapter 4.

In conclusion, ENO greatly appreciates the continued, collaborative efforts of the Council, its Advisors, Intervenors, and the public that resulted in this 2024 IRP report. The IRP continues to be an instructive view of resource options under a range of possible future Scenarios that should be useful in ongoing discussions about meeting the electricity needs of ENO's customers and supporting the policy goals of the Council.

CHAPTER

1

Integrated Resource Planning Process

1.1: Planning Principles and Objectives

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

Planning Objectives

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

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

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

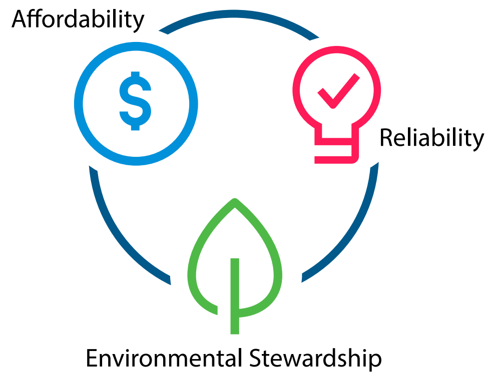


FIGURE 1: KEY PLANNING OBJECTIVES

- Affordability means keeping customer costs reasonable, considering current and future cost impacts of infrastructure improvements made on behalf of our customers, and taking advantage of scale to provide cost synergies.
- Reliability means ensuring that the stability of the grid is maintained through adequate resources to meet capacity and energy needs, along with adequate transmission and distribution systems to ensure that power is consistently delivered to customers.
- Environmental stewardship refers to the use and protection of the natural environment, ensuring compliance with existing and likely regulation, adaptability[4] of resources, and progress towards a lower carbon economy.

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

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

Our customers' needs and interests continue to change, as do the technologies available to meet those needs and the associated local and federal policies. Consistent review of technology options and cost and operational data, and further innovation on grid configuration, open new possibilities to meet customer need while realizing our planning objectives. Improvements in existing generating technology, new and innovative clean generating technologies, and increased data availability provide new tools for ENO to continue to meet customer needs reliably and affordably. Additionally, we continue to monitor pricing of utility-scale renewable energy and explore energy storage and technologies that utilize

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

alternative fuels as possible resources. As options for smaller grid-connected devices like distributed generation and energy storage increase, both at a utility and customer level, different grid configurations could become more viable to meet customer needs.

1.2: Existing Resources

As shown in Tables 1 and 2 below, ENO's portfolio includes a mix of nuclear, efficient gas-fired generation, renewables, and load modifying resources.

ENO currently controls about 1.4 GW of generation capacity either through direct ownership or contracts with affiliate Entergy Operating Companies and other counterparties. The tables below show ENO's current generation portfolio by unit and fuel type. Capacity ratings are shown in MW of accredited capacity for the summer season.

TABLE 1: ENO 2024 RESOURCE PORTFOLIO BY FUEL TYPE

Unit Type	Capacity Rating	Percentage of Portfolio
CCCT	632.9	45%
Nuclear	423.1	30%
Coal	32.9	2%
Solar	88.9	6%
Legacy Gas	43.0	3%
CT/Rice	129.1	9%
Hydro	3.3	0%
PPA	8.8	1%
LMR	29.4	2%
Total	**1391.4**	**100%**

TABLE 2: ENO 2024 RESOURCE PORTFOLIO BY UNIT

Plant	Unit	MW	Fuel Type	Typical Operating Role	Operation Date
Acadia	1	6.5	CCCT	Base Load/Load Following	2002
ANO	1	23.1	Nuclear	Base Load	1974
ANO	2	27.2	Nuclear	Base Load	1980
Grand Gulf EAMP		31.6	Nuclear	Base Load	1985
Grand Gulf ELMP		3.3	Nuclear	Base Load	1985
Grand Gulf ENMP		216.0	Nuclear	Base Load	1985
Independence	1	7.2	Coal	Base Load/Load Following	1983
Iris Solar PPA		49.5	Solar	Renewable	2022
Little Gypsy	2	6.7	Legacy Gas	Seasonal Load Following	1955
Little Gypsy	3	9.2	Legacy Gas	Seasonal Load Following	1959
New Orleans Power Station		128.5	CT/Rice	Peaking/Reserves	2020
New Orleans Solar Station		19.6	Solar	Peaking/Reserves	2020
Ninemile	4	13.4	Legacy Gas	Seasonal Load Following	1971
Ninemile	5	13.6	Legacy Gas	Seasonal Load Following	1973
Ninemile	6	117.0	CCCT	Base Load/Load Following	2015
Perryville	1	2.6	CCCT	Base Load/Load Following	2002
Perryville	2	0.7	CCCT	Peaking/Reserves	2001
Riverbend		100.3	Nuclear	Base Load	1986
St. James Solar PPA		19.8	Solar	Renewable	2022
Union Power Block	1	506.2	CCCT	Base Load/Load Following	2016
Vidalia		3.3	Hydro	Renewable	1985
Waterford	2	0.0	Legacy Gas	Seasonal Load Following	1975
Waterford	3	21.5	Nuclear	Base Load	1985
Waterford	4	0.6	CT/Rice	Peaking/Reserves	2009
White Bluff	1	12.3	Coal	Base Load/Load Following	1980
White Bluff	2	13.4	Coal	Base Load/Load Following	1981
Third Party PPA		8.8	PPA	N/A	N/A
Load Modifying Resources		29.4	LMR	Peaking/Reserves	N/A
Total		**1391.4**			

1.3: Future of Existing Resources

The IRP includes deactivation assumptions for existing generation in order to plan for and evaluate the best options for replacing that capacity over the planning horizon. Based on current planning assumptions, during the planning period, the total net reduction in ENO's generating capacity from the anticipated unit deactivations is expected to be approximately 675 MWs. Generally, current planning assumptions reflect generic deactivation assumptions for the generation fleet: 60 years for coal and legacy gas resources, and 30 years for combustion turbine ("CT") technology which includes both CTs and combined cycle combustion turbines ("CCCTs"). As resources age and assumed deactivation dates near, as equipment failures occur, or as operating performance diminishes, cross-functional teams are assembled to evaluate whether to keep a particular unit in service for an additional length of time at an acceptable level of cost and reliability. These deactivation assumptions do not constitute a definitive deactivation schedule but are based upon the best available information and are used as planning tools to help prompt cross-functional reviews and recommendations. It is not unusual for these assumptions to change over time, given the dynamic use and operating characteristics of generating resources. ENO's unit deactivation assumptions for the 2024 IRP are outlined below:

Union Power Block 1 – Deactivation currently assumed for Union 1 is 2041, based on an evaluation performed by Entergy's Power Generation team. As shown in Table 2, above, Union 1 accounts for approximately 506 MW of capacity for ENO. The assumed deactivation date of Union 1 was accelerated to 2032 and 2035 in different manual portfolios developed under one of the Planning Strategies.

Affiliate PPAs – ENO receives allocations of several units that could deactivate during the planning period through affiliate life-of-unit Purchased Power Agreements ("PPAs"). These resource deactivations are assumed to total approximately 70 MW of capacity for ENO as shown in Table 2, above.

1.4: Planned Resources

In the near term, ENO is planning to add the battery storage resource included in the Sherwood Forest GRIP project, which is expected to come online in 2026.

1.5: Environmental Considerations

Entergy (along with its subsidiaries such as ENO) aspires to be an industry leader in protecting the environment. Environmental laws, regulations, and orders affect many areas of the Company's business, including restrictions on hazardous and toxic materials, air and water emissions, and waste disposal. ENO is committed to meeting or surpassing compliance with all applicable environmental and regulatory requirements and enhancing the communities it serves.

ENO strives to minimize any potential adverse effects of its activities on the local communities it serves, including the communities of its low-income customers. ENO considers environmental impacts in its policies and planning to minimize adverse environmental effects and to sustain its communities. ENO maintains open communication and seeks opportunities to partner with its stakeholders on environmental concerns.

Entergy has been an industry leader in voluntary climate action for over two decades. In 2001, Entergy was the first U.S. utility to voluntarily limit its carbon dioxide emissions. After beating this target by more than twenty percent, Entergy renewed and strengthened this commitment twice and outperformed by eight percent its 2020 commitment to maintain carbon emissions from Entergy-owned facilities and controllable power purchases through 2020 at twenty percent below year 2000 levels.

Building on its longtime legacy of environmental stewardship, Entergy has enhanced its climate action strategy with near-term goals (to achieve 50% carbon-free energy generating capacity and to reduce the utility emission rate by 50 percent in comparison to Entergy's emission rate from its baseline year of

2000) and a longer-term commitment to work over the next three decades to reduce carbon emissions from its operations to net-zero by 2050.

ENO intends to contribute to the accomplishment of these goals by working to meet the more aggressive emissions goals set by the Council.

1.6: Customer Preferences and Long-Term Planning

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

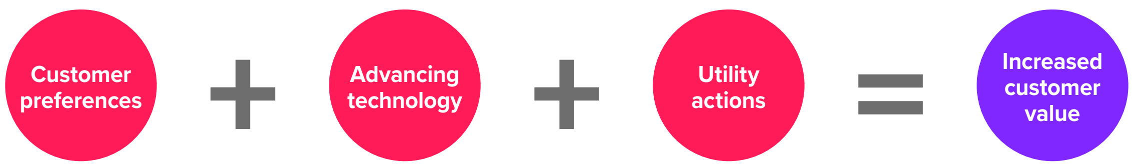


FIGURE 2: CHANGES AND OPPORTUNITIES WITHIN THE UTILITY INDUSTRY

Given ENO's goal to engage its customers to obtain a better sense of their expectations, the IRP is one tool to help accomplish that goal. Increased understanding of customer needs will allow ENO to:

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

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

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

1.7: Innovation

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

For example, ENO expects its customers to increasingly electrify as more vehicle models become available and their prices reach parity with, or become less expensive than, internal combustion engine alternatives. Specific to the commercial space, ENO also sees a growing number of organizations exploring electric vehicle alternatives in order to help them reach their own sustainability goals. ENO's forecasting processes include assumptions around increased energy usage tied to electrification and are discussed in greater detail in Chapter 2.

1.8: MISO Resource Adequacy & Planning Reserve Requirements

MISO Resource Adequacy Requirements

As a load serving entity ("LSE") within MISO since 2013, ENO is responsible for planning and maintaining a resource portfolio to reliably meet our customers' power needs. To this end, we must maintain proper type, location, control, and amount of capacity in our portfolio. With respect to the amount of capacity, two considerations are relevant:

1. MISO's Resource Adequacy requirements
2. Long-term planning reserve margin targets

Resource Adequacy is the process by which MISO obligates participating LSEs to procure sufficient short-term capacity, through the procurement of zonal resource credits ("ZRCs") equal to their seasonal Planning Reserve Margin Requirements ("PRMR"), in order to ensure regional reliability. Both supply-side generation and demand side alternatives provide ZRCs. Load serving entity PRMRs are based on forecasted load coincident with MISO's forecasted peak load, plus transmission losses and a planning reserve margin for each season that MISO establishes for its footprint in an annual study process.

MISO's annual planning resource auction ("PRA") is not, and should not be relied upon as, a long-term source of capacity. MISO relies on LSEs and their retail regulators to ensure each LSE has an appropriate amount of long-term physical capacity to support resource adequacy. If ZRCs submitted in the planning auction are less than the PRMR, the planning resource auction will clear at the Cost of New Entry ("CONE"). Notably, ZRCs are not sold through the planning auction. Rather, utilities participating in the planning auction merely make a payment, up to CONE, that fulfills their obligations vis-a-vis their respective PRMRs. It is possible that other MISO-participating utilities may make such a payment and still not have secured sufficient capacity from identifiable, physical resources to support their loads. This could increase the risk of load shed events. For this reason, reasonable and responsible resource planning requires a long-term plan for physical resources.

Under MISO's Resource Adequacy process, the MISO-wide seasonal planning reserve margins are determined annually by November 1 prior to the upcoming planning year (June-May). MISO determines the amount of physical capacity needed within a particular region or LRZ based on load requirements, capability of existing generation, and import capability of the LRZ. Those capacity requirements are referred to as the LCR for the LRZ for each season in the planning year. Through MISO's proposed changes to the methodology for setting each Local Resource Zone's LCR, MISO has signaled the need for in-zone resources to contribute to LRZ resource adequacy. Table 3 below shows the PY2024-25 seasonal reserve margin targets.

TABLE 3: MISO PLANNING YEAR 2024-25 SEASONAL RESERVE MARGIN TARGETS

Seasonal Reserve Margin Target			
Summer	Fall	Winter	Spring
9.0%	14.2%	27.4%	26.7%

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

MISO market constructs, rules, and methodologies continue to evolve, as do their impacts on Resource Adequacy requirements and capacity accreditation. In November 2021, MISO filed a proposal at the FERC that shifted the annual Resource Adequacy construct to a seasonal construct and modified the way requirements and accreditation are derived. Over the protest of ENO and the other Entergy operating companies, FERC accepted MISO's proposed Tariff changes in August 2022, and these changes were implemented starting with the 2023/2024 planning year.

In light of the recent tariff changes, ENO has adjusted generation planned outage scheduling practices in an effort to protect unit accreditation ratings and has revised PRA unit offer strategies to minimize PRA costs. Our long-term planning approach is currently being re-evaluated to determine what updates are needed to align with MISO's new resource adequacy construct. Additionally, as capacity accreditation for non-thermal resources such as solar, wind, and battery is updated by MISO per FERC's recent approval of MISO's Direct Loss of Load ("DLOL") proposal, ENO and the other Entergy operating companies will also align their long-term planning strategies with these updates. With anticipated increases in renewables penetration, MISO and ENO expect that the capacity value contribution of solar and wind will decline. The seasonal construct and associated accreditation changes are contributing factors driving capacity needs for ENO over the planning period.

It should also be noted that MISO's Resource Adequacy construct is still evolving. As mentioned above, MISO's recent DLOL filing further changed the accreditation methodology for both thermal and non-thermal resources . MISO is also conducting a stakeholder process regarding reforms to LMR accreditation. ENO is engaged and participating in these stakeholder processes and will adapt its long-term planning efforts and strategies to align with the resulting market design changes.

Long-Term Planning Reserve Margin Targets – Although the MISO Resource Adequacy process establishes minimum requirements that must be met in the short term and are reviewed regularly as part of the resource planning process, it does not provide an appropriate basis for determining ENO's long term resource needs. As part of its long term planning construct, ENO used the Aurora model to evaluate summer and winter reserve margin targets based on MISO's Planning Year 2024-2025 Loss of Load Expectation ("LOLE") study as applied to ENO's forecasted summer and winter coincident peak loads for each study year. Candidate resources received seasonal capacity credit consistent with this framework. While MISO's Resource Adequacy construct establishes reserve margins for each season, modeling the summer and winter reserve margin constraints captures the meaningful seasonal variations in performance and accreditation between candidate resources (e.g., solar, wind and gas in summer vs. winter). Adding fall and spring reserve margin constraints would increase modeling complexity without an expected improvement in the capacity expansion portfolios. ENO is currently evaluating its long-term planning reserve margin target in light of MISO's transition to a seasonal Resource Adequacy construct and its RBDC and DLOL proposals.

A key difference between MISO's reserve margin requirements and ENO's view on an appropriate long-term reserve margin is load forecast uncertainty. MISO's LOLE study includes only one year of load forecast uncertainty, while ENO's current long-term target was assessed by modeling a distribution based on economic uncertainty and corresponding forecast error associated with a four-year period, which was the assumed minimum lead time required to plan and install new capacity. As discussed above, ENO will continue to evaluate what changes, if any, should be proposed to the long-term planning construct.

1.9: Resource Needs

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

Long-Term Capacity Requirements – ENO is projected to need new generating capacity over the course of the 20-year IRP period in order to reliably serve customers. Taking deactivation assumptions and load growth into account, the long-term deficit in the winter season is expected to exceed 100 MW by 2037. This need may grow to over 800 MW by the end of the planning horizon. Figures 3 to 6 below show the 2024-25 MISO PRMs along with ENO's existing fleet deactivation assumptions. An assumption for the effect of future energy savings due to continued and expanded EE programs is included in the peak load forecast. The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life.

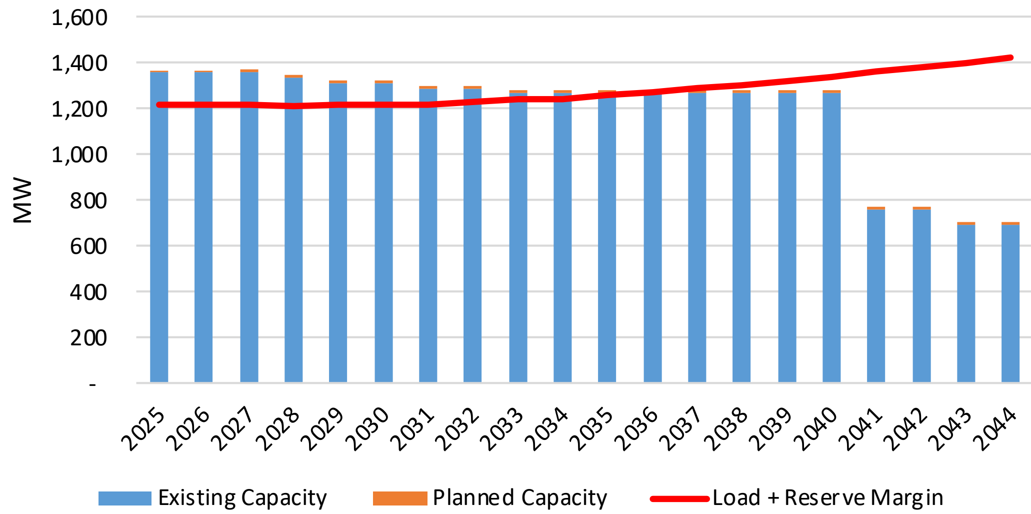


FIGURE 3: ENO SUMMER CAPACITY POSITION

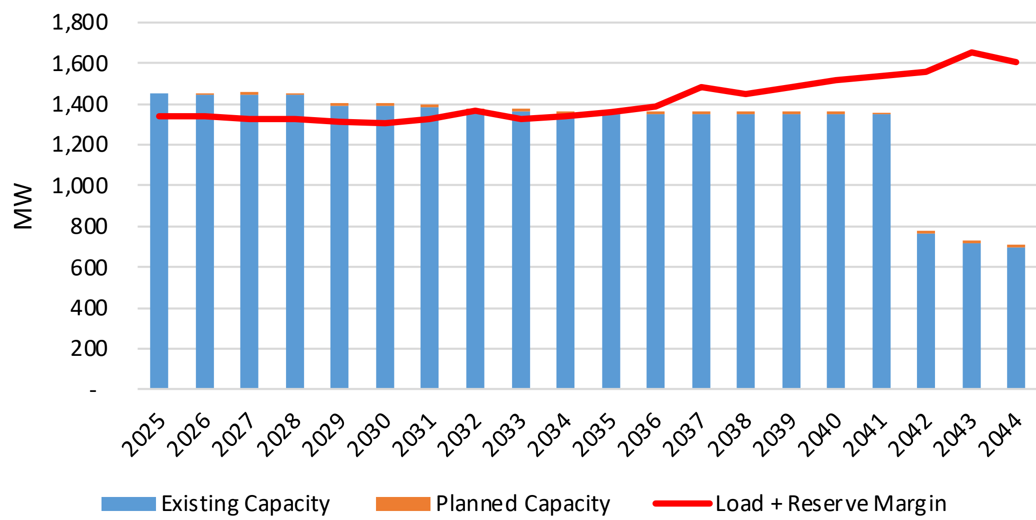


FIGURE 4: ENO WINTER CAPACITY POSITION

Energy Requirements – In addition to addressing long-term capacity requirements, ENO regularly assesses how the current generating fleet is expected to align with its long-term energy requirements. ENO is expected to remain a net seller in MISO's energy markets for the next decade. Without the addition of supply resources, beginning in 2041, ENO is expected to fall short of effectively meeting its long-term energy requirements without relying on the MISO market. However, the amount of energy produced by owned generation is subject to change based on fuel prices, market conditions, and unit operations.

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

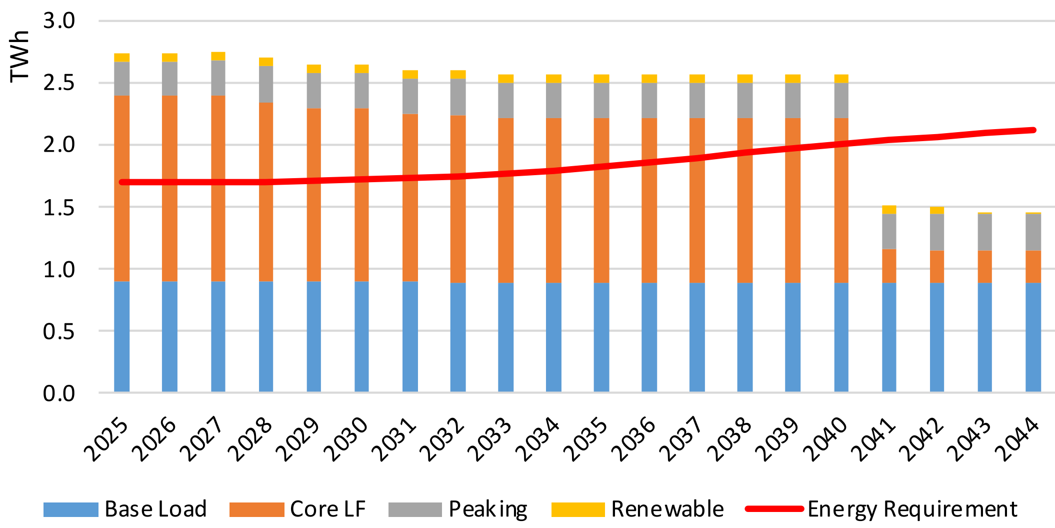


FIGURE 5: ENO SUMMER ENERGY REQUIREMENTS

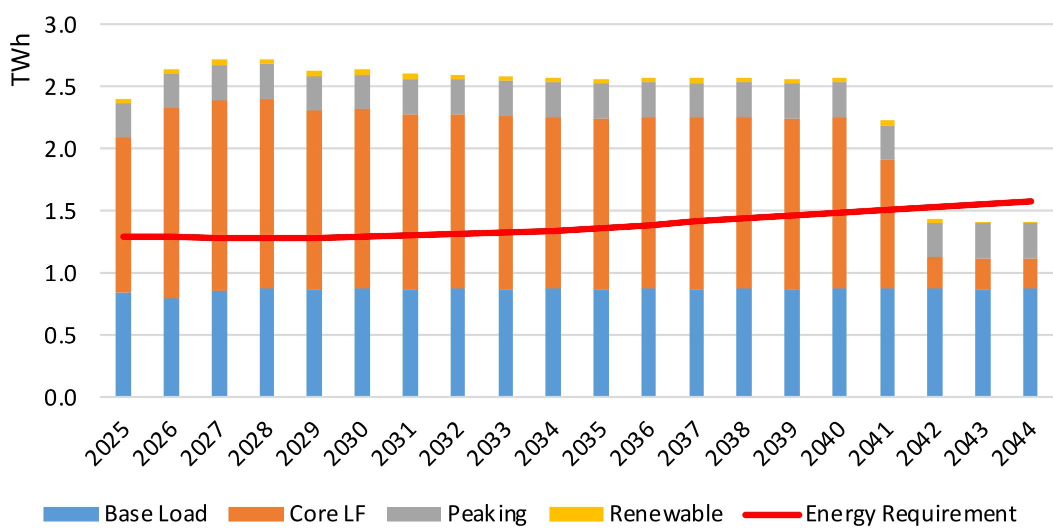


FIGURE 6: ENO WINTER ENERGY REQUIREMENTS

Customer Usage – Of course, both capacity and energy resource needs are driven by customers' consumption and preferences. Customer conservation efforts, some of which are currently driven by EE programs, have already directly affected resource needs as discussed further in Chapter 2. The type, size, and timing of future resource needs may be affected as additional resources become available to manage consumption, such as those that will be enhanced by AMI or those affected by increased accessibility to rooftop solar or battery storage technology.

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

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

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

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

1.10: Transmission Planning

Entergy's transmission planning process ensures that ENO's transmission system: (1) remains compliant with applicable North American Electric Reliability Corporation (NERC) Reliability Standards, related Southeastern Reliability Corporation (SERC) standards, and ENO's local planning criteria, and (2) is designed to efficiently deliver energy to end-use customers at a reasonable cost. Functional control of ENO's transmission assets – including top-down transmission planning – lies with MISO, and our transmission system is planned in accordance with MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).

A key responsibility of MISO is the development of the annual MISO Transmission Expansion Plan (MTEP), which considers proposed projects derived from ENO's "bottom-up" planning process. We actively participate in the MISO MTEP development process, and this participation is the method by which ENO's transmission plan is incorporated into the annual MTEP document. The overall planning process can be described as a combination of "bottom–up" projects identified in the individual MISO Transmission Owner's transmission plans, which address issues more local in nature and are driven by the need to provide service safely and reliably to customers, and projects identified during MISO's "top-down" studies, which address issues more regional in nature and provide economic benefits or address public policy mandates or goals.

Economic transmission system upgrades are identified through MISO's economic planning process as part of the annual MTEP review cycle. This process includes the evaluation of Multi-Value Projects (MVPs) and Market Efficiency Projects (MEPs), as well as other projects that provide economic benefits but do not meet the criteria for MEPs or MVPs. These economic upgrades are identified by MISO in collaboration with transmission owners and other stakeholders to address regional policy, reliability, and economic issues. Economic benefits considered in the transmission expansion planning process include Adjusted Production Cost savings, avoided reliability project savings, and MISO-SPP/Joint Parties Settlement cost savings. Other economic benefits directly related to transmission service may be identified and considered as well. Under the MISO Tariff, quantifiable benefit metrics and mechanisms exist to allocate the costs of economic transmission projects to the entities expected to receive those benefits.

In 2021, MISO began its Long-Range Transmission Plan (LRTP) study, which is intended to ensure that the MISO transmission system is capable of integrating the resources necessary to meet state and utility clean energy goals. The first of four phases (Tranche 1) focused on the MISO Midwest Subregion, and in July 2022, the MISO Board of Directors approved the Tranche 1 transmission project portfolio at a cost of approximately $10.3 billion. The Tranche 2 effort, also focused on the MISO Midwest Subregion, commenced in the fourth quarter of 2022 and the Tranche 2.1 portfolio of projects is expected to be finalized with MISO board's approval during 2024. MISO continues to focus on the LRTP in MISO North, using updated resource mix and siting assumptions for futures 1A, 2A, and 3A, for Tranche 2, and potentially beyond. Tranche 3 will focus on the MISO South Subregion, and Tranche 4 will address the North/South interface limit. ENO's engagement in the MISO transmission planning process continues to inform the overall utility planning process to ensure the protection of customers' needs through reasonable costs and enhanced reliability and resiliency.

Integration of Transmission and Resource Planning

The availability and location of current and future generation on the transmission system can have a significant impact on the long-term transmission plan, on meeting NERC reliability standards, and for efficiently delivering energy to customers at a reasonable cost. The continued evaluation and condition of ENO's generation fleet must be considered for integrated generation and transmission planning. Like transmission, new generation must be planned well in advance, and due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential generation needs is critical in meeting ENO's planning objectives of low cost, improved reliability, and reduced risk.

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

Resource planning in the IRP also incorporates inputs from the transmission system. While the implementation of a sound transmission plan is necessary to ensure reliability and can facilitate the efficient flow of energy within a system, it does not address capacity needs. The Resource Portfolios identified through the IRP analysis, which incorporate zonal transmission limits, are designed primarily to meet projected capacity and energy needs as prescribed by ENO's planning principles and Council policies.

1.11: Distribution Planning Developments

DER/Distribution Planning Requirements

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

The Company has made progress in developing tools and processes to support the interconnection and planning of DERs on its distribution grid. The following sections explain various steps being undertaken to implement foundational systems, software, and processes that will be necessary for ENO to further develop the ability to evaluate locational and reliability benefits and impacts of DERs in the future.

Smart Infrastructure & Software Systems

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

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

An outage management system ("OMS") is a utility network management software application that models network topology for safe and efficient field operations related to outage restoration. The OMS tightly integrates with the call centers to provide timely, accurate, customer-specific outage information, and with the SCADA system for real-time confirmed switching and breaker operations. These systems track, group, and display outages to safely and efficiently manage service restoration activities while providing connectivity to customer facing platforms such as "View Outages" on the www.entergy.com public website. The DMS/OMS deployment was coordinated with the deployment of the AMI meters and was completed in 2020.

The availability of AMI meter information has proven to be beneficial to the planning and operations of the distribution system. Integrated AMI data has already provided the ability to analyze historical feeder voltage profiles, increased granularity of data to help validate modeling assumptions, and increased access to more detailed point-in-time data from the customer meters. For example, in 2024 the Company developed a visualization tool for AMI data featuring the ability to analyze historical feeder voltage profiles and service transformer loading. AMI data used through this visualization tool has significantly increased access to the granularity of information to help distribution engineers validate modeling assumptions and analyze the distribution system in both on- and off-peak conditions on an hourly basis. Prior to AMI meter integration, this level of detail was previously unavailable and will continue to provide benefits as future work to utilize additional AMI meter data within the distribution planning process continues.

Other smart grid technologies being deployed are DA devices that are installed on the distribution grid and communicate the status and configuration of the grid through the AMI integrated communication network to the DMS/OMS. The DA devices, such as advanced reclosers, work in conjunction with the AMI communications network to automatically reconfigure the path of power to isolate any outage conditions and restore power to unaffected customers. The DA devices provide additional monitoring of the system and introduce control of the distribution grid. DA devices are another foundational technology required to safely and reliably incorporate distributed resources on to the distribution grid. Since 2020, there have been 225 distribution automation devices installed in ENO. To date, these devices have eliminated approximately 71,000 customer interruptions.

Additionally, the Company is actively integrating participating Demand Response (DR) resources into a Distributed Energy Resource Management System ("DERMS") through EnergyHub. The EnergyHub platform integrates with participating customer-sited smart technologies to enable the monitoring and control of distributed energy resources on the distribution grid. Current managed DR resources include smart thermostats and solar connected battery systems which, when utilized, reduce peak demand on the grid. The Company is continuing to explore the development of a DERMS system in combination with the utility operation systems previously mentioned.

Resilience and Microgrid Advancements

The Company has been actively seeking federal funding opportunities to implement advanced technologies such as microgrids to improve the resiliency of the distribution system and to reduce costs for customers. ENO applied to the DOE for federal funding for resilience through the Grid Resilience and Innovative Partnership ("GRIP") Program under IIJA, and in October 2023, the DOE selected ENO to receive matching funds totaling nearly $55 million through the program. The DOE funds primarily apply to three projects: 1) transmission hardening of approximately 97 structures on the Michoud-Front Street 230kV transmission line; 2) distribution hardening of approximately 381 structures on the Sherwood Forest Distribution Circuit; and 3) deployment of a battery backup project connected to the New Orleans Solar Station that includes a 30.8MWh battery installation that will be capable of 7.7MW full load discharge for a 4-hour period. The Company's GRIP project also includes a microgrid controller that will be capable of providing for the operation of the microgrid and battery system to increase local reliability. Such innovative programs enable the Company to improve the resilience of the distribution system while also reducing costs for customers.

DER Integration Studies

To support DER integration and other advanced planning processes, a new department within Entergy Services, LLC named System Planning and Operations – Advanced Network Planning was formed in 2020. This department's responsibilities include performing Feasibility Studies and System Impact Studies for customers requesting interconnection of commercial scale (300 kW and above) DERs to ENO's distribution grid. In 2024 alone, approximately 20 commercial scale DER projects totaling 66 MW of DER capacity have had Feasibility Studies and/or System Impact Studies completed. This has enabled ENO to identify potential grid impacts and the appropriate mitigations and upgrades to the ENO distribution system to accommodate the interconnection of these projects in order to maintain a safe and reliable grid. The study of these projects has also provided more insight into potential limitations of the distribution system and led to more collaboration with our Power Delivery Planning and Grid Technology departments to develop better planning forecasts and improved technology solutions to support the growing demand of DERs.

A primary focus of Advanced Network Planning is to identify personnel, knowledge, and skills that will be needed to accommodate these higher penetrations of DERs on the distribution grid. This includes reviewing how best to utilize existing tools, what new tools or analysis will be needed, how to work with transmission planning and assess potential MISO impacts, and how to train engineers in these new areas. It is important to create effective interconnection processes and standards that use data to understand the effects and impacts of DERs on the grid. Many of these process improvements related to DERs have already been implemented by the Advanced Network Planning department over the past two years, including:

- Revisions to DER Interconnection Standards to allow more clear and consistent understanding of DER requirements for customers;
- Utilization of DER interconnection guidelines for more clear and consistent understanding of internal DER related processes for Entergy personnel which will lead to faster DER request processing times and a better overall customer experience;
- Streamlining the processing and tracking of net metering applications through the launch of the Grid Unity online interconnection portal in May 2023. This portal has provided a digital intake tool for DER application requests, making the process easier and more straightforward for ENO customers while also making the interconnection review process more efficient and simpler for ENO personnel. It provides customers with real time project status as well as transparency in the interconnection process. The data repository this tool creates will allow ENO better insights into DER interest and activity and will help inform planning functions of the growing demand of DERs on the grid;
- Incorporating existing DERs into power flow models and increasing the use of time series data over traditional "peak only" modeling. This methodology is utilized for seasonal planning studies as well as project specific interconnection studies;
- Development of initial technical screening review criteria for DER requests, resulting in faster review and approval times for many projects;
- Building a team of five in-house engineers to perform detailed interconnection impact studies and streamline the process for prospective DER projects;
- Analyzing solar generation penetration by feeder and identifying feeders with penetration greater than 15% of feeder peak capacity. This has enabled ENO to identify areas where new DER requests could trigger additional studies and/or upgrades due to the aggregate capacity of smaller DER systems, including residential rooftop applications;
- Mapping known DER technologies (smart thermostats, EV chargers, and solar connected batteries) by feeder; and
- Participating in numerous research and development projects with EPRI and other industry entities focused on modernizing distribution grid planning.

In summary, the investments, process improvements, and capabilities added over the past several years have shown progress in the Company's ability to evaluate and integrate DERs into the distribution grid. Many of these will also aid in the Company's compliance with future obligations under FERC Order 2222. The smart infrastructure of AMI and DA-enabled devices, the smart systems of DMS/OMS, enhanced DER analysis and interconnection process improvements, and the securing of DOE funds for the purpose of furthering innovative resilience solutions are all essential components of ENO's capability.

CHAPTER 2

Model Inputs and Assumptions

2.1: Resource Planning Considerations

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

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

2.2: Load Forecasting Methodology

Each year, ENO develops a sales and load forecast that is used for financial and resource planning purposes. The most recent forecast available typically is used as the Base Case or Reference Case for Scenario analysis for IRPs. This Reference Case is developed sequentially starting with a forecast of monthly billed sales, which is then converted to a calendar month view and then into hourly loads across each month. Alternative Scenario forecasts are developed in a similar manner, i.e., starting with monthly energy and then converting those levels to hourly loads. For ENO's 2024 IRP, two alternate sensitivity forecasts were developed, Low and High cases, in addition to the Reference Case forecast.[5]

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

1. Levels of economic activity and growth, including expansion or contraction of large industrial load, as well as changes in population affecting residential and commercial classes
2. Increased adoption of electric vehicles (EVs) in place of vehicles using internal combustion engines
3. Increases in energy efficiency ("EE"), brought about by:
   - Technological changes – lighting, heating, ventilation, and air conditioning ("HVAC"), appliance efficiency
   - Structural changes – changes in building codes or state/national requirements
   - Other conservation measures – changes in personal behavior
4. Other electrification opportunities brought about by customers' reductions in natural gas usage in favor of electric end-use equipment
5. Potential adoption of behind-the-meter self-generation technologies (e.g., rooftop solar)

[5] While three load forecast cases were developed, only the Reference and High cases were used in development of the Planning Scenarios, as agreed among the parties through the Technical Meetings.

6. Increased participation in demand response and/or interruptible programs
7. Changes in temperature and weather patterns over time

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

2.3: Reference Case Energy Forecast

The Reference Case forecast is the same as ENO's BP24 forecast and was developed using a bottom-up approach by customer class – residential, commercial, large industrial, small industrial, and governmental. The forecast was developed using historic sales volumes, customer counts, and temperature inputs from January 2010 through April 2023, as well as future estimates for normal weather and energy efficiency. In addition, the forecast includes estimates for changes in customer counts, future growth in large industrial usage, and estimates of future consumption growth from EVs and declines due to future rooftop solar adoption.

The Reference Case Energy Forecast concludes that, for total electricity sales volume, the compound annual growth rate ("CAGR") for 2025-2044 is 1.2% per year. Overall, this forecast projects growth driven by increased residential and commercial sales, with higher EV and electrification adoption levels projected for both classes, as well as increases in the industrial classes. The forecast for these customer classes and the methods by which they are developed are discussed further below.

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

Residential Forecasts – The long-term residential forecast projects an increase in electricity consumption with a 1.0% CAGR for 2025-2044. This increase is largely due to increasing average Use Per Customer ("UPC") in the long-term, mostly attributable to EV adoption increases. That increase is slightly offset by nearly flat customer count growth and assumed reductions in energy usage resulting primarily from ENO's customer DSM programs. The customer counts are projected based on S&P Global's parish level economic data for ENO's service territory. Overall, average annual kWh consumption per household is expected to grow at a 1.0% CAGR over the period from 2025-2044, with the largest growth rate beginning in 2035, as EV levels increase.

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

Residential UPC per day =

Heating Degree Days **x** Heating efficiency index **x** Heating coefficient **+**

Cooling Degree Days **x** Cooling efficiency index **x** Cooling coefficient **+**

other use coefficient **x** other use efficiency index

TABLE 4: YEAR OVER YEAR GROWTH - RESIDENTIAL

Year	Energy	Cust	UPC
2026	-0.6%	0.0%	-0.6%
2028	0.0%	0.0%	0.0%
2030	0.6%	0.0%	0.6%
2032	1.3%	-0.1%	1.4%
2034	1.7%	0.1%	1.7%
2036	1.9%	0.2%	1.8%
2038	1.5%	0.1%	1.4%
2040	1.4%	0.0%	1.4%
2042	1.3%	-0.1%	1.4%
2044	1.2%	-0.1%	1.3%
2025-2044 CAGR	1.0%	0.0%	1.0%

Commercial Forecast – The commercial sales forecast is developed using a similar methodology to the residential forecast with the exception that commercial sales are forecasted in total rather than by UPC because of the diversity of commercial customers such as a large hospital versus a small office. Otherwise, the commercial forecast accounts for organic energy efficiency, primarily from HVAC and refrigeration, as well as ENO's DSM programs discussed further below.

The long-term commercial forecast projects electricity consumption increasing at a 1.9% CAGR for 2025-2044. While customer count growth is mostly flat, overall usage is expected to grow and is largely driven by estimated increases for electrification modifications and EV adoption levels in the commercial sector. Since the prior IRP, the EV adoption curve now reflects much more rapid growth in that sector, based on announced plans from auto manufacturers and other positive news around vehicle charging. Industry trends, combined with refining the EV forecast methodology using vehicle registration data, resulted in a higher EV forecast. Similarly, more electrification opportunities are expected since the last IRP.

Commercial Sales =

Heating Degree Days **x** Heating efficiency index **x** Heating coefficient **+**

Cooling Degree Days **x** Cooling efficiency index **x** Cooling coefficient **+**

other use coefficient **x** other use efficiency index

TABLE 5: YEAR OVER YEAR GROWTH - COMMERCIAL

Year	Energy	Cust	UPC
2026	0.0%	0.4%	-0.4%
2028	0.6%	0.4%	0.2%
2030	1.4%	0.3%	1.0%
2032	1.9%	0.3%	1.6%
2034	2.7%	0.3%	2.4%
2036	3.3%	0.3%	3.0%
2038	2.9%	0.2%	2.6%
2040	2.4%	0.2%	2.1%
2042	2.1%	0.2%	1.9%
2044	2.0%	0.2%	1.8%
2025-2044 CAGR	1.9%	0.3%	1.6%

Governmental Forecast – Governmental energy usage is forecasted to have a slight decrease for 2025-2044 with an overall CAGR of -0.2%. This is primarily due to the effects of energy efficiency.

Small Industrial Forecast – The small industrial forecast includes industrial sales that are not forecasted individually in the large industrial forecast, described below. Forecasts are based on historical trends and economic indices from S&P Global Market, such as for labor force and food production. Small industrial sales can be volatile and are generally not temperature related.

Large Industrial Growth – The 2025 – 2044 CAGR for ENO's large industrial sales is 0.6%. Due to their size, customers in the large industrial class are forecasted individually.

Existing large industrial customers are forecasted based on historical usage, known or expected future outages, and information about expansions or contractions. Forecasts for new or prospective large industrial customers are based on information from the customer and from ENO's economic development team as to each customer's expected MW size, operating profile, and ramping schedule. The forecasts for new large customers are also risk-adjusted based on the customer's progress towards achieving commercial operation.

TABLE 6: YEAR OVER YEAR GROWTH - LARGE INDUSTRIAL

Year	Sales
2026	0%
2028	0%
2030	2%
2032	0%
2034	0%
2036	0%
2038	0%
2040	0%
2042	0%
2044	0%
2025-2044 CAGR	0.6%

Energy Consumption by Class – ENO's energy consumption comes mostly from the residential and commercial customer classes, which account for 39% and 38%, respectively, of the forecasted sales for 2025. Governmental customers consume 15% of the energy with industrial customers consuming the remaining 8%.

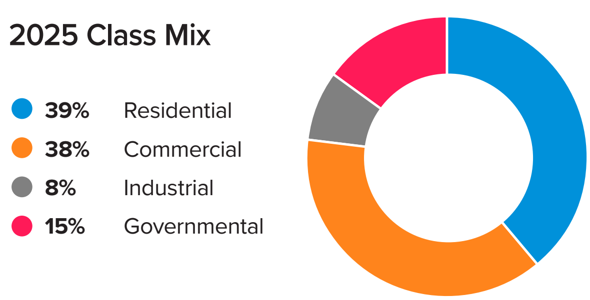


FIGURE 7:
ENERGY CLASS MIX - FIRST YEAR OF IRP

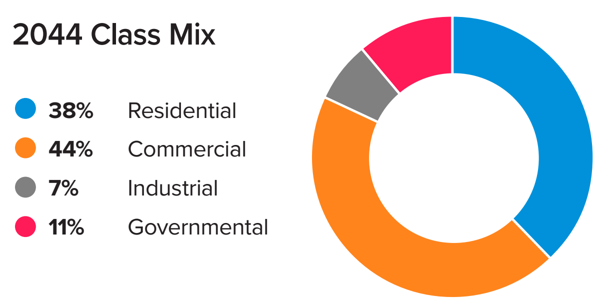


FIGURE 8:
ENERGY CLASS MIX - LAST YEAR OF IRP

This class-level consumption mix is expected to remain largely unchanged throughout the study period, apart from some slight increases in the commercial sector. See Figure 14 above for the projected 2044 energy mix by customer class.

2.4: Load Forecast Inputs

Energy Efficiency and Demand Side Management – From a load forecasting perspective, energy efficiency's influence comes from consideration of two sources: (1) the effects of naturally occurring or organic energy efficiency, and (2) the effects of ENO's energy efficiency and DSM programs. Naturally occurring/organic energy efficiency includes effects such as customers replacing older HVAC systems or appliances with newer, more efficient units, replacing incandescent lighting with LED lighting, and through the growth in the numbers of new multi-family (apartments) residences over single-family residences. Data for naturally occurring energy efficiency is derived from the Statistically Adjusted End Use estimates that come from the EIA to reflect expected changes in energy efficiency codes and standards as well as adoption and turnover rates for each end use. ENO's energy efficiency programs incent customers to make the same types of efficiency improvements and help move the timeline forward from when naturally occurring efficiency would occur. Together, organic energy efficiency and the energy efficiency programs result in ENO's customers using less electricity on a per-customer basis than they would have otherwise. As shown in Figure 9, below, these programs have effects in the program year and those effects accumulate and carry forward to future periods as well.

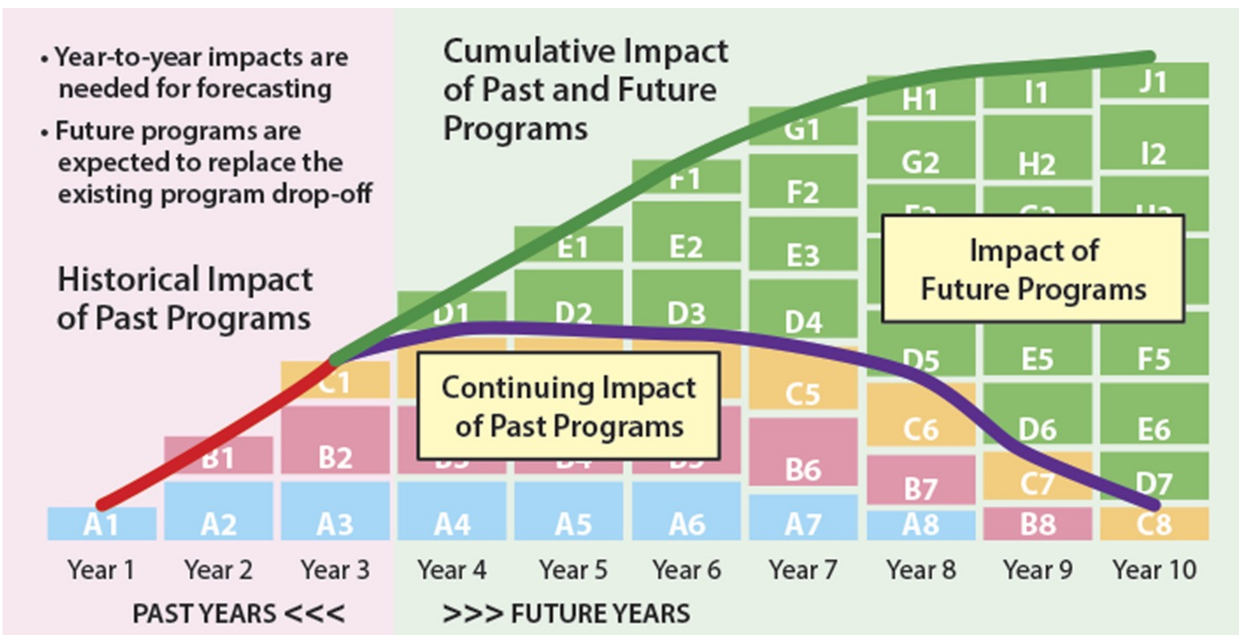


FIGURE 9: CHRONOLOGICAL DSM IMPACTS

Using this methodology, the Reference Forecast shows that new programs are expected to reduce 2% of the total annual sales for ENO by 2025. Table 7, below, shows ENO's expected incremental savings from DSM programs.

TABLE 7: ANNUAL MWH DESIGNED SAVINGS 2025 (INCREMENTAL ASSUMPTIONS)

	Annual Value
Small C&I	6,846
Large C&I	47,767
Publicly Funded Institutions	15,981
C&I Construction Solutions	5,000
Home Performance with Energy Star	2,392
Retail Lighting and Appliances	1,587
Multifamily Solutions	2,403
Income Qualified Weatherization	2,990
A/C Solutions	3,651
Appliance Recycling & Replacement	1,917
School Kits & Education	797
Behavioral	20,052

Figure 10 below shows the estimated levels of annual energy savings included in the Reference Case forecast as a result of ENO's historically implemented DSM programs as well as savings from future DSM programs based on the incremental levels laid out in Table 7 above. DSM levels are expected to increase gradually through the early 2030s, and then level off by the mid-2030s and decrease thereafter.

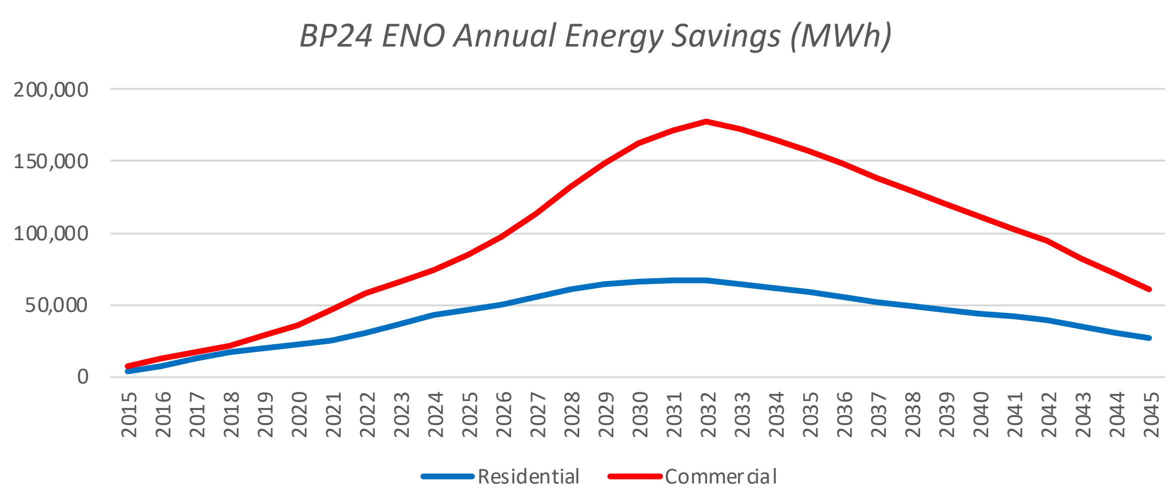


FIGURE 10: ENO ANNUAL ENERGY SAVINGS

Electrification and Conversions – The Reference Case forecast includes an assumption for sales growth as a result of programs sponsored by ENO to encourage electrification. The programs include electrification of various industrial and commercial processes as well as conversion of gas or diesel equipment. Based on estimates from BP24, these projects are expected to add 1.4% to total sales by 2027.

Behind-the-meter Solar – The Reference Case forecast includes an assumed reduction of energy consumption resulting from the adoption of behind the meter ("BTM") solar. With other assumed increases in electrification (EV and non-EV), the solar installations will provide some offsetting reductions. The High Case reflects 150 MW of residential solar and 50 MW of commercial solar by 2030 with escalation of those amounts using a fixed inflator beyond 2030. Residential rooftop solar adoption is estimated to increase in the late-2030s for the Reference Case, and a more aggressive adoption is expected for the High Case. Commercial solar adoption levels are relatively modest for Reference Case, with a more aggressive adoption for High Case.

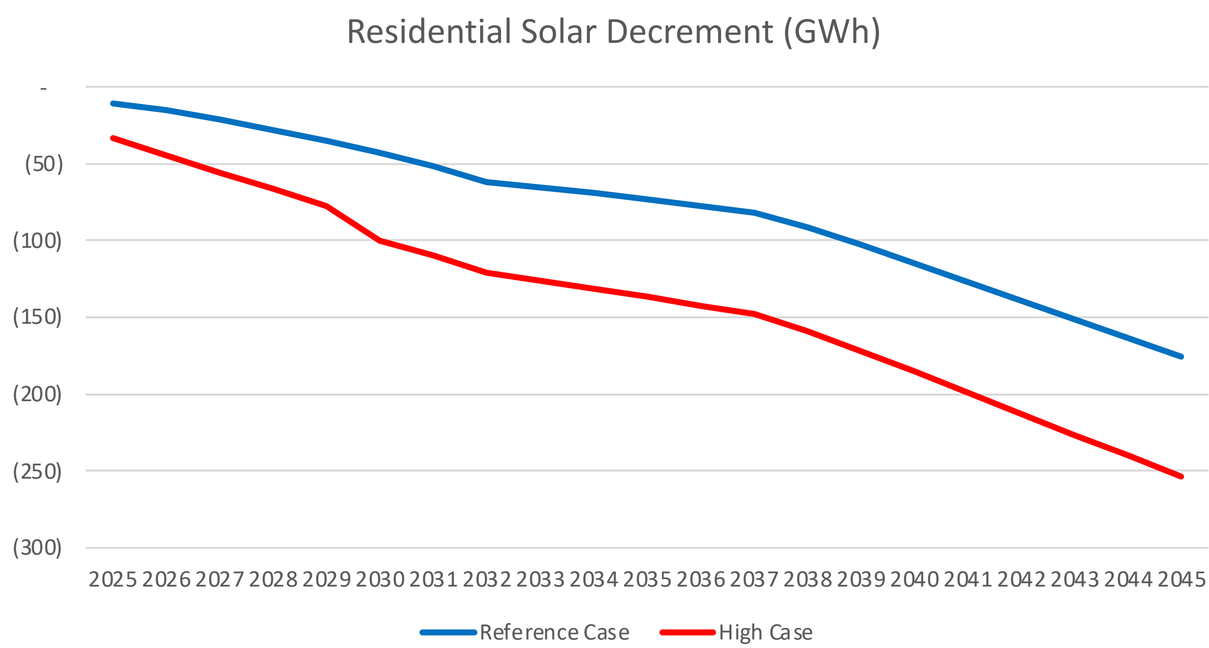


FIGURE 11: RESIDENTIAL SOLAR ENERGY LEVELS

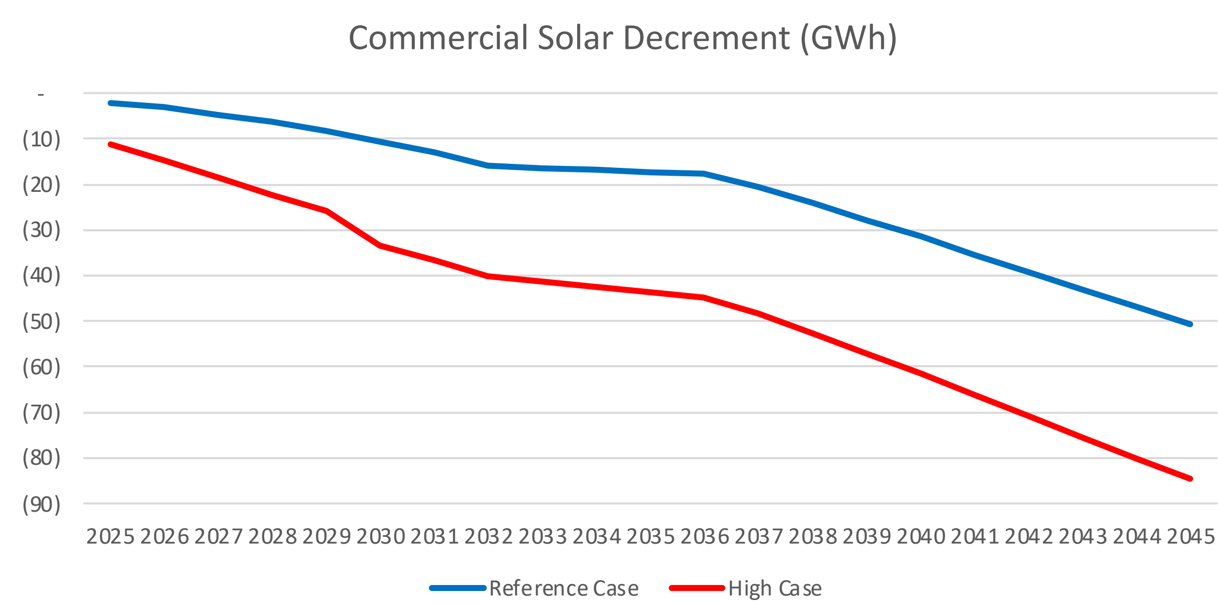


FIGURE 12: COMMERCIAL SOLAR ENERGY LEVELS

Electric Vehicles (EVs) – The Reference Case forecast includes an assumed level of additional energy consumption resulting from the adoption of EVs, as well as growth in the numbers of total on-road vehicles over time, as overall population is expected to continue to increase. Overall, the additional GWh volumes from the EV forecast in the Reference Case are minimal in the near term with growth to the residential and commercial consumption volume estimated to start appearing in the late-2030s. In the High Case, a more aggressive forecast projects usage levels to rise by an additional 25% in the near term compared to the Reference Case. This leads to a 35% increase in ENO's total sales by 2044. Meanwhile, the Reference Case assumes a market saturation rate of 95% by 2070.

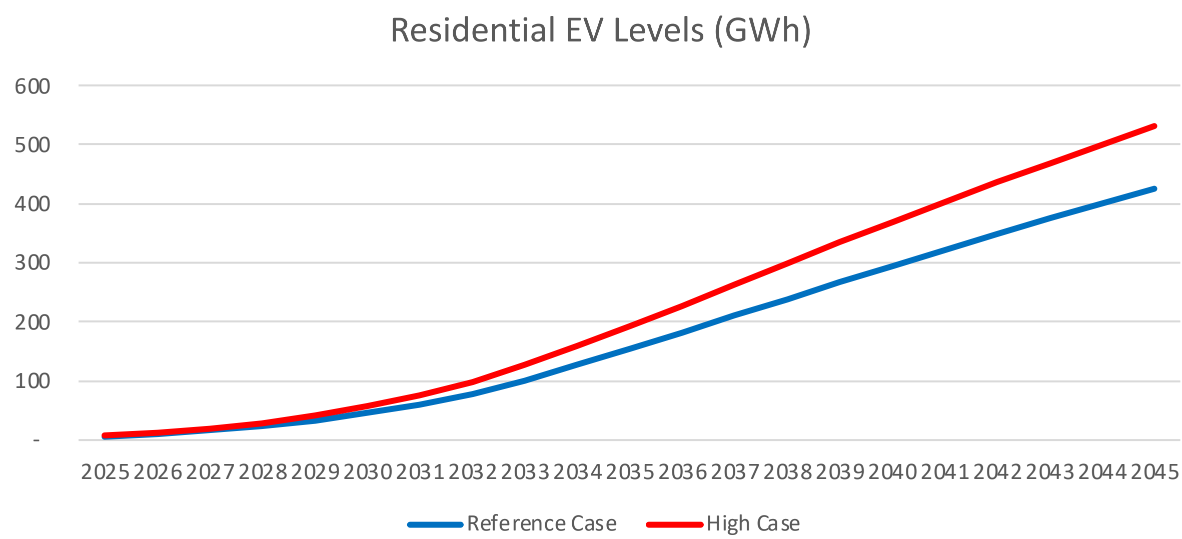


FIGURE 13: RESIDENTIAL EV LEVELS

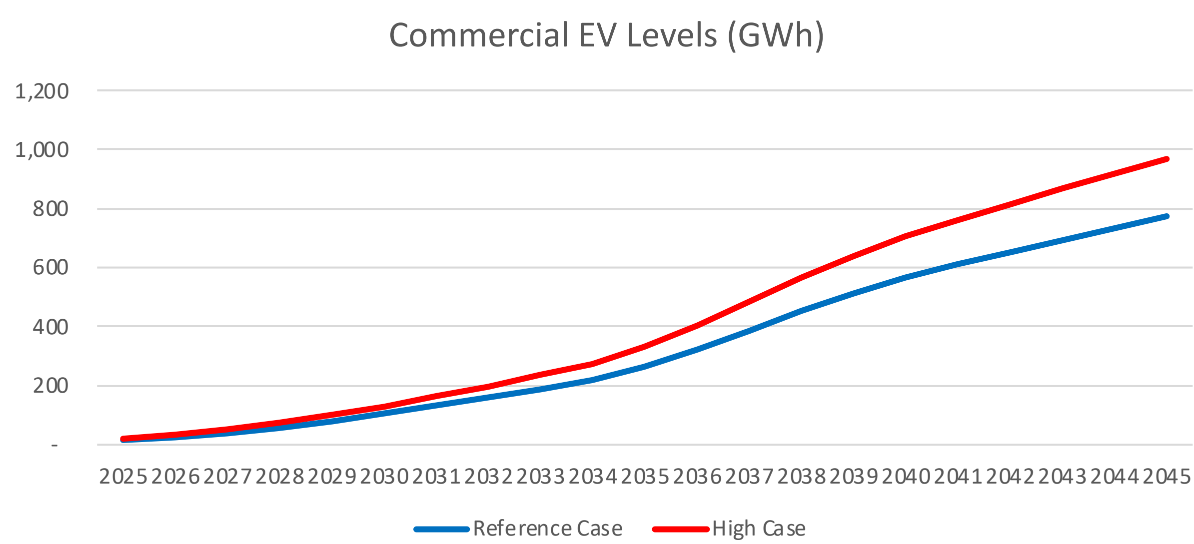


FIGURE 14: COMMERCIAL EV LEVELS

Trended Normal Weather – As is customary utility forecasting practice, the temperature assumptions used for long-term planning are based on "normal" weather. For ENO, this is an average based on 20 years of temperature history. The use of 20 years strikes a reasonable balance between longer periods (30 years), which may take longer to pick up changing weather trends and shorter periods (10 years), which may not provide enough data points to smooth out volatility.

Analysis of historical data reveals that trends in average temperatures, expressed as CDDs and HDDs, have not been flat over the last few decades, and there is no evidence at this time to support an assumption of future temperatures remaining flat compared to current levels. As such, ENO has calculated a "trended normal" assumption for long-term energy planning using trends in 20-year rolling averages of monthly temperatures. Those trends are applied to the base level of the 20-year normal temperatures, and the trended normal result is used in the forecasts.

The 20-year trended normal temperatures are built from hourly temperatures and are allocated to each calendar month. By 2044, the effect of the trended normal temperature assumption increases summer (July-September) residential and commercial energy by 56 GWh (3.4%) and decreases winter (December-February) energy consumption by 18 GWh (-1.4%).

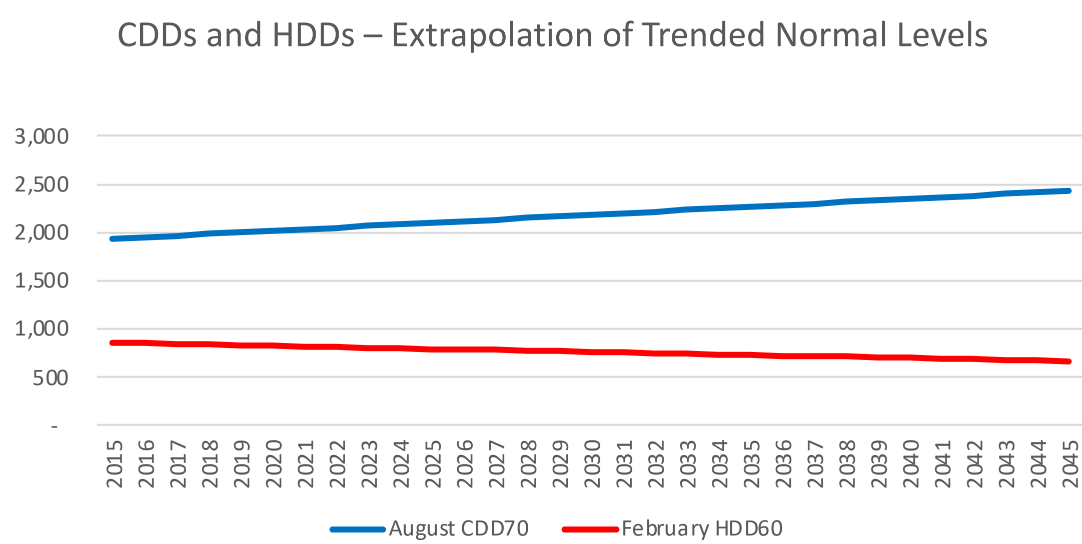


FIGURE 15: CDDS AND HDDS - EXTRAPOLATION OF 20-YEAR ROLLING

Non-EV Electrification and Conversions – The Reference Case forecast includes an assumption for ENO-run sales growth programs to encourage electrification. The programs include non-road conversions, such as commercial process electrification. Based on estimates from 2023, these projects are expected to add nearly 232 GWh to commercial sales by 2045.

2.5: Hourly Load Forecast

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

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

The final step in producing the hourly load forecasts is to combine – or calibrate – the monthly energy, monthly peak, and the hourly shapes described above. Using Itron's Metrix LT® software, the energy volumes, the estimated peaks, and the typical hourly shapes are calibrated such that the three elements fit together in a way that preserves the volume of energy assumed in the final result, while fitting it to the hourly profiles and at the same time maintaining, as closely as possible, the relationship of peak MW to monthly MWh. This process also reallocates the forecasted solar and EV energy using specific profile hours for each product technology. The result is a set of hourly load values, by class, for the forecast period from which a peak level can be determined. These hourly values are adjusted to account for transmission and distribution losses, which represent the estimated energy required to be produced at the generating plant to serve at-the-meter loads. The loss levels are based on the most recent class-level estimates available during the development of the Reference Case forecast. For ENO, the average total company loss levels were 3.9% for distribution-only losses and 4.4% for combined transmission and distribution losses. Estimates of the MISO coincident peaks include only distribution losses.

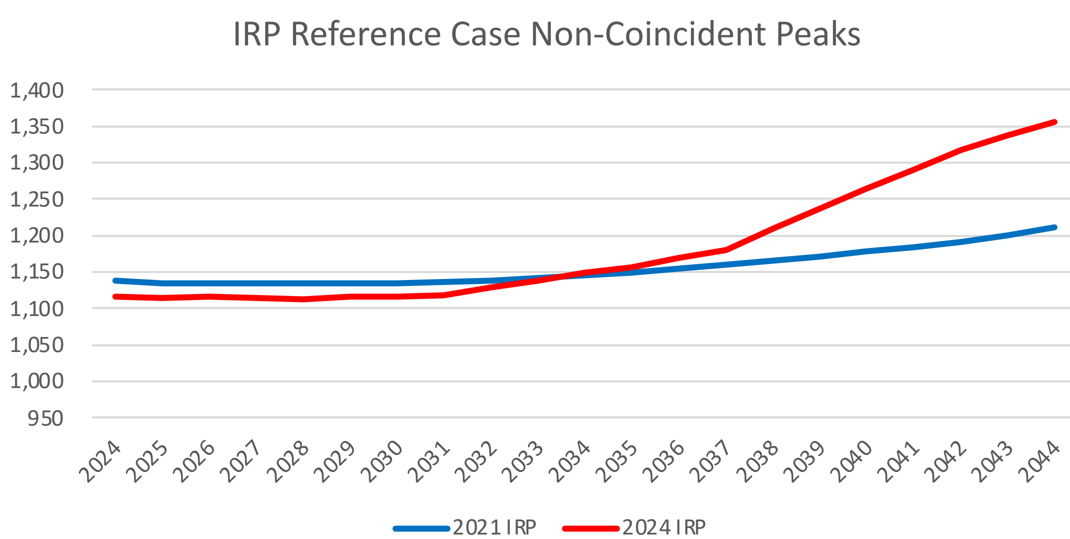


FIGURE 16: ENO IRP REFERENCE CASE PEAKS BY VERSION

Reference Case Peak Comparison to Previous IRP – Compared to the ENO 2021 IRP, there have been increases in the peak load forecast levels starting in the mid-2030s, largely due to estimated growth in electrification of the Industrial and Commercial classes and higher levels of EV adoption, including fleet vehicles.

2.6: Sales and Load Forecast Sensitivities

For the 2024 IRP, ENO has created a "high" sensitivity forecast by adjusting different levers in the Reference Case forecast up by a certain percentage to reflect a range of load possibilities.

The high sensitivity assumed more year-over-year growth among residential and commercial customers, as well as a higher UPC. There are also higher levels of solar, EV, and non-EV electrification adoption expected. Industrial customer growth rose in total, using increases to the anticipated sales volume included in the Reference case.

The results of these volumetric changes provide forecasted sales, which are converted to hourly loads to model estimated impacts to ENO's peaks, as shown below.

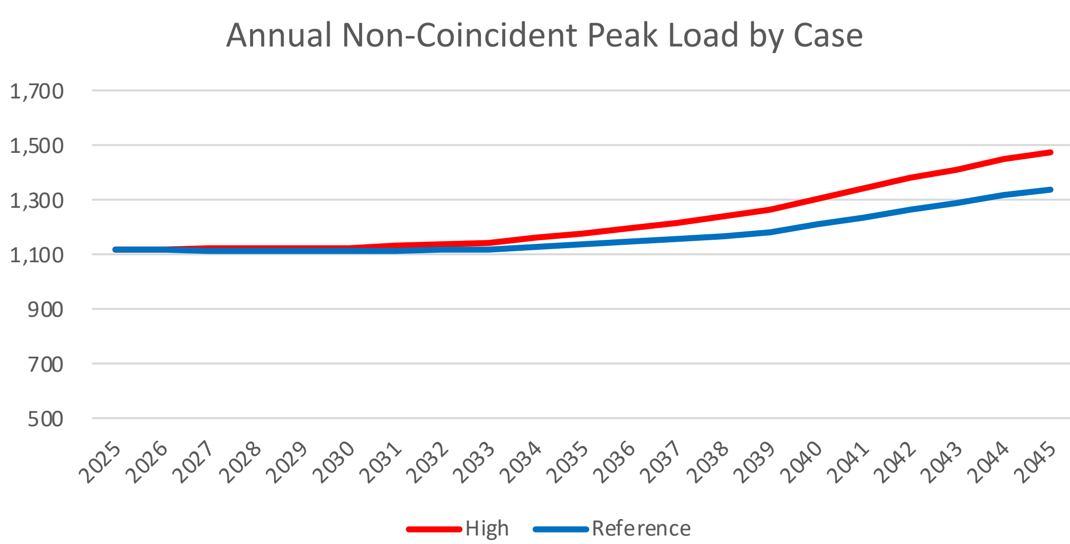


FIGURE 17: ANNUAL NON-COINCIDENT PEAK LOAD BY CASE

2.7: Capacity Resource Options

Entergy's commitment to reduce utility emissions by 50% below 2000 levels and achieve net-zero emissions by 2050, and the efforts of ENO to meet the Council's more aggressive emissions goals, require a continued transformation of the generation portfolio. The IRP process evaluates available generation alternatives to meet customer energy needs, including the existing generation fleet, DSM programs, and supply-side resources. As part of this process, a generation and storage technology assessment was prepared to identify a range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet ENO's planning objectives.

Technology Evaluation and Selection – As illustrated in Figure 18, ENO conducted an evaluation of the cost-effectiveness and feasibility of deployment for many potential supply-side resources. The three-phased (i.e., Technical, Economic, Technology Selection) process to select generation alternatives considers qualitative and quantitative criteria and results in a final selection of supply-side resources that are best positioned to meet customer energy needs in accordance with ENO's planning objectives.

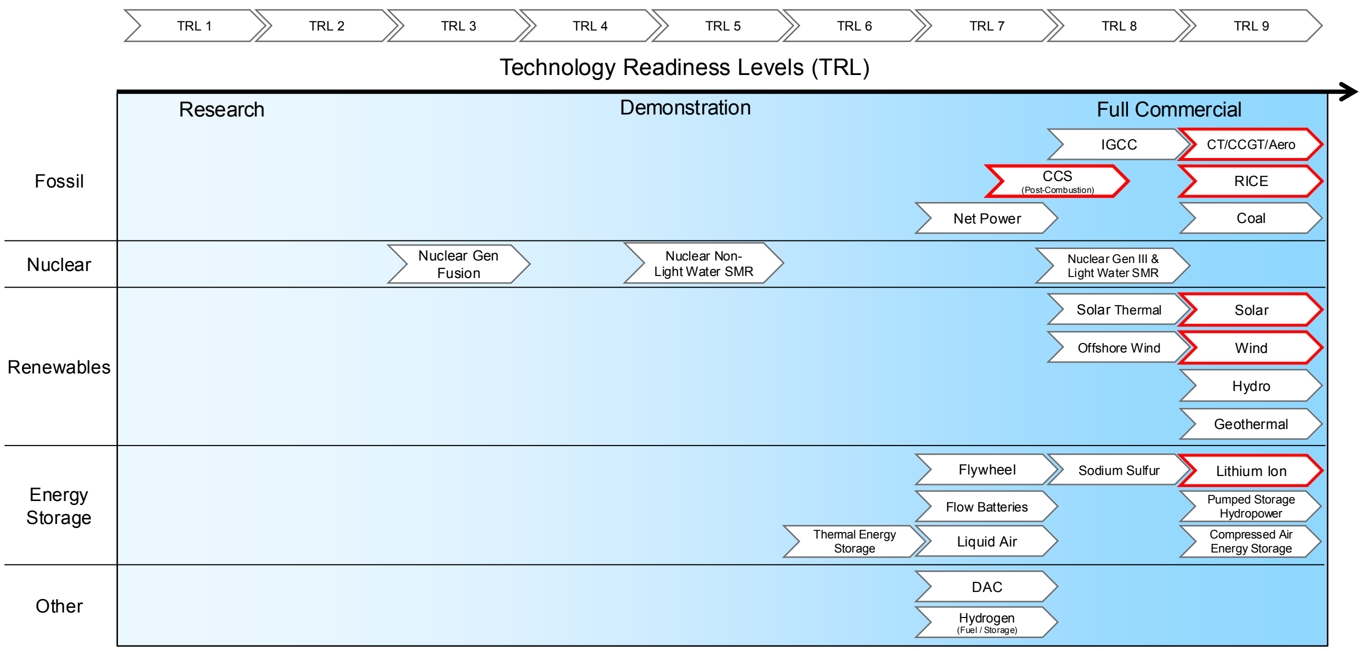


FIGURE 18: POTENTIAL SUPPLY-SIDE RESOURCE ALTERNATIVES TECHNICAL SCREENING

In the technical evaluation, potential supply-side resources were evaluated relative to technology maturity, environmental impact, operational characteristics, fuel availability, and feasibility of deployment to serve ENO's service area. In the economic evaluation, we developed and compared technology alternatives relative to capital and operations and maintenance (O&M) cost estimates, including renewables, energy storage, and conventional generation with carbon capture and hydrogen co-firing pathways. Following the economic screening, the supply-side resources selected for inclusion in the capacity expansion models are those deemed to be the most feasible to serve ENO's generation needs based on comparative cost and performance parameters, deployment risks (cost/schedule certainty), and emerging commercial, technical, and policy trends. Besides the technologies specifically discussed in this IRP and included in the capacity expansion models, we continually evaluate existing, new, and emerging technologies to inform deployment decisions and building a balanced generation portfolio that optimizes our planning objectives. Figure 19 lists the technologies selected for inclusion in the capacity expansion models. In the sections that follow, the selected technologies and others are discussed in more detail as well as the key emerging supply trends and implications that will shape the future of ENO's resource portfolio.

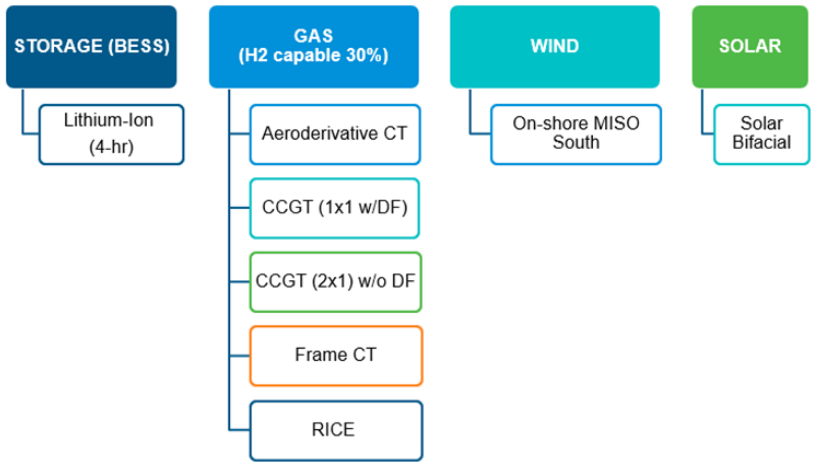


FIGURE 19: TECHNOLOGIES SELECTED FOR CAPACITY EXPANSION MODEL

Conventional Generation – Natural gas-powered generation technologies are a competitive supply-side resource alternative due to relatively lower natural gas prices in Louisiana and suitability to serve a variety of supply roles (baseload, load-following, limited peaking). These technologies offer synergies with our existing fleet, including supply chain economies of scale and deep-rooted operational expertise.

The long-term suitability of dual fuel natural gas and hydrogen powered generation technologies to meet our planning and sustainability objectives is largely dependent on natural gas prices, technology improvements, and advancements in infrastructure investment.

Hydrogen firing/co-firing can also provide decarbonization solutions due to the lack of a carbon presence in the gas. The newest large frame turbines have the capability to run with up to 30% or higher co-blending, if the gas supply is available and balance of plant equipment is designed to accommodate. The turbine OEMs are actively working to achieve commercial viability for firing with 100% hydrogen. For wider deployment of this technology, necessary advancements that need to be made include, but are not limited to, building hydrogen production and delivery infrastructure, combustor systems, and emission reduction technologies for NOx. As OEMs make advancements, ENO continues to track the development of hydrogen-fueled power generation technology.

TABLE 8: CONVENTIONAL GENERATION WITH HYDROGEN CAPABILITY RESOURCE ASSUMPTIONS

Technology	H2 Capable (%)	Summer Net Maximum Capacity [MW]	Installed Capital Cost Nominal [2023$/kWac]	Fixed O&M Levelized Real [2023$/kW-yr.]	Variable O&M Levelized Real [2023$/MWh]	Full HHV Summer Heat Rate [Btu/kWh]	Life [Yr.]
CT	30%	408	$1,134	$6.76	$8.65	9,450	30
CCGT (1x1) w/ duct firing	30%	729	$1,296	$12.58	$4.97	6,759	30
CCGT (2x1)	30%	1,216	$1,349	$10.90	$5.16	6,308	30
Aeroderivative CT	30%	89.9	$3,277	$32.99	$9.39	9,703	30
RICE	25%	129	$1,998	$34.48	$14.03	8,440	30

Excludes transmission interconnection costs. Sources: Sargent & Lundy, Burns & McDonnell, NREL, EPRI, and Entergy Capital Projects.

Combined Cycle Combustion Turbines – Driven by economies of scale and relatively low gas prices, CCCT fleet operators have remained competitive, from a price per megawatt-hour ("$/MWh") perspective, when compared to solar and wind resources. CCCTs are suitable to efficiently serve as baseload or load-following resources and offer plant flexibility. In this analysis, CCCT units are composed of either one or two frame combustion turbines and a steam turbine that recovers thermal energy from the CTs. These combinations provide an efficient heat rate and moderate flexibility. CCCTs can be combined with CCS technology to reduce carbon emissions without much retrofit, assuming nearby land is available for the capture facility. Achieving greater volumes for hydrogen co-firing will be dependent on the technology development of hydrogen fired CTs. Depending on the relative hydrogen co-firing volume, system modifications would be required in the CT and steam system of the plant. In addition to advancements in CT technology, potential modifications for a future hydrogen-fueled CCCT plant could include, but not be limited to, modifications to the heat recovery steam generator system and post-combustion NOx control systems.

Frame Combustion Turbine with 30% Hydrogen Firing Capability – Historically, CTs have functioned as the technology of choice to support peaking applications, resulting from consistent technological improvements, supported by relatively lower natural gas prices. Over time, renewable resources have become an economically competitive source of capacity. While renewable resources are expected to play a larger share of the role for peaking applications, CTs can support integrating renewables and build a balanced, reliable, portfolio by offering quick-start (~30 minutes) backup power when renewables cannot meet peak demands.

Most dry, low-NOx designs can accommodate hydrogen blends in the range of 20%-30% with advanced dry, low-NOx technologies under development to enable higher blend rates up to 100% hydrogen. Achieving higher hydrogen firing rates will be dependent on combustor designs as well as other system modifications, for example, fuel management systems and compression, CT enclosures, and control system updates.

Aeroderivative Combustion Turbine ("AERO CT") with 30% Hydrogen Firing Capability – AERO CTs have gained market share in applications to serve peak and intermittent power, offering inherent flexibility as to a range of applications from the aviation to power industry. Traditionally, AERO CTs provide higher flexibility than frame CTs due to their hot start time (10 minutes), minimum up/down time, and ramp rate.

AERO CT OEMs are continuing to develop combustion systems to enable higher hydrogen blend rates. Current dry, low-NOx systems utilized within AERO CTs enable blending of hydrogen in the range of 30% with ongoing development of advanced combustor systems to enable higher blending rates, up to 100%.

Reciprocating Internal Combustion Engines (RICE) – As renewables penetration increases, RICE units may be leveraged to support the integration of these resources. RICE units can support increased demand for reliability through dispatchable power that can be placed online rapidly with the ability to frequently start/stop in response to changing load conditions.

RICE OEMs have demonstrated that existing models are able to accompany blends of hydrogen. Technology advancements and the necessary plant modifications required to increase the hydrogen blend capability above 25% are under development. RICE OEMs are also working to develop models compatible with other potential low-carbon fuels.

Renewables and Energy Storage Systems – Over the past decade, driven by technology improvements resulting in lower costs and improved performance, renewable and energy storage technologies have been increasingly deployed around the world, particularly utility-scale solar, followed by onshore wind and battery energy storage systems ("BESS"). Renewable energy resources add fuel diversity and play a core role in building a balanced resource portfolio. Due to the intermittent nature of renewable generation, a balanced portfolio must maintain the ability to meet the changing instantaneous nature of customer usage and renewable production curves (e.g., on-peak production versus off-peak production).

The IRP total relevant supply cost analysis incorporates key renewable energy provisions included in the Inflation Reduction Act ("IRA"). The IRA includes tax credits for clean energy technology, with the goal of reducing carbon emissions. The modeled tax credits include full production tax credits ("PTCs") beginning at $30/MWh (2024) based on Section 45Y and increasing subject to the inflation factor published by the IRS for solar, offshore wind, onshore wind, and the solar portion of hybrid resources, and assume the PTCs are realized at 90% through the cash conversion or monetization process permitted in the IRA. The analysis includes investment tax credits (ITCs) at the full rate of 30% for standalone battery storage and the battery portion of hybrid resources, which are applied to 90% of total resource cost. Consistent with the IRA provisions, both the ITCs and PTCs are phased out over the IRP evaluation period, beginning in 2036.

TABLE 9: RENEWABLE AND ENERGY STORAGE RESOURCE ASSUMPTIONS

Technology	Max Summer Capacity [MW-ac]	Installed Capital Cost Nominal [2023$/kWac]	Fixed O&M L. Real [2023$/ kW-yr.]	Assumed Capacity Factor	Life [Yr.]	DC:AC Ratio [%]	Degradation [%]
Utility-Scale Solar	100MW	$1,866	$13.10	24.8%[6]	30	1.3	0.5% per year
Hybrid: Solar + BESS	100MW 50MW/200MWh	$2,950	$19.02	24.8%	30 (Solar) / 20 (BESS)	1.3	0.5% per year (Solar only)
On-shore Wind, MISO South	100 - 200 MW	$2,010	$42.63	30.9%[7]	30	n/a	n/a
Storage (4hr, Li-Ion)[8]	50MW / 200MWh	$2,332	$14.79	n/a	20	n/a	Degradation negated by Augmentation

[6] Solar resources assume a 0.3% improvement in capacity factor in each subsequent year installed. Therefore, the capacity factor for solar resources installed in the second year of the outlook improve from 25.68% to 25.75%.

[7] Wind resources assume a 0.1% improvement in capacity factor in each subsequent year installed.

[8] BESS Installed Capital Cost includes 10% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by an additional 10% augmentation every five years (year 6, 11, and 16). This corresponds to a degradation rate of 2% of BESS capacity per year.

There are no variable costs assumed to be incurred. Excludes transmission interconnection costs. Hybrid resources will be modeled in Aurora as stand-alone solar with the option to add a coupled storage at a discounted cost. Sources: S&P Global, Wood Mackenzie, EPRI, NREL, Entergy Power Development.

Solar – Across the U.S., deployment of solar energy resources has continued to grow rapidly. As the underlying economics have improved for solar resources generally over the last decade, solar has become a central resource in building a balanced portfolio. While the cost for solar has recently increased due to several factors, resource alternatives have also increased in cost and PTCs for solar have helped to offset some of this increase. Therefore, despite the near-term market issues, solar remains an economic addition to ENO's portfolio and our point of view remains that beyond 2030, project costs are expected to remain relatively flat as the industry continues to mature. In addition to cost impacts from the industry maturing, new module designs and configurations continue to be developed to improve efficiency and offset cost due to demand and inflation.

However, because solar energy production is variable in nature, grid flexibility and quick start backup generation are necessary to ensure reliability. Additionally, as part of the planning considerations for utility-scale facilities, land size requirements and site-specific needs must be evaluated.

Onshore Wind – Onshore wind resources have gained momentum in the U.S. and international markets, driven by technology improvements that reduced capital costs. Taller wind turbine hub heights have rapidly entered the market and are expected to support the economics of lower wind speed territories.

We are actively evaluating cost effective ways to integrate wind resources into our portfolio. However, some aspects of wind energy near the area ENO serves are currently challenging compared to wind energy that serves other regions. For example, wind energy in MISO South has an estimated capacity factor of ~32%, compared to MISO North (~46%) and SPP (~44%).

Offshore Wind – In the U.S., the offshore wind industry has been developing with its first commercial offshore wind farm becoming operational in Rhode Island in 2016 (30 MW Block Island Wind Farm). At this time, while most of the U.S. industry is concentrated in the northeastern United States, potential projects have been developing across the country with more widespread maturity having been achieved in Europe. Offshore wind technologies are composed of both fixed and floating foundations, and in recent years, turbine capacity has increased significantly with OEMs offering larger diameter systems. In August 2023, the U.S. Bureau of Ocean Energy Management held lease sales which had limited interest, with RWE winning one lease auction and no bidders in the other wind area auction. Assuming technology improvements (particularly advancements in resiliency to withstand major hurricane force wind speeds) and cost declines are achieved, conditions in the Gulf of Mexico and current economics, position fixed turbines may be suitable for deployment, particularly in areas with relatively shallower depths. Additional development of offshore wind projects in the northeast may positively impact costs, but for offshore wind resources in the Gulf of Mexico to be included in the longer- term transmission and supply planning efforts, technology improvements suited for ENO's service area, along with reduction in resource cost projections relative to alternative, will need to show a positive impact for our key stakeholders.

Battery Energy Storage Systems ("BESS") – Utility-scale BESS capital costs have held steady in recent years, balanced by lithium cost declines and labor and material cost increases. Current use cases of battery technology are applied to discharge times that are four-hours or less to provide peak shaving capabilities. When strategically and efficiently integrated into the electric grid, there is the potential for BESS to provide transmission and distribution grid benefits by avoiding investments required due to line overloads that occur under peak conditions. In addition to these peak shaving applications, BESS can provide voltage support, which mitigates the effects of electrical anomalies and disturbances. If paired together, there is the potential for BESS to deliver solar energy production into late afternoon hours, mitigating the ramping requirement created by the daily decline in solar energy production.

In addition to the above, BESS may also be able to offer additional value through MISO markets to benefit customers by effectively enabling an intra-day temporal shift between energy production and energy use. Through this process, energy can be absorbed and stored during off-peak/low-cost hours and discharged during on-peak/high-cost hours. When dispatched advantageously, the spread (i.e., cost difference) between the time periods can create cost savings for customers. BESS qualify in some markets for various ancillary service applications such as frequency regulation, reserves, voltage regulation, and given enough discharge duration, can qualify for MISO's capacity market. As the industry learns more and further deploys this technology, safety considerations and practices are becoming clearer, including fire prevention.

Advanced Nuclear Technology and Small Modular Reactors – Nuclear energy is a key component for meeting ENO's long-term resource planning objectives. As we continue to operate our existing nuclear fleet, we continue to observe industry developments in Advanced Nuclear Technology and Small Modular Reactors ("SMRs") to meet customer needs. SMRs may potentially offer several benefits, including being physically smaller, requiring reduced capital investments, presenting opportunities for incremental power additions, as well as supplying base load electricity including system "inertia" that is lacking in inverter-based resources. In addition, SMRs generally rely on passive safety systems, requiring no manual intervention or externally applied forces to safely shut down. Pairing SMRs with renewable resources would provide complementary technology that does not depend on climate and time of day. The Company will continue to monitor the development of this technology.

2.8: Demand-Side Management Study and Input Cases

For the 2024 IRP, ENO again engaged Guidehouse to prepare a demand side management ("DSM") potential study (the "Study"). The study assessed the long-term potential for reducing energy consumption in the residential and commercial and industrial (C&I) sectors by using energy efficiency and peak load reduction measures and improving end-user behaviors.

To develop the study, Guidehouse relied upon forecast data from ENO, the New Orleans Technical Resource Manual ("NOTRM") as a source document for measure information, a New Orleans-specific Residential Appliance Saturation Study ("RASS") and the historical results and implementation plans for the Energy Smart programs. Guidehouse and ENO began work on the Study in September 2023, and eventually filed the completed version on February 1, 2024, as required by the Initiating Resolution.

Significant results from the 2024 DSM Potential Study are summarized below. The data provided to Guidehouse was used to run its proprietary DSM Simulator (DSMSim™) model, which calculated various levels of EE savings potential across the ENO service area. Guidehouse further delineated the achievable potential using a range of assumptions in four alternative cases to estimate the effect on customer participation of funding for customer incentives, awareness, and other factors. All four cases were run with two different discount rates—the ENO Weighted Average Cost of Capital ("WACC") of 6.86% and a Societal Discount Rate of 3%. The four achievable cases included:

- Reference: Assumes both current (Program Year 12, 2022, and Program Year 13, 2023) incentive levels (as a percentage of incremental costs) and expected behavioral participation and aligns with historic program achievements. Administrative costs on a dollar per kilowatt-hour (kWh)-saved basis are the same as the historic program expenditure and are carried through the other cases. The TRC measure screening threshold for all measures is 0.9, recognizing the fact that numerous viable measures implemented through Energy Smart meet or exceed this level.

- Two Percent (2%) Savings: Uses the parameters defined by the Reference case. The savings goal under this case is the Council's goal of 2% of ENO sales by PY 15, 2025. The incentives assume ten times the existing levels up to a maximum of 100% and estimate aggressive behavioral program participation rollout plan. The TRC measure screening threshold is relaxed to 0.75 from 0.9.
- Low: Uses the same inputs as the Reference case, except for lower levels of behavioral program participation. Incentives are set to 50% of current (or Reference case) levels.
- High: Assumes higher incentives at 100 times the Reference case (up to 100% of incremental measure costs) and no change in administrative cost levels on a dollar per kWh saved basis. Model assumptions use the same aggressive behavior program rollout for all sectors as in the 2% savings case. There is no TRC measure screening threshold, as every measure is passed on to the achievable potential analysis.

In consideration of the Council's attention to low-income participation in energy efficiency programs, Guidehouse also analyzed the savings potential for low income customers. To view the results of the low income analysis, please see the 2024 DSM Potential Study attached as Appendix D.

The cumulative annual achievable electric energy savings identified by Guidehouse is illustrated in the figure below. The range of savings increases over the 20-year period, from the Low case which shows more than 1,000 GWh of savings through the High case with savings of more than 2,000 GWh. The pace of savings slows by 2031 due to increasing saturation of the existing set of measures.

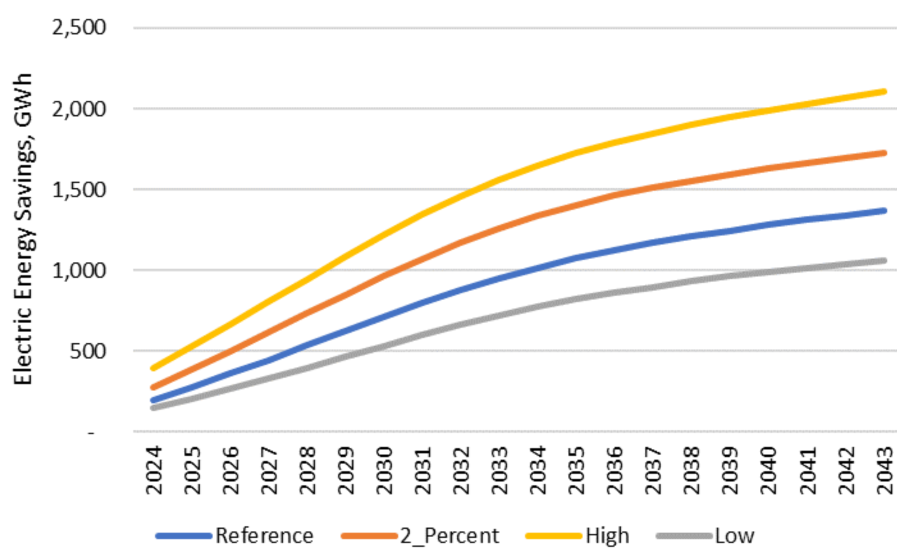


FIGURE 20: CUMULATIVE ANNUAL ACHIEVABLE POTENTIAL – ELECTRICITY SAVINGS BY CASE

The cumulative annual peak demand savings for each EE case identified by Guidehouse is illustrated in the table below. The range of savings increases over the 20-year period, with the Low case showing more than 400 MW and the high case 700 MW, and the pace of savings slowing by 2031, similar to the electric energy savings.

The incremental annual energy and peak demand potential for each case is shown in the table below.

TABLE 10: ACHIEVABLE POTENTIAL ELECTRICITY AND PEAK DEMAND BY CASE

Year	Electricity (GWh)				Peak Demand (MW)			
	Reference	2%	High	Low	Reference	2%	High	Low
2024	70	98	119	49	19	25	30	14
2025	79	110	133	57	23	29	35	17
2026	84	114	138	61	25	33	38	19
2027	85	115	138	63	28	36	41	21
2028	89	117	141	66	30	39	45	24
2029	91	117	139	68	32	41	47	26
2030	89	114	135	68	34	42	48	27
2031	86	108	127	66	33	41	46	28
2032	79	99	115	62	32	38	43	27
2033	73	89	102	58	29	34	39	25
2034	65	78	88	53	26	29	34	23
2035	56	67	76	47	22	25	29	20
2036	50	58	65	42	19	20	24	18
2037	45	50	57	37	16	17	21	15
2038	40	44	51	34	14	14	18	13
2039	36	39	46	31	12	12	16	11
2040	34	37	44	28	11	11	15	10
2041	32	34	41	25	10	10	14	9
2042	30	32	38	23	9	10	13	8
2043	29	31	37	22	9	9	12	7

For DR, Guidehouse prepared a DR potential assessment for ENO's electric service area from 2024 to 2043 as part of the DSM potential study. The objective of this assessment was to estimate the potential for using DR to reduce customer loads during peak demand during summer periods.

Guidehouse identified and analyzed a suite of DR options for potential implementation in ENO's service area based on what ENO currently offers and similar program offers in other jurisdictions, including:

1. Direct Load Control (DLC): This program controls water heating and cooling loads for residential customers using either a DLC device (switch for water heaters only) or a programmable controlling thermostat (PCT). For AC control, this option represents the EasyCool Bring Your Own Thermostat (BYOT) program that ENO offers to residential customers.
2. C&I Curtailment: This program represents the Energy Smart Large Commercial DR program that ENO currently offers, where large commercial customers agree to reduce load by a specific amount when called and get paid an incentive based on performance.
3. Dynamic Pricing: This program encourages load reduction through a Critical Peak Pricing (CPP) tariff, with a 6:1 critical peak-to-off-peak price ratio. All customer types are eligible to participate.
4. Peak Time Rebate (PTR): This program represents ENO's planned opt-in PTR offer to residential

customers. ENO could call PTR events year-round. Enrolled customers receive a $/kWh rebate on the amount of energy reduced during events over the baseline energy use. The customer participation pathway for this option is designed to integrate with existing customer engagement and behavioral EE customer offerings.

5. BTM Storage (BTMS): This program triggers power dispatch from BTM battery storage systems that are grid-connected during peak load conditions. Battery dispatch helps reduce net system load during DR event periods.
6. EV Managed Charging (Bring Your Own Charger, or BYOC): ENO offers a BYOC program that rewards customers for shifting their EV charging load to off-peak hours. This program would be open to all EV customers with Level 2 chargers.

The summer peak achievable potential by DR option is illustrated in the figure below.

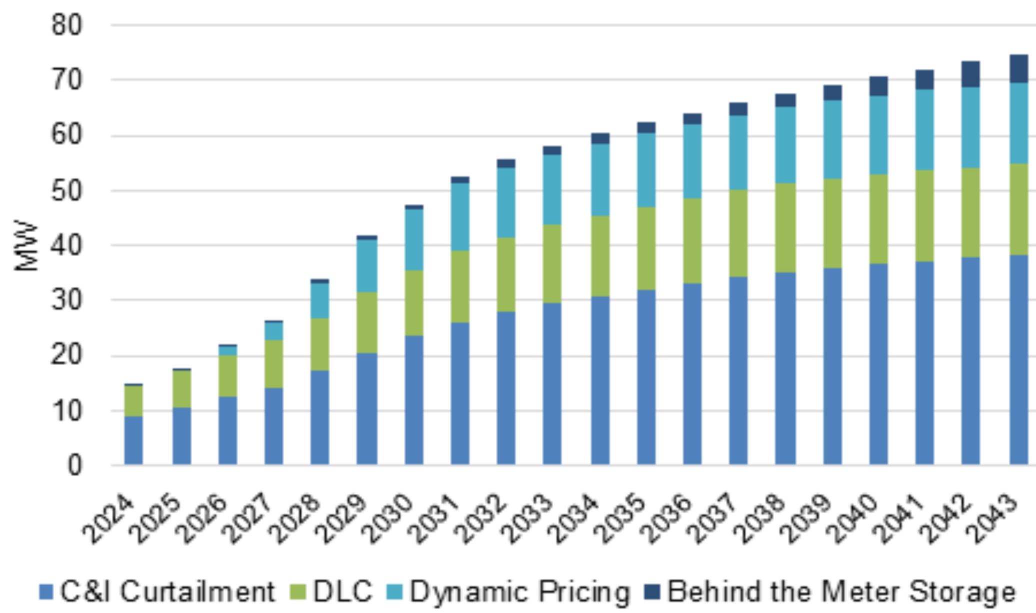


FIGURE 21: DR SUMMER PEAK ACHIEVABLE POTENTIAL BY PROGRAM

In addition, Guidehouse further analyzed DR potential estimates for three different cases. These cases were also developed using the two different discount rates noted above. These cases are based on the DR program incentive levels:

- Reference case: Reflects DR program participation based on incentives at levels that match current programs (e.g., ENO's Smart EasyCool program) and industry best practice.
- Low case: Assumes incentives are 50% lower than in the Reference case. This drives program participation down and results in lower implementation costs.
- High case: Assumes incentives are 50% higher than in the Reference case. This drives program participation up and results in higher implementation costs.

The figure below shows the summer DR achievable potential by each case.

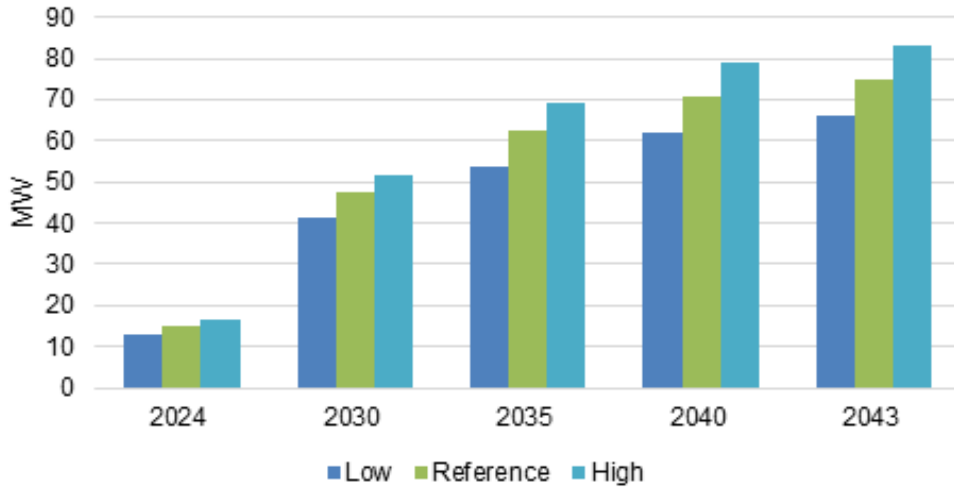


FIGURE 22: DR SUMMER ACHIEVABLE POTENTIAL BY CASE

2.9: Fuel and CO2 Price Forecasts

Natural Gas Price Forecasts – Three natural gas price forecasts were used in the development of the 2024 IRP. The near-term portion of the natural gas forecast is based on NYMEX Henry Hub forward prices. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long term. Due to this limitation, the long-term point-of-view is based on a consensus across a number of independent, third-party consultants' forecasts. Gas markets are influenced by a number of complex forces; consequently, long-term natural gas prices are highly uncertain and become increasingly uncertain as the time horizon increases. The Planning Scenarios agreed to by the parties for use in the IRP modeling included either Reference or High natural gas price cases as shown in Figure 23, below.

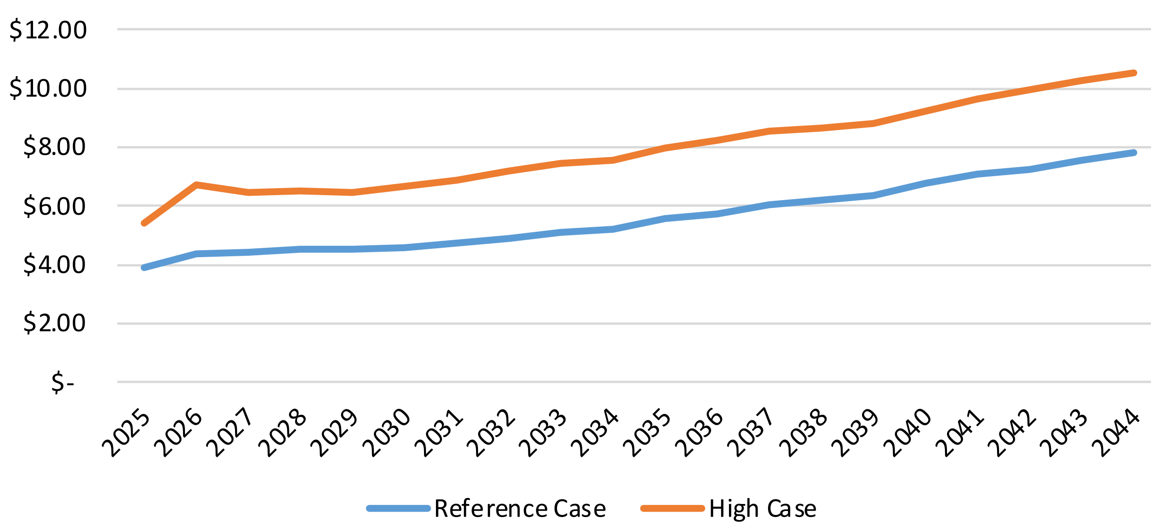


FIGURE 23: ANNUAL NATURAL GAS PRICE FORECAST SCENARIOS (NOMINAL $/MMBTU)

CO2 Price Assumptions – ENO's point of view is that national carbon regulation or pricing for the power generation sector will occur; however, the timing, design, and outcome of any carbon control program remain uncertain. Our perspective on CO2 is based on the following three cases from the ICF International, Inc., ("ICF") Q4 2023 Core CO2 Price Trajectory issued in October 2023:

$0/ton CO2 price, "Clean Energy Standards or No Policy" case represents either no program or a program that requires only "inside-the-fence" measures at generating facilities, such as efficiency improvements, that do not result in a tradable CO2 price but may require some capital expenditures.

"Regulatory" case, in which prices representative of action under the Clean Air Act are utilized.

"Legislative" case, in which high prices consistent with the Climate Leadership Council's Carbon Dividend proposal are utilized.

After deriving projections of CO2 allowance prices for each of these three cases, the following probability weightings were applied to each to derive the Reference and High cases used in the ENO IRP:

TABLE 11: CO2 PROBABILITY WEIGHTINGS

Case	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045
Clean Energy Standards or No Policy	100%	100%	100%	100%	95%	90%	85%	80%	70%	60%
Regulatory	-	-	-	-	5%	10%	15%	20%	20%	20%
Legislative	-	-	-	-	-	-	-	-	10%	20%

Planning Scenarios 1 and 2 assume Reference case CO2, and Planning Scenario 3 assumes High case CO2 Legislative Price Case in accordance with ENO's point of view.

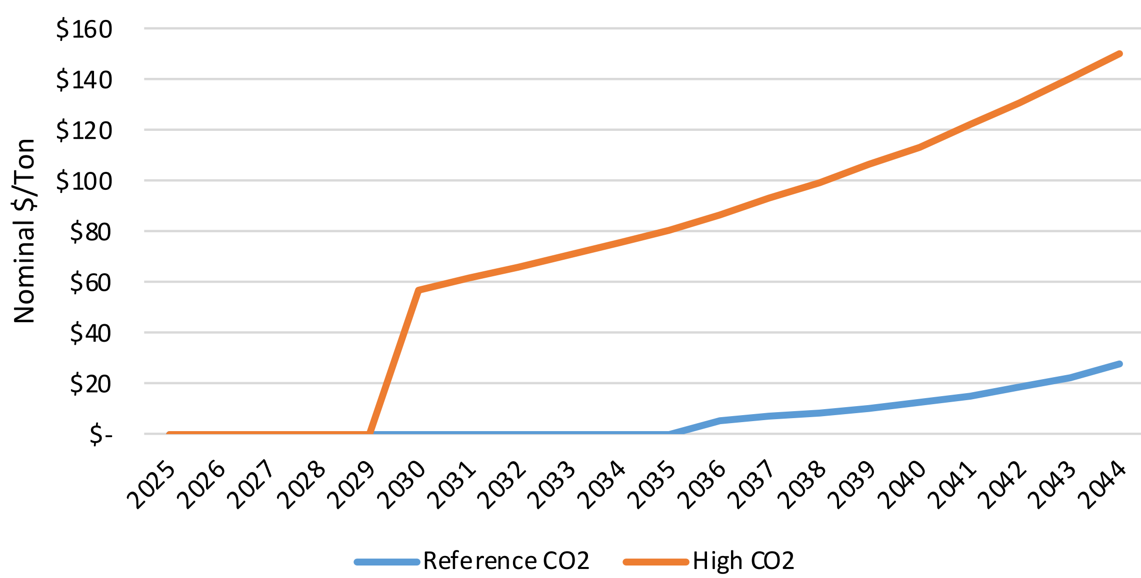


FIGURE 24: CO2 PRICE FORECAST

CHAPTER 3

Modeling Framework

3.1: Scenario- and Strategy-Based Approach

To support the evaluation of a broad range of resource portfolios, ENO, the Advisors, and the Intervenors agreed on three Planning Scenarios representing a range of market drivers and possible futures. Additionally, the parties came to consensus on four Planning Strategies that informed or constrained the Portfolio development process consistent with defined objectives or policies. Using the Aurora Capacity Expansion Model, twelve optimized Portfolios were developed based on a combination of each Scenario and Strategy. Additionally, two manual portfolios were developed under Strategy 1 which each accelerated the assumed deactivation of Union 1 to an earlier year.

Planning Scenarios – The 2024 IRP utilized three Scenarios which varied based on economic, policy, and customer behavior assumptions that impact market prices, including:

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

The three Scenarios agreed to among the parties for inclusion in the 2024 IRP are shown in Table 10, below:

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

Scenario 2 (Clean Air Act Section 111 Compliance) is defined by reference load growth and gas prices, high DSM additions, and moderately accelerated coal and legacy gas retirements.

Scenario 3 (Stakeholder Scenario), as defined by the Intervenors, is characterized by high load growth, gas prices, and DSM additions, as well as low renewable capital cost assumptions.

TABLE 12: OVERVIEW OF PLANNING SCENARIOS

	Scenario 1 – Reference	Scenario 2 – Clean Air Act Section 111 Compliance	Scenario 3 – Stakeholder Scenario
Peak Load & Energy Growth	Reference	Reference	High
Natural Gas Prices	Reference	Reference	High
MISO Coal Deactivations	All ETR coal by 2030 All MISO coal aligns with MTEP Future 2 (36 year life)	All ETR coal by 2030 All MISO coal by 2030	All ETR and MISO coal by 2030
MISO Natural Gas CC Deactivations	45 year life	NGCC by 2035	Deactivated by 2035
MISO Natural Gas Other Deactivations	36 year life	Steam gas EGUs by 2030	Deactivated by 2035
Carbon Tax Scenario	Reference Cost	Reference Cost	High Cost
Renewable Capital Cost	Reference Cost	Reference Cost	Low Cost
Narrative	Assumptions align with the 2024 Business Plan case. Moderate amount of industrial growth forecasted which would drive the need for new development	Entergy and utilities across MISO deactivate existing units early to be compliant with proposed changes to Clean Air Act Section 111(d) New resources built would comply with proposed changes to 111(b)	High energy growth from both industrial and residential sectors forecasted. Renewable cost assumed to be low due to more efficient supply chain

Planning Strategies – The Strategies were developed to support a range of potential planning objectives, Council policies, and clean energy priorities. Portfolios developed under all four Strategies were designed to meet the forecasted MISO-coincident peak load plus a planning reserve margin of 9% in summer and 27.4% in winter based on seasonal accredited capacity value. The details provided in Table 11 below were used to constrain the capacity expansion modeling to conform to the objectives defined by each Strategy.

TABLE 13: OVERVIEW OF PLANNING STRATEGIES

	Strategy 1	Strategy 2	Strategy 3	Strategy 4
Description	Least Cost Planning	But For RCPS	RCPS Compliance	Stakeholder Strategy— Accelerated Grid Cleaning
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals	800 MW of renewables by 2030, including 200 MW of BTM solar and 55 MW of IFOM Community Solar; high load growth driven by EVs and electrification
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.	Accelerate achievement of RCPS goals using local generation and PPAs to increase portfolio of solar, storage, and wind
DSM Input Case	WACC, Reference Case	WACC, 2% Program Case	WACC, 2% Program Case	Societal Discount Rate, High Case
Optimized Portfolio	Yes	Yes	Yes	No[9]
Manual Portfolios	Early Deactivation of Union 1 in 2032 Early Deactivation of Union 1 in 2035	N/A	N/A	Yes

Strategy 1 (Least Cost Planning) focuses on least cost alternatives to meet planning needs as required by Section 7.D.1 of the Council's IRP Rules. Demand and supply-side alternatives are selected based solely on need and cost. Strategy 1 allows the Aurora model to select any Guidehouse EE or DR program (at whichever level is determined to be the most economic) based on the costs and demand reduction provided by Guidehouse.

Strategy 2 (But for RCPS) (Reference) is described as the "But For RCPS" strategy and is intended to represent the resource plan that would comply with regulatory policies in New Orleans that existed before Council approval of the RCPS rules. Strategy 2 incorporates the Guidehouse 2% Program case and allows the model to select other least cost resources required to meet identified capacity needs.

[9] Given the defined amounts and timing of renewables specified by the Stakeholders for their Strategy, it was agreed upon by the parties that this portfolio should be developed manually rather than through capacity expansion optimization.

The Strategy forces the selection of all EE and DR programs to meet the 2% goal. Additionally, Strategy 2 allows the selection of any available generation technologies as capacity resources to satisfy the Planning Reserve Margin Requirements. This strategy is included to provide this same "But For RCPS" point of comparison in successive IRPs, as required by the Council's RCPS rules.

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

Strategy 4 (Stakeholder Strategy), defined by the Intervenors, uses the Guidehouse Societal High case DR and EE programs, as well as amounts of different renewables as specified by the Intervenors. The Strategy forces the selection of all EE and DR programs into the optimized Portfolios.

Manual Portfolios – In addition to the twelve optimized portfolios produced through Aurora, two manual portfolios were produced that accelerated the assumed 2041 deactivation date of Union 1. Manual Portfolio 1a accelerated the deactivation to 2032 and Manual Portfolio 1b accelerated to 2035. Both manual portfolios were informed by the optimized portfolio developed under Strategy 1/Scenario 1.

3.2: Peak Capacity Credit Modeling

Thermal Resource Capacity Credit – The capacity credit assumption for thermal resource alternatives in the IRP is based on MISO's planning year 2024-2025 Schedule 53 class averages (ISAC/ICAP), published in February 2024, and Seasonal UCAP/ISAC Ratios, also published in February 2024. The class average is multiplied by the UCAP/ISAC ratio for each season for each thermal resource technology type to arrive at the assumed capacity credit.

TABLE 14: MISO THERMAL CAPACITY CREDIT

Technology	Summer Capacity Credit [%]	Winter Capacity Credit [%]
1X1 CCCT (M501JAC)	98.4	96.7
CT (M501JAC)	96.5	88.3
AERO CT (LMS100PA)	96.5	88.3
RICE (7x18V50SG)	96.5	88.3

Renewable Capacity Credit – The solar and wind capacity credit used in the IRP was calculated using the Dynamic Peak credit function within Aurora. This function instructs Aurora to calculate the peak credit for each type of renewable resource for each iteration of the long-term capacity expansion run based on the penetration of total renewables in the previous iteration. The top 3% of the peak load hours per month, net of solar, wind, and hydro resource output is used to determine how much contribution to the planning reserve margin a resource type will have in a season. The calculation is based on all of MISO, including ENO. Below are the seasonal peak credit values for solar and wind resources for the five downselected portfolios.

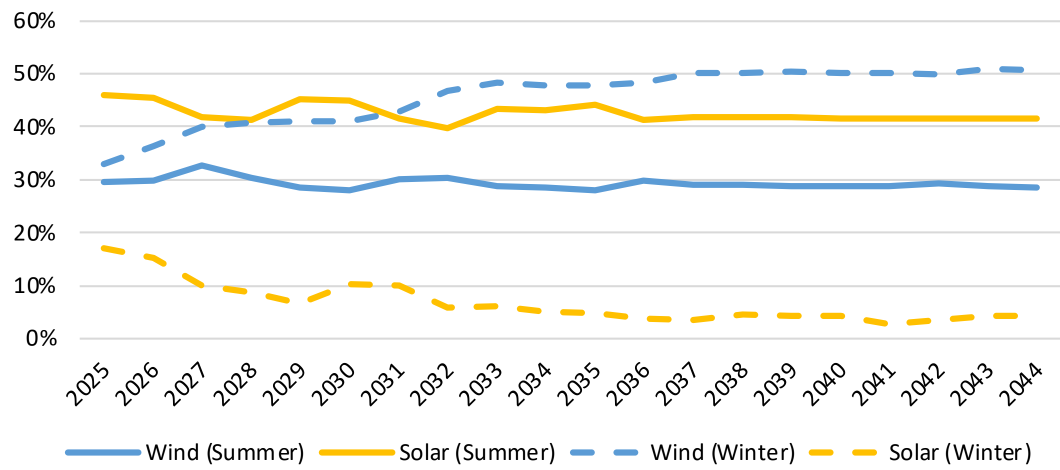


FIGURE 25: STRATEGY 1/SCENARIO 1
PROJECTED MISO MARKET (INCL. ENO) PEAK CREDIT FOR SUMMER & WINTER

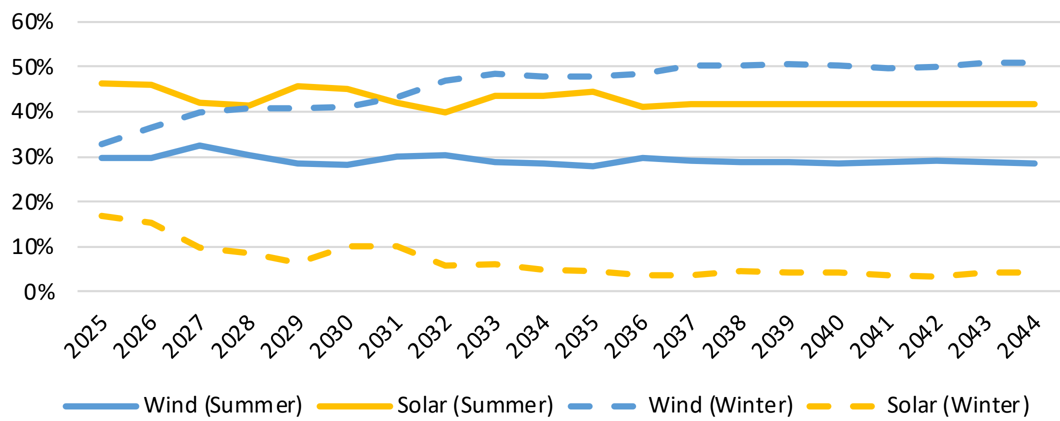


FIGURE 26: STRATEGY 1/SCENARIO 1 MANUAL PORTFOLIO 1B (2035 UNION DEACTIVATION)
PROJECTED MISO MARKET (INCL. ENO) PEAK CREDIT FOR SUMMER & WINTER

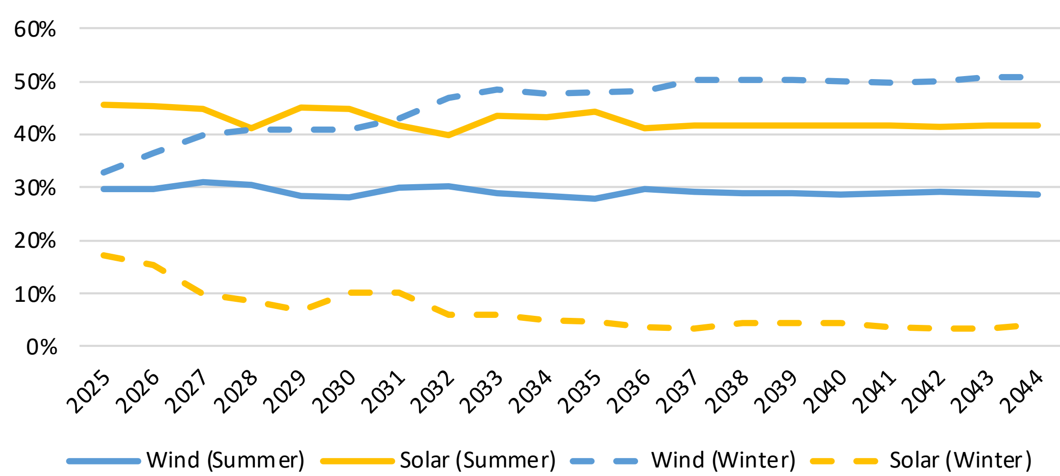


FIGURE 27: STRATEGY 2/SCENARIO 1
PROJECTED MISO MARKET (INCL. ENO) PEAK CREDIT FOR SUMMER & WINTER

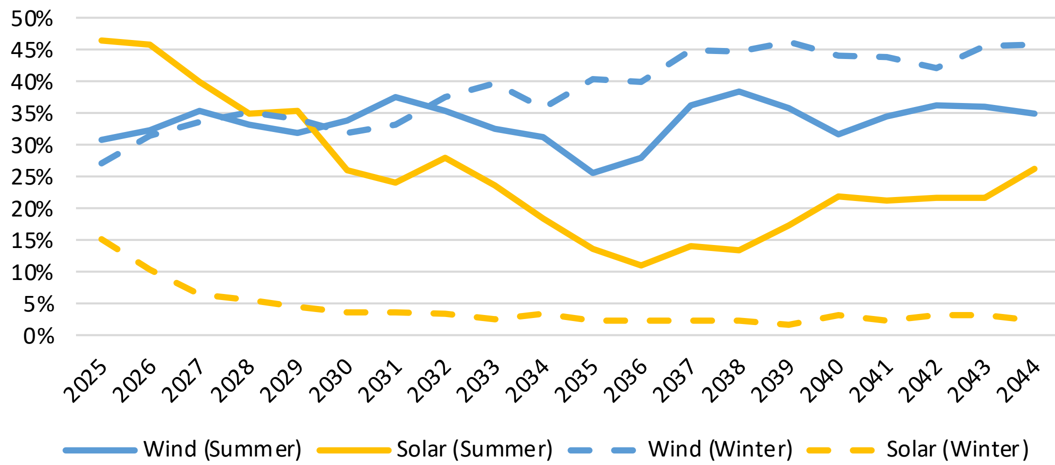


FIGURE 28: STRATEGY 4/SCENARIO 2
PROJECTED MISO MARKET (INCL. ENO) PEAK CREDIT FOR SUMMER & WINTER

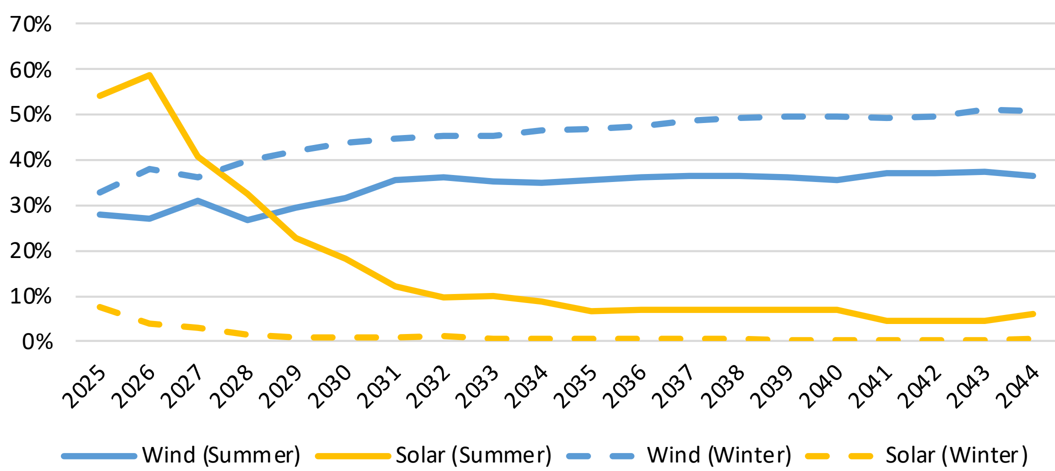


FIGURE 29: STRATEGY 3/SCENARIO 3
PROJECTED MISO MARKET (INCL. ENO) PEAK CREDIT FOR SUMMER & WINTER

Battery Storage – Battery storage peak credit is calculated using an effective load carrying capability ("ELCC") model and input as tranches to account for expected decline in peak credit with increased penetration. This decline in peak credit varies by season and is driven by the need for longer storage durations to continue to flatten peak loads at higher storage penetration. Initial tranche battery peak credit is assumed to be 95% for the summer and 43% for the winter seasons.

3.3: Market Modeling

The development of the 2024 IRP relied on the Aurora Energy Market Model to produce optimized portfolios for the MISO energy market and for ENO under the identified Scenario and Strategy combinations. Aurora is a production cost and capacity expansion optimization tool that simulates energy market operations using hourly demand and individual resource operating characteristics in a chronological dispatch algorithm and uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, available DSM program alternatives, environmental constraints, and future demand forecasts. Aurora's optimization process identifies the set of future resources that most economically meets the identified requirements given the defined constraints. For the 2024 IRP, the model optimized the MISO market and ENO market simultaneously rather than separately, as was done in prior IRPs. Figures 30 to 34 below shows the projected market supply for each of the downselected portfolios. Figure 35 represents projected annual MISO (excluding ENO) power prices for each Strategy/Scenario combination. The MISO power prices from Strategy 1/Scenario 1, Manual Portfolio 1b, and Strategy 2/Scenario 1 nearly overlap each other due to the similar market builds. The price spike in 2030 for Strategy 3/Scenario 3 is caused by the CO2 emission price beginning that year.

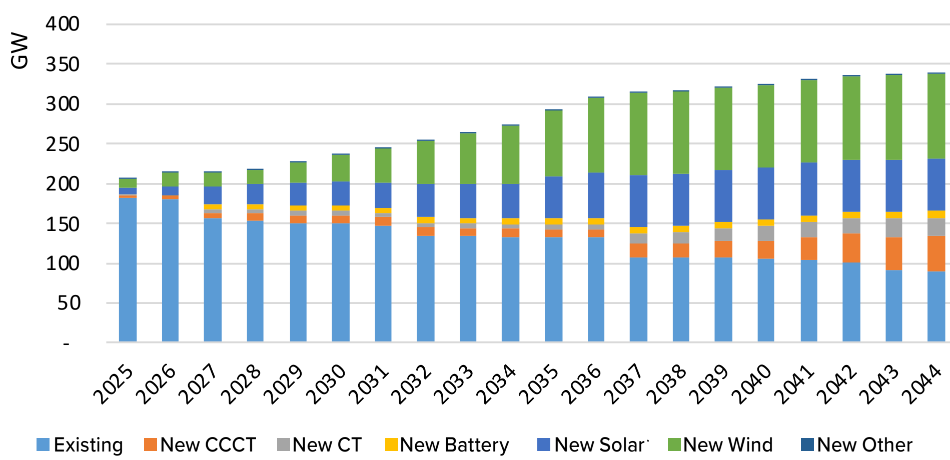


FIGURE 30: STRATEGY 1/SCENARIO 1
PROJECTED MISO MARKET NON-ENO INSTALLED CAPACITY

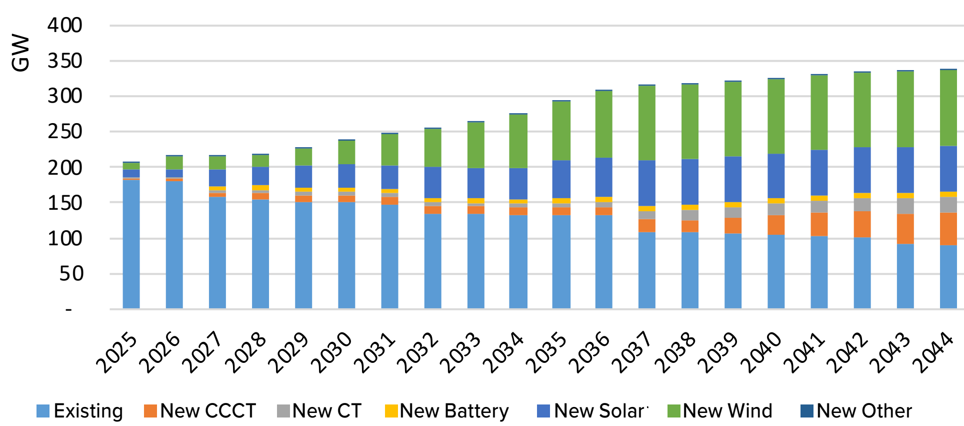


FIGURE 31: MANUAL PORTFOLIO 1B (2035 UNION DEACTIVATION)
PROJECTED MISO MARKET NON-ENO INSTALLED CAPACITY

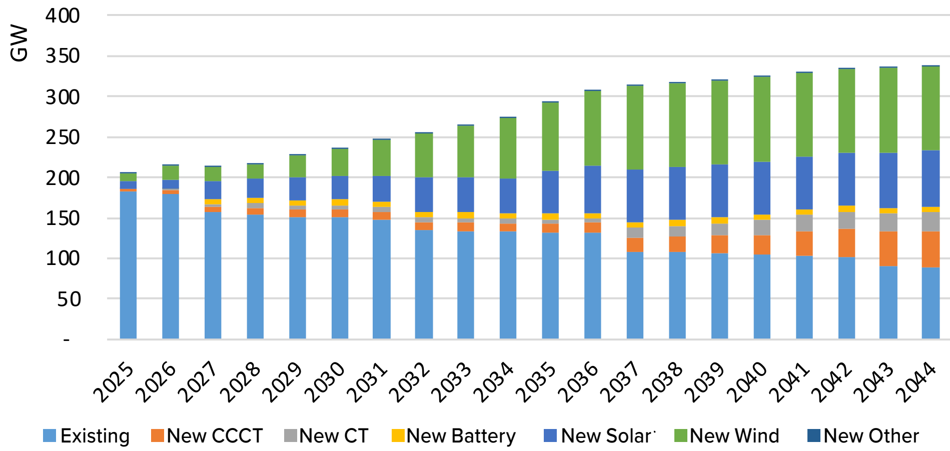


FIGURE 32: STRATEGY 2/SCENARIO 1
PROJECTED MISO MARKET NON-ENO INSTALLED CAPACITY

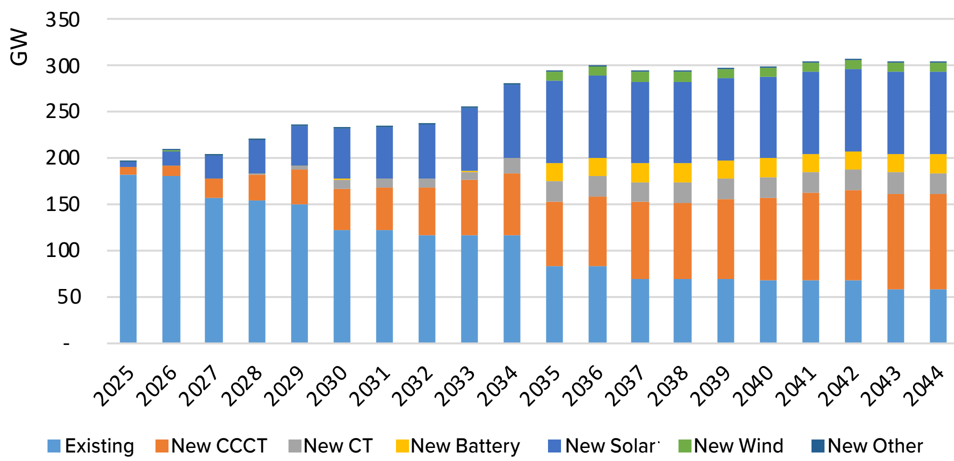


FIGURE 33: STRATEGY 4/SCENARIO 2
PROJECTED MISO MARKET NON-ENO INSTALLED CAPACITY

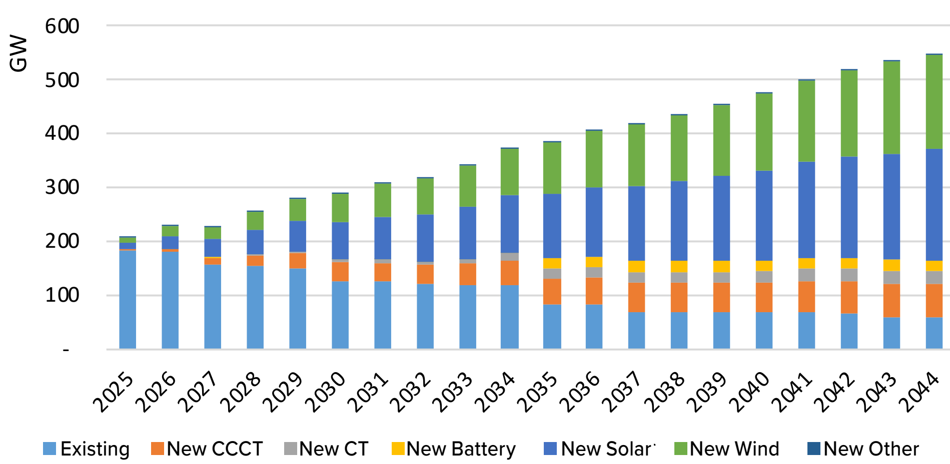


FIGURE 34: STRATEGY 3/SCENARIO 3
PROJECTED MISO MARKET NON-ENO INSTALLED CAPACITY

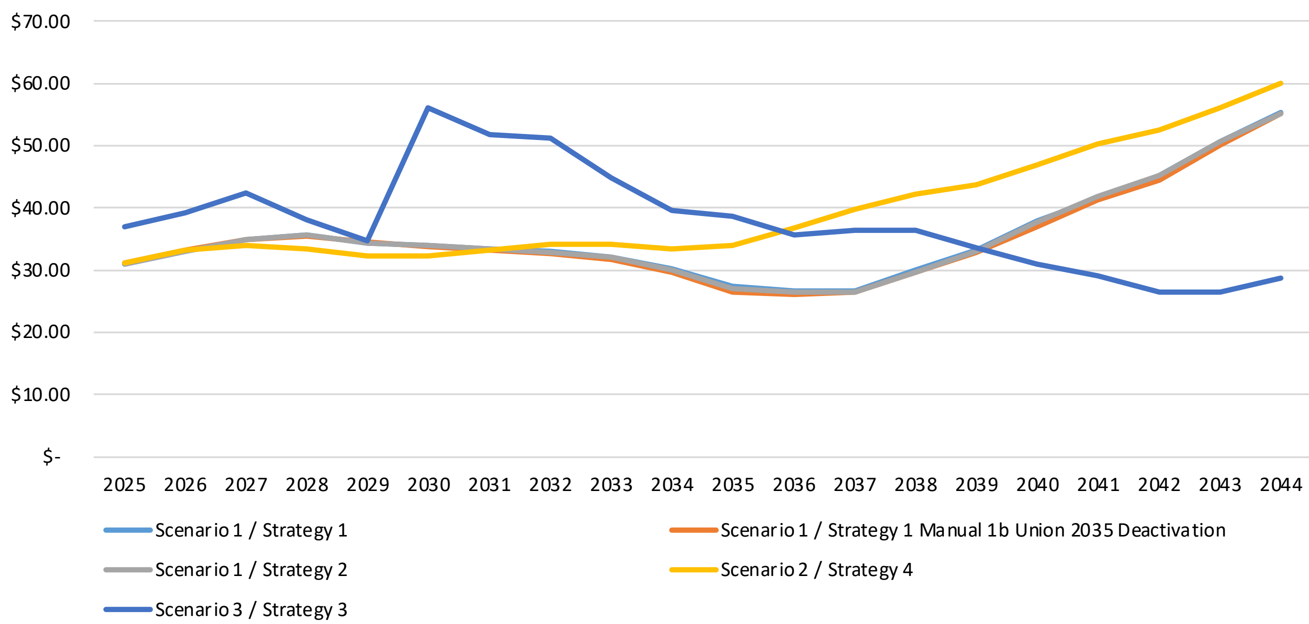


FIGURE 35: AVERAGE ANNUAL MISO MARKET NON-ENO LMPS

3.4: ENO Optimized and Manual Portfolios

Optimized Portfolios – While the Aurora model was building out the non-ENO MISO region, it simultaneously used the long-term capacity expansion logic to identify economic type, amount, and timing of demand-side resources (as noted earlier, DSM was forced in for Planning Strategies 2 – 4 consistent with the defined objectives of those Strategies) and supply-side resources needed to meet ENO's capacity needs for each Strategy under each Scenario. The result of this process was a portfolio of demand-side resources and supply-side resources that produces the lowest total supply cost to meet the identified need within the constraints defined in each of the 12 Strategy and Scenario combinations. Figures 36 to 38 below depict the incremental supply-side resource additions of the Portfolios that resulted from each Scenario and Strategy Combination.

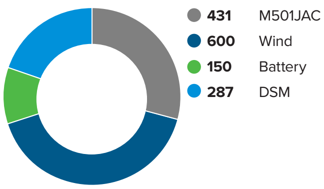
Scenario 1: Reference

Reference Gas, Reference Demand, Reference CO2

Strategy 1

Optimized Portfolio

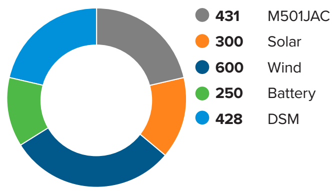
Least Cost Planning
DSM Optimized
All Resources Available



Strategy 2

Optimized Portfolio

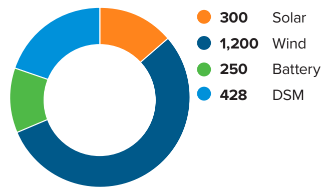
But for RCPS
2% DSM Program Forced in
All Resources Available



Strategy 3

Optimized Portfolio

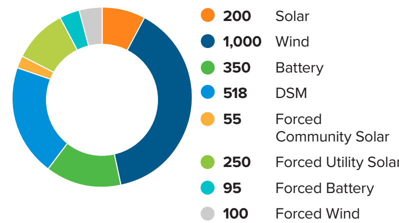
RCPS Compliance
2% DSM Program Forced in
Only Renewable Resources Available



Strategy 4

Optimized Portfolio

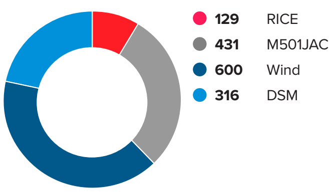
Stakeholder Strategy
Societal High DSM Program Forced in
500 MW Renewables Block Forced in
Only Renewable Resources Available



Strategy 1

Manual Portfolio 1a: Union 1 Deactivation

Least Cost Planning
DSM Optimized
All Resources Available



Strategy 1

Manual Portfolio 1b: 2035 Union 1 Deactivation

Least Cost Planning
DSM Optimized
All Resources Available

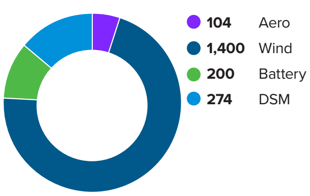


FIGURE 36: CAPACITY EXPANSION RESULTS FOR SCENARIO 1, ICAP MW

Scenario 2: Clean Air Act Compliance

Reference Gas, Reference Demand, Reference CO2

Strategy 1

Least Cost Planning
DSM Optimized
All Resources Available

Strategy 2

But for RCPS
2% DSM Program Forced in
All Resources Available

Strategy 3

RCPS Compliance
2% DSM Program Forced in
Only Renewable Resources Available

Strategy 4

Stakeholder Strategy
Societal High DSM Program Forced in
500 MW Renewables Block Forced in
Only Renewable Resources Available

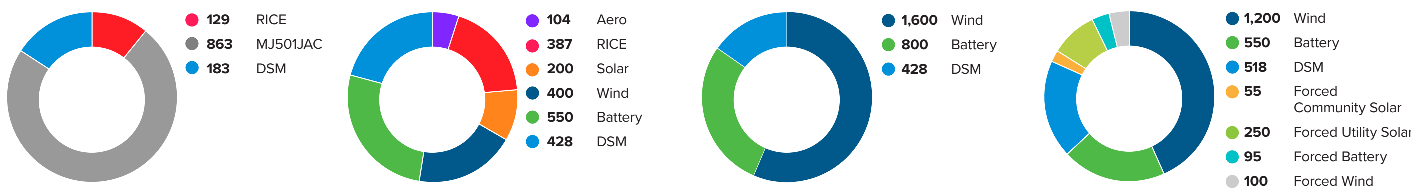


FIGURE 37: CAPACITY EXPANSION RESULTS FOR SCENARIO 2, ICAP MW

Scenario 3: Stakeholder

High Gas, High Demand, High CO2

Strategy 1

Least Cost Planning
DSM Optimized
All Resources Available

Strategy 2

But for RCPS
2% DSM Program Forced in
All Resources Available

Strategy 3

RCPS Compliance
2% DSM Program Forced in
Only Renewable Resources Available

Strategy 4

Stakeholder Strategy
Societal High DSM Program Forced in
500 MW Renewables Block Forced in
Only Renewable Resources Available

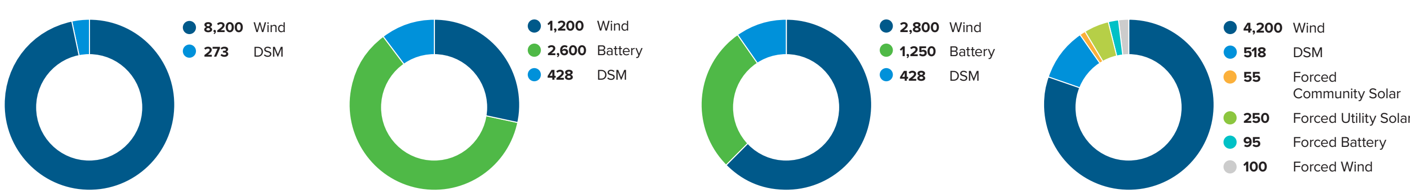


FIGURE 38: CAPACITY EXPANSION RESULTS FOR SCENARIO 3, ICAP MW

Downselected Portfolios – After the results for the Optimized and Manual Portfolios were created, the parties agreed at Technical Meeting #4 on a subset of five representative portfolios to be downselected for further analysis and evaluation. Figures 39 to 43 below are representations of the annual capacity from the downselected Portfolios.

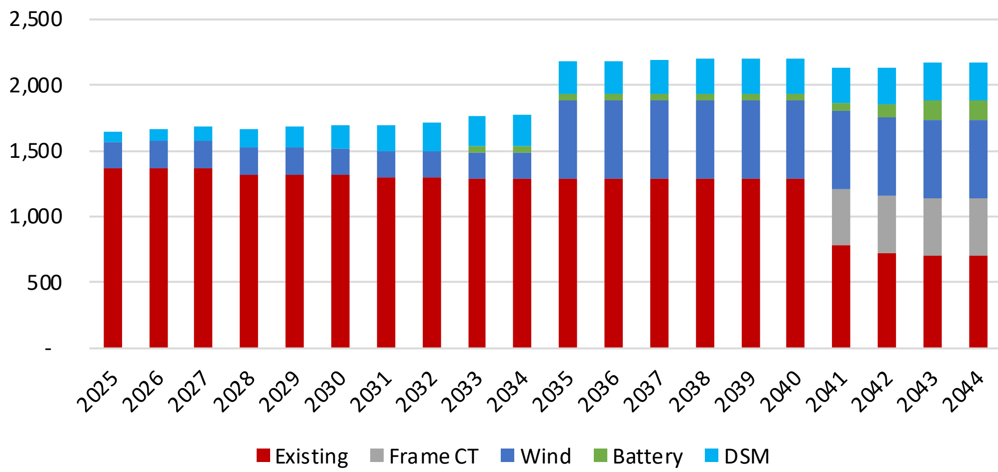


FIGURE 39: CAPACITY EXPANSION RESULTS FOR STRATEGY 1/SCENARIO 1, ICAP MW

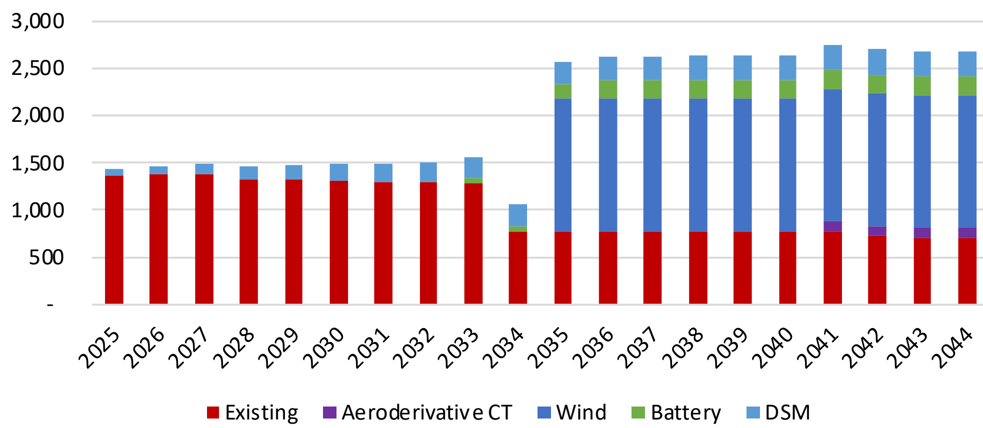


FIGURE 40: CAPACITY EXPANSION RESULTS FOR MANUAL PORTFOLIO 1B (2035 UNION DEACTIVATION), ICAP MW

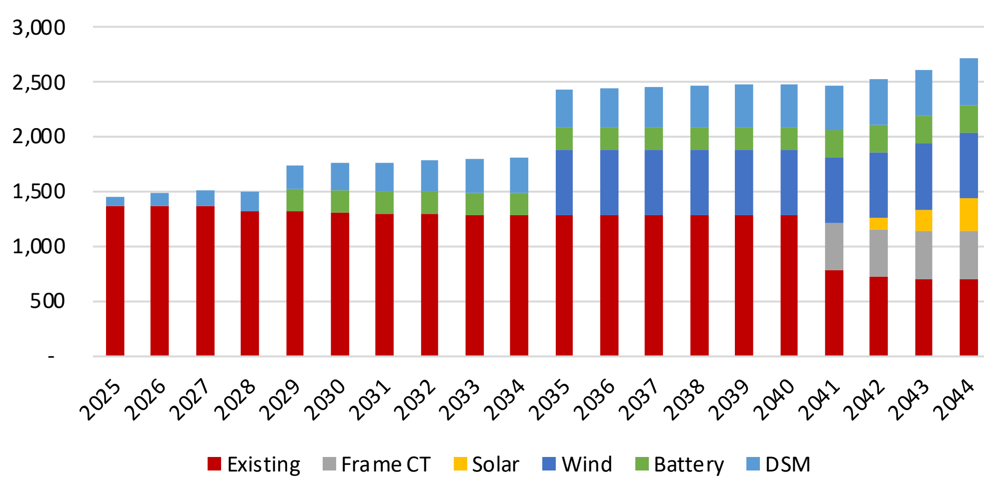


FIGURE 41: CAPACITY EXPANSION RESULTS FOR STRATEGY 2/SCENARIO 1, ICAP MW

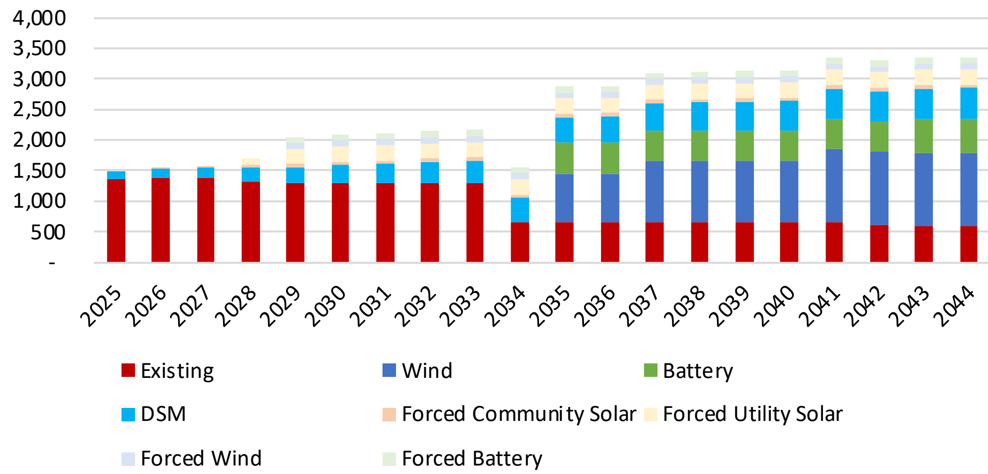


FIGURE 42: CAPACITY EXPANSION RESULTS FOR STRATEGY 4/SCENARIO 2, ICAP MW

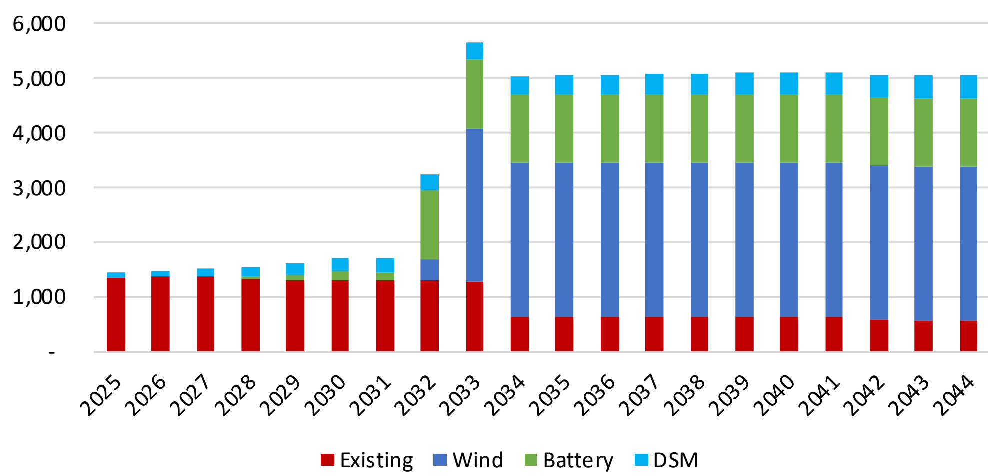


FIGURE 43: CAPACITY EXPANSION RESULTS FOR STRATEGY 3/SCENARIO 3, ICAP MW

DSM Modeling – For Strategy 1, all levels of each EE program and DR program were evaluated as resource alternatives in the Aurora capacity expansion optimization in order to identify the programs that indicated the potential for positive net benefits to be included in ENO's portfolio. Only one level for each program could be selected. For Strategies 2 and 3, the Goal (2%) level for EE programs and the Reference level for DR programs was forced into the resource portfolio. Strategy 4 had the High level for EE programs and the High level for DR programs forced into the resource portfolio.

For the DSM programs that were not forced into the portfolios, Aurora considered the cost and revenue of energy and capacity in the context of the MISO market for each DSM alternative. Because the forecasted DSM programs gain adoption by customers over time, each program was designed to start in 2025 and continue through the end of the technical life of the technology, if applicable, or through the end of the planning horizon. The estimated demand reduction of selected DSM programs is counted toward meeting ENO's capacity needs. The following table displays the DSM ending capacity selected in each of the downselected Portfolios. The selections for Strategy 1 portfolios were decided through economic evaluation by Aurora based on costs and energy savings provided by Guidehouse. The other Strategies had the DSM programs forced in, not selected based on economic evaluation in Aurora.

TABLE 15: DSM PROGRAMS FOR EACH DOWNSELECTED PORTFOLIO, MW IN LAST YEAR OF STUDY

	Programs	Strategy 1 Scenario 1	Strategy 1 Scenario 1 Manual 1b (2035 Union Deactivation)	Strategy 2 Scenario 1	Strategy 4 Scenario 2	Strategy 3 Scenario 3
Energy Efficiency Program	Com Behavior	29.5	29.5	26.2	29.5	26.2
	HPwES	-	-	40.3	42.9	40.3
	HVAC	17.8	17.8	17.8	44.2	17.8
	Large C&I	82.1	82.1	82.1	109.6	82.1
	LI-MF	40.8	40.8	48.8	51.5	48.8
	Recycling	-	-	1	1.1	1
	Res Behavior	-	-	2.8	2.8	2.8
	Retail	-	-	7.9	8.8	7.9
	School Kits	0.8	0.8	0.8	0.8	0.8
	Small C&I	45.8	45.8	45.8	61.2	45.8
	Subtotal Energy Efficiency Programs	**216.7**	**216.8**	**273.6**	**352.4**	**273.6**
Demand Response Program	BTMG - Battery Storage	5.4	4.6	5.4	5.9	5.4
	C&I Curtailment- Advanced Lighting Control	0.1	0.1	0.1	0.1	0.1
	C&I Curtailment- Auto-DR HVAC Control	28.7	28.7	31.3	32.0	31.3
	C&I Curtailment- Industrial	4.2	3.9	4.2	4.3	4.2
	C&I Curtailment- Other	1	1	1	1	1
	C&I Curtailment- Refrigeration Control	0.2	0.2	0.2	0.2	0.2
	C&I Curtailment- Standard Lighting Control	2	1.8	2	2	2
	C&I Curtailment- Water Heating Control	0.1	0.1	0.1	0.2	0.1
	DLC-Switch-Water Heating	-	-	15.5	17	15.5
	DLC-Thermostat-Res	11.5	-	16.8	25.5	16.7
	Dynamic Pricing with enabling tech.	11	11	11	10.6	11
	Dynamic Pricing w/o enabling tech.	5	5	4.1	2.7	4.1
	EV Managed Charging	-	-	50.3	50.3	50.3
	Peak Time Rebate	-	-	11	11.7	11
	Subtotal Demand Response Programs	**69.1**	**56.3**	**152.7**	**163.5**	**152.7**
	Total DSM Programs	**285.8**	**273.1**	**426.3**	**515.9**	**426.3**

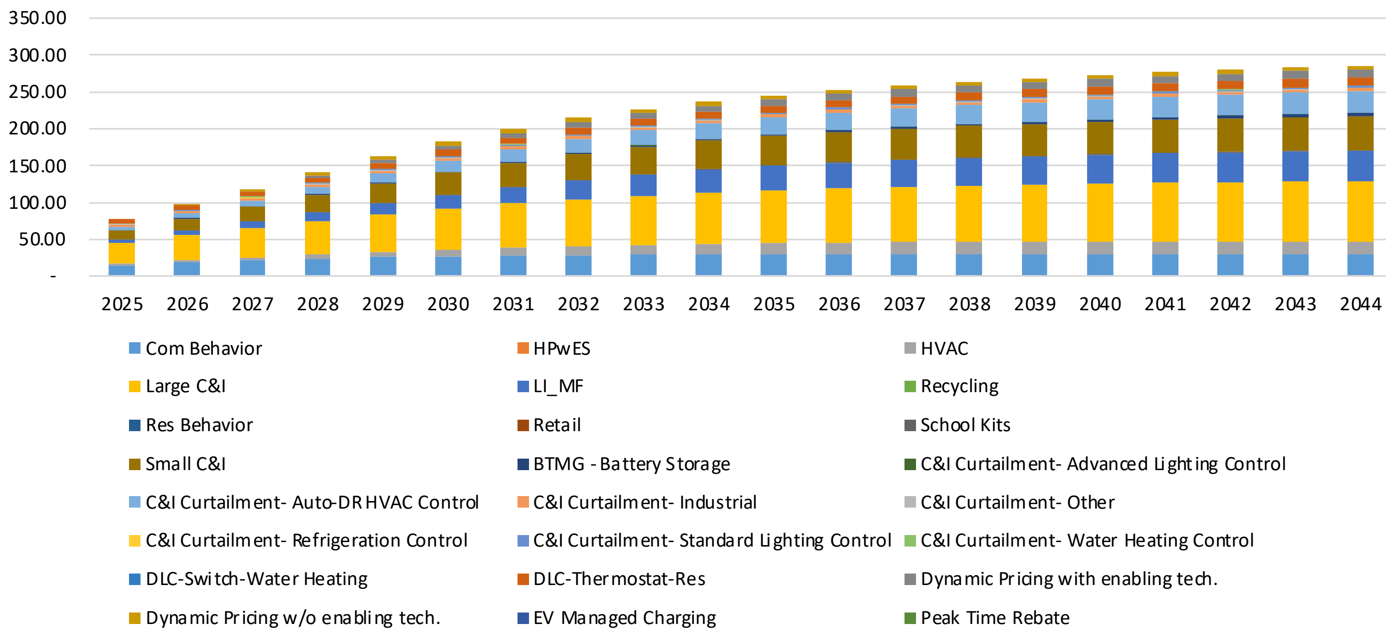


FIGURE 44: ANNUAL DSM CAPACITY FOR STRATEGY 1/SCENARIO 1, MW

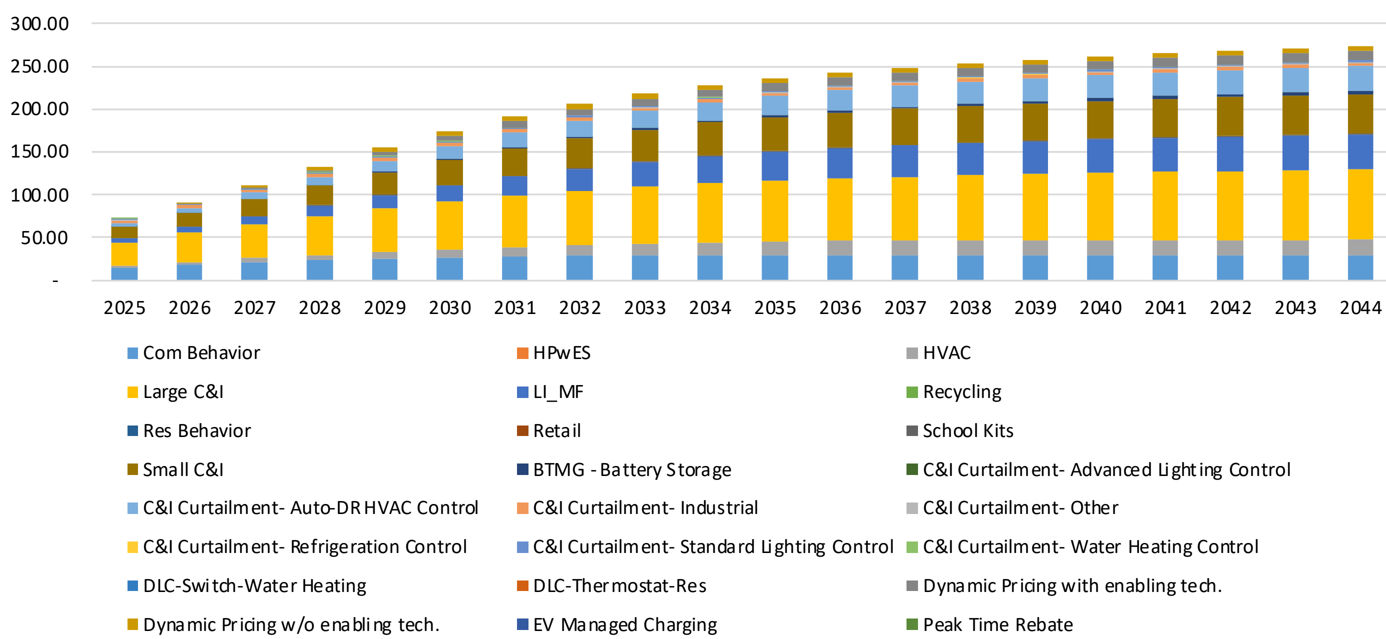


FIGURE 45: ANNUAL DSM CAPACITY FOR MANUAL PORTFOLIO 1B, MW

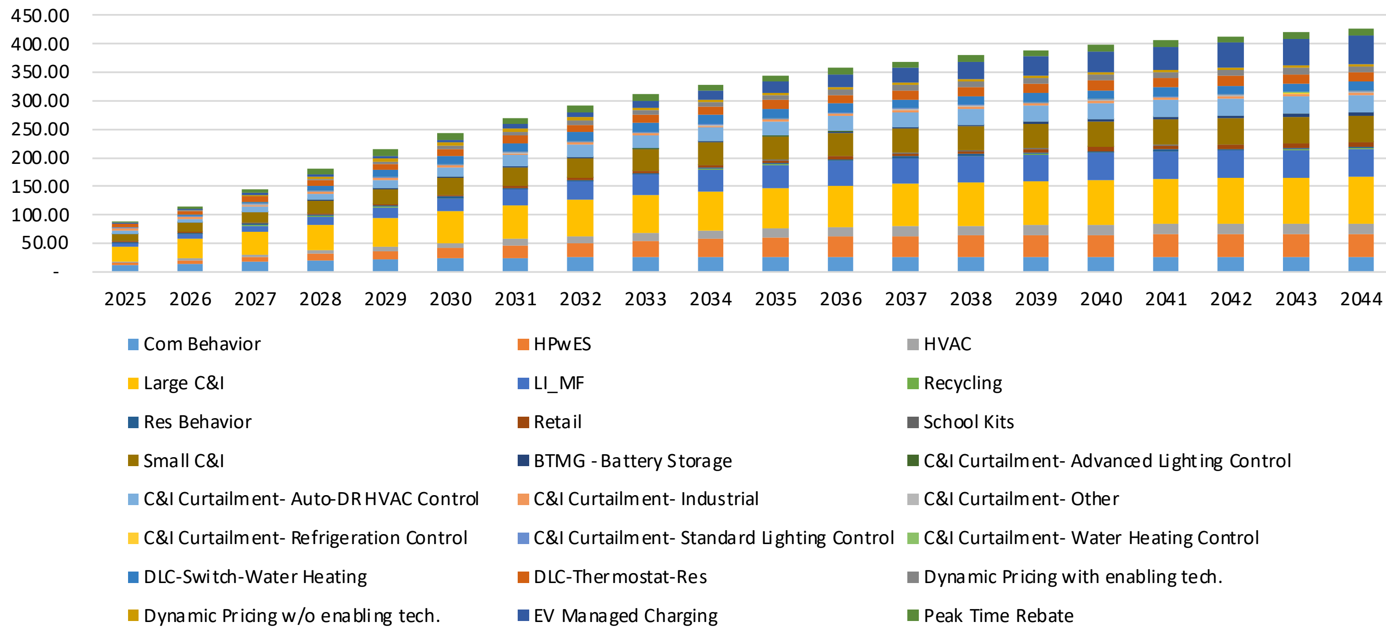


FIGURE 46: ANNUAL DSM CAPACITY FOR STRATEGY 2/SCENARIO 1, MW

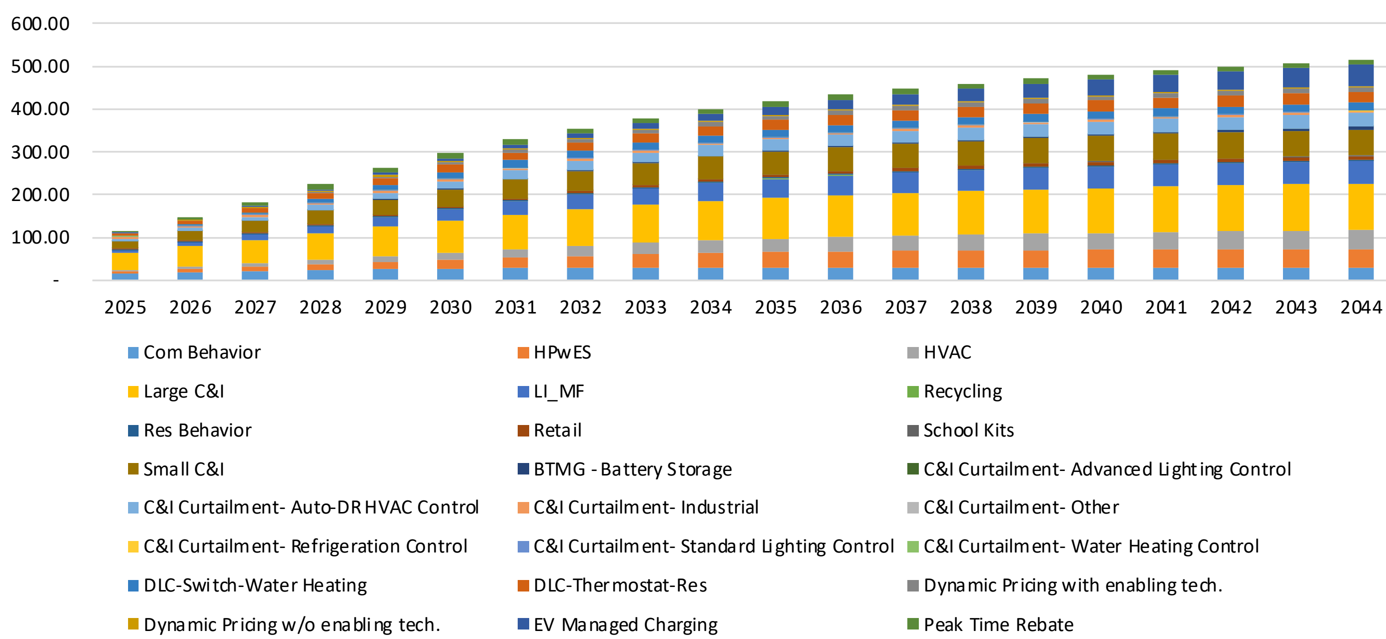


FIGURE 47: ANNUAL DSM CAPACITY FOR STRATEGY 4/SCENARIO 2, MW

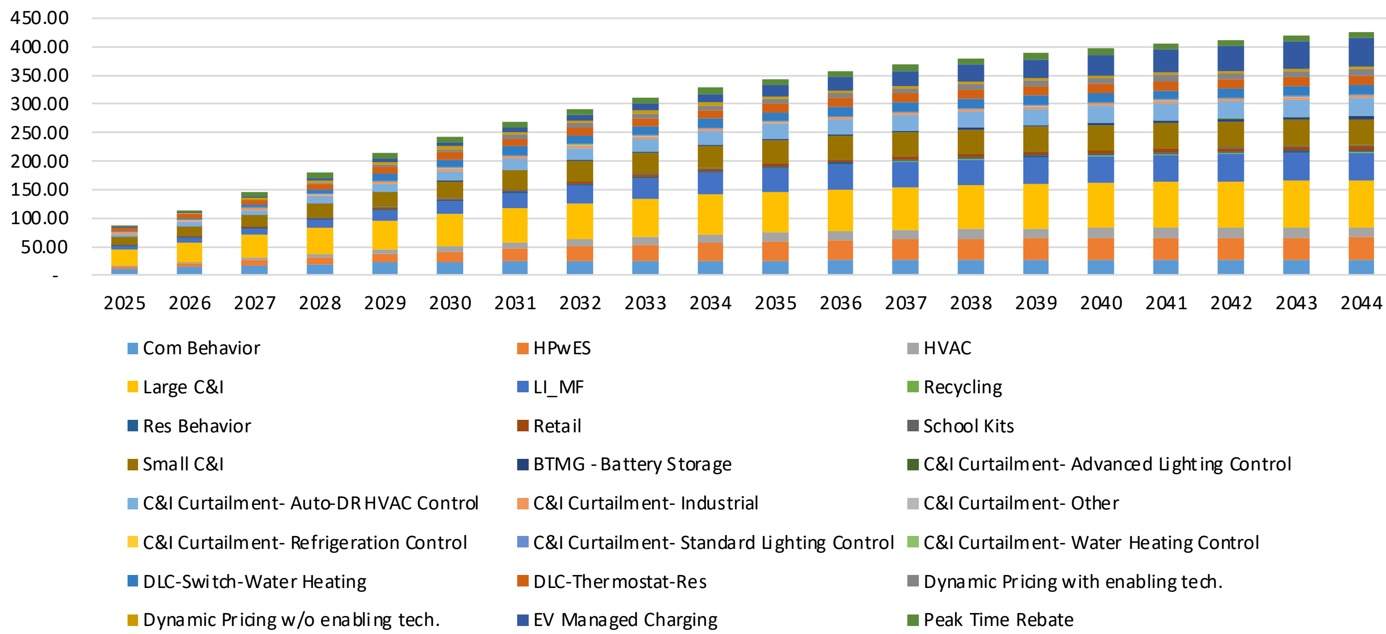


FIGURE 48: ANNUAL DSM CAPACITY FOR STRATEGY 3/SCENARIO 3, MW

3.5: Total Relevant Supply Cost Results

The TRSC for each portfolio was calculated for the Scenario under which it was developed. The TRSC was calculated using:

- Variable supply cost – The variable output from the Aurora model for all of ENO's fleet, which includes fuel costs, variable O&M, emissions costs, startup costs, energy revenue, make-whole payments, and uplift revenue.
- Levelized real non-fuel fixed costs – Return of and on capital investment, fixed O&M, and property taxes and insurance for the incremental resource additions in each portfolio, calculated on a levelized real basis.
- DSM levelized fixed cost –Fixed costs for each DSM program provided by Guidehouse
- Capacity purchases/(sales) - The capacity amount above or below the target reserve margin in each Scenario multiplied by the assumed capacity value.
- Avoided Costs of Union 1 deactivating early - The avoided costs of the return of and on future capital investment, fixed O&M and property taxes attributable to Union 1 deactivating in 2035 rather than 2041 in the applicable Manual Portfolio.

Each ENO portfolio was also run through the Aurora production cost model for the relevant Scenario and combined with other spreadsheet-based cost components to produce the TRSC. This "cross test" of ENO portfolios allows better understanding of costs in different futures. The ENO portfolios built under Scenarios with the Reference load case were not adjusted when cross tested under Scenario 3 (High load case), and therefore saw greater reliance on the MISO market to meet energy demand. The results of the analysis are summarized below. The shading indicates the Scenario under which the portfolio was originally optimized.

TABLE 16: TOTAL RELEVANT SUPPLY COST ($MM, 2024$ NPV)

	Scenario 1	Scenario 2	Scenario 3
Strategy 1/Scenario 1 (Least Cost Planning)	$1,227	$1,552	$1,951
Strategy 1/Scenario 1 (Manual Portfolio 1b)	$1,207	$1,232	$1,645
Strategy 2/Scenario 1 (But For RCPS)	$1,347	$1703	$2,034
Strategy 4/Scenario 2 (Stakeholder Strategy)	$1,793	$2,175	$2,362
Strategy 3/Scenario 3 (RCPS Compliance)	$988	$1,316	$808

The comparative value of the analyses comes from considering the different inputs, assumptions, and risk sensitivities of each Portfolio as a guide for the future, not from focusing solely on the costs of one Portfolio versus another, particularly given that actual costs in the future will be driven by resource certifications and DSM implementations that rely on then-current, actual market costs.

The TRSC analysis presents an interesting range of results for the Council to consider. The various portfolios analyzed in the 2024 IRP indicate that the optimal combination of resource additions will depend on ENO's capacity need and the market forces and regulations in place at the time. Portfolios developed under Scenario 1 (Least Cost Planning) included combinations of renewables, batteries, DSM, and either frame or Aero combustion turbines added late in the planning horizon. Portfolios developed under Scenario 2 (Clean Air Act Compliance) and Scenario 3 (Stakeholder), both of which assumed earlier deactivation of existing fossil generation, included combinations of renewables, batteries, and DSM. The timing of capacity needs, as well as the amounts and types of resources best suited to fill the needs, varied based on the Scenario and Strategy constraints imposed and represented a shift from the portfolios developed and analyzed in the 2021 IRP, which included only renewables batteries, and DSM in varying amounts. This evolution in the point of view of possible future portfolio composition reinforces the importance of conducting IRPs on a periodic basis and considering a broad range of assumptions. This information is also important given the climate goals articulated in the Council's RCPS and Entergy's own corporate sustainability goals.

The downselected portfolios incorporated different cases from the Guidehouse DSM Potential Study. Strategy 1 portfolios economically optimized the DSM programs selected, Strategy 2 and 3 portfolios forced in the 2% DSM programs, and Strategy 4 portfolio forced in the societal/high DSM programs. As discussed in Chapter 2, these cases estimate a range of increasing DSM potential savings, albeit at notably different costs. These findings from the DSM study suggest there is still achievable DSM and DR potential in the city, and that the Energy Smart Implementation Plan for Program Years 16-18 should draw on these concepts in presenting options for the Council's consideration.

The Least Cost Planning portfolio developed under Strategy 1/Scenario 1, which included the current 2041 deactivation assumption for Union 1, showed a TRSC of $1,227 million while Manual Portfolio 1b, also developed under Strategy 1/Scenario 1 but with an assumed deactivation of Union 1 in 2035, showed a TRSC of $1,207 million, approximately 2% lower over 20 years. Compared to the Strategy 1/Scenario 1 portfolio, Manual Portfolio 1b included significantly lower Variable Supply Cost (as would be expected from retiring Union 1 early and replacing it with wind resources) that offset the increase in Resource Additions Levelized Fixed Costs, as well as avoided costs from retiring Union 1 early that contribute to the slightly lower TRSC. For comparison, the manual portfolios in the 2021 IRP that accelerated the deactivation of Union 1 resulted in TRSC values about 8% higher than the Least Cost Planning portfolio. The results of the manual portfolio analysis over the last two IRPs underscore the sensitivity of the TRSC results to input assumptions and the value of further analysis in future IRPs.

The RCPS Compliance portfolio developed under Strategy 3 / Scenario 3 has the lowest Total Relevant Supply Cost because of the large quantities of wind and battery resources built and the earlier thermal deactivations (compared to Scenario 1), which result in Net Variable Supply benefits. The Fixed Cost is high due to the amount of renewables built, but there is enough energy revenue incorporated in the Variable Supply Cost to result in the lowest TRSC of the five downselected portfolios. It is important to note that this is the only downselected portfolio developed using the High load forecast case, and this allows for a large quantity of renewables that would not be feasible in other Scenarios without significantly building capacity resources over the reserve margin target and exposing customers to energy market price risk. The comparatively low TRSC for this portfolio must be considered in light of the full range of assumptions specified by the Stakeholders for their Planning Scenario 3.

The high TRSC associated with the portfolio developed for the Stakeholder Strategy 4 / Scenario 2 combination is caused by the forced-in resources associated with the portfolio (i.e., wind, solar, and battery resources added in the 2020s as specified by the Stakeholders). Adding the renewables earlier in the study period when the renewable cost curves are relatively high compared to the early 2030s also causes higher cost for this portfolio; manually adding renewables early in the study period increases the TRSC compared to capacity expansion optimization, which has the benefit of foresight of the technology cost curves. Similarly, the forced-in High Case DSM resources contribute to increased costs by selecting all programs, regardless of economics. The Variable Supply Cost is lower because wind and solar resources do not have any variable cost; they only receive energy revenue and therefore have a negative variable supply cost. Additionally, under Scenario 2, the thermal resources are assumed to deactivate relatively earlier as part of Clean Air Act Section 111 Compliance, reducing the costs associated with fuel, emissions, and startups. While the Variable Supply Cost for the portfolio is relatively low compared to some of the others because of the large quantities of renewables paired with earlier deactivation of existing thermal resources, it is not large enough to offset the higher level of Resource Additions Levelized Fixed Costs. Ultimately, these results suggest building resources when energy or capacity needs are present, instead of arbitrarily adding resources before they are needed may reduce overall cost to customers.[10]

The total relevant supply cost calculated for the optimized portfolio produced for Strategy 2 (designated as the “But For RCPS” portfolio) under Scenario 1 (the Scenario under which the portfolio was originally developed) will be used as the baseline for calculating incremental costs associated with the three-year RCPS compliance plan for 2026-2028 in accordance with Section 4.d.1 of the RCPS rules.

[10] The 2021 IRP included a separate Manual Portfolio 3a that was not required this time. The goal of that portfolio was to evaluate the viability of achieving near-term RCPS compliance by keeping Union 1's deactivation at the then-assumed deactivation date of 2033 while accelerating the addition of renewable resources as alternatives to relying on the purchase of unbundled RECs. In the current IRP, the Strategy 4/Scenario 2 portfolio was retained in downselection and includes manual solar, wind, battery storage, and DSM additions by 2030 and assumes an accelerated 2035 deactivation of Union 1 instead of CCS or hydrogen co-firing for CAA 111 compliance. Therefore, no additional manual portfolio was required to similarly assess RCPS compliance. The relatively higher TRSC of Strategy 4/Scenario 2 suggests that completely excluding the use of RECs from near-term RCPS compliance could result in added costs for customers.

3.6: Energy-Based Solutions

The IRP Initiating Resolution directed ENO to work with the Stakeholders and Advisors toward evaluating energy-based solutions to provide additional information as part of the 2024 IRP ENO facilitated a discussion among the parties during the stakeholder process to discuss the parameters of an energy-based modeling approach that could be accomplished within the procedural schedule. The parties discussed the fact that the IRP Rules, as well as ENO's Planning Principles, contemplate a resource planning approach that focuses primarily on addressing capacity needs as opposed to energy position, since energy-based resource planning carries higher risk for ENO's customers. While it is possible that ENO's pursuing an energy-based approach and investing above its capacity need could lower customer costs by generating excess energy market revenues, there is a significant risk that such an approach could increase customer costs if future energy market conditions vary from modeling assumptions and the additional resources do not produce enough energy revenue to cover their costs Based on those discussions at the technical meetings, ENO took an approach of relaxing the maximum reserve margin target that the Aurora model uses to judge whether a resource need exists or not in a particular summer or winter season each year. This change allowed the model to select more resources than needed to meet ENO's load plus reserve margin targets if it deemed it economic to do so (i e , if the energy revenue is projected to offset the additional cost) under the assumptions of the relevant Scenario and Strategy combination. This modeling change provided additional insight regarding the types of resources the model may see as economically attractive across the Scenarios evaluated, even if ENO did not have a significant need for capacity, while executing a capacity-based resource planning analysis that remained fundamentally aligned with the Council's IRP Rules and ENO's planning principles. Among the downselected portfolios, two results highlight the effect of relaxing the reserve margin. The Strategy 1/Scenario 1 portfolio built a wind resource in 2025 despite there not being a capacity need. The Aurora model determined which resources to build and when based on economics and capacity requirements for the entire study period. Also, the build decisions of the MISO market in the IRP capacity expansion modeling influenced which ENO resources were selected. For this reason, the wind resource appeared in this portfolio but not in others where Union 1 deactivates earlier, or resources such as DSM programs are forced in. This outcome does not suggest ENO should immediately add a wind resource in the absence of a capacity need, but rather suggests that additional renewable resources in the future could be justified depending on the assumed market outlook and other factor. The reserve margin relaxation also allowed for results seen in Strategy 3/Scenario 3 which built significant renewable capacity above the reserve margin requirements. The low renewable capital cost and high gas/CO2 prices assumed in Scenario 3 created an opportunity for profitable renewable resources that resulted in the Aurora model building more ENO resources than needed for capacity purposes.

3.7: Stochastic Assessment of Risks

The stochastic risk assessment gives an indication of the variability of a Portfolio's costs as underlying assumptions change (e.g., gas price, CO2 cost). Given schedule and resource constraints, the parties agreed to run the stochastic assessments for the five downselected portfolios described earlier in the report.

The sensitivity of a Portfolio's performance was assessed relative to changes in assumptions for natural gas prices and CO2 emission prices through stochastic analysis. Distributions of potential gas prices were developed based on the historical gas price since 1997. The distribution of potential CO2 emission prices was developed based on the Reference and High Scenario price forecast inputs cases used in the IRP modeling due to the fact that there is no historical data for nationwide carbon pricing. Oracle's Crystal Ball software was used to identify the distribution type and generate scenario price curves. In total, 30 price curve scenarios were generated for each of the two variables. Figures 49 and 50 below display the different distributions generated and used for the stochastic analysis. Please note that the reference price is the solid black line, the high price is the solid orange line, and the stochastic distributions are the thin lines. Table 17 displays the stochastic percentiles of the distributions.

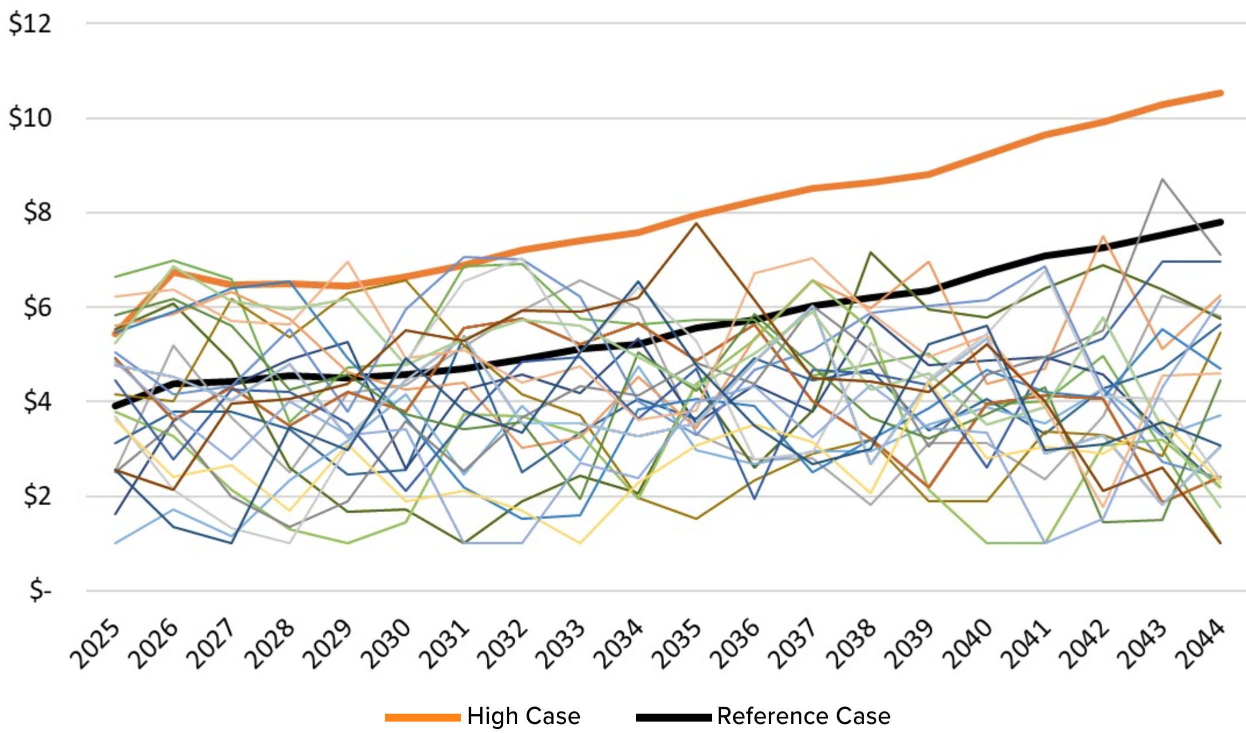


FIGURE 49: ANNUAL HENRY HUB GAS PRICE ($/MMBTU) OF REFERENCE CASE, HIGH CASE, AND STOCHASTIC DISTRIBUTIONS

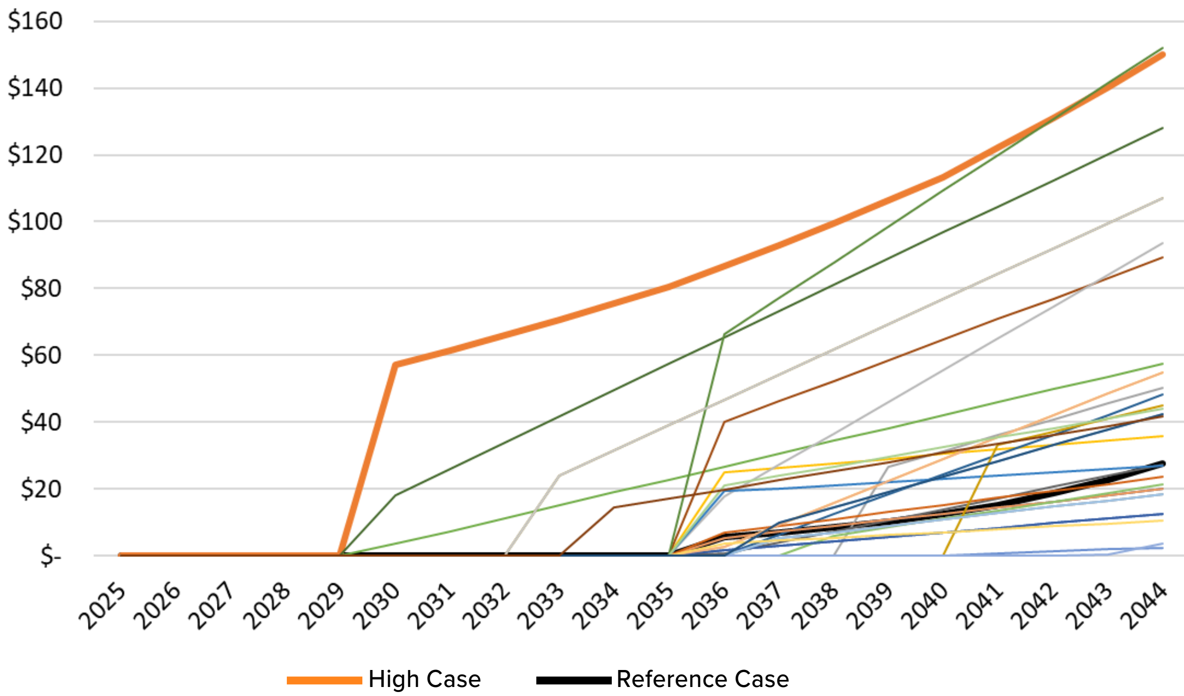


FIGURE 50: ANNUAL CO2 EMISSION PRICE ($/TON) OF REFERENCE CASE, HIGH CASE, AND STOCHASTIC DISTRIBUTIONS

TABLE 17: STOCHASTIC PRICE DISTRIBUTION PERCENTILES

Percentile	Nominal Gas Price	Nominal CO2 Price
1	$1.00	-
5	$1.54	-
10	$2.00	-
20	$2.69	-
30	$3.30	-
40	$3.70	-
50	$4.15	-
60	$4.49	$5.42
70	$4.94	$14.67
80	$5.56	$26.92
90	$6.07	$46.10
95	$6.58	$74.63
99	$7.12	$112.52

After the stochastic distributions were generated, the Henry Hub gas prices and CO2 emission prices were randomized and assigned for stochastic runs. In total, 30 stochastic runs were analyzed for each of the five downselected portfolios, totaling 150 altogether. The results in the figure below display the range of TRSCs of the stochastic analysis by downselected portfolio (please note that the y axis does not begin at zero). Only the Net Variable Supply Cost component changed in the stochastic analysis as the fixed costs and the capacity purchases/sales remained the same as the base cases optimized and described in the TRSC section, above.

The 'x' marker within each box represents the average of all 30 runs, while the bar within the box represents the median. The box itself displays the range of the Interquartile Range (IQR), with the bottom of the box representing the lower quartile (1st quartile) and the top of the box representing the upper quartile (3rd quartile). The lines coming off of the box represent the maximum and minimum values excluding outliers, and the markers outside of these lines represent the outliers. To note, only the, Strategy 4/Scenario 2 portfolio contains an outlier (represented by a circle below the minimum value line), which is from a stochastic run with CO2 emission cost beginning in 2030 and ending with a cost of $128/ton in 2044. Additionally, the gas price in this iteration was high, with several years seeing an average gas price higher than $6/MMBtu. The TRSC for this specific iteration was lower than the others because the high CO2 and gas prices, combined with the modeled portfolio's large quantities of renewables built, resulted in especially high generation revenue from the solar, wind, and battery resources, thus reducing the total net cost. Also worth pointing out is the difference in TRSC between the base results for Strategy 3/Scenario 3 and the stochastic results. The base TRSC is $808 million on a levelized real $2024 basis compared to an average stochastic TRSC of $1,652 million. This is again due to the difference in gas price and CO2 price, with the Strategy 3/Scenario 3 portfolio having been produced under the Stakeholder Scenario 3, which assumed a high gas price and CO2 price forecast that resulted in higher renewable generation revenue, and thus lower TRSC, compared to lower CO2 and gas prices on average in the stochastic runs.

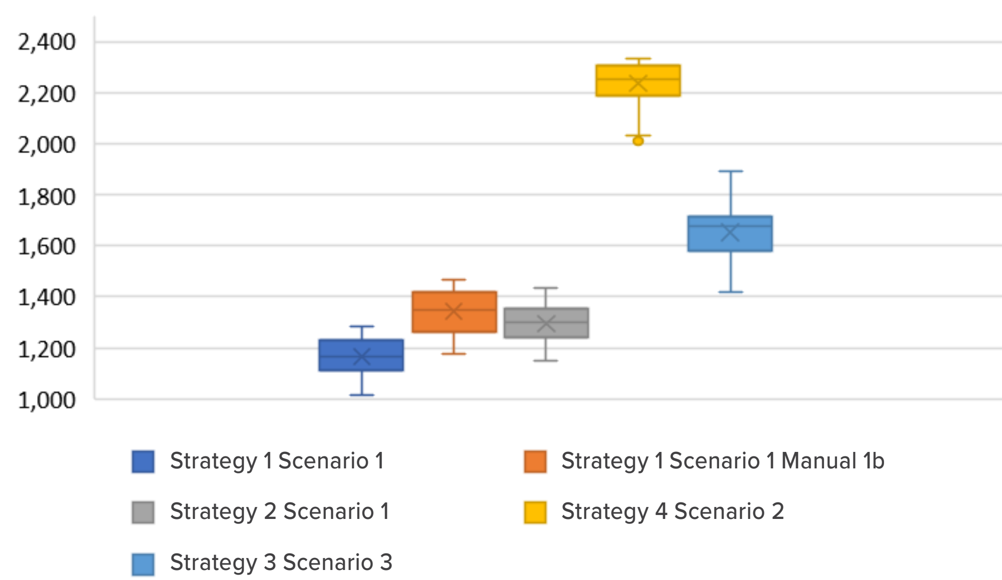


FIGURE 51: LEVELIZED REAL TOTAL RELEVANT SUPPLY COST OF STOCHASTIC RUNS BY PORTFOLIO, $MM 2024

Ultimately, the stochastic assessment provides insights into the range of potential costs of each portfolio. The Strategy 1/Scenario 1 portfolio has the lowest average TRSC compared to other portfolios while the portfolio from Strategy 4/Scenario 2 has the highest. The portfolios for Strategy 4/Scenario 2 and Strategy 3/Scenario 3 see higher TRSCs than the other portfolios in part due to the high renewable capacity built that is not offset by generation/capacity revenue. The Strategy 4/Scenario 2 portfolio's average cost is much higher than the others partially because of the large volume of forced-in resources (e.g. DSM, community solar, utility solar, wind, and battery) specified by the Stakeholders to be added early in the study period, which resulted in a high fixed cost. Since the TRSC results are levelized, the early year resource costs have more impact than resource costs in later years. On the other hand, as discussed in more detail in later sections, this portfolio would benefit the most if gas/CO2 prices are high and occur early.

The Interquartile Range (IQR) (difference between the first and third quartile) and range of the portfolios' TRSCs provides a degree of insight into the sensitivity of each portfolio to gas and CO2 prices. A larger value represents a higher sensitivity around gas and CO2 prices. Portfolios from Strategy 1/Scenario 1, Strategy 2/Scenario 1, and Strategy 4/Scenario 2 have very similar IQRs (represented by box size). The other two portfolios' IQR is larger, with Manual Portfolio 1b having the largest IQR. The range follows a similar trend as the IQR, but the Strategy 3/Scenario 3 portfolio has the largest range and the Strategy 4/Scenario 2 portfolio has the second largest. This indicates that these portfolios are more sensitive to extreme prices and can have a much lower TRSC if gas and CO2 prices are high.

Looking to the distributions, Portfolios from Strategy 1/Scenario 1, Manual Portfolio 1b, and Strategy 2/Scenario 1 are normally distributed while the Strategy 4/Scenario 2 and Strategy 3/Scenario 3 portfolios tend towards being more negatively skewed. These negatively skewed portfolios are likely to have more upside (lower TRSC) during high gas price and/or high CO2 price futures than downside (higher TRSC) during low price futures providing a higher level of resiliency to gas and CO2 emission prices as compared to other portfolios. This result is expected given the high amount of renewable capacity added in these two portfolios, and the earlier assumption of MISO natural gas combined cycle deactivations in Scenarios 2 and 3 under which these portfolios were developed. Manual Portfolio 1b does not have a negatively skewed distribution despite the earlier assumed deactivation date of Union 1 like the portfolios for Strategy 4/Scenario 2 and Strategy 3/Scenario 3, and large quantities of renewables added because of the assumptions in the MISO market in those Scenarios. The deactivation assumptions for coal, combined cycle, and gas resources are later in the study period compared to Scenarios 2 and 3 resulting in ENO being exposed to fluctuations in market prices. It is worth noting that on an annual basis, the TRSC for Manual Portfolio 1b does have some tendency towards negatively skewed distributions in the later years as many of the market thermal resources are retired and replaced with more renewables.

3.8: Scorecard Metrics and Results

As required by the IRP Rules, ENO, with the help of the Advisors and Intervenors, developed the 2024 scorecard to assist the Council in assessing the downselected Resource Portfolios. For the 2024 IRP, the parties updated the 2021 scorecard metrics based on discussions at Technical Meetings #3 and #4. Three new metrics were added to the "Environmental Impact" section and include metric to measure SOx, NOx, and Land Usage. The scorecard metrics agreed upon by the parties for the 2024 IRP are shown below.

TABLE 18: SCORECARD METRICS

Metric	Description	Measure
Expected Value	The average total relevant supply cost of Portfolios across Scenarios and relative to other optimized Portfolios (all Scenarios are weighted equally)	1-10 Grading Scale
Net present Value of Revenue Requirements	The Total Relevant Supply Cost of the Portfolio in the Scenario it was optimized in	1-10 Grading Scale
Nominal Portfolio Value (residential/ other customer classes) - initial 5 year planning period	A sum of the initial 5 years of the planning period	1-10 Grading Scale
Distribution of Potential Utility Costs	The standard deviation of total relevant supply cost across Scenarios divided by the expected value to get to a coefficient of variation	1-10 Grading Scale
Range of potential utility costs	The sum of the total relevant supply cost upside and downside risk of Portfolios	1-10 Grading Scale
Probability of high CO2 intensity - initial 5 years of planning period	Probability of high CO2 intensity in the initial 5 years of the planning period	1-100% Grading Scale
Probability of high groundwater usage - initial 5 years of planning period	Probability of high groundwater usage in the initial 5 years of the planning period	1-100% Grading Scale
Relative Loss of Load Expectation	The relative amount of perfect capacity added or subtracted to obtain the 0.1 Loss of Load Expectation target in the final year of the planning period	1-10 Grading Scale
Flexible Resources (MW of ramp)	The total MW of ramp available in the final year of the planning period	1-10 Grading Scale
Quick Start Resources (MW of Quick-Start)	The total MW of quick start available in the final year of the planning period (Includes supply and demand side dispatchable resources)	1-10 Grading Scale
CO2 Intensity (tons CO2/GWh)	The cumulative tons of CO2/GWh over the planning period	1-10 Grading Scale
SOx Intensity (tons SOx/GWh)	The cumulative tons of SOx/GWh over the planning period	1-10 Grading Scale
NOx Intensity (tons NOx/GWh)	The cumulative tons of NOx/GWh over the planning period	1-10 Grading Scale
Groundwater usage (% of energy generated using Groundwater)	The cumulative percentage of energy generated by resources that use ground water	1-100% Grading Scale
Land Usage	The cumulative acreage necessary for portfolio resources over the planning period	1-10 Grading Scale
Renewable and Clean Portfolio Standard (RCPS) - Compliance with Schedule in 3.A. of RCPS Rules	The average annual percent of a portfolios clean energy targeted to align with Schedule 3.A. of the RCPS.	1-(-15)% Grading Scale
Macroeconomic Factor (Jobs, local economy impacts)	DSM spending represents only quantifiable macroeconomic impact at this time. Future ability to evaluate/model DERs could provide additional basis for comparison.	1-10 Grading Scale

Based on the metrics discussed above, the downselected Portfolios were assigned a grade determined by how the given Portfolio performed in relation to the others. Due to the differing Scenario and Strategy characteristics, a review of the grades required consideration of the inherent compositional differences among the Portfolios. As contemplated by the IRP rules, these grades are intended to assist the Council in assessing the results of the overall IRP analysis, not stand on their own as any kind of definitive statement about the modeled portfolios. The results of the scorecard are outlined in Table 17 and key takeaways are described below.

Utility Costs measure the relative economics of each portfolio in both the Scenario for which it was crated as well as the other Scenarios. Strategy 3/Scenario 3 had the lowest cost of the portfolios resulting in the highest grade. For analysis regarding the cost, please refer to Section 3.5 of the report, Total Relevant Supply Cost Results.

Risk/Uncertainty assesses the distribution, range, and probabilities associated with each portfolio's costs, CO2 intensity, and groundwater use across each Scenario. Strategy/Scenario 1 (Manual Portfolio 1b) and Strategy 4/Scenario 2 were given the higher grades because of a lower distribution and tighter range of costs across all Scenarios. As none of the portfolios present a risk of high CO2 emissions or high groundwater usage within the first five years of the study period, they all received the same grade for this metric.

Reliability ranks the portfolios based on the Relative Loss of Load Expectation, ramping, and quick start capabilities. Loss of Load Expectation scoring is based on the relative quantity of imported capacity required to solve the modeled system (ENO's load and generation) to the industry standard 0.1 LOLE. Lower (or negative) import quantities received the highest score, and portfolios requiring higher import capacity received a lower score. Strategy 3/Scenario 3 was rated highly on reliability due to the large amount of battery MW included and because the relaxation of reserve margin constraints due to the energy-based modeling approach allowed the model to build above the reserve requirements, adding more MW than any of the other portfolios.

Environmental Impact highlights a difference in grades among the portfolios due to emissions, groundwater, and land usage for each of the portfolios. This section included three new metrics for the 2024 IRP cycle. Two of them were for the SOx and NOx emissions as requested by the Advisors and Intervenors during Technical Meeting #4. The third addition was in the form of a Land Usage metric which ENO proposed to include due to the increased involvement of utility-scale renewables in resource planning evaluations. Strategy 4/Scenario 2 and Strategy 3/Scenario 3 received high grades due to the inclusion of mostly renewables in the selected incremental generation. Strategy 1/Scenario 1, Strategy 1/Scenario 1 (Manual Portfolio 1b), and Strategy 2/Scenario 1 received lower grades for the three emissions metrics due to the inclusion of CTs in the later years of the evaluation period. Strategy 3/Scenario 3 received a low land usage grade as it includes two to three times the amount of wind resources compared to the other downselected portfolios.

RCPS Compliance provides a grading of the Portfolios related to the percent of clean energy targeted to align with Schedule 3.A. of the RCPS. As all of the portfolios show a high RCPS compliance, all portfolios were rated highly. Strategy 4/Scenario 2 and Strategy 3/Scenario 3 received the highest grade with 100% compliance and Strategy 1/Scenario 1, Strategy 1/Scenario 1 (Manual Portfolio 1b), and Strategy 2/Scenario 1 were rated slightly lower due to the inclusion of CTs in the later years of the evaluation period.

Macroeconomic Impact shows the difference in DSM programs included in the different portfolios, specifically the levelized spend related to the downselected portfolios. Strategy 4/Scenario 2 includes the Stakeholder Strategy which, as discussed in Section 3.1 of the Report, forces the selection of all EE and DR programs into the portfolio; therefore, Strategy 4/Scenario 2 received the highest grade. The other Optimized Portfolios were ranked in order of the highest program spend.

TABLE 19: SCORECARD RESULTS

Scoring Parameters/Descriptions[11]	Strategy 1 Scenario 1	Strategy 1 Scenario 1 Manual 1b	Strategy 2 Scenario 1	Strategy 4 Scenario 2	Strategy 3 Scenario 3
Utility Costs (Portfolio optimization in Aurora model)					
Expected Value (average cost across Scenarios & relative to other optimized portfolios)	B	B	C	D	A
Utility Costs Impact on ENO's Revenue Requirements					
Net present Value of Revenue Requirements	B	B	C	D	A
Nominal Portfolio Value (residential/other customer classes) - initial 5 year planning period	B	A	B	D	B
Risk/Uncertainty					
Distribution of Potential Utility Costs	D	A	C	A	D
Range of potential utility costs	D	A	D	B	A
Probability of high CO2 intensity - initial 5 years of planning period	A	A	A	A	A
Probability of high groundwater usage - initial 5 years of planning period	A	A	A	A	A
Reliability					
Relative Loss of Load Expectation	D	D	C	A	A
Flexible Resources (MW of ramp)	C	D	C	C	A
Quick Start Resources (MW of Quick-Start)[12]	C	D	B	C	A
Environmental Impact					
CO2 Intensity (tons CO2/GWh)	D	D	D	A	A
SOx Intensity (tons SOx/GWh)	C	D	C	A	A
NOx Intensity (tons NOx/GWh)	D	A	D	A	A
Groundwater usage (% of energy generated using Groundwater)	B	A	B	B	B
Land Usage	A	B	A	B	D
Consistency with City Policies/Goals					
Renewable and Clean Portfolio Standard (RCPS) - Compliance with Schedule in Section 3.A. of the RCPS Rules	B	B	B	A	A
Macroeconomic Impact to ENO					
Macroeconomic Factor (Jobs, local economy impacts)[13]	D	D	C	A	C

[11] Except as otherwise noted, A is the top quartile of portfolios, B is the second quartile, C is the third quartile, and D is the bottom quartile.

[12] Quick-start includes supply- and demand-side dispatchable resources.

[13] DSM spending represents the only quantifiable macroeconomic impact at this time. Based on discussion at Technical Meeting #4, this metric takes into account different levels of DSM spending included in portfolios.

CHAPTER 4

Action Plan

2024 IRP Action Plan

The following table describes various actions ENO intends to pursue following the submission of this 2024 Integrated Resource Plan.

TABLE 20: ENO 2024 IRP ACTION PLAN

Description	Action to be taken
RCPS Compliance Plan	ENO will develop and file its three year RCPS compliance plan for 2026-2028.
DSM/DR Program Implementation	File Implementation Plan for Energy Smart Program Years 16-18 as required by Resolution R-23-254 and work with the Advisors and Stakeholders towards Council review and approval.
Bring Your Own Battery (BYOB) Demand Response Pilot Expansion	ENO will pursue continuation of the BYOB DR pilot that was conducted in 2023 and 2024 and seek further expansion of the program through the DER Programs docket (UD-24-02).
System Resiliency and Storm Hardening Plan	Building on the resilience projects approved through Resolutions R-24-73 and R-24-625, ENO will develop plans detailing additional investments and projects to support further system resiliency and storm hardening.
DER Programs docket (UD-24-02)	Actively participate in docket to help shape policy and program outcomes.
Community Solar rulemaking (UD-18-03)	Continue active participation to help shape policy, rules, and processes for program administration.
Federal Funding	Identify and pursue additional opportunities for available federal grants and/or loans to support utility infrastructure projects and reduce project costs.

List of Appendices

Appendix A	Rules Compliance Matrix
Appendix B	Actual Historic Load and Load Forecast [HSPM in part]
Appendix C	Total Relevant Supply Cost - Detail [HSPM]
Appendix D	Guidehouse DSM Potential Study
Appendix E	Macro Inputs Workbook [HSPM]
Appendix F	Technical Meeting Materials
Appendix G	Annual DSM Values
Appendix H	Load & Capability Tables [HSPM]

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-23-01**

APPENDIX A

2024 IRP RULES
COMPLIANCE MATRIX

DECEMBER 2024

Requirement No.	Section No.	Page No.	Key phrase or Issue	Excerpt	Response and/or Citation to IRP Report
1	1.C.	1	Rules Matrix	*Each Utility IRP shall include a matrix of these rules, the corresponding section of the IRP responsive to that rule, and a brief description of how the Utility complied with the rules.*	Appendix A
2	3.A.	4	Specific Objectives	*The Utility shall state and support specific objectives to be accomplished in the IRP planning process, which include but are not limited to the following:*	
3	3.A.1.	4	Integration of Supply Side and Demand Side Resources	*optimize the integration of supply-side resources and demand-side resources, while taking into account transmission and distribution, to provide New Orleans ratepayers with reliable electricity at the lowest practicable cost given an acceptable level of risk;*	Pg 10: Planning Objectives; Pg 22: Transmission; Pg 23: Distribution; Chapter 3: Modeling Framework
4	3.A.2.	4	Maintain Financial Integrity	*maintain the Utility's financial integrity;*	Pg 10: Planning Objectives
5	3.A.3.	4	Mitigate Risks	*anticipate and mitigate risks associated with fuel and market prices, environmental compliance costs, and other economic factors;*	Pg 70-74: Stochastic Assessment of Risks
6	3.A.4.	4	Support Resiliency and Sustainability	*support the resiliency and sustainability of the Utility's systems in New Orleans;*	Pg 22: Transmission; Pg 23: Distribution; Pg 74: Scorecard Metrics and Results
7	3.A.5.	4	Comply with Requirements and Council Policies	*comply with local, state and federal regulatory requirements and regulatory requirements and known policies (including such policies identified in the Initiating Resolution) established by the Council;*	Pg 52: Planning Strategy Overview; Pg 74: Scorecard Metrics and Results
8	3.A.6.	4	Evaluate Incorporation of new technology	*evaluate the appropriateness of incorporating advances in technology, including, but not limited to, renewable energy, storage, and DERs, among others;*	Pg 38: Capacity Resource Options
9	3.A.7.	4	Acceptable Risk	*achieve a range of acceptable risk in the trade-off between cost and risk;*	Pg 70: Stochastic Assessment of Risks
10	3.A.8.	4	Transparency and Engagement	*maintain transparency and engagement with stakeholders throughout the IRP process by conducting technical conferences and providing for stakeholder feedback regarding the Planning Scenarios, Planning Strategies, input parameters, and assumptions.*	Technical Meeting #1: 11/9/23; Technical Meeting #2: 2/29/24; Technical Meeting #3: 5/7/24; Technical Meeting #4: 10/2/24
11	3.B.	4	Efforts to Achieve Objectives	*In the IRP Report, the Utility shall discuss its efforts to achieve the objectives identified in Section 3A and any additional specific objectives identified in the Initiating Resolution.*	Pg 10: Planning Objectives; Chapter 3, Modeling Framework
12	4.A.	5	Reference Load Forecasts and alternatives	*The Utility shall develop a reference case Load Forecast and at least two alternative Load Forecasts applicable to the Planning Period which are consistent with the Planning Scenarios identified in Section 7C. The following data shall be supplied in support of each Load Forecast:*	Pg 27: Load Forecasting Methodology
13	4.A.1.	5	Forecast of Demand and Energy by Customer Class	*The Utility's forecast of demand and energy usage by customer class for the Planning Period;*	Pg 27: Load Forecasting Methodology; Appendix B

14	4.A.2.	5	Methodology	*A detailed discussion of the forecasting methodology and a list of independent variables and their reference sources that were utilized in the development of the Load Forecast, including assumptions and econometrically evaluated estimates. The details of the Load Forecast should identify the energy and demand impacts of customer-owned DERs and then existing Utility-sponsored DSM programs;*	Pg 27: Load Forecasting Methodology
15	4.A.3.	5	Independent Variables	*Forecasts of the independent variables for the Planning Period, including their probability distributions and statistical significance;*	Pg 27: Load Forecasting Methodology
16	4.A.4.	5	Expected Value of forecast	*The expected value of the Load Forecast as well as the probability distributions (uncertainty ranges) around the expected value of the Load Forecast;*	Pg 27: Load Forecasting Methodology; Appendix B
17	4.A.5.	5	Line Losses	*A discussion of the extent to which line losses have been incorporated in the Load Forecast.*	Pg 37: Hourly Load Forecast Methodology
18	4.B.	5	Composite Customer Hourly Load Profiles	*The Utility shall construct composite customer hourly load profiles based on the forecasted demand and energy usage by customer class and relevant load research data, including the factors which determine future load levels and shape.*	Pg 27: Load Forecasting Methodology; Appendix B
19	4.C.	5	Demand and Energy data for 5 preceding years	*Concurrent with the presentation of the Load Forecasts to the Advisors, CURO, and stakeholders, the Utility shall provide historical demand and energy data for the five (5) years immediately preceding the Planning Period. At a minimum, the following data shall be provided:*	Appendix B
20	4.C.1.	5	Monthly energy consumption by class	*monthly energy consumption for the Utility in total and for each customer class;*	Appendix B
21	4.C.2.	5	Monthly CP for utility and classes	*monthly coincident peak demand for the Utility and estimates of the monthly coincident peak demand for each customer class;*	Appendix B
22	4.C.3.	5	Monthly peak demand by class	*estimates of the monthly peak demand for each customer class;*	Appendix B
23	4.D.	5	Section 4 data in attachment	*The data and discussions developed pursuant to Section 4A and Section 4B, and Section 4C shall be provided as an attachment to the IRP report and summarized in the IRP report.*	Pg 27: Load Forecasting Methodology; Appendix B
24	4.E.	6	Known cogen and >300kW DER resources	*The Utility shall also provide a list of any known co-generation resources and DERs larger than 300 kW existing on the Utility's system, including resources maintained by the City of New Orleans for city/parish purposes, (e.g. Sewerage and Water Board, Orleans Levee District, or by independent agencies or entities such as universities, etc.).*	New Orleans Solar Power Project; Sites constructed under Commercial Rooftop Project (UD-17-05)
25	5.A.	6	Identification of resource options	*Identification of resource options. The Utility shall identify and evaluate all existing supply-side and demand-side resources and identify a variety of potential supply-side and demand-side resources which can be reasonably expected to meet the Utility's projected resource needs during the Planning Period.*	Pg 38: Capacity Resource Options; Appendix D
26	5.A.1.	6	Existing supply side resource costs	*Existing supply-side resources. For existing supply-side resources, the Utility should incorporate all fixed and variable costs necessary to continue to utilize the resource as part of a Resource Portfolio. Costs shall include the costs of any anticipated renewal and replacement projects as well as the cost of regulatory mandated current and future emission controls.*	Appendix C--Variable Supply Cost reflects the optimized run time of existing units
27	5.A.1.a.	6	Changes to resource mix	*The Utility shall identify important changes to the Utility's resource mix that occurred since the last IRP including large capital projects, resource procurements, changes in fuel types, and actual or expected operational changes regardless of cause.*	N/A
28	5.A.1.b.	6	Supply side resource info	*Data supplied as part of the Utility's IRP filing should include a list of the Utility's existing supply-side resources including: the resource name, fuel type, capacity rating at time of summer and winter peak, and typical operating role (e.g. base, intermediate, peaking).*	Pg 13: Table 2

29	5.A.2.	6	Load reductions from existing DSM resources	*For existing demand-side resources, the Utility should account for load reductions attributable to the then-existing demand-side resources in each year of the Planning Period. Each existing demand-side resource will be identified as either a specific energy efficiency program or DR program with an individual program lifetime and estimated energy and demand reductions applicable to the Planning Period, or as a then-existing Utility owned or Utility-managed distributed generation resource with energy and demand impacts that are estimated for applicable years of the Planning Period. Data supplied as part of the Utility's IRP filing should include:*	Pg 27: Load Forecasting Methodology; Pg 44: Demand-Side Management
30	5.A.2.a.	6	Projected reductions	*Details of projected kWh/kW reductions from existing DSM programs based on quantifiable results and other credible support derived from Energy Smart New Orleans, or any successor program, using verified data available to the Utility from prior DSM program implementation years.*	Pg 32-33: Load Forecast Inputs
31	5.A.2.b.	6	Existing DSM resources	*A list categorizing the Utility's existing demand-side resources including anticipated capacity at time of summer and winter peak.*	Pg 33: Table 7
32	5.A.3.	6	Potential SS resources	*With respect to potential supply-side resources, the Utility shall consider: Utility-owned and purchased power resources; conventional and new generating technologies including technologies expected to become commercially viable during the Planning Period; technologies utilizing renewable fuels; energy storage technologies; cogeneration resources; and Distributed Energy Resources, among others.*	Pg 38-44: Capacity Resource Options
33	5.A.3.a.	7	Incorporate known policy goals	*The Utility should incorporate any known Council policy goals (including such policy goals identified in the Initiating Resolution) with respect to resource acquisition, including, but not limited to, renewable resources, energy storage technologies, and DERs.*	Pg 51-52: Planning Strategies
34	5.A.3.b.	7	Required data for resources	*Data supplied as part of the Utility's IRP filing should include: a description of each potential supply-side resource including a technology description, operating characteristics, capital cost or demand charge, fixed operation and maintenance costs, variable charges, variable operation and maintenance costs, earliest date available to provide supply, expected life or contractual term of resource, and fuel type with reference to fuel forecast.*	Pg 38-44: Capacity Resource Options
35	5.A.4.	7	Potential DSM Resources	*Potential demand-side resources. With respect to potential demand-side resources, the Utility should consider and identify all cost-effective demand-side resources through the development of a DSM potential study. All DSM measures with a Total Resource Cost Test value of 1.0 or greater shall be considered cost effective for DSM measure screening purposes.*	Appendix D: Guidehouse Study; Pg 43: Demand-Side Management
36	5.A.4.a.	7	DSM Potential Study	*The DSM potential study shall include, but not be limited to: identification of eligible measures, measure life expectancies, baseline standards, load reduction profiles, incremental capacity and energy savings, measure and program cost assumptions, participant adoption rates, market development, and avoided energy and capacity costs for DSM measure and program screening purposes.*	Appendix D
37	5.A.4.b.	7	N.O. TRM	*The principal reference document for the DSM potential study shall be the New Orleans Technical Reference Manual.*	Appendix D
38	5.A.4.c.	7	CA Standard Practice Tests	*In the development of the DSM potential study, all four California Standard Practice Tests (i.e. TRC, PACT, RIM and PCT) will be calculated for the DSM measures and programs considered.*	Appendix D
39	5.A.4.d.	7	Known policy goals re: DSM	*The Utility should incorporate any known Council policy goals or targets (including such policy goals or targets identified in the Initiating Resolution) with respect to demand-side resources.*	Pg 51-52: Planning Strategy Overview; Pg 74-77: Scorecard Metrics and Results
40	5.A.4.e.	7	Cost effective DR programs	*The cost-effective DR programs should include consideration of those programs enabled by the deployment of Advanced Meter Infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer classes.*	Appendix D
41	5.A.4.f.	8	Required data for DSM analysis	*Data supplied as part of the Utility's IRP filing should include: a description of each potential demand-side resource considered, including a description of the resource or program; expected penetration levels by planning year; hourly load reduction profiles for each DSM program utilized in the IRP process; and results of appropriate cost-benefit analyses and acceptance tests, as part of the planning assumptions utilized within the IRP planning process.*	Appendix D; Pg 44: Demand-Side Management
42	5.B.	8	Stakeholder process	*Through the Stakeholder Process, the Utility shall strive to develop a position agreed to by the Utility, the Advisors, and a majority of the Intervenors regarding the potential supply-side and potential demand-side resources and their associated defining characteristics (e.g., capital cost, operating and maintenance costs, emissions, DSM supply curve, etc.).*	Consensus among parties reached at Technical Meeting #3

43	5.B.1.	8	Reference Planning Strategy	*To the extent such a consensus can be achieved among the Utility, the Advisors, and a majority of the Intervenors, the resulting collection of potential supply-side and demand-side resources and their associated defining characteristics will be utilized in the reference Planning Strategy developed pursuant to Section 7D.*	See #44, below
44	5.B.2.	8	Stakeholder Strategy	*To the extent such a consensus cannot be achieved, the Utility shall model, in coordination with the requirements in Section 7D, two distinct Planning Strategies: a reference Planning Strategy and a stakeholder Planning Strategy. The reference Planning Strategy will be based on the Utility's assessment of the collection of potential supply-side and demand-side resources and their associated defining characteristics. The stakeholder Planning Strategy will be determined by a majority of the Intervenors and modeled by the Utility based on inputs provided to the Utility describing the collection of potential supply-side and demand-side resources and their associated defining characteristics. To maintain consistency in the modeling process, the Advisors will work with the Intervenors and the Utility to ensure that input that is provided for the stakeholder Planning Strategy can be accommodated within the framework of the existing model and software.*	Consensus among parties reached regarding set of four Planning Strategies at Technical Meeting #3 and through followup communications prior to May 17, 2024 deadline
45	6.A.	8	Integration of T&D planning into IRP	*The Utility shall explain how the Utility's current transmission system, and any planned transmission system expansions (including regional transmission system expansion planned by the RTO in which the Utility participates) and the Utility's distribution system are integrated into the overall resource planning process to optimize the Utility's resource portfolio and provide New Orleans ratepayers with reliable electricity at the lowest practicable cost.*	Pg 22-23: Transmission Planning; Pg 23-26: Distribution Planning
46	6.B.	9	Planned transmission topology	*Models developed for the integrated resource planning process should incorporate the planned configuration of the Utility's transmission system and the interconnected RTO during the Planning Period.*	Pg 22-23: Transmission Planning
47	6.C.	9	Major changes to T&D systems	*To the extent major changes in the operation or planning of the transmission system and/or distribution system (including changes to accommodate the expansion of DERs) are contemplated in the Planning Period, the Utility should describe the anticipated changes and provide an assessment of the cost and benefits to the Utility and its customers.*	Pg 22-23: Transmission Planning; Pg 23-26: Distribution Planning
48	6.D.	9	Transmission solutions for reliability	*To the extent that new resource additions are selected by the Utility for a Resource Portfolio based on reliability needs rather than as a result of the optimized development of a Resource Portfolio, the Utility shall identify reasonable transmission solutions that can be employed to either reduce the size, delay, or eliminate the need for the new reliability-driven resource additions and provide economic analyses demonstrating why the new reliability-driven resource addition was selected in lieu of the transmission solutions identified.*	N/A
49	6.E.	9	Evaluation of DERs	*It is the Council's intent that, as part of the IRP, the Utility shall evaluate the extent to which reliability of the distribution system can be improved through the strategic location of DERs or other resources identified as part of the IRP planning process. The Utility should provide an analysis, discussion, and quantification of the costs and benefits as part of the evaluation. To the extent the Utility does not currently have the capability to meet this requirement, the utility shall demonstrate progress toward accomplishing this requirement until such time as it acquires the capability.*	Pg 23-26: Distribution Planning
50	7.A.	9	IRP Modeling parameters	*The integrated resource planning process should include modeling of specific parameters and their relationships consistent with market fundamentals, and as appropriate for long-term Portfolio planning. This overall modeling approach is an accepted analytic approach used in resource planning considering the range of both supply-side and demand-side options as well as uncertainty surrounding market pricing. To represent and account for the different characteristics of alternative types of resource options, mathematical methods such as a linear programming formulation should be used to optimize resource decisions.*	Chapter 3, Modeling Framework
51	7.B.	9	External Capacity sales	*The optimization process shall be constrained to mitigate the over-reliance on forecasted revenues from external capacity market sales and external energy market sales driving the selection of resources.*	Pg 56-58: Market Modeling; Pg 59-60: Optimized and Manual Portfolios

52	7.C.	9	Planning Scenarios	*The Utility shall develop three to four Planning Scenarios that incorporate different economic and environmental circumstances and national and regional regulatory and legislative policies.*	Consensus among parties reached regarding set of four Planning Strategies at Technical Meeting #3 and through followup communications prior to May 17, 2024 deadline
53	7.C.1.	10	Reference and Alternative Scenarios	*The Planning Scenarios should include a reference Planning Scenario that represents the Utility's point of view on the most likely future circumstances and policies, as well as two alternative Planning Scenarios that account for alternative circumstances and policies.*	Consensus among parties reached regarding set of four Planning Strategies at Technical Meeting #3 and through followup communications prior to May 17, 2024 deadline
54	7.C.2.	10	Scenario Assumptions	*In the development of the Planning Scenarios, the Utility should seek to develop a position agreed to by the Utility, Advisors, and a majority of Intervenors regarding the assumptions surrounding each of the Planning Scenarios. To the extent such a consensus is not reasonably attainable regarding the Planning Scenarios, the Utility shall model a fourth Planning Scenario which is based upon input agreed to by a majority of the Intervenors.*	Consensus among parties reached regarding set of four Planning Strategies at Technical Meeting #3 and through followup communications prior to May 17, 2024 deadline
55	7.C.3.	10	Data for Scenarios	*For each IRP Planning Scenario, data supplied as part of the Utility's IRP filing should include:*	
56	7.C.3.a.	10	Fuel Price Forecast	*a fuel price forecast for each fuel considered for utilization in any existing or potential supply-side resource;*	Pg 47: Natural Gas Price Forecast
57	7.C.3.b.	10	Hourly Market Price Forecast for Energy	*an hourly market price forecast for energy (e.g. locational marginal prices);*	Pg 58: Average Annual MISO LMPs
58	7.C.3.c.	10	Annual Capacity Price Forecast	*an annual capacity price forecast for both a short-term capacity purchase (e.g. bilateral contract or Planning Resource Credit) and a long-term capacity purchase (e.g. long-run marginal cost of a new replacement gas combustion turbine);*	Appendix E
59	7.C.3.d.	10	Other Price Components	*forecasts of price for any other price related components that are defined by the Planning Scenario (e.g. CO2 price forecast, etc.).*	Pg 49: CO2 Price forecast
60	7.D.	10	Strategies	*Distinct from the Planning Scenarios, the Utility shall identify two to four Planning Strategies which constrain the optimization process to achieve particular goals, regulatory policies and/or business decisions over which the Council, the Utility, or stakeholders have control.*	Consensus among parties reached regarding set of four Planning Strategies at Technical Meeting #3 and through followup communications prior to May 17, 2024 deadline

61	7.D.1.	10	Lowest Cost Strategy	*The Utility shall develop a Planning Strategy that allows the optimization process to identify the lowest cost option for meeting the needs identified in the IRP process.*	Pg 52: Planning Strategies; Strategy #1 identified as Least Cost Planning Strategy
62	7.D.2.	10	Reference Strategy	*The Utility shall develop a reference Planning Strategy agreed to by the Utility, Advisors, and a majority of the Intervenors. To the extent such a consensus cannot be reasonably achieved, the reference Planning Strategy shall reflect the Utility's point of view on resource input parameters and constraints, and the Utility shall model a separate stakeholder Planning Strategy based upon input determined by a majority of the Intervenors.*	Consensus reached among parties at and following Technical Meeting #3; Strategy #2 identified as "But For RCPS" Strategy as required by RCPS Rules
63	7.D.3.	11	Alternate Strategies	*As necessary, the Utility shall develop alternate Planning Strategies to reflect known utility regulatory policy goals of the Council (including such policy goals or targets identified in the Initiating Resolution) as established no later than 30 days prior to the date the Planning Strategy inputs must be finalized.*	Consensus reached among parties at and following Technical Meeting #3; Strategy #3 identified as the "RCPS Compliance" Strategy
64	7.E.	11	Finalization of Scenario and Strategy Parameters	*Prior to the development of optimized Resource Portfolios, the parameters developed for the Planning Scenarios and Planning Strategies shall be set, considered finalized, and not subject for alteration during the remainder of the IRP planning cycle. The IRP Report shall describe the parameters of each Planning Scenario and each Planning Strategy, including all artificial constraints utilized in the optimization modeling.*	Pg 51: Planning Scenarios; Pg 52-53: Planning Strategies
65	7.F.	11	Portfolio Optimization	*Resource Portfolios shall be developed through optimization utilizing the Utility's modeling software. The Utility shall identify the least-cost Resource Portfolio for each Planning Scenario and Planning Strategy combination, based on total cost. Resource Portfolios shall consist of optimized combinations of supply-side and demand-side resources, while recognizing constraints including transmission and distribution.*	Pg 59-60: Optimized and Manual Portfolios
66	7.G.	11	Results of Scenario&Strategy combinations	*The Utility shall provide a discussion and presentation of results for each Planning Scenario/Planning Strategy combination, the annual total demand related costs, energy related costs, and total supply costs associated with each least-cost Resource Portfolio identified under each Planning Scenario/Planning Strategy combination, a load and capability table indicating the total load requirements and identifying all supply-side and demand-side resources included in the Resource Portfolio (including identifying the impacts of existing demand-side resources on the total load requirements), and a description of the supply-side and demand-side resources that are planned and, if applicable, their principal rationale for selection (i.e., supply peak demand, supply non-peak demand or operational constraints, achieve more economical production of energy, etc.).*	Pg 66-69: Total Relevant Supply Cost Results; Appendix C
67	7.G.1.	11	Annual and Cumulative portfolio costs	*Data supplied as part of the Utility's IRP filing shall include a cumulative present worth summary of the results as well as the annual estimates of costs that result in the cumulative present worth to enable the Council to understand the timing of costs and savings of each least-cost Resource Portfolio.*	Pg 66-69: Total Relevant Supply Cost Results; Appendix C
68	7.H.	11	Discussion of Portfolio Results	*The IRP report's discussion and presentation of results for each Resource Portfolio should identify key characteristics of that Resource Portfolio and significant factors that drive the ultimate cost of that Resource Portfolio such that the Council may understand which factors could ultimately and significantly affect the preference of a Resource Portfolio by the Council.*	Pg 66-69: Total Relevant Supply Cost Results

69	7.I.	11	Scorecard template	*The Utility will develop and include a scorecard template or set of quantitative and qualitative metrics to assist the Council in assessing the IRP based on the Resource Portfolios. The scorecard should rank the resource portfolios by how well each portfolio achieves each metric. Such metrics should include but not necessarily be limited to: cost; impact on the Utility's revenue requirements; risk; flexibility of resource options; reasonably quantifiable environmental impacts (such as national average emissions for the technologies chosen, amount of groundwater consumed, etc.); consistency with established, published city policies, such as the City's sustainability plan; and macroeconomic impacts in New Orleans.*	Pg 74-77: Scorecard Metrics and Results
70	8.A.	12	Cost/Risk Analysis	*The Utility shall develop a cost/risk analysis which balances quantifiable costs with quantifiable risks of the identified least-cost Resource Portfolios. The risk assessment must be presented in the IRP to allow the Council to comprehend the robustness of each Resource Portfolio across the cost/risk range of possible Resource Portfolios.*	Pg 70: Stochastic Assessment of Risks
71	8.A.1.	12	Assessment of social and environmental costs	*In quantifying Resource Portfolio costs/risks, the IRP shall assess any social and environmental effects of the Resource Portfolios to the extent that: 1) those effects can be quantified and have been modeled for a Resource Portfolio, including the applicable Planning Period years and ranges of uncertainty surrounding each externality cost, and 2) each quantified cost must be clearly identified by the portion which relates to the Utility's revenue requirements or cost of providing service to the Utility's customers under the Resource Portfolio.*	Pg 73: Scorecard Metrics and Results
72	8.A.2.	12	Probabilities of outcomes	*It is the Council's intent that, as part of the IRP, a risk assessment be conducted to evaluate both the expected outcome of potential costs as well as the distribution and potential range and associated probabilities of outcomes. To the extent the Utility believes the risk assessment described herein is beyond the current modeling capabilities of the Utility or that the risk assessment cannot be accomplished within the procedural schedule set forth in the Initiating Resolution, the Utility shall so inform the Council and meet with the Intervenors and Advisors to agree upon an alternative form of risk analysis to recommend to the Council.*	Pg 70-74: Stochastic Assessment of Risks
73	8.A.2.a.	12	Cost/MWh in future years	*The risk assessment shall include the expected cost per MWh of the Resource Portfolios in selected future years, along with the range of annual average costs foreseen for the 10th and 90th percentiles of simulated possible outcomes.*	Pg 70-74: Stochastic Assessment of Risks
74	8.A.2.b.	12	Supporting Methodology Included	*The supporting methodology shall be included, such as the iterations or simulations performed for the selected years, in which the possible outcomes are drawn from distributions that describe market expectations and volatility as of the current filing date.*	Pg 70-74: Stochastic Assessment of Risks
75	9.A.	12	IRP Process Requirements	*At a minimum, the IRP process shall include, but not be limited to, the following elements:*	
76	9.A.1.	12	Collaboration on IRP inputs	*The opportunity for Intervenors to participate in the concurrent development of inputs and assumptions for the major components of the IRP in collaboration with the Utility within the confines of the IRP timeline and procedural schedule.*	Stakeholder process conducted in accordance with IRP Rules and Initiating Resolution
77	9.A.2.	12	Four Technical Meetings	*At least four technical meetings attended by the parties in the Docket focused on major IRP components that include the Utility, Intervenors, CURO, and the Advisors with structured comment deadlines so that meeting participants have the opportunity to present inputs and assumptions and provide comments, and attempt to reach consensus while remaining mindful of the procedural schedule established in the Initiating Resolution.*	Technical Meeting #1: 11/9/23; Technical Meeting #2: 2/29/24; Technical Meeting #3: 5/7/24; Technical Meeting #4: 10/2/24
78	9.A.3.	13	Three Public Meetings	*At least 3 public engagement technical conferences advertised through multiple media channels at a minimum of 30 days prior to the public technical conference.*	Public Meeting #1: 8/23/23; Public Meeting #2: 1/21/25; Public Meeting #3: 2/26/25
79	10.A.	13	Public Review of IRP	*The Utility shall make its IRP available for public review subject to the provisions of the Council Resolution initiating the current IRP planning cycle and referenced in Section 1B.*	Public IRP Available on ENO IRP Website

80	10.B.	13	Filing of IRP	*The Utility shall file its IRP with the Council consistent with and subject to the provisions of the Council Resolution initiating the current IRP planning cycle referenced in Section 1B.*	IRP Report Filed: 12/13/24
81	10.C.	13	Discussion of Stakeholder engagement	*The IRP report should discuss the stakeholders' engagement throughout the IRP process; the access to data inputs and specific modeling results by all parties; the consensus reached regarding all demand-side and supply-side resource inputs and assumptions; specific descriptions of unresolved issues regarding inputs, assumptions, or methodology; the formulation of the stakeholder Planning Scenario and/or stakeholder Planning Strategy as needed; and recommendations to improve the transparency and efficiency of the IRP process for prospective IRP cycles.*	Pg 7: Executive Summary; Pg 50: Scenario- and Strategy-Based Approach
82	10.D.	13	Action Plan	*The IRP shall include an action plan and timeline discussing any steps or actions the Utility may propose to take as a result of the IRP, understanding that the Council's acceptance of the filing of the Utility's IRP would not operate as approval of any such proposed steps or actions.*	Pg 78: Action Plan

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-23-01**

APPENDIX B

ACTUAL HISTORIC LOAD AND LOAD FORECAST

PUBLIC VERSION

DECEMBER 2024

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

Historic Peak Demand and Energy

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

	Residential	Commercial	Industrial	Governmental	Total
2010	1,858	1,899	503	810	5,069
2011	1,888	1,939	498	795	5,120
2012	1,772	1,968	484	785	5,009
2013	1,867	1,998	481	758	5,105
2014	1,963	2,046	452	768	5,230
2015	2,104	2,167	461	814	5,547
2016	2,231	2,268	441	794	5,733
2017	2,155	2,248	429	790	5,621
2018	2,401	2,270	448	795	5,914
2019	2,353	2215	438	815	5,821
2020	2,294	1975	423	755	5,447
2021	2,258	1978	415	755	5,405
2022	2,364	2,079	409	786	5,638
2023	2,406	2,126	422	783	5,737

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

	Summer	Winter
2010	1,101	975
2011	1,115	993
2012	1,104	830
2013	1,104	903
2014	1,066	1,056
2015	1,161	1,008
2016	1,142	952
2017	1,118	1,023
2018	1,150	1,181
2019	1,151	924
2020	1,124	898
2021	1,155	1,098
2022	1,182	1,120
2023	1,208	825

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

	Residential	Commercial	Industrial	Governmental	Total
1/1/2008	114,075	144,142	45,426	61,989	365,631
2/1/2008	112,563	138,661	43,559	60,235	355,018
3/1/2008	79,136	124,789	42,151	56,159	302,235
4/1/2008	82,457	143,731	45,492	59,039	330,719
5/1/2008	95,351	143,467	46,676	62,066	347,560
6/1/2008	144,455	165,163	46,912	70,427	426,957
7/1/2008	161,144	167,161	48,559	71,020	447,884
8/1/2008	166,402	177,352	50,306	71,864	465,924
9/1/2008	141,835	161,424	49,588	72,483	425,330
10/1/2008	112,074	148,510	39,117	65,853	365,554
11/1/2008	80,324	123,642	42,807	62,300	309,073
12/1/2008	104,454	136,389	39,950	59,980	340,773
1/1/2009	123,125	141,233	40,006	64,555	368,919
2/1/2009	107,916	126,821	37,515	58,241	330,493
3/1/2009	102,046	137,023	35,368	59,345	333,782
4/1/2009	80,599	130,193	42,528	60,631	313,951
5/1/2009	104,073	139,448	45,557	67,844	356,922
6/1/2009	151,812	169,688	46,329	61,938	429,768
7/1/2009	199,030	179,654	49,439	78,433	506,555
8/1/2009	182,792	176,060	51,567	76,915	487,333
9/1/2009	167,614	169,463	46,871	72,571	456,519
10/1/2009	145,142	159,632	45,045	73,643	423,462
11/1/2009	101,583	144,330	44,913	67,957	358,782
12/1/2009	111,043	139,135	40,936	63,776	354,890
1/1/2010	179,921	151,178	40,363	65,903	437,366
2/1/2010	159,381	142,735	32,322	59,204	393,643
3/1/2010	146,460	134,268	35,021	57,458	373,206
4/1/2010	92,298	135,186	43,730	57,566	328,780
5/1/2010	114,665	151,184	41,015	63,780	370,645
6/1/2010	172,176	171,779	49,094	69,876	462,925
7/1/2010	199,176	186,908	46,230	77,750	510,064
8/1/2010	216,973	188,679	50,137	77,149	532,938
9/1/2010	191,740	179,188	42,450	76,541	489,920
10/1/2010	147,993	161,356	42,863	76,771	428,983
11/1/2010	110,358	153,488	41,678	65,151	370,676
12/1/2010	127,019	142,588	38,240	62,425	370,273
1/1/2011	181,190	153,844	35,871	63,459	434,365
2/1/2011	164,921	139,287	38,053	58,554	400,815
3/1/2011	120,894	145,897	37,792	60,941	365,524

4/1/2011	107,134	147,743	41,150	62,692	358,718
5/1/2011	128,907	154,333	41,538	63,959	388,736
6/1/2011	187,998	177,707	46,731	69,557	481,993
7/1/2011	207,021	188,637	45,380	74,520	515,558
8/1/2011	207,089	186,587	47,720	74,318	515,715
9/1/2011	206,174	186,007	46,512	74,375	513,068
10/1/2011	147,396	169,136	41,381	70,540	428,453
11/1/2011	103,867	147,240	41,280	61,653	354,041
12/1/2011	125,248	142,290	34,472	60,837	362,847
1/1/2012	146,027	151,302	37,679	60,852	395,860
2/1/2012	120,258	144,784	37,216	59,637	361,897
3/1/2012	117,043	150,577	36,108	60,944	364,672
4/1/2012	110,747	151,841	37,289	63,109	362,986
5/1/2012	130,405	163,704	40,159	62,845	397,112
6/1/2012	194,937	191,287	46,755	71,588	504,567
7/1/2012	207,621	191,295	43,023	72,967	514,906
8/1/2012	196,602	187,542	43,944	72,930	501,018
9/1/2012	174,737	174,459	42,683	72,773	464,651
10/1/2012	145,664	168,165	44,742	66,937	425,508
11/1/2012	113,255	150,617	36,138	61,995	362,005
12/1/2012	114,992	142,360	38,576	57,998	353,925
1/1/2013	161,718	156,576	33,536	59,472	411,303
2/1/2013	140,035	149,482	34,265	62,904	386,685
3/1/2013	130,082	144,781	35,598	59,970	370,430
4/1/2013	109,798	141,019	37,511	57,269	345,597
5/1/2013	106,279	150,277	33,565	59,552	349,673
6/1/2013	176,880	183,333	44,523	65,513	470,249
7/1/2013	199,988	189,754	45,683	67,921	503,347
8/1/2013	206,422	190,508	45,739	67,432	510,101
9/1/2013	206,555	196,753	47,547	69,604	520,459
10/1/2013	172,771	185,164	43,988	68,988	470,911
11/1/2013	112,254	155,326	41,032	61,036	369,648
12/1/2013	144,472	155,452	38,258	58,608	396,790
1/1/2014	203,822	163,569	39,652	59,589	466,633
2/1/2014	199,387	159,754	30,515	57,316	446,972
3/1/2014	137,747	148,471	35,494	57,741	379,453
4/1/2014	106,718	152,772	36,419	57,670	353,580
5/1/2014	117,880	154,766	37,176	58,727	368,549
6/1/2014	169,678	183,369	40,333	64,815	458,195
7/1/2014	198,382	194,327	40,870	72,084	505,662
8/1/2014	211,035	198,126	41,264	70,154	520,580

9/1/2014	204,812	196,301	41,964	77,161	520,238
10/1/2014	152,295	173,345	38,716	67,667	432,022
11/1/2014	127,234	168,444	36,104	65,619	397,400
12/1/2014	134,386	153,250	33,975	59,297	380,907
1/1/2015	168,087	162,304	35,337	59,914	425,642
2/1/2015	176,838	159,758	33,355	59,578	429,530
3/1/2015	148,446	153,380	33,656	62,515	397,997
4/1/2015	118,379	162,760	38,132	61,054	380,325
5/1/2015	133,556	169,522	34,485	67,526	405,088
6/1/2015	175,745	183,660	42,760	65,792	467,957
7/1/2015	225,248	211,817	44,721	71,322	553,108
8/1/2015	249,885	210,776	43,165	83,999	587,825
9/1/2015	242,074	211,902	44,023	76,832	574,830
10/1/2015	187,021	195,552	40,933	70,740	494,247
11/1/2015	139,019	175,382	35,927	68,433	418,760
12/1/2015	139,562	170,363	34,742	66,596	411,264
1/1/2016	178,568	177,522	36,821	62,336	455,247
2/1/2016	175,616	160,036	31,585	55,476	422,711
3/1/2016	145,066	172,416	32,223	60,035	409,740
4/1/2016	119,352	165,316	34,945	59,261	378,873
5/1/2016	135,321	171,054	34,929	62,566	403,871
6/1/2016	204,623	201,329	37,081	67,746	510,780
7/1/2016	264,987	223,156	42,085	73,904	604,133
8/1/2016	239,623	209,788	40,528	75,202	565,141
9/1/2016	247,790	219,512	42,709	75,363	585,375
10/1/2016	220,888	209,712	38,250	72,836	541,685
11/1/2016	156,298	186,334	36,451	66,449	445,532
12/1/2016	142,745	171,370	33,001	63,157	410,273
1/1/2017	177,349	179,242	31,260	62,288	450,139
2/1/2017	144,210	166,961	35,949	62,623	409,744
3/1/2017	134,177	168,723	31,116	58,862	392,878
4/1/2017	135,116	170,949	34,094	59,930	400,089
5/1/2017	149,105	178,925	33,880	60,373	422,282
6/1/2017	183,982	191,567	36,783	67,370	479,702
7/1/2017	227,517	208,816	39,083	71,921	547,337
8/1/2017	249,650	216,178	39,204	71,035	576,068
9/1/2017	233,404	208,945	40,375	73,969	556,693
10/1/2017	210,577	206,058	38,924	70,943	526,502
11/1/2017	153,747	178,674	34,209	66,347	432,976
12/1/2017	155,809	172,821	33,989	64,397	427,016
1/1/2018	237,027	183,430	33,687	62,394	516,539

2/1/2018	206,863	174,067	31,683	59,377	471,991
3/1/2018	133,384	166,744	33,404	59,355	392,887
4/1/2018	121,577	156,580	34,884	58,840	371,882
5/1/2018	138,072	166,998	35,024	58,485	398,579
6/1/2018	229,864	202,967	41,466	67,743	542,040
7/1/2018	261,418	226,463	41,675	72,711	602,266
8/1/2018	267,772	213,686	43,081	75,663	600,201
9/1/2018	249,569	220,494	43,389	76,821	590,274
10/1/2018	225,794	211,439	40,343	74,443	552,019
11/1/2018	160,357	184,564	35,107	68,619	448,647
12/1/2018	169,266	162,711	33,942	60,528	426,447
1/1/2019	182,917	169,120	32,303	62,193	446,533
2/1/2019	180,315	161,801	32,348	58,532	432,996
3/1/2019	147,748	160,798	32,722	60,470	401,737
4/1/2019	133,266	162,553	35,239	61,174	392,233
5/1/2019	159,568	178,902	30,424	64,746	433,640
6/1/2019	224,127	207,744	38,853	71,539	542,264
7/1/2019	286,860	224,468	40,253	77,888	629,469
8/1/2019	249,439	208,767	41,123	75,517	574,846
9/1/2019	257,138	211,941	42,299	74,474	585,852
10/1/2019	224,164	199,350	41,257	79,450	544,220
11/1/2019	151,740	171,744	38,060	67,058	428,602
12/1/2019	155,927	158,204	32,730	62,131	408,993
1/1/2020	178,838	170,211	35,405	63,779	448,234
2/1/2020	162,147	158,598	33,295	60,528	414,568
3/1/2020	159,644	166,849	32,908	59,454	418,854
4/1/2020	154,820	144,486	36,068	57,430	392,805
5/1/2020	152,054	132,328	34,266	55,622	374,271
6/1/2020	213,079	163,110	35,871	63,734	475,794
7/1/2020	255,401	182,012	37,223	68,923	543,559
8/1/2020	257,275	186,943	41,927	71,618	557,764
9/1/2020	260,603	195,323	40,846	70,686	567,458
10/1/2020	193,572	180,609	37,188	66,646	478,015
11/1/2020	152,406	149,706	33,870	61,323	397,305
12/1/2020	154,495	145,133	23,774	54,975	378,377
1/1/2021	213,042	155,124	31,241	58,712	458,119
2/1/2021	177,420	147,458	29,908	57,263	412,049
3/1/2021	204,457	147,123	30,518	55,512	437,610
4/1/2021	128,601	147,959	31,166	59,470	367,195
5/1/2021	153,079	153,339	35,767	62,898	405,082
6/1/2021	210,374	182,445	41,043	67,104	500,965

7/1/2021	239,818	188,959	41,149	74,233	544,159
8/1/2021	254,897	199,331	39,159	74,260	567,648
9/1/2021	204,013	165,382	37,516	63,145	470,056
10/1/2021	174,376	177,065	32,319	62,093	445,852
11/1/2021	162,579	157,756	34,532	61,133	416,001
12/1/2021	135,652	155,695	30,341	58,682	380,370
1/1/2022	189,345	158,837	35,127	62,930	446,239
2/1/2022	207,861	153,175	25,167	53,681	439,885
3/1/2022	160,507	147,868	30,222	59,708	398,305
4/1/2022	133,025	147,518	34,758	56,153	371,455
5/1/2022	173,704	153,417	34,669	65,513	427,302
6/1/2022	254,256	188,516	38,682	65,994	547,448
7/1/2022	276,738	193,142	38,206	76,753	584,839
8/1/2022	237,410	190,734	33,914	75,760	537,818
9/1/2022	230,625	180,926	37,430	70,888	519,869
10/1/2022	194,166	228,666	39,071	70,774	532,678
11/1/2022	144,235	161,473	28,258	65,204	399,170
12/1/2022	162,476	175,151	33,023	62,287	432,936
1/1/2023	193,800	164,891	31,300	61,319	451,309
2/1/2023	150,973	147,667	30,057	56,171	384,868
3/1/2023	152,033	159,376	31,262	56,410	399,082
4/1/2023	142,738	153,931	34,048	58,700	389,417
5/1/2023	151,053	164,721	35,247	58,681	409,703
6/1/2023	223,609	189,130	37,781	65,651	516,172
7/1/2023	289,474	205,027	39,616	74,568	608,685
8/1/2023	311,945	227,222	39,714	78,664	657,546
9/1/2023	305,609	224,276	42,365	79,673	651,923
10/1/2023	201,738	185,844	37,370	69,204	494,155
11/1/2023	136,920	157,287	32,077	63,046	389,330
12/1/2023	146,023	146,594	30,909	61,094	384,621

Evaluation of Previous IRP Load Forecast

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

Peak (MW)	2021	2022	2023
Previous IRP Peak Forecast (BP21)	1,112	1,126	1,133
Weather Normalized Actual Peak	1,172	1,172	1,186
Deviation	-60	-46	-54
% Deviation	-5%	-4%	-5%

2024 IRP Load Forecast

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

[redacted]

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

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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

Date	Res	Com	Ind	Gov	Company Use	Total
2024	550	386	60	119	1	1,117

2025	544	386	60	124	1	1,115
2026	540	388	63	124	1	1,116
2027	538	389	63	124	1	1,115
2028	534	390	64	124	1	1,112
2029	537	390	64	123	1	1,115
2030	538	390	65	123	1	1,117
2031	539	391	65	123	1	1,119
2032	545	395	65	122	1	1,129
2033	550	399	65	122	1	1,138
2034	526	426	67	129	1	1,149
2035	563	407	65	121	1	1,157
2036	534	442	66	126	1	1,168
2037	574	428	67	111	1	1,181
2038	586	445	67	111	1	1,209
2039	598	461	67	110	1	1,237
2040	608	478	67	110	1	1,264
2041	620	492	67	110	1	1,289
2042	632	508	67	109	1	1,316
2043	643	518	67	109	1	1,337
2044	653	527	67	108	1	1,356

Table 8: Annual Load Factor Forecast

Date	Res	Com	Ind	Gov	Total
2024	47%	64%	85%	76%	58%
2025	47%	64%	86%	76%	58%
2026	47%	64%	86%	76%	59%
2027	47%	64%	86%	76%	58%
2028	47%	64%	85%	75%	59%
2029	47%	65%	86%	76%	59%
2030	47%	65%	86%	76%	59%
2031	47%	66%	86%	76%	59%
2032	47%	67%	86%	76%	59%
2033	47%	67%	86%	76%	59%
2034	50%	64%	84%	72%	60%
2035	48%	69%	87%	76%	60%
2036	51%	66%	86%	73%	61%
2037	49%	70%	85%	83%	62%
2038	48%	69%	85%	83%	61%
2039	48%	69%	85%	83%	61%
2040	48%	68%	85%	83%	61%

2041	48%	68%	85%	83%	60%
2042	48%	67%	86%	84%	60%
2043	47%	67%	86%	84%	60%
2044	47%	68%	86%	84%	60%

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2024 TRIENNIAL**	**)**	
INTEGRATED RESOURCE PLAN OF	**)**	
ENTERGY NEW ORLEANS, LLC	**)**	**DOCKET NO. UD-23-01**
	)	

APPENDIX C

TOTAL RELEVANT SUPPLY COSTS

HIGHLY SENSITIVE PROTECTED MATERIALS

INTENTIONALLY OMITTED

DECEMBER 2024

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-23-01**

APPENDIX D

GUIDEHOUSE 2024
DSM POTENTIAL STUDY

DECEMBER 2024

Entergy New Orleans, LLC

2024 Integrated Resource Plan

DSM Potential Study

Draft Report

Submitted by:

Guidehouse Inc.
guidehouse.com

Reference No.: 224821

February 1, 2024

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1. Executive Summary

1.1 Introduction

In support of the development of the 2024 Integrated Resource Plan (IRP), Entergy New Orleans, LLC (ENO), engaged Guidehouse, Inc. (Guidehouse or the team) to prepare a demand-side management (DSM) potential study for the 2024-2043 period (20 years). The study assesses the long-term potential for reducing energy consumption in the commercial and industrial (C&I) and residential sectors by using energy efficiency (EE) and peak load reduction measures and improving end-user behaviors.

ENO previously engaged Guidehouse to prepare a DSM potential study to be used in its 2021 IRP. The 2021 study included four cases that informed both the 2021 IRP analysis and the Implementation Plan for Energy Smart (ES) program years (PYs) 13 to 14 (2023-2024) that were later approved by the Council of the City of New Orleans (Council) in Dockets UD-20-02 and UD-08-02. The 2021 study projected certain levels of achievable energy savings and program costs based on business assumptions, existing ES implementation plans, and historical results of ES at the time. The PY 13-15 Implementation Plan developed with ENO's third-party administrator, APTIM, and subsequent actual program results reflect the original energy savings target set forth by the Council of 2% of total annual sales by 2025 (PY 15). The actual PY 10-12 (2020-2022) results reflected a lower savings achievement, particularly for the C&I sector, at about 75% of goal, and lower utilization of behavioral efficiency programs than were identified in the 2021 study for that three-year period.[1] This 2024 study highlights the long-term effects of moderated C&I savings trajectories and the impacts of adopted federal equipment standards for residential lighting.

For the 2024 study, the team approached the EE component of the potential study with a rigorous analysis of input data. This data was necessary for Guidehouse to run the DSM Simulator (DSMSim) model, which calculates various levels of EE savings potential across the ENO service area. Guidehouse further delineated the achievable potential using a range of assumptions for alternative cases to estimate the effect on customer participation of changes in funding for customer incentives, awareness, and other factors.

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

ENO intends to inform the 2024 IRP with the results from this potential study. Although the results may also be used to further ENO's DSM planning and long-term conservation goals, EE program design efforts, and long-term load forecasts, a long-term (20-year) potential study does not replace the need for detailed near-term implementation planning and program design. Accordingly, ENO should use this study only to inform such program planning and design efforts in combination with ENO's ES program experience and the market intelligence and insights of the Council and its Advisors and stakeholders.

[1] Lower savings might be attributed to the COVID-19 pandemic. Lower behavior program savings compared to the study may be a result of a smaller program rollout with fewer behavioral measures.

1.1 Study Objectives

ENO will use the results of the potential study as an input to its 2024 IRP, providing a long-range outlook on the cost-effective potential for delivering demand-side resources such as EE and DR and the associated levels of investment required to implement such programs. Guidehouse designed its project approach to ensure the study results adequately address ENO's objectives and the Council's IRP rules. Table 1 summarizes the study's objectives and how Guidehouse met those objectives.

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

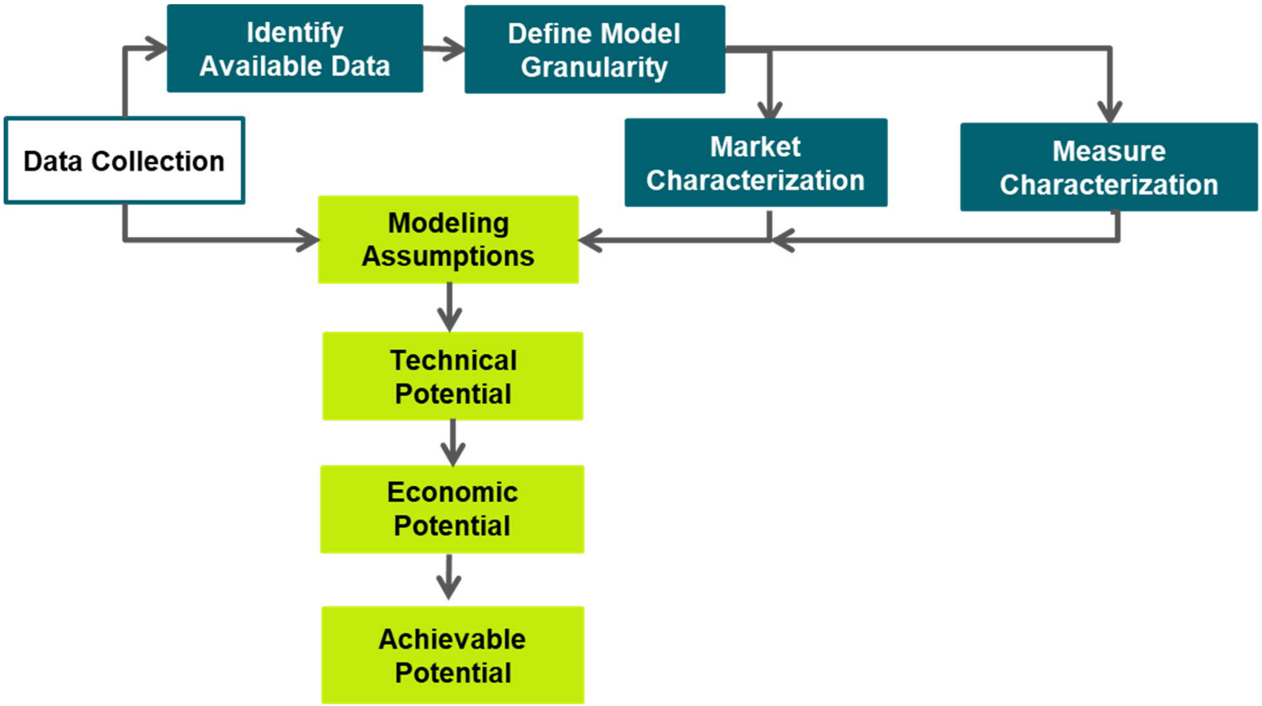
Objective		Guidehouse's Approach
1	Use consistent methodology and planning assumptions	Guidehouse developed analytical tools and approaches to inform DSM planning and the establishment of long-term conservation targets. The team worked closely with ENO to ensure transparency and vet methodology.
2	Reflect current information	With ENO's support, Guidehouse collected inputs, such as the New Orleans technical reference manual (TRM), and other up-to-date information (new codes and standards, saturation data from surveys and ES programs, avoided costs, etc.).
3	Quantify achievable potential	Guidehouse quantifies achievable potential for EE by first calculating the technical and economic (EE only) potential. The achievable potential Reference case is then calibrated to the historical ES program data, primarily PY 10-12 (2020-2022). For DR, Guidehouse estimated achievable potential from DR that represents ENO's current offers (calibrated to historical program achievements) and new DR programs/rates that the Company could potentially offer.
4	Provide input to the IRP	Guidehouse's approach will provide the following for all modeled cases: • Supply curve of potential savings for input to ENO's IRP; • Output available with 8,760 hourly EE impact load shapes; and • DR annual savings and levelized costs

Source: Guidehouse

1.2 EE Potential

Guidehouse analyzed EE savings potential in the ENO service area for 2024-2043 (20 years). After gathering existing data sources (step 1), the team characterized the market and measures (step 2), and estimated EE potential using the DSMSim tool, a bottom-up stock forecasting model (step 3). The third step involved three sequential stages—calculating technical, economic, and achievable potential. Figure 1 illustrates Guidehouse's EE analysis approach.

Figure 1. EE Analysis Approach Overview



Source: Guidehouse

1.2.1 EE Market Characterization

Characterizing the EE market involved identifying and understanding key factors defining the service area or market and codifying assumptions for the model to accurately represent the market. Specifically, the market characterization required defining the sales and stock[2] for 2022 (the study's base year),[3] then forecasting sales and stock out from 2022-2043 to create the study's Reference case, or baseline. To complete this effort, Guidehouse collected multiple datasets, including:

- 2022 ENO billing and customer account data
- 2022 Residential Appliance Saturation Survey (RASS) conducted for ENO
- ENO Business Plan 2024 (BP24) forecast sales and customer counts
- US Energy Information Administration (EIA) Commercial Buildings Energy Consumption Survey (CBECS)[4]
- US Department of Labor SIC[5]

[2] Guidehouse defines sales as the kilowatt-hour consumption, typically by sector. The customer count defines the stock, typically per household for the residential sector and per 1,000 square feet for the non-residential (C&I) sector. For the potential analysis, Guidehouse prefers more disaggregated analysis at the segment level (or building types).

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

[4] US Energy Information Administration, Commercial Buildings Energy Consumption Survey, 2018, https://www.eia.gov/consumption/commercial/building-type-definitions.php.

[5] US Securities and Exchange Commission, Division of Corporation Finance: Standard Industrial Classification (SIC) Code List, https://www.sec.gov/corpfin/division-of-corporation-finance-standard-industrial-classification-sic-code-list.

- Guidehouse research

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

The team also aggregated additional inputs from ENO for inclusion in the model, including various economic and financial parameters such as carbon pricing, avoided costs, inflation rate, weighted average cost of capital (WACC), societal discount rate, and historic program costs.

1.2.2 EE Measure Characterization

EE measure characterization consisted of defining enough data points for all measures in the study to accurately model them. Key data points used to characterize measures included assumptions about energy and demand savings, codes and standards, measure life, and measure costs. Guidehouse used data provided by ENO, data from regional efficiency programs offered by other utilities, and TRMs, primarily the New Orleans TRM version 7.0,[6] and other TRMs to fill the gaps.

The team used a measure list with sufficient characteristics to identify and focus its efforts on technologies likely to have the highest feasible, cost-effective contribution to savings potential over the 20-year study horizon. The study does not account for unknown or emerging but unproven technologies that might arise and increase savings opportunities over the forecast horizon. The analysis also does not account for broader societal changes that might affect levels of energy use in unanticipated ways.

1.2.3 Estimation of EE Potential

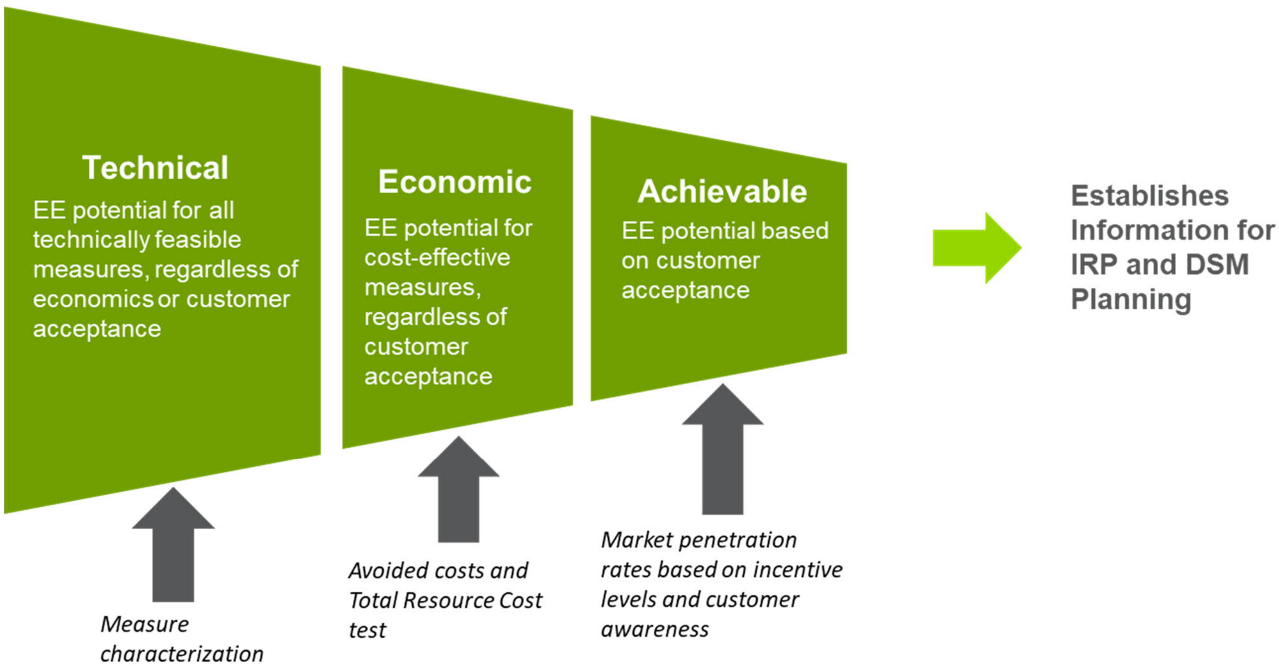
After defining the EE market and measure characteristics, Guidehouse employed its DSMSim potential model to estimate the technical, economic, and achievable savings potential for electric energy and demand across ENO's service area from 2024 to 2043. Each type of potential is defined here and in Figure 2:

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

[6] New Orleans Energy Smart Technical Reference Manual: Version 7.0, November 2023, prepared by ADM Associates, Inc. https://www.entergy-neworleans.com/energy_efficiency/energy_smart_filings/

- **Achievable potential** is a subset of economic potential. The team determined achievable potential by modifying economic potential to account for measure adoption rates and the diffusion of technology through the market. Figure 2 depicts each potential type and the respective data inputs.

Figure 2. EE Potential Analysis Approach



Source: Guidehouse

With these definitions and data inputs, the DSMSim model uses a bottom-up technology diffusion and stock tracking model implemented by means of a system dynamics framework to estimate the different potential types.[7] The model outputs technical, economic, and achievable savings potential for the service area, sector, customer segment, end use category, and highest impact measures.

Given ENO's objective to quantify the achievable potential for use in the 2024 IRP and gain a better understanding of the best path for planning ENO's ES programs, the project team modeled several possible future cases of EE program portfolio performance, including:

- **Reference:** Assumes both current (PY 12, 2022, and PY 13, 2023) incentive levels (as a percentage of incremental costs) and expected behavior participation and aligns with historic program achievements. Administrative costs on a dollar per kilowatt-hour (kWh)-saved basis are the same as the historic program expenditure and are carried through the other cases. The TRC measure screening threshold for all measures is 0.9, recognizing the fact that numerous viable measures implemented through Energy Smart meet or exceed this level.
- **Two Percent (2%) Savings:** Uses the parameters defined by the Reference case. The savings goal under this case is the Council's goal of 2% of ENO sales by PY 15, 2025. The

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

incentives assume ten times the existing levels up to a maximum of 100% and estimated aggressive behavior program participation rollout plan. The TRC measure screening threshold is relaxed to 0.75 from 0.9.

- **Low:** Uses the same inputs as the Reference case, except for lower levels of behavior program participation rollout. Incentives are set to 50% of current (or Reference case) levels.
- **High:** Assumes higher incentives at 100 times the Reference case (up to 100% of incremental measure costs) and no change in administrative cost levels on a dollar per kWh saved basis. Model assumptions us the same aggressive behavior program rollout for all sectors as used in the 2% savings case. There is no TRC measure screening threshold, as every measure is passed on to the achievable potential analysis.

In all cases, a measure's incentive is capped at 100% of incremental measure cost. Income-qualified (IQ) measures are incentivized at 100% in all cases except for low.

As with the prior 2021 potential study, the 2024 study reports gross savings, which do not account for free ridership or spillover impacts, as would net savings. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about net-to-gross (NTG) ratios or changing EUIs with natural occurring energy usage becomes available. Study results then can be used to define the portfolio energy savings goals, projected costs, and forecasts.

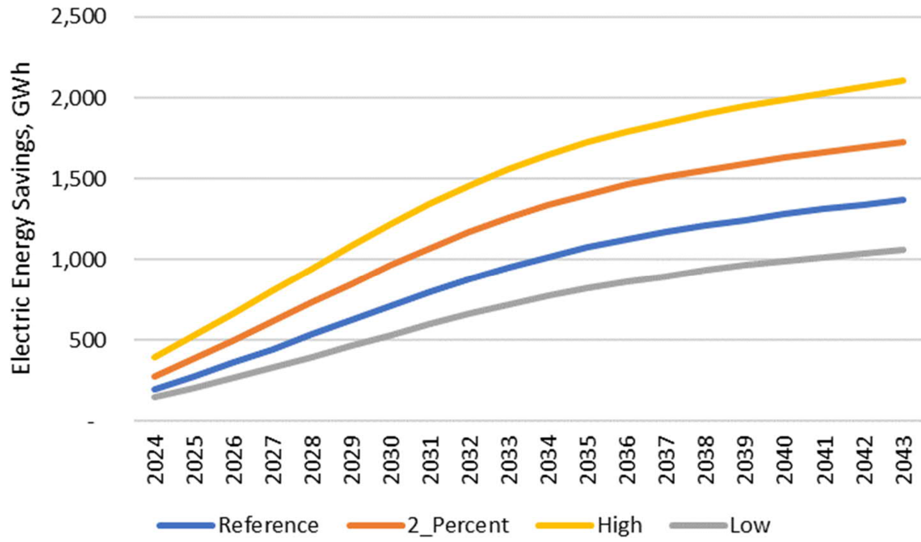
This study includes only known, market-ready, quantifiable measures. However, over the lifetime of EE programs, new technologies and innovative program interventions could result in additional, cost-effective savings. ENO should periodically revisit and reanalyze the potential forecast to account for these technologies and programs (typically every 3 to 5 years).

1.2.4 EE Analysis Results

Figure 3 shows the cumulative annual electric energy savings for each case using the WACC.[8] The range of savings increases over the 20-year period, from the Low case which shows more than 1,000 GWh of savings through the High case with savings in excess of 2,000 GWh. The pace of savings slows by 2031 due to increasing saturation of the existing set of measures.

[8] In the Executive Summary, tables and figures only reflect savings using the WACC for the sake of brevity. Complete screening results reflecting the societal discount rate are included in the body of the study as required by the IRP Resolution R-23-254. Additionally, the residential sector savings are provided as income qualified versus market rate customers in the appendix.

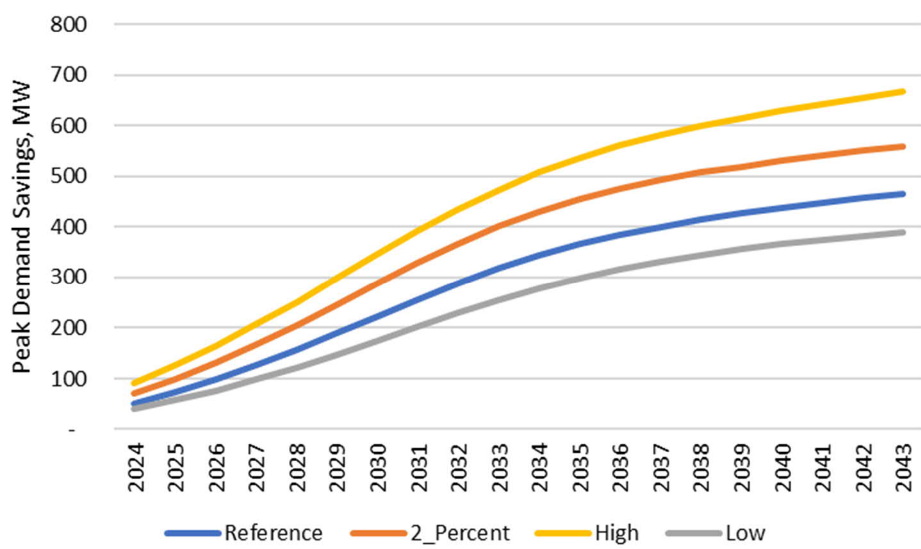
Figure 3. Cumulative Annual Achievable Potential – Electricity Savings by Case



Source: Guidehouse analysis

Figure 4 show the cumulative annual peak demand savings for each EE case using the WACC. The range of savings increases over the 20-year period, with the Low case more than 400 MW and the high case 700 MW, with the pace of savings slowing by 2031 similar to the electric energy savings.

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



Source: Guidehouse analysis

The four cases show significantly different results from each other, thanks to marked differences in program design (i.e., changes in ENO-influenced parameters, including incentive level setting and behavioral program rollout).[9] Table 2 summarizes the EE potential study results, showing achievable annual incremental energy and peak demand savings by case in 5-year increments.

Table 2. Incremental Annual Achievable Potential – Savings by Case

Year	Electric Energy (GWh)				Peak Demand (MW)			
	Reference Case	2% Savings Case	High Case	Low Case	Reference Case	2% Savings Case	High Case	Low Case
2024	70	98	119	49	19	25	30	14
2028	89	117	141	66	30	39	45	24
2033	73	89	102	58	29	34	39	25
2038	40	44	51	34	14	14	18	13
2043	29	31	37	22	9	9	12	7

Source: Guidehouse analysis

Table 3 shows the incremental annual achievable energy savings as a percentage of ENO's total electricity sales for each case in 5-year increments. The 2% savings case, which was calibrated with the historical achievement through mid-year 2023 and not to the current PY 13-15 Implementation Plan (which targets 2% savings by 2025), achieves at least 2% of sales savings from 2027 through 2029. The 2% case and the High case fall below 2% in later years because most of the measures will have been adopted, depleting the available potential in future years.

Table 3. Incremental Annual Achievable Potential, Percentage of Electricity Sales, by Case

Year	Reference Case	2% Savings Case	High Case	Low Case
2024	1.25%	1.74%	2.11%	0.87%
2028	1.54%	2.04%	2.44%	1.15%
2033	1.24%	1.51%	1.72%	0.99%
2038	0.58%	0.62%	0.70%	0.50%
2043	0.38%	0.39%	0.47%	0.29%

Source: Guidehouse analysis

The total administrative and incentive costs for each case are provided in 5-year increments for the 20-year study period, as Table 4 shows. Administrative spending is relatively consistent between the cases, while the incentive spending varies significantly between the cases, with higher spending correlated to higher savings.

[9] Incentive levels influence the customer payback period, which results in a change in the payback acceptance curve influencing the market share potential of the energy efficient option. The payback acceptance curves for ENO were developed based on the results of customer surveys and are the same as used in the 2021 Potential Study.

Table 4. Achievable Potential, Annual Investment by Case

Year	Total Investment				Incentives				Administrative Costs			
	Ref.	**2%**	**High**	**Low**	**Ref.**	**2%**	**High**	**Low**	**Ref.**	**2%**	**High**	**Low**
2024	$11	$32	$81	$6	$6	$25	$71	$2	$5	$8	$10	$4
2028	$18	$42	$115	$9	$10	$32	$101	$3	$8	$11	$13	$6
2033	$17	$35	$95	$10	$10	$27	$85	$4	$7	$9	$11	$6
2038	$8	$15	$54	$6	$4	$11	$49	$3	$4	$4	$5	$4
2043	$4	$8	$39	$4	$2	$6	$36	$2	$2	$2	$3	$2
20-Year Total	**$250**	**$558**	**$209**	**$152**	**$139**	**$415**	**$1,439**	**$56**	**$111**	**$143**	**$174**	**$96**

Note: Values in nominal dollars, rounded to the nearest million, which may result in rounding errors.
Source: Guidehouse analysis

Table 5 shows the portfolio TRC test ratios[10] to be cost-effective for all cases except for the High case, which is less than 1.0. One of the screening criteria in the potential analysis is for the measures to pass a certain TRC threshold. A handful of measures were allowed into the analysis that fell below a TRC threshold of 0.9 for the Reference case. As a result, the portfolio is still cost-effective. Typically, the more aggressive the portfolio, the lower the TRC as less cost-effective measures are added and administrative efforts to address more services to the market are increased.

Table 5. Achievable Potential – Portfolio Cost Test Ratios

Study Period	WACC (TRC)			
	Reference	2% Savings	High	Low
2024-2043	1.78	1.51	0.72	2.16

Source: Guidehouse analysis

1.3 DR Potential

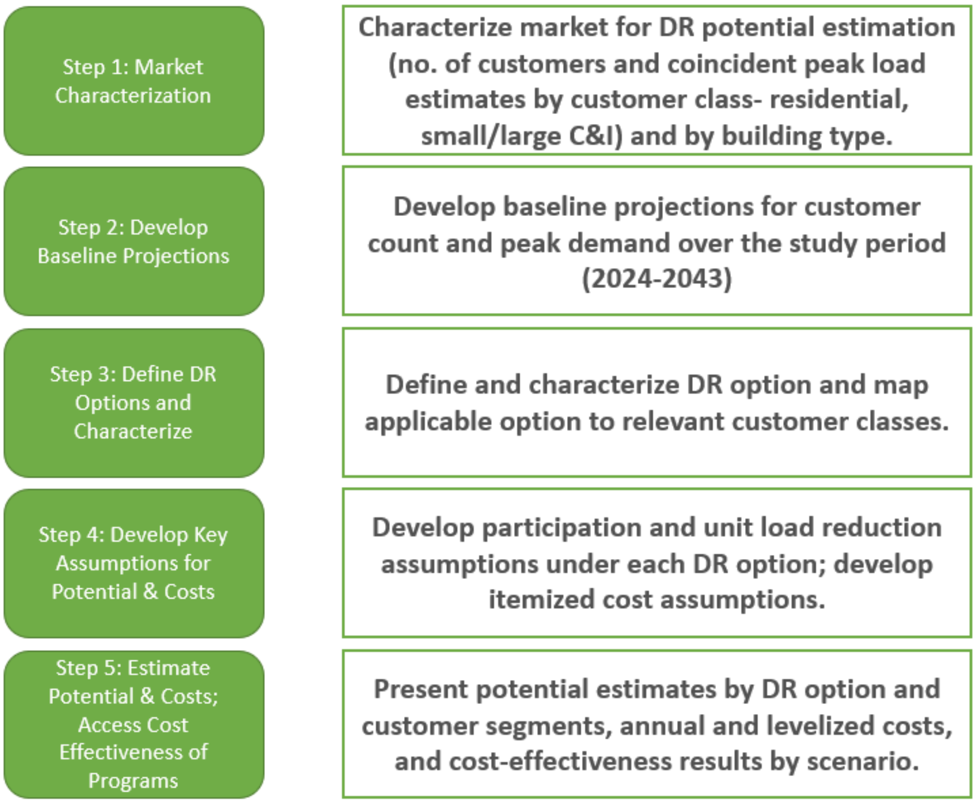
Guidehouse developed ENO’s DR potential and cost estimates using a bottom-up modeling approach consisting of five steps:

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

[10] The study also included analysis and cost-effectiveness calculations using the societal discount rate. The resulting values are provided in the body of the report, below.

Figure 5 summarizes the DR potential estimation approach.

Figure 5. DR Potential Assessment Steps



Source: Guidehouse

1.3.1 DR Market Characterization

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

As part of characterizing the market, the team identified the peak period during which DR events are likely to be called. ENO expressed a desire to align the peak period definition with times used by the Midcontinent Independent System Operator (MISO). Per MISO's business practice manual, the expected peak occurs during the summer (June through August) during the hours from 2:00 p.m. through 6:00 p.m."[11] Guidehouse included only the top 40 weekday hours within this window, which is the typical limit for calling summer DR events. This approach allows ENO to use the findings of the DR potential assessment should it seek to register any DR resources as load modifying resources with MISO.

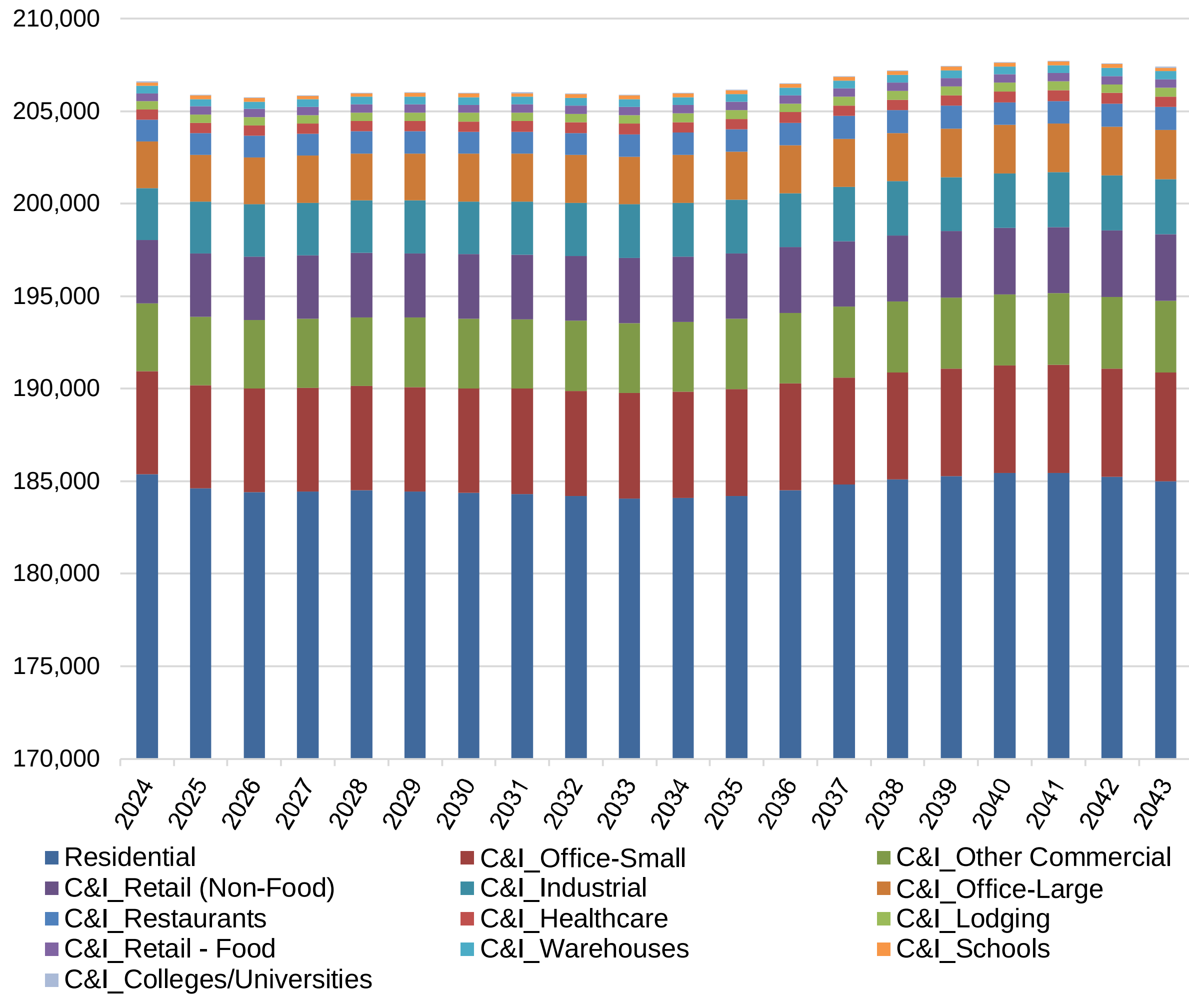
[11] Midcontinent Independent System Operator, *Business Practices Manual*, Demand Response, Manual No. 026, effective date October 1, 2023, page 20.

1.3.2 DR Baseline Projections

Baseline projections in the DR potential assessment are a forecast of customer demand over the study period based on existing trends and market characteristics, similar to the Reference case in the EE potential study. The project team used these projections as a basis for modeling savings. More specifically, Guidehouse applied the year-over-year change in the stock forecast of the 2022 customer count data broken out by customer class and segment for the projections. These projections are calibrated to the sector-level customer count forecast ENO provided.

Figure 6 shows the aggregate customer count forecast by segment, summed across all customer segments for the Reference case.

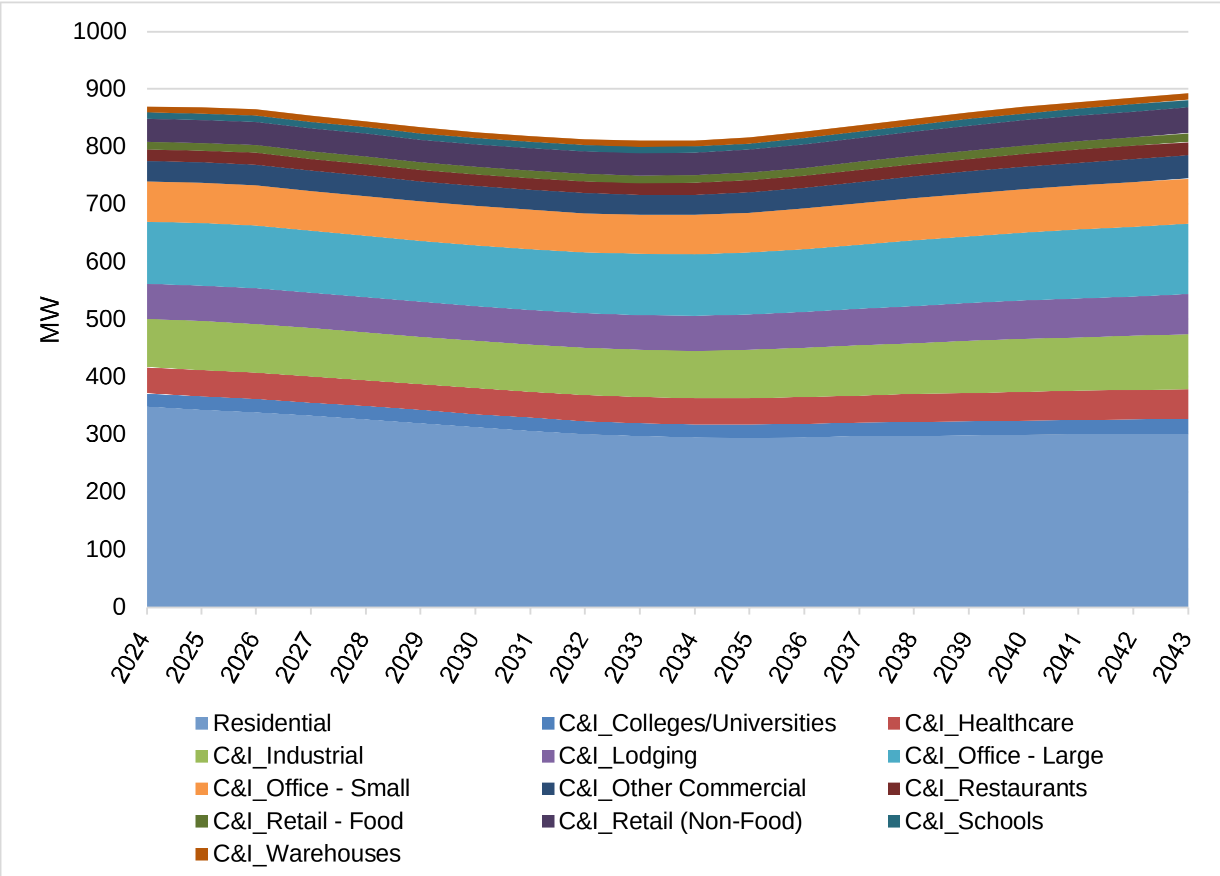
Figure 6. Customer Count Projections by Segment for DR Potential Assessment



Source: Guidehouse analysis

Figure 7 shows the Reference case summer peak demand projections Guidehouse developed by combining 2022 hourly system load data, 2022 customer count and sales data by segment, load profiles by revenue class, and sales projections by revenue class. Section 4 of the report describes the approach Guidehouse used to develop disaggregate peak demand projections by customer class and segment. The peak demand projections are adjusted with EE potential estimated to derive the net load post EE, which serves as the baseline load for DR potential estimation. Guidehouse developed the baseline peak demand projections for all three cases (Reference, Low, High) corresponding to the EE achievable potential estimates for these three cases. The baseline peak demand projections progressively decline over time due to higher penetration of EE.

Figure 7. Reference Case Peak Load Projections by Customer Segment



Source: Guidehouse analysis

1.3.3 DR Options

The team characterized different types of DR options that could be used to reduce peak demand from the developed baseline peak demand projections. Table 6 summarizes the DR options included in the analysis. The DR options represent ENO's current DR program offers and those that are commonly deployed in the industry. These programs align with the Council's IRP rules, which state that DR programs should include those "… enabled by the deployment of advanced meter infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer classes."

Table 6. Summary of DR Options

DR Option	Characteristics	Eligible Customer Classes	Targeted End Use or Technology
DLC[12] • Thermostat for space cooling • Switch for water heating	Control of cooling load using smart thermostat; control of water heating load using a load control switch	Residential	Cooling, water heating
C&I Curtailment • Manual • Auto-DR enabled	Firm capacity reduction commitment with pay-for-performance ($/kW) based on nominated amount or actual performance	Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads (based on facility type)
Dynamic pricing[13] • Without enabling technology • With enabling technology	Voluntary opt-in dynamic pricing offer, such as Critical Peak Pricing (CPP)	All customer classes	All
BTMS[14] • Solar-paired battery storage	Dispatch of BTM batteries for load reductions during peak demand periods	Residential[15]	Batteries
EV managed charging (BYOC)[16]	BYOC program that will reward customers for shifting their EV charging load to off-peak hours	EVs	Light Duty Vehicles with L2 chargers
PTR	Opt-in offer that provides a $/kWh rebate to customers for energy reduced during DR events	Residential Small C&I	All

Source: Guidehouse

1.3.4 Estimation of DR Potential

With the market, baseline projections, and DR options characterized, Guidehouse estimated achievable potential by inputting those parameters into its model. Guidehouse developed

[12] DLC, or direct load control, represents the smart thermostat-based EasyCool program offered by ENO to residential customers (switch-based option offered only for water heater control).

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

[14] BTMS = behind the meter storage

[15] The DR potential assessment from BTM batteries only considered residential batteries. No battery forecast was available from ENO. Guidehouse used the NEM forecast data to project residential BTM batteries paired with solar. However, for C&I, there was no basis to develop battery forecasts and therefore this analysis did not consider DR potential from BTM batteries for C&I customers. Future potential studies should consider this update as and when C&I BTM battery forecast data is available.

[16] BYOC=bring your own charger

programmatic assumptions such as participation, unit impacts, and costs to estimate potential and assess cost-effectiveness. The team developed variations in assumptions across the three cases to assess variations in potential estimates with varying levels of incentives and participation projections. The achievable potential estimates presented in the results represent potential from cost-effective DR options that pass the benefit-cost threshold of 1.0 based on the TRC test.

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

- Program participation and enrollment assumptions and the rates at which these ramp up;
- Technology market penetration (e.g., penetration of DR-enabling technologies such as smart thermostats and energy management systems [EMSs]);
- Realizable load reduction from different types of control mechanisms, referred to as unit impacts;
- Annual attrition and event opt-out rates; and
- Incentive and non-incentive costs.

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

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

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

1.3.5 DR Results

Among the DR options analyzed in the study, switch-based water heating under DLC, Peak Time Rebate, and EV Managed Charging are the only three options that are not cost-effective. All other DR options are cost-effective and are included in the DR achievable potential results discussed below.

Achievable peak demand reduction potential is estimated to grow from 15 MW in 2024 to 75 MW in 2043. Cost-effective achievable potential makes up approximately 8.4% of ENO's peak demand in 2043. The team made several key observations:

- C&I Curtailment has the greatest cost-effective achievable potential: 51% share of total cost-effective potential in 2043. C&I Curtailment potential grows rapidly starting from 9.0 MW in 2024. This growth is calibrated to evaluated programs and implementation plan values before 2026. Beginning in 2026, C&I Curtailment follows the S-shaped ramp assumed for the program over a 5-year period. By 2031, the program attains a steady participation level with 26 MW of cost-effective potential, which increases gradually to 38.3 MW in 2043.

- DLC-Thermostat-Res has a 22% share of the total cost-effective achievable potential in 2043. The potential for this measure grows from 5.7 MW in 2024 to 16.6 MW in 2043. DLC-Switch-Water Heating is not cost-effective and does not contribute to achievable potential.

- Dynamic Pricing has a 20% share of the total cost-effective achievable potential in 2043. The dynamic pricing offer is assumed to begin in 2026 since ENO would need lead time to design and file a Critical Peak Pricing tariff and have that approved to start offering it to customers. The program ramps up over a 5-year period (2026-2030) until it reaches a value of 12 MW. From then on, potential slowly increases from 1.6 MW in 2026 to 14.8 MW in 2043.

- BTMS contributes the remainder of the 7% share of the total cost-effective achievable potential in 2043. This program uses a linear ramp to reach steady state by 2033 and increases in residential battery count grows from 0.2 MW in 2024 to 4.9 MW in 2043.

Table 7 lists the DR potential results by option in 5-year increments. The calculated achievable potential for peak load reduction in the Reference case is 75 MW in 2043.

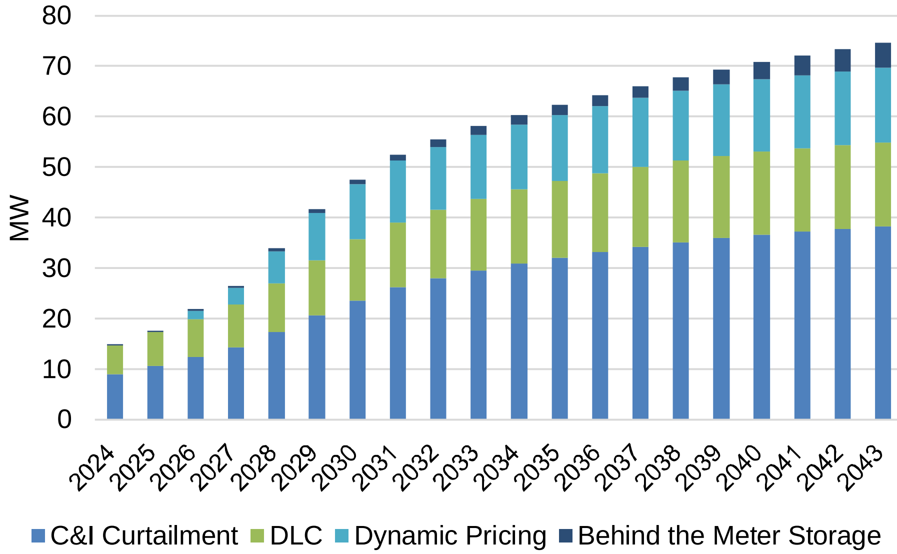
Table 7. Achievable Summer DR Potential by Option (MW)

Year	C&I Curtailment	DLC-Res Thermostat	Dynamic Pricing	BTM Batteries	Total
2024	9.0	5.7	-	0.2	**14.9**
2028	17.3	9.6	6.4	0.6	**33.9**
2033	29.6	14.1	12.7	1.8	**58.1**
2038	35.1	16.1	13.9	2.6	**67.7**
2043	38.2	16.6	14.8	4.9	**74.6**

Source: Guidehouse analysis

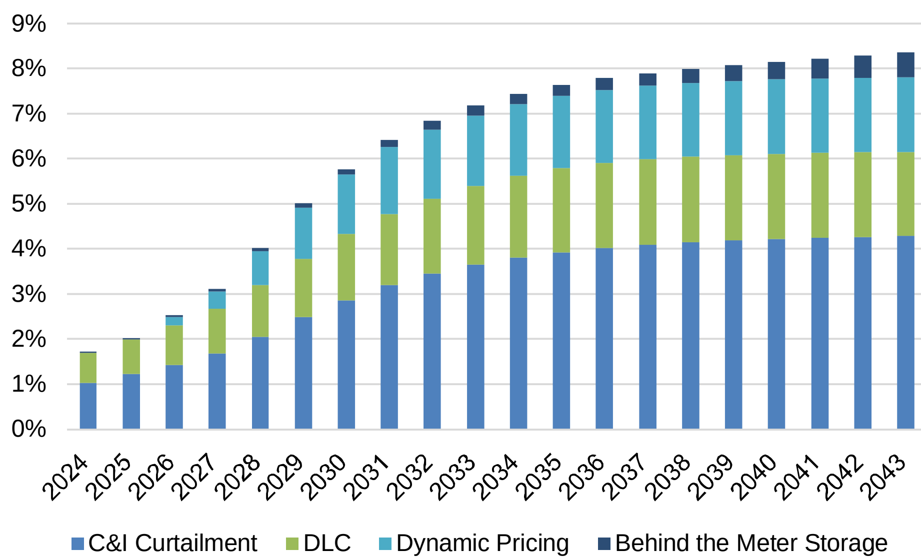
Figure 8 and Figure 9 summarize the cost-effective, programs where the benefits exceed the costs (TRC ≥1.0) achievable potential by DR option for the Reference case in megawatts and as a percentage of ENO’s peak demand.

Figure 8. Summer Peak Achievable Potential by DR Option (MW)



Source: Guidehouse analysis

Figure 9. Summer DR Achievable Potential by DR Option (% of Peak Demand)



Source: Guidehouse analysis

Figure 10 summarizes the cost-effective achievable potential by DR option for the Reference case. Guidehouse had the following key observations:

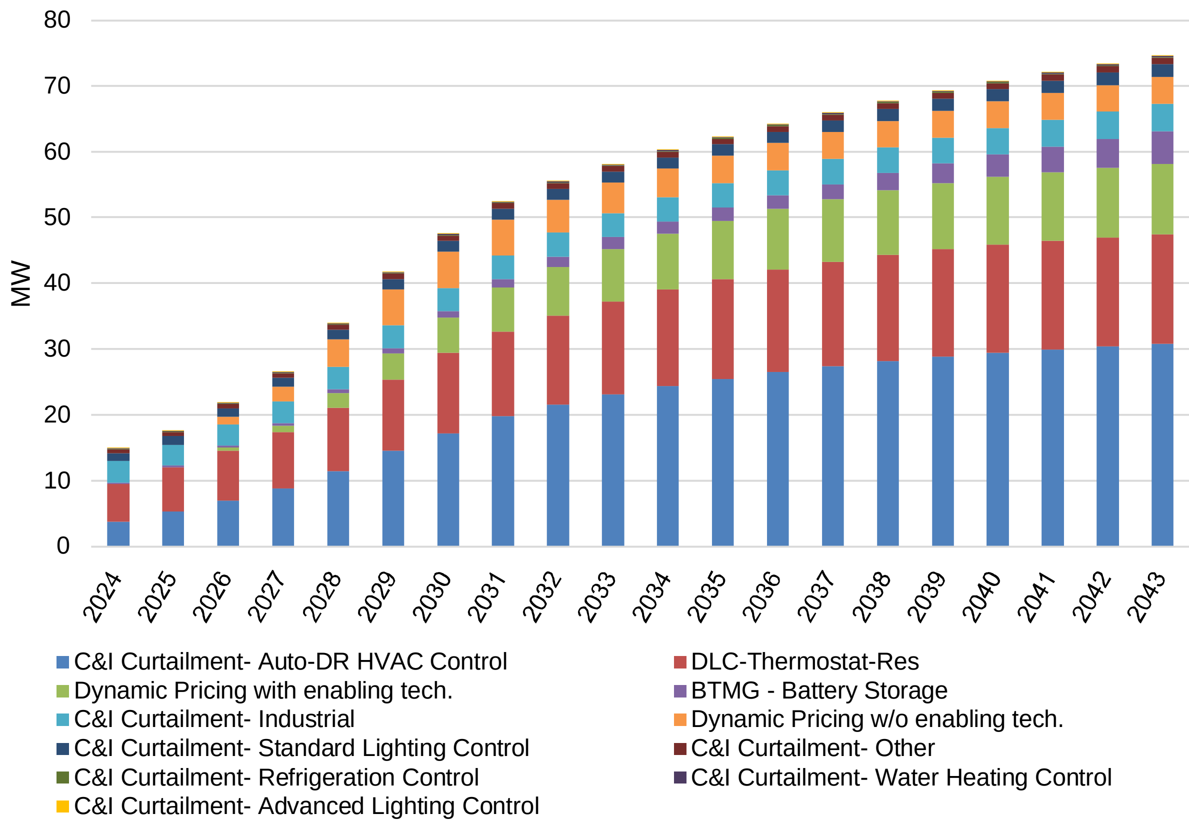
- Most of the C&I Curtailment reductions are associated with Auto-DR HVAC control, which reaches 30.8 MW or 41% of the total cost-effective potential in 2043. Other C&I Curtailment suboptions total to contribute 10% of the total cost-effective potential in 2043. Overall, C&I Curtailment options are projected to reach 38.3 MW by 2043.

- Only direct control of residential HVAC loads under the DLC-Thermostat suboption is cost-effective (and not water heating). This suboption makes up about 22% of the total cost-effective achievable potential in 2043 at 16.6 MW.

- Dynamic pricing makes up 20% of the total cost-effective achievable potential in 2043. Potential from customers with enabling technology in the form of thermostats/energy management systems is more than two times higher than that from customers without enabling technology—10.7 MW versus 4.1 MW in 2043.

- Battery storage projected to reach 4.9 MW of savings or 7% of the total cost-effective potential in 2043.

Figure 10. Summer DR Achievable Potential by DR Suboption



Source: Guidehouse analysis

1.4 Conclusions and Next Steps

The team benchmarked the study results against the 2021 study and identified how the results could be used in ENO's 2024 IRP. The 2021 and 2024 potential studies leveraged the same methodology and similar data sources; however, there are key differences between the two studies, aside from data updates.

1.4.1 EE

The differences in results and projected achievable potential between the 2021 and 2024 studies were driven in part by the following changes in methodology and approach:

- Calibration targets differed for the two studies, as explained in detail in Appendix D:
    - The 2021 study used the planned targets for savings from the PY10-12 implementation plan, with a 2% savings goal for 2025;
    - The 2024 study used the actual savings and budget from PY 10-12 (2020-2022) and performance to date for PY 13 (2023). Underperformance was seen in the C&I sector across the years 2020-2023 and was consistent with results in other jurisdictions, based on Guidehouse's research;
- Different assumptions on planned rollout for home energy reports and savings percentage of consumption (from 1.3% in 2021 to 0.8% 2024);
- Updated data on residential saturation and density using the 2022 ENO RASS data;
- Updates to commercial saturation values based on year-over-year program data (for measures where data was available);
- Changes in federal residential lighting standards, eliminating any residential lighting end use potential;
- Updates in the N.O. TRM from version 4.0 to version 7.0, resulting in many changes in residential measure assumptions, including those reflecting updated state building code changes; and
- Removal of behavior programs that do not show any promise for implementation or significant savings in the ENO service area, or in other utility territories.

1.4.2 DR

The 2024 and 2021 DR analysis differed in the following ways:

- Current peak definition for MISO is slightly altered from the one used in the 2021 study in defining the peak period for calling DR programs;
- Added new DR options to the analysis (EV Managed Charging and Peak Time Rebate) in recognition of programs currently being offered through Energy Smart;
- Used historical program implementation data for Smart Thermostats and for C&I Curtailment and pilot program information from ENO's most recent activities. There has been growth in residential and C&I program participation compared with the data from 3 years ago;
- Updated BTM battery projections and assumed all batteries are paired with solar for the DR analysis and updated cost assumptions with a Bring Your Own Battery (BYOB) type program offer, which leads to the program being cost-effective.
- Updated data on the penetration of smart thermostats and other control technologies based on the EE analysis.

These changes resulted in differences in program potential.[17]

1.4.3 Program Planning

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

Key findings from this potential study may inform program planning and include the following observations on high potential measures that have not varied much from the 2021 study:

- Significant savings potential exists in promoting retrocommissioning, occupancy sensor controls, and interior high bay and 4 ft. LEDs for the C&I sector. For any measure not reaching its potential to date may be experience barriers such as limited supply, workforce readiness, or other independent factors.
- There is high potential in O&M (residential duct sealing and AC tune-up) and behavior-type programs, such as home energy reports, in the residential sector.
- There is significant DR potential with large C&I customers from both C&I Curtailment (with increased adoption of DR-enabling control technologies) and dynamic pricing. Residential sector contribution from smart thermostat DLC is projected to grow progressively with increasing adoption of smart thermostats along with contribution from dynamic pricing.

[17] The two added DR options – Peak Time Rebate and EV Managed Charging are both not cost-effective and are therefore not included in the achievable potential results.

2. DSM Potential Study Introduction

2.1 Context and Study Goals

ENO engaged Guidehouse to prepare a DSM potential study for electricity as an input to its 2024 IRP for the 2024-2043 period (20 years). The study assesses the long-term potential for reducing energy consumption in the C&I and residential sectors by analyzing EE and peak load reduction measures with DR and improving end-user behaviors. The EE and behavior potential analysis efforts provide input data to Guidehouse's DSMSim model, which calculates achievable savings potential across the service area. This study also includes DR program potential analyzed within Guidehouse's DRSim. While ENO primarily plans to use the results from the potential study to inform the IRP, these results may also be used as inputs to DSM planning, long-term conservation goals, and program design.

2.1.1 Study Objectives

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

Guidehouse designed its study approach to ensure the results adequately address ENO's objectives and the Council's rules. Table 8 details these objectives and presents Guidehouse's approach to meeting each objective.

Table 8. Guidehouse's Approach to Addressing ENO's Objectives

Objective		Guidehouse's Approach
1	**Use consistent methodology and planning assumptions**	Guidehouse developed analytical tools and approaches to inform DSM planning and the establishment of long-term conservation targets. The team worked closely with ENO to ensure transparency and vet methodology.
2	**Reflect current information**	With ENO's support, Guidehouse collected inputs, such as the New Orleans TRM and other up-to-date information (new codes and standards, saturation data from surveys and ES programs, avoided costs, etc.).
3	**Quantify achievable potential**	Guidehouse quantifies achievable potential for EE and DR by first calculating the technical and economic (EE only) potential. The achievable potential Reference case is then calibrated to the historical ES program data, primarily PY 10-12 (2020-2022).
4	**Provide input to the IRP**	Guidehouse's approach will provide the following for all modeled cases: • Supply curve of potential for input to ENO's IRP • Output available with 8,760 hourly EE impact load shapes

Source: Guidehouse

2.2 Organization of the Study

Guidehouse organized this study into five sections that detail the study's approach, results, and conclusions, as follows:

- Section 2 summarizes the study, including its background and purpose.
- Section 3 and 4 describes the methodologies and approaches Guidehouse used to estimate EE and DR potential respectively, including discussions of base year calibration, Reference case forecast, and measure characterization.
- Section 5 details the EE achievable potential forecast, including the approach and results by case, segment, end use, and measure.
- Section 6 describes the process for estimating DR potential and details the achievable potential savings forecast for ENO, including the modeling results by customer segment.
- Section 7 summarizes the next steps that result from this study's findings and discusses findings in comparison with the previous ENO potential study from 2021.

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

2.3 Study Overview

The Guidehouse potential analysis includes a set of parameters and limitations that are important to highlight prior to presenting the study's data sources, analysis, and results.

2.3.1 Limitations

There are several limitations associated with the results of this study. Potential studies typically begin as a bottom-up, measure-level effort and are calibrated to system, sector, and sometimes end-use base loads. The calibration parameters are used with a reference consumption forecast to calculate the future potential. Potential studies are an exercise in data management and analysis requiring a careful balancing of abundant, quality data for some inputs with scarce, low-quality data for other inputs. Accordingly, the team must understand what data gaps exist and determine how to fill those to provide reasonable and realistic savings potential estimates. This study documents Guidehouse's approach and the decisions made in cases where appropriate data was not available.

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

As a result, there are inherent uncertainty or probability bands in the results due to the error bands of the inputs. Furthermore, calibration anchors the analysis based on existing ENO programmatic conditions.

2.3.2 Segmentation

Guidehouse obtained data from ENO to segment the residential and C&I sectors, including customer counts by premise type for residential and industry type for C&I. The team supplemented this data through its subject matter expertise and ENO's experience and judgment to ensure alignment of sales and stock data within segments. Government customers were included as part of the C&I sector. As was the case in the 2021 Study, City-owned streetlighting is not included in this study as the majority of (if not all) lamps have been converted to LEDs, and ne large industrial customer also is not included as it has opted out of participating in ENO's DSM programs.

2.3.3 Measure Characterization

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

EE measures: The study's scope did not include primary data collection. The EE potential analysis relied on the New Orleans TRM[18] version 7.0. Other data sources for characterizing EE measures included data from ENO and other regional efficiency programs and utilities. Guidehouse sourced density and saturation data for the residential section from ENO's 2022 RASS. Guidehouse used historical program participation data for the C&I programs to provide evidence on saturation levels of efficient technologies.

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

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

2.3.4 Measure Interactive Effects

This study models EE measures independently. The total aggregated EE potential estimates may be higher or lower than the actual potential available if a customer installs multiple measures in a home or business. Multiple measure installations at a single site generate two types of interactive effects: within end-use interactive effects and cross end-use interactive effects. An example of a within end-use interactive effect is when a customer implements temperature control strategies and installs a more efficient cooling unit. If the controls reduce cooling requirements at the cooling unit, the savings from the efficient cooling unit are reduced.

[18] New Orleans Energy Smart Technical Reference Manual: Version 7.0, November 2023, prepared by ADM Associates, Inc.. https://www.entergy-neworleans.com/energy_efficiency/energy_smart_filings/

An example of a cross end-use interactive effect is when a homeowner replaces heat-producing less-efficient light bulbs with efficient LEDs. This change influences the cooling and heating load of the space, however slightly, by increasing the amount of heat and decreasing the amount of cooling generated by the HVAC system.

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

- Where measures compete for the same application (e.g., an air source Heat Pump (HP) being replaced by a more efficient air source HP or a ground source HP), the team created competition groups to eliminate the potential for double counting savings.
- For measures with significant interactive effects (e.g., HVAC control upgrades and building automation systems), the team adjusted applicability percentages to reflect varying degrees of interaction.
- Wherever cross end-use interactive effects were appreciable (e.g., lighting and HVAC), the team typically characterized those interactive effects for the same fuel (e.g., lighting and electric heating) applications, but not for cross-fuel because no natural gas savings or consumption were considered in this study.

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

2.3.5 Gross Savings

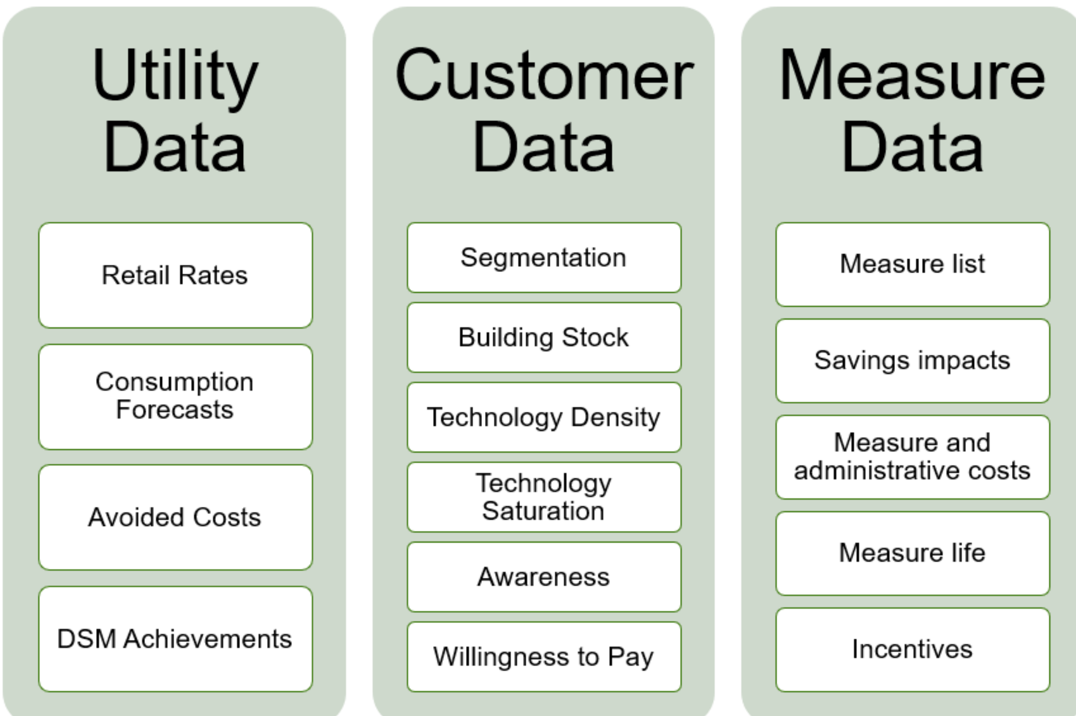
As in prior IRP potential studies, savings are shown at the gross level to account for natural change (either natural conservation or natural growth in consumption). Accordingly, free ridership and spillover are not included in the savings estimates. Providing gross potential is advantageous because it permits a reviewer to easily calculate net potential when new information about changing EUI (natural changes in consumption), considerations of program design, or NTG ratios become available from program evaluation studies.

3. EE Study Approach and Data

This section provides the study approach for EE and DR. The study approach includes the data inputs, including developing the market characterization, gathering the global inputs, and characterizing the measures and programs.

Guidehouse modeled technical, economic, and program achievable electricity savings potential in the ENO service area from 2024 through 2043 (20 years) using a bottom-up potential model. These efficiency forecasts relied on disaggregated estimates of building stock and electricity sales before conservation and a set of detailed measure characteristics for a thorough list of EE measures relevant to ENO's service area. This section details the team's approach and methodology to develop the key inputs to the EE potential model, as Figure 11 illustrates.

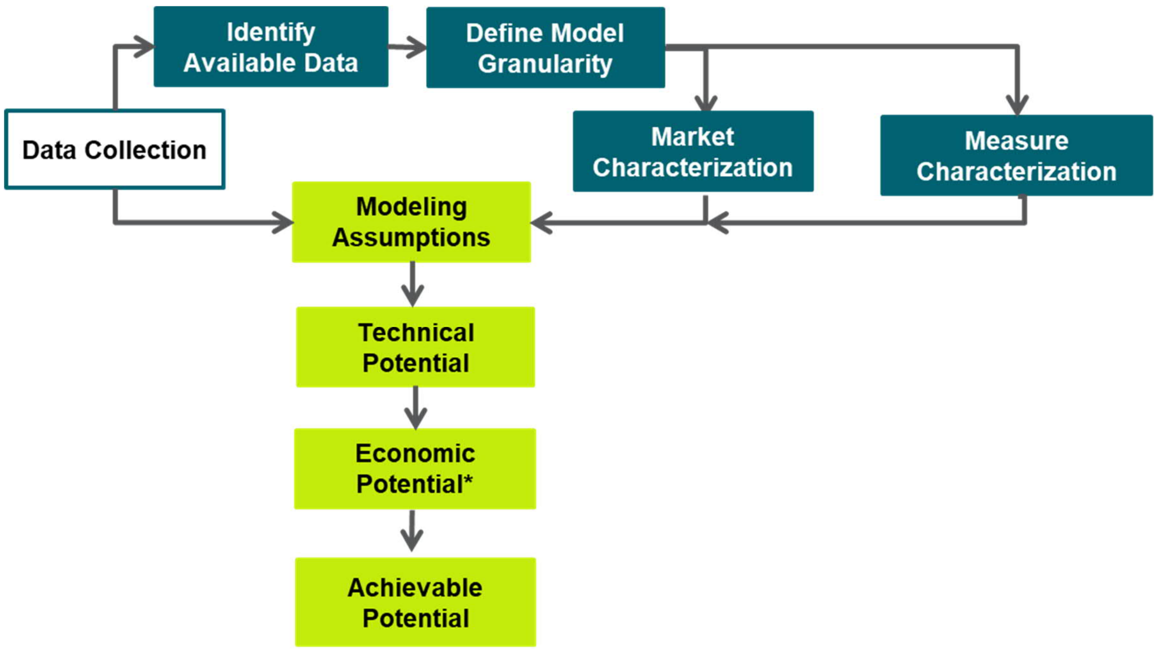
Figure 11. EE Potential Study Inputs



Source: Guidehouse

Calculating achievable potential includes a base year calibration, a Reference case forecast, and full measure characterization. Figure 12 shows how these elements interact to result in the achievable savings potential.

Figure 12. EE Potential Study Methodology



*Not calculated for DR potential

Source: Guidehouse

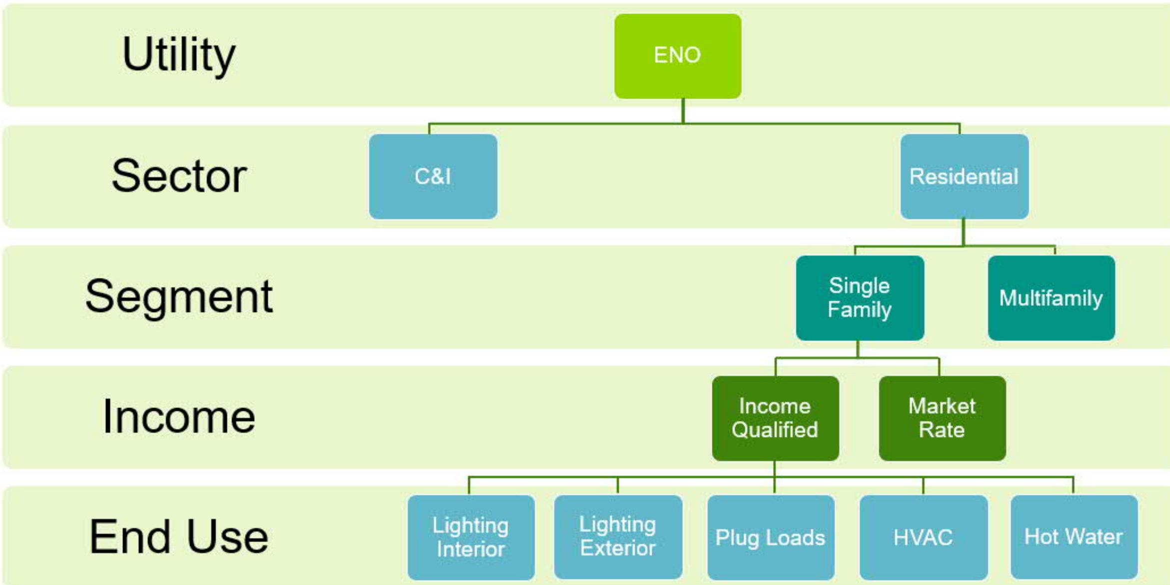
3.1 Market Characterization

Guidehouse's model uses inputs from two workflows: market characterization and measure characterization. This section describes the steps involved in the first workflow, market characterization. The market characterization workflow aims to define the base year profile and Reference case used to calculate potential. Furthermore, the market characterization includes the gathering of global inputs such as inflation rates and avoided cost data.

3.1.1 Base Year Profile

This section describes the approach used to develop the base year (2022) profile of electricity use in ENO's service area, a key input to the potential model. The objective of the base year is to define a detailed profile of electricity sales by customer sector and segment (see Figure 13). The end-use level data is not used in calculating potential but more quality control review of the model outputs. The selected year is the most recent year with actual (not forecast) reported data. The model uses the base year as the foundation to develop the Reference case forecast of peak demand from 2024 through 2043. Given that 2022 is the base year, the analysis also forecasts 2023; however, 2023 is not in the IRP forecast timeline.

Figure 13. Base Year Electricity Profile – Residential Example



Source: Guidehouse

Guidehouse developed the base year profile based on ENO's anonymized 2022 billing and customer account data because it was the most recent year with a fully complete and verified dataset. Where ENO-specific information was unavailable, Guidehouse used data from publicly available sources such as the US EIA CBECS and the US Department of Labor Standard Industrial Classification (SIC) system, in addition to internal Guidehouse data sources. The team used these resources to support ENO's data sources and to ensure consistency.

3.1.2 Defining Customer Sectors and Segments

The first major task to develop the base year electricity calibration involved disaggregating the main sectors—residential and C&I—into specific customer segments. The team selected customer segments based on several factors, including the previous study, TRM characterization, data availability, and sufficient planning level of detail. Table 9 shows the segmentation used for the residential and C&I sectors. The following subsections describe the characterization for the segmentation used for these sectors.

Table 9. Customer Segments by Sector

Residential	C&I	
Single-Family Market Rate	Colleges / Universities	Small Office
Single-Family Income Qualified	Healthcare	Other
Multifamily Market Rate	Industrial / Warehouse	Retail – Food
Multifamily Income Qualified	Lodging	Retail – Non-Food
-	Large Office	Restaurants
-	Schools	

Source: Guidehouse

3.1.3 Residential Segments

After establishing the study sectors and segments, Guidehouse and ENO aligned ENO's data to the segments established in Table 10. The team divided the residential sector into two segments based on consumption: single-family and multifamily. ENO provided Guidehouse with 2022 RASS data, which divided residential customers by household segment. Guidehouse mapped the household segments to the appropriate customer segment (single-family or multifamily). Table 10 provides the descriptions for each residential segment.

Table 10. Residential Segment Descriptions

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

Source: Guidehouse

For the 2024 study, Guidehouse further disaggregated the residential sector into market rate and income qualified. Guidehouse used 2022 American Census Survey data,[19] along with data provided by ENO, to calculate the proportion of residential counts for each income level according to ENO's IQ definition of less than 200% of the Federal Poverty Level.[20]

3.1.4 C&I Segments

Guidehouse combined the commercial, industrial, and government sectors, noted as C&I. Working with ENO, the team divided the C&I sector into 11 customer segments. Table 11 describes each segment. The team selected these C&I segments to be representative of the population of C&I customers in ENO's service area by comparing similar building characteristics such as patterns of electricity use, operating and mechanical systems, and annual operating hours. Generally, the selection of these segments aligned with the New Orleans TRM version 7.0 and the SIC code for the account and kilowatt-hour sales data from ENO. Table 11 provides details on the allocation of the sales and stock data into the C&I sector.

Table 11. C&I Segment Descriptions

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

[19] https://data.census.gov/table/ACSST1Y2022.S1701?q=Federal+Poverty+level+in+New+Orleans+2022

[20] The Federal Poverty Level can be defined by total income per household and depends on the number of residents living in that household. Guidehouse research used base year values and definitions for its analysis, https://www.healthcare.gov/glossary/federal-poverty-level-fpl/.

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

Source: Guidehouse

3.1.5 Defining End Uses

The next step in the base year analysis was to establish end uses for each customer sector. Guidehouse defined these end uses based on common industry frameworks, the TRM, past ENO potential studies, and internal expertise. The end uses in Table 12 are important for reporting and defining savings. For instance, the team uses the categories to report achievable savings with more granularity than at the sector and segment levels. Guidehouse derives these reported end-use savings by rolling up individual EE measures that map to the broader end-use categories. For example, savings from ENERGY STAR refrigerators and freezers are reported under the plug load end use.

Table 12. End Uses by Sector

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

Source: Guidehouse

In addition to the end uses, Guidehouse reports savings for total facility. These savings represent the sum of all the individual end uses and any miscellaneous loads not captured.

3.1.6 Base Year Inputs

This section summarizes the breakdown of stock (households), electricity sales, and End Use Intensities (EUIs) at the sector, segment, and end-use levels. The team used adjusted base year sales as direct inputs to the potential model. Adjusted base year sales indicate that the sales value is converted to gross load minus the EV load. The proliferation of BTM distributed energy resources (DER) is causing shifts to the usage profiles. To properly estimate EE and DR potential, Guidehouse wanted a gross consumption value. Figure 14 provides the calculation methodology for gross consumption.

Figure 14. Calculating Adjusted Base Year Sales

Source: Guidehouse

describes the methodology used to develop these estimates. Table 13 shows the high-level breakdown of electricity sales by sector. Of total electricity sales, 58% comes from the C&I[21] sector with 42% from the residential sector. The DR portion of this study reconciles and derives the breakdown of demand across the sectors, segments, and end uses.[22] For the potential analysis, Guidehouse removes from the C&I sector sales consumption data for streetlighting and any customers who are ineligible to participate in DSM programs.

Table 13. 2022 Base Year Electricity Sector Sales (GWh and Percentage)

Sector	GWh	Percentage
Residential	2,364	42%
C&I	3,274	58%
Total	**5,638**	**100%**

Source: Guidehouse analysis

All other base year inputs are presented in the following sections, with additional details provided in Appendix A.

3.1.6.1 Residential Sector

To define the base year residential sector inputs, Guidehouse began by determining the base year stock using ENO's number of households in the class breakdown, which was an estimated number of households in 2022 using analysis of ENO 2022 RASS data, shown in Table 14.

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

[22] Guidehouse developed the peak demand for the base year using the average peak demand factors from the 2022 sales data for the top 40 weekday hours in the summer season (June-August) consistent with the MISO Business Practice Manual definition. Further description included in Section 4.1.1.2 .

Table 14. 2022 RASS Analysis Percentages

Household Type	Percentage of Total
Single-Family Detached House	60%
Manufactured or Mobile Home	2%
Duplex or Town Home	18%
Apartment or Condominium	17%
Other	3%

Source: ENO RASS data

Base year consumption values used the 2022 reported sales provided by ENO and adjusted per Table 14. Guidehouse used the 2022 analysis of the RASS data to calculate the segment-level base year sales based on the definition of single-family and multifamily provided in Table 10. The “other” category is assumed to be multifamily.

Table 15 shows the base year residential stock, electricity sales, and average electricity usage per home by segment. The EUI by segment comes from the 2022 RASS and was scaled to the sales and stock forecast provided by ENO. It is assumed that the kilowatt-hour per account from RASS is based on actual meter consumption which may or may not include EV charging or solar PV.

As a part of the 2024 study, Guidehouse needed to disaggregate values for IQ and market rate residential customers. Guidehouse used 2022 American Census Survey data,[23] along with data provided by ENO, to calculate the proportion of residential counts for each income level according to ENO’s IQ definition of less than 200% of the Federal Poverty Level.[24] Details of this analysis are provided in Appendix A.

Table 15. Base Year Residential Results

Segment	Income	Stock (Accounts)	Total Electricity Use (GWh)	kWh per Account
Multifamily	IQ	22,558	214	9,488
	Market Rate	24,437	232	
Single-Family	IQ	68,575	971	14,162
	Market Rate	74,289	1,052	
Total or Weighted Average	**-**	**189,859**	**2,469**	**12,592[1]**

[1] This number represents the average annual kilowatt-hour consumption for all households (total electricity use/ total accounts), not the sum of the kilowatt-hour per account for the two segments.

Source: Guidehouse analysis of ENO data

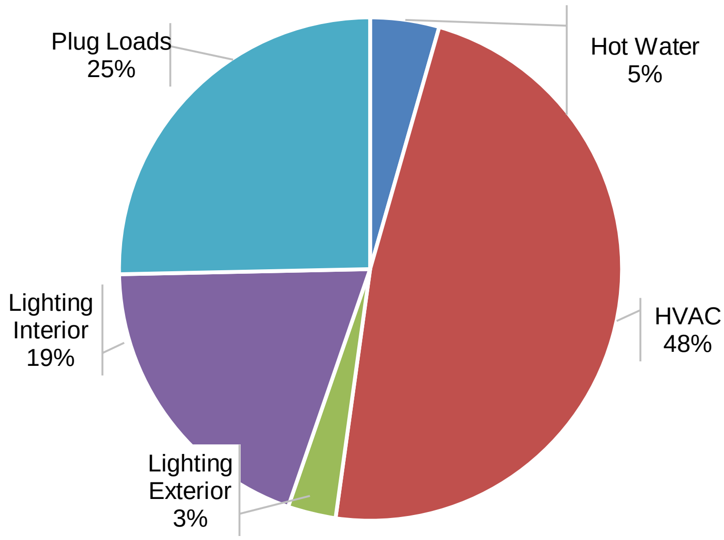
Figure 15 shows the breakdown of base year residential electricity sales by end use and segment. In terms of end uses, lighting, HVAC, and plug loads represent the largest residential end uses and account for 90% of residential electricity sales. HVAC represents the largest

[23] https://data.census.gov/table/ACSST1Y2022.S1701?q=Federal+Poverty+level+in+New+Orleans+2022

[24] The Federal Poverty Level can be defined by total income per household and depends on the number of residents living in that household. Guidehouse research used base year values and definitions for its analysis, https://www.healthcare.gov/glossary/federal-poverty-level-fpl/.

portion of the residential end uses at 48% of the total and includes the sum of heating, cooling, and ventilation. This end-use allocation was based on the allocation used in the ENO 2018 and 2021 IRP potential studies prepared by Guidehouse.[25]

Figure 15. Base Year Residential Electricity Usage by End Use (Percentage, GWh)



Source: Guidehouse analysis

3.1.6.2 C&I Sector

Similar to the residential sector, Guidehouse needed to determine the base year stock (thousands square feet [SF]) by segment, sales (kilowatt-hour) by segment, and EUIs (kilowatt-hour/thousands SF) by end use. Guidehouse followed multiples steps to determine these values for the base year, with details provided in Appendix A.3.

For step 1, Guidehouse used a mapping of SIC codes to customer segment to aggregate ENO's account and billing data to the segment level for the base year 2022. Once the segment mapping was complete, Guidehouse used the segment-level intensities from EIA that were used in the 2018 study for the industrial sector. For commercial and government intensities, Guidehouse took the EIA segment-level intensities[26] used in 2018 and 2021 and adjusted these so that the C&I sector-level intensity equaled the Itron-developed intensity for 2022. Using the resulting intensities, Guidehouse calculated stock (square feet) for each segment by dividing sales by intensity. Table 16 shows the base year C&I stock (SF of floor space), electricity sales, and average electricity usage per SF by segment.

[25] ENO provided Guidehouse end-use breakdown analysis for its load forecast. The residential allocation was like Guidehouse previous estimates. Furthermore, the 2022 RASS did not provide a breakdown of end use EUIs.

[26] Table C.20 Electricity consumption and conditional energy intensity by climate zone. Guidehouse used the hot/very hot climate zone designation, https://www.eia.gov/consumption/commercial/data/2018/ce/xls/c20.xlsx.

Table 16. Base Year C&I Results

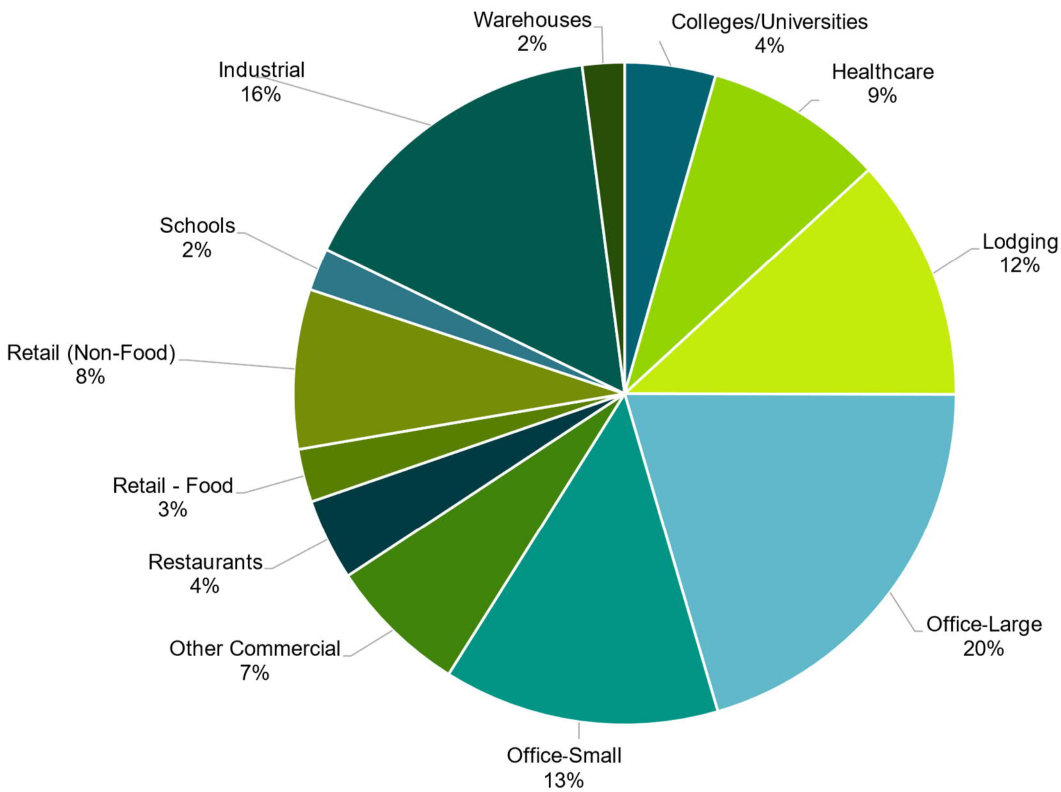
Segment	Stock (1,000 SF)	Total Electricity Use (GWh)	kWh per SF
Colleges / Universities	20,071	149	7
Healthcare	17,522	294	17
Lodging	35,556	398	11
Office-Large	50,083	686	14
Office-Small	44,173	452	10
Other Commercial	11,366	229	20
Restaurants	4,041	134	33
Retail – Food	3,110	87	28
Retail (Non-Food)	21,273	261	12
Schools	9,486	70	7
Industrial	18,940	530	28
Warehouses	14,233	69	5
Total	**249,853**	**3,360**	**-**

Note: Totals may not sum due to rounding.

Source: Guidehouse analysis

Figure 16 shows the breakdown of base year C&I electricity sales by segment. Offices and lodging consume the most electricity, accounting for almost half (46%) of C&I electricity sales.

Figure 16. Base Year C&I Electricity Usage by Segment (Percentage, GWh)



Source: Guidehouse analysis

3.2 Reference Case Forecast

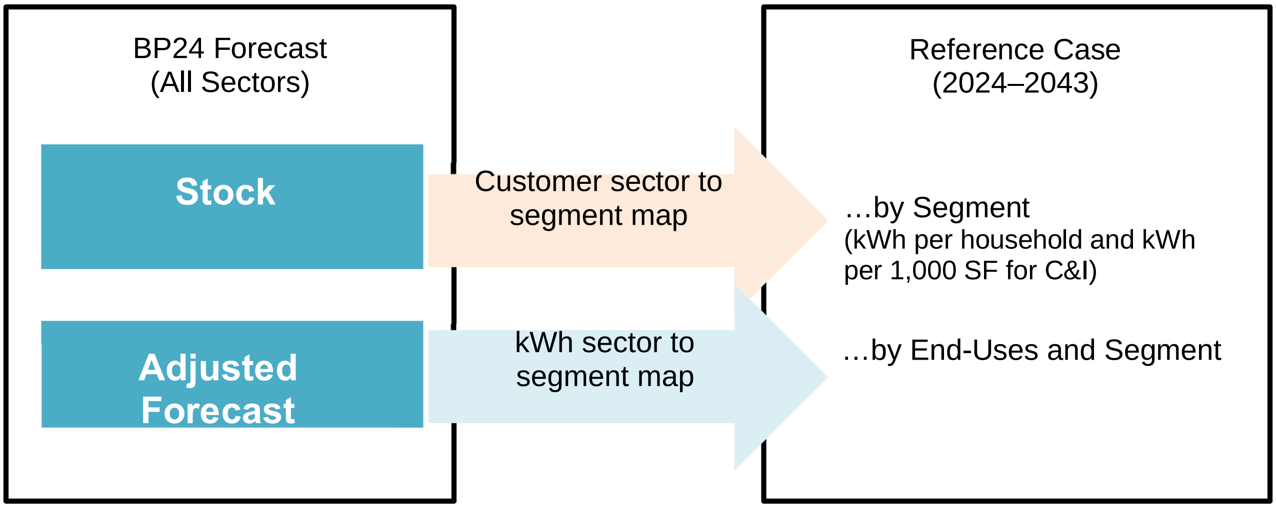
This section presents the Reference case forecast from 2024 to 2043. The Reference case represents the expected level of electricity sales and adjusted consumption over the study period, absent incremental DSM activities (including adoption of EVs) and load impacts from rates, and removing any offset of sales attributed to BTM PV generation, Figure 17 shows.

Figure 17.Adjusted Reference Case Consumption

Source: Guidehouse

The Reference case is significant because it acts as the point of comparison (i.e., the reference) for the calculation of achievable potential cases. Figure 18 illustrates the process Guidehouse used to develop the Reference case forecast. The Reference case uses the BP24 forecast as its foundation and converts that to the required customer segments to develop the residential and C&I forecasts.

Figure 18. Schematic of Reference Case



Source: Guidehouse

Guidehouse constructed the Reference case forecast by using the BP24 sales forecast, adjusting to gross consumption values and then disaggregating from ENO sectors[27] to customer segments. The forecast applies growth rates from ENO's account and load forecasts directly to the base year stock, sales, and EUI values.

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

3.2.1 Residential Reference Case

Guidehouse used the BP24 residential customer count forecast to develop the Reference case for stock. Using the same analysis of RASS data from ENO and described in Section 1.5, Guidehouse disaggregated the residential forecast to the segment level (single-family and multifamily) by multiplying the household segment percentages by the total residential forecast. Table 17 shows the growth in the residential stock forecast from 2023 to 2043. Residential stock decreases at an annual growth rate of -0.08%, from approximately 190,000 accounts in 2023 to around 187,000 accounts in 2043.

As a part of the 2024 report, Guidehouse needed to disaggregate values for IQ and market rate residential customers. Guidehouse used 2022 American Census Survey data,[28] along with data provided by ENO, to calculate the proportion of residential counts for each income level according to ENO's income qualified definition of less than 200% of the Federal Poverty Level.[29]

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

[28] https://data.census.gov/table/ACSST1Y2022.S1701?q=Federal+Poverty+level+in+New+Orleans+2022

[29] The Federal Poverty Level can be defined by total income per household and depends on the number of residents living in that house, Guidehouse research used base year values and definitions for its analysis: https://www.healthcare.gov/glossary/federal-poverty-level-fpl/

Table 17. Residential Reference Case Stock Forecast (Accounts)

Segment	Type	2023	2043
Single-Family	Income Qualified	68,193	67,493
	Market Rate	73,876	73,118
Multifamily	Income Qualified	22,432	22,202
	Market Rate	24,301	24,052
Total		**188,802**	**186,864**

Note: Totals may not sum due to rounding.

Source: Guidehouse analysis of ENOs residential load forecast

Guidehouse followed a similar methodology for sales, using ENO's forecasting. The team used the BP24 sales forecasts and disaggregated to the segment level using the class breakdowns adjusted for energy use, as Section 3.1 describes. Finally, Guidehouse used the end-use proportion forecast from the previous study. Appendix A details this process.

3.2.2 C&I Reference Case

Like the residential Reference case, Guidehouse built the C&I Reference case based on the BP24 sales forecast from ENO with adjustments for a gross consumption value. Appendix A.3 describes the process used to develop the C&I stock forecast.

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

To forecast the stock, Guidehouse developed escalators using the sales forecast and the Itron-developed intensity forecast. For non-industrial segments, Guidehouse divided the sales forecast by the Itron intensity forecast and converted the resulting time series into an escalation factor. For industrial segments, Guidehouse escalated stock based on the forecast number of customers. Then the escalation factors were applied to the base year stock to develop the Reference case forecast through 2043. Table 18 shows the results of the Reference case analysis.

Table 18. C&I Reference Case Stock Forecast (Thousands SF)

Segment	2023	2043
Colleges / Universities	19,686	24,641
Healthcare	17,186	21,511
Lodging	34,875	43,653
Office-Large	49,122	61,486
Office-Small	43,326	54,231
Other Commercial	11,148	13,954
Restaurants	3,963	4,961
Retail – Food	3,050	3,818

Segment	2023	2043
Retail (Non-Food)	20,865	26,117
Schools	9,304	11,646
Industrial	19,507	21,431
Warehouses	13,960	17,474
Total	**245,993**	**304,924**

Note: Totals may not sum due to rounding.

Source: Guidehouse analysis

Guidehouse used the 2018 and 2021 end-use proportions to distribute energy use among end uses.

3.3 EE Measure Characterization

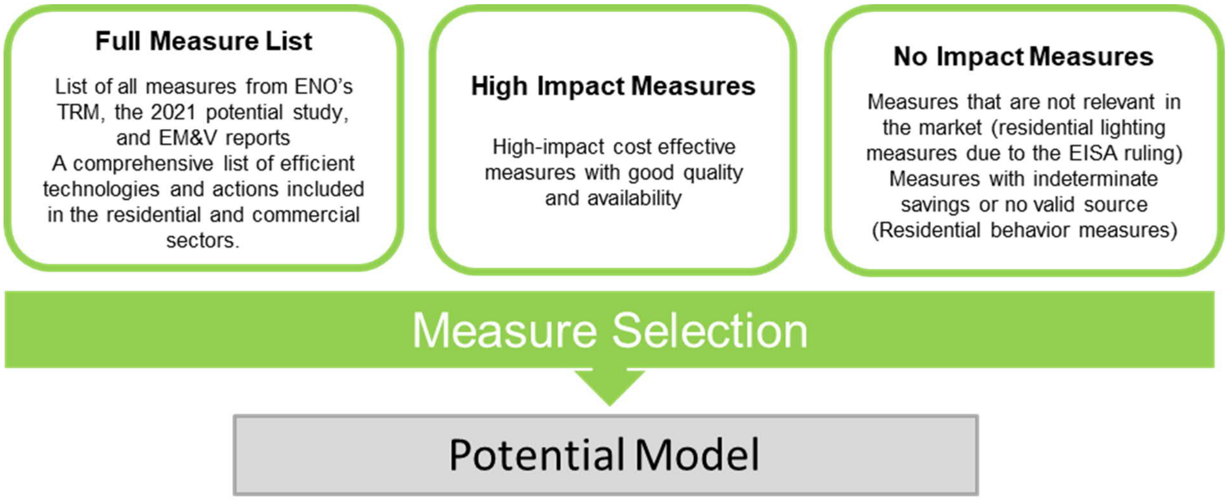
Guidehouse characterized 128 measures across ENO's residential and C&I sectors. While finalizing the measure list, the team prioritized high-impact, cost-effective measures with good data quality and availability.

3.3.1 Measure List

Guidehouse developed a thorough list of EE measures likely to contribute to achievable potential. To identify EE measures with the highest expected economic impact, the team used the measure list from the 2021 ENO potential study as the basis and updated it with measures in the New Orleans Energy Smart (ES) TRM version 7.0, current ENO ES program offerings, and potential model measure lists from other states. The team supplemented the measure list using secondary data from publicly available sources such as TRMs from various US regions, including California, Illinois, and the mid-Atlantic. Guidehouse prioritized measures in existing ENO ES programs based on data availability for appropriate characterization and the measures most likely to be cost-effective. The team worked with ENO to finalize the measure list and ensure it contained technologies viable for future ENO program planning activities. Guidehouse removed 16 measures from the 2021 study and added two new ones. One set of measures removed included residential lighting measures to reflect the impacts of the updated EISA standards.[30] The other set was behavior-based programs that have low savings and most likely will not be included in future portfolios. Figure 19 shows the process Guidehouse implemented to finalize the measure list.

[30] In 2022, the DOE released its two final rules (Federal Register: Energy Conservation Program: Backstop Requirement for General Service Lamps (federalregister.gov) and Energy Conservation Program: Energy Conservation Standards for General Service Lamps pertaining to General Service Lamps (GSLs) and their definitions (2022-05-09 Energy Conservation Program: Definitions for General Service Lamps; Final rule (Regulations.gov). The DOE finalized the rules, which expand the definition of GSLs to include reflectors and candelabras that were previously exempt and that all GSLs must meet a 45 lumen/watt minimum efficiency.

Figure 19. Measure Screening Process



Source: Guidehouse

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

- **Residential and commercial behavior measures:** Guidehouse retained only Home Energy Reports, Building Benchmarking, and Retrocommissioning as the behavior measures applicable to the ENO service area. Other measures, such as Building Energy Information Management System, Business Energy Reports, Web-based Real-time Feedback, Large Residential Competitions, and Prepay Electricity Bills were removed as these measures did not have adequate and reliable data to continue supporting the characterization or were no longer deemed relevant in the ENO market.

- **Industrial measures:** ENO reported that its industrial energy use is relatively low compared with the commercial and residential sectors. Guidehouse retained the industrial measures from the 2021 potential study and did not add any new industrial measures. The team aggregated the industrial sector potential with the commercial sector potential.

3.3.2 Measure Characterization Key Parameters

The EE measure characterization involved defining nearly 50 individual parameters for each measure included in this study. This section defines the top 14 parameters and how each influences the technical and economic (and therefore achievable) potential savings estimates. Table 19 includes parameters used to qualitatively define each characterized measure.

Table 19. EE Measure Characterization Parameter Definitions

Parameter Name	Definition	Example
Baseline Measure	Existing inefficient equipment or process to be replaced.	Baseline storage water heater
EE Measure	Efficient equipment, process, or project to replace the baseline.	HP Water Heater (HPWH)

Parameter Name	Definition	Example
Measure Lifetime	Lifetime in years for the base and energy efficient technologies. Base and energy efficient lifetimes only differ in instances where the two cases represent inherently different technologies, such as solar water heaters compared with a baseline of regular storage water heaters.	Baseline storage water heater: 10 years HPWH: 10 years
Measure Costs	Calculated in two ways. Either the incremental cost is the full installation cost (typically for retrofit applications) or the incremental cost is calculated between the assumed baseline and efficient technology using the following variables: • Base Costs of the base equipment, including both material and labor costs • Energy Efficient Costs of the energy efficient equipment, including both material and labor costs	Incremental cost of HPWH = 1050 per water heater
Replacement Type	Identifies when in the technology or building's life an efficiency measure is introduced. Replacement type affects when in the potential study period the savings are achieved as well as the duration of savings and is discussed in greater detail in Section 2.1.4.1	Retrofit (RET), replace-on-burnout (ROB), and new construction (NEW)
Annual Energy Consumption / Savings	Annual energy consumption in electricity (kWh) and demand (kW) for each baseline and EE measure or energy savings if that is available.	HPWH: 882.75 kwh savings
Unit Basis	Normalizing unit for energy, demand, cost, and density estimates.	Per widget (e.g., water heater, dryer, clothes washer), per square foot, per hp, per kWh consumed
Scaling Basis	Unit used to scale the energy, demand, cost, and density estimate for each measure according to the Reference forecast.	Per residential household, per kwh consumption per 1,000 square feet of commercial area, etc.
Sector and End Use Mapping	The team mapped each measure to the appropriate end uses, customer segments, and sectors across ENO's service area. Section 2.1.1 describes the breakdown of customer segments within each sector.	HPWHs are mapped to the hot water end use for all residential segments
Measure Density	Used to characterize the occurrence or count of a baseline or EE measure, or stock, within a residential household or within 1,000 square feet of a commercial building. This	1.02 water heaters per home

Parameter Name	Definition	Example
	parameter was not defined for industrial measures.	
EE Saturation	Fraction of the residential housing stock or commercial building space that has the efficiency measure installed each year. For the industrial sector, saturations are based on energy consumption.	11% of all water heaters are tankless water heaters, so efficient saturation of tankless water heaters is 11%
Technical Suitability	Percentage of the base technology that can be reasonably and practically replaced with the specified efficient technology.	Ground source HPs have a technical applicability of less than 1.0 because their installation may not be feasible for 100% of the sites
Competition Group	Identifies measures competing to replace the same baseline density to avoid double counting of savings. Section 2.1.4.1 provides further explanation on competition groups.	Efficient tankless water heater, solar water heater, or an HPWH can replace an inefficient storage water heater, but not all three of them

Source: Guidehouse

3.3.3 Measure Characterization Approaches and Sources

This section provides approaches and sources for the main EE measure characterization variables. Table 20 provides the sources by input type.

Table 20. EE Measure Characterization Input Data Sources

Measure Input	Data Sources
Measure Costs, Measure Life, Energy Savings	• New Orleans ES TRM version 7.0 • ES program tracking data • 2021 ENO potential study data • Engineering analyses • Other TRMs • Guidehouse measure database and previous potential studies
Fuel Type Applicability Splits, Density, Baseline Initial Saturation, Technical Suitability, End-Use Consumption Breakdown	• ENO 2022 RASS • ES program tracking and participation data • Guidehouse's previous potential studies
Codes and Standards	• Local building codes

Source: Guidehouse

3.3.3.1 Energy Savings

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

1. **New Orleans TRM calculations:** The New Orleans ES TRM version 7.0 was the primary source for unit energy savings calculations. The TRM provided deemed (default) savings values for the majority of the EE measures in the study.
2. **Standard algorithms:** Guidehouse used standard algorithms for unit energy savings calculations for most EE measures not contained in the New Orleans TRM. To supplement that data, the team used ENO ES Program Evaluation Reports, other relevant TRMs such as the Illinois and Mid-Atlantic TRMs, and DOE Appliance Standards and Rulemaking supporting documents.
3. **Engineering analysis and engineering studies:** Guidehouse used engineering algorithms to calculate energy savings for any EE measures not included in the New Orleans TRM or other TRMs. The team also referenced established engineering studies with savings estimates in the absence of engineering algorithms. The team used its internal expertise with potential studies to calculate energy savings for measures that were not a part of the New Orleans TRM version 7.0.

3.3.3.2 Peak Demand Savings

Peak demand savings were either from the New Orleans ES TRM version 7.0 or calculated by dividing the annual energy use by the annual hours of use and then multiplying by a coincidence factor. The coincidence factor is an expression of how much of the equipment's demand occurs during the system's peak period. According to the TRM, the defined peak period is the average peak demand savings, Monday-Friday, non-holidays from 4 p.m.-5 p.m. in June, July, and August.

3.3.3.3 Incremental Costs

New Orleans ES TRM version 7.0 was the primary source for incremental cost information. The team used other publicly available cost data sources such as the California, Illinois, and the Mid-Atlantic TRMs, ENERGY STAR, and US DOE Appliance Standards and Rulemaking for EE measures where cost information was not available in the ENO TRM.

3.3.3.4 Densities

For the residential density values, the team used the ENO 2022 results to extract home square footage by housing type, space heating and cooling system splits, density, and saturation values for EE measures such as dishwashers, clothes washers, dryers, refrigerators, thermostats, windows, attic insulation, central ACs and room ACs. The team cross tabulated the data for each housing type to get these values for single-family and multifamily segments. As this cross tabulation was not available for the IQ segments, Guidehouse used the single-family values for the IQ single-family values and vice versa for the multifamily segment.

For commercial measures, the density values from the previous potential study were retained for most EE measures. Measure saturations were updated for EE measures available in the ES program data. The Commercial Building Stock Assessment and previous potential studies in other jurisdictions were reviewed for any other overall updates to the saturation values. For water and space heating measures, the fuel type multipliers from the previous ENO potential study were incorporated directly into the measures.

3.3.3.5 Measure Quality Control

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

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

3.4 Potential Estimation Approach

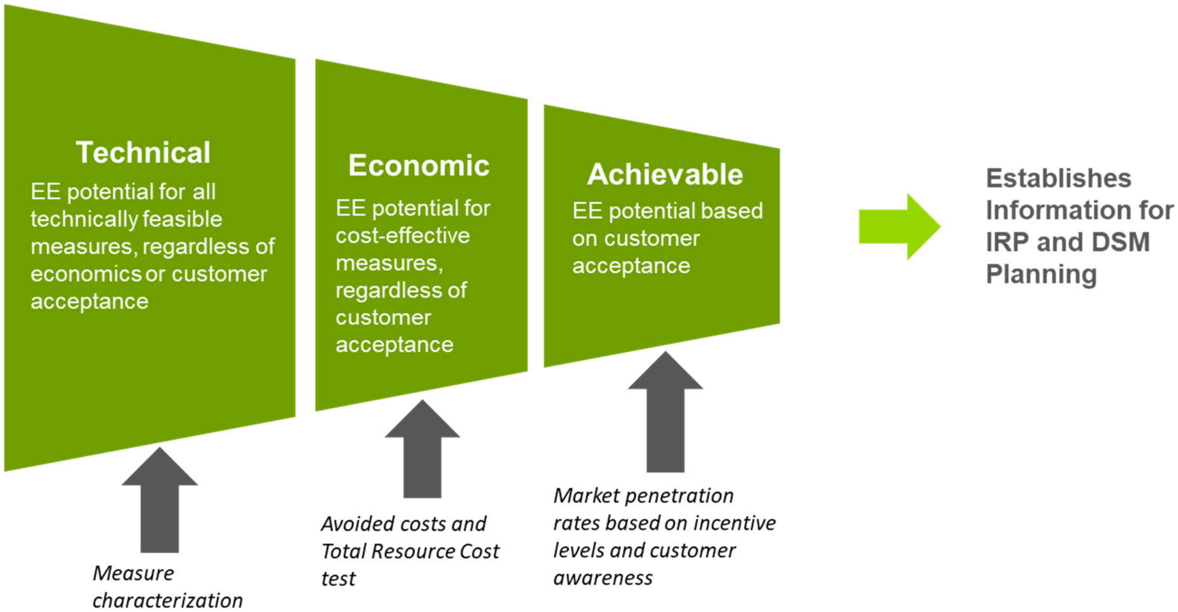
Guidehouse used its proprietary DSMSim potential model to estimate the technical, economic, and achievable savings potential for electricity and demand across ENO's service area. DSMSim is a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics[31] framework. The DSMSim model accounts for different efficiency measures such as RET, ROB, and NEW and the effects the measures have on savings potential. The model then reports the technical, economic, and achievable potential savings in aggregate for the service area, sector, customer segment, end-use category, and highest impact measures.

This study defines technical potential as the total energy savings available assuming all installed measures can immediately be replaced with the efficient measure or technology—wherever technically feasible. This assumption is made regardless of the cost, market acceptance, or whether a measure has failed and must be replaced. Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential but including only those measures that have passed the benefit-cost test chosen for measure screening; in this case, that is a TRC test ratio of 0.9 (for the Reference case).[32] Finally, the achievable potential is analyzed based on the measure adoption ramp rates and the diffusion of technology through the market. Figure 20 provides the methodology overview.

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

[32] Typically, the TRC threshold is set to 1.0. However, due to the drop in avoided energy costs as compared to the 2021 Study, many typical measures were deemed no longer cost-effective. The overall portfolio impact on cost-effectiveness does not change and remains above 1.0.

Figure 20. EE Potential Calculation Methodology



Source: Guidehouse

The study reports gross savings, which do not account for free ridership or spillover impacts, as would net savings. Providing gross potential permits a reviewer to more easily calculate net potential when new information about NTG ratios or changing EUIs becomes available.

Once the potential results and cases are analyzed, the outputs can help define the portfolio energy savings goals, costs, and forecast for alignment into other utility planning efforts, such as the IRP. This study does not examine the impact of future end-user electricity rates on sales or projected EE savings on electricity rates.

3.4.1 Technical Potential

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

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

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

3.4.1.1 Retrofit and Replace on Burnout Measures

Commonly referred to as advancement or early retirement measures, RET measures are replacements of existing equipment before the equipment fails. RET measures also can be efficient processes that are not in place and that are not required for operational purposes. These measures usually incur the full cost of implementation rather than incremental costs to some other baseline technology or process because the customer could choose not to replace the measure and thus would incur no costs.

In contrast, ROB measures—sometimes referred to as lost opportunity measures—are replacements of existing equipment that failed and must be replaced or are existing processes that must be renewed. Because the failure of the existing measure requires a capital investment by the customer, the cost of implementing ROB measures is always incremental to the cost of a baseline (and less efficient) measure.

RET and ROB measures have a different meaning for technical potential compared with NEW measures. In any given year, the model uses the existing building stock to calculate technical potential.[33] This method does not limit the calculated technical potential to any pre-assumed adoption rate of RET measures. Existing building stock is reduced each year by the quantity of demolished building stock in that year and does not include new building stock added throughout the simulation. For RET and ROB measures, annual potential is equal to total potential, offering an instantaneous view of technical potential. Equation 1 calculates technical potential for RET and ROB measures.

Equation 1. Annual or Total Technical Potential for RET / ROB Measures

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

Where:

- Total Potential: kWh
- Existing Stock:[34] C&I floor space per year or residential households per year
- Measure Density: Widgets per unit of stock
- Savings: kWh per widget per year
- Technical Suitability: Percentage of applicable stock
- Baseline Initial Saturation: Percentage of energy efficient stock

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

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

3.4.1.2 New Construction Measures

The cost of implementing NEW measures is incremental to the cost of a baseline (and less efficient) measure. However, NEW technical potential is driven by equipment installations in new building stock rather than by equipment in existing building stock.[35] New building stock is added to keep up with forecast growth in total building stock and to replace existing stock that is demolished each year. Demolished (sometimes called replacement) stock is calculated as a percentage of existing stock in each year; this study uses a demolition rate of 0.5% per year for residential and C&I stock. New building stock determines the incremental annual addition to technical potential, which is then added to the total from the previous year to calculate the total potential in any given year. Equation 2 and Equation 3 provide calculations of technical potential for new construction measures.

Equation 2. Annual Incremental Technical Potential for NEW Measures

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

Where:

- Annual Incremental NEW Technical Potential: kWh
- New Stock:[36] C&I floor space per year or residential households per year
- Measure Density: Widgets per unit of stock
- Savings: kWh per widget per year
- Technical Suitability: Percentage of the total baseline measures that could be replaced with the efficient measure. Occupancy sensors have a technical applicability of less than 1.0 because these are only practical for interior lighting fixtures that do not need to be on at all times.

Equation 3. Total NEW Technical Potential

$$\textit{Total NEW Technical Potential} = \sum_{YEAR=2024}^{YEAR=2043} \boldsymbol{Annual\ Incremental\ Technical\ Potential_{YEAR}}$$

3.4.1.3 Competition Groups

Guidehouse's modeling approach recognizes that some efficient technologies will compete against each other in the calculation of potential. The study defines competition as an efficient measure competing for the same installation as another efficient measure. For instance, a consumer has the choice to replace an air source HP with a more efficient air source HP or a ground source HP, but not both. These efficient technologies compete for the same installation.

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

- Competing efficient technologies share the same baseline technology characteristics, including baseline technology densities, costs, and consumption.

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

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

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

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

3.4.2 Economic Potential

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

Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential but including only those measures that have passed the benefit-cost test chosen for measure screening (in this study, the TRC test, as per the Council's IRP rules). The TRC ratio for each measure is calculated each year and compared against the measure-level TRC ratio. A measure with a TRC ratio greater than or equal to 1.0 is a measure that provides monetary benefits greater than or equal to its costs. If a measure's TRC meets or exceeds the threshold, it is included in the economic potential. However, for this study, the TRC screening threshold has been selected to be below a 1.0 while ensuring that the portfolio TRC would be at 1.0 in aggregate. Furthermore, measures installed because of programs targeting IQ residential customers do not have a TRC requirement. Therefore, there is no TRC screening threshold for IQ measures for the IQ portion of the residential sector.

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

Equation 4. Benefit-Cost Ratio for the TRC Test

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

Where:

- PV( ): The present value calculation that discounts cost streams over time
- Avoided Costs: The monetary benefits that result from electric energy and capacity savings—e.g., avoided or deferred costs of infrastructure investments and avoided long-run marginal cost (commodity costs) due to electric energy conserved by efficient measures

- Externalities: The monetary or quantifiable benefits associated with greenhouse gas reductions (i.e., the market cost of carbon)
- Incremental Cost: The measure cost as defined (see definition in Section 3.3.3.3)
- Admin Costs: The administrative costs incurred by the utility or program administrator (excluding incentive costs paid to participants)

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

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

3.4.3 Achievable Potential

Achievable market potential further considers the likely rate of DSM resource acquisition, given factors such as the rate of equipment turnover (a function of a measure's lifetime), simulated incentive levels, consumer willingness to adopt efficient technologies, word-of-mouth effects that increase awareness in customers, and the likely rate at which marketing activities can facilitate technology adoption. The adoption of DSM measures can be broken down into calculation of the equilibrium market share and calculation of the dynamic approach to equilibrium market share, as discussed in more detail below.

Achievable potential differs from program potential because achievable potential does not specifically consider the various delivery mechanisms that can be used by program managers to tailor their approach depending on the specific measure or market. Rather, achievable potential represents a high-level assessment of savings that could be achieved over time, factoring in broader assumptions about customer acceptance and adoption rates that are not dependent on a specified program design. Additional effort is typically undertaken by program designers, using the directional guidance from a market potential study, to develop detailed plans for delivering EE programs. Achievable potential in this report relies on a TRC measure screen for cost-effectiveness, with the threshold set at a TRC of 0.90 for the majority of measures (and those that are targeting IQ with no TRC threshold), intended to reflect a target portfolio-level TRC of 1.0.

Table 21 summarizes the key methodology considerations and decision points informing the analysis in this report. Guidehouse decided upon this methodology through discussions with

ENO about which approach best serves the objective of the study to understand achievable potential.

Table 21. EE Achievable Potential Methodology Overview

Methodology Parameters	Approach
Benefit-cost test screen	Use the TRC as the primary screen for economic and achievable potential.
Diffusion parameters	Adjust diffusion parameters referencing ranges recommended by industry standard data sources to produce savings that are reasonably aligned with ENO's sector-level historical achievements.
Budget constraints	Do not apply budget constraints.
Incentive strategy	Set incentive levels equal to historical program levels where applicable and 50% of incremental costs.
Treatment of administrative costs	Include program-level incentive to administrative cost ratios, benchmarked to historical performance, that scale administrative costs with calculated incentive budget.
NTG	Develop achievable potential estimates using gross savings, which allows for post-processing analysis of the savings with an NTG other than 1.0.
Re-participation	Assume 100% of measures participate as an efficient measure at the end of the measure life.

Source: Guidehouse

3.4.4 Calculation of Equilibrium Market Share

The equilibrium market share can be thought of as the percentage of individuals choosing to purchase a technology provided those individuals are fully aware of the technology and its relative merits (e.g., the energy-saving and cost-saving features of the technology). For DSM measures, a key differentiating factor between the base technology and the efficient technology is the energy and cost savings associated with the efficient technology. Of course, that additional efficiency often comes at a premium in initial cost. This study calculates an equilibrium market share as a function of the payback time of the efficient technology relative to the baseline technology. In effect, measures with more favorable customer payback periods after the incorporation of incentives will have higher equilibrium market share, which reflects consumers' economically rational decision-making. While such approaches certainly have limitations, these are nonetheless directionally reasonable and simple enough to permit estimation of market share for the hundreds of technologies appearing in most potential studies.

To inform this study, the team used equilibrium payback acceptance curves that Guidehouse developed using primary research from 2015. To develop these curves, Guidehouse relied on surveys of residential and C&I customers. These surveys presented decision makers with numerous choices between technologies with low upfront costs and high annual energy costs, and measures with higher upfront costs and lower annual energy costs. Guidehouse fitted generalized logit models to customer willingness to pay survey results by technology cost bin and segment to develop the set of curves, which are used in this study.

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

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

4. DR Approach and Data

Guidehouse prepared a DR potential assessment for ENO's electricity service area from 2024 to 2043 as part of the DSM potential study. The objective of this assessment was to estimate the potential for using DR to reduce customer loads during peak demand during summer periods.

Guidehouse identified and analyzed a suite of DR options for potential implementation in ENO's service area based on what ENO currently offers and similar program offers in other jurisdictions, including:

1. **Direct Load Control (DLC):** This program controls water heating and cooling loads for residential customers using either a DLC device (switch for water heaters only) or a programmable controlling thermostat (PCT). For AC control, this option represents the EasyCool Bring Your Own Thermostat (BYOT) program that ENO offers to residential customers.
2. **C&I Curtailment:** This program represents the ES Large Commercial DR program that ENO currently offers, where large commercial customers agree to reduce load by a specific amount when called and get paid an incentive based on performance.
3. **Dynamic Pricing:** This program encourages load reduction through a Critical Peak Pricing (CPP) tariff, with a 6:1 critical peak-to-off-peak price ratio. All customer types are eligible to participate.
4. **Peak Time Rebate (PTR):** This program represents ENO's planned opt-in PTR offer to residential customers. ENO could call PTR events year-round. Enrolled customers receive a $/kWh rebate on the amount of energy reduced during events over the baseline energy use. The customer participation pathway for this option is designed to integrate with existing customer engagement and behavioral EE customer offerings.
5. **BTM Storage (BTMS):** This program triggers power dispatch from BTM battery storage systems that are grid-connected during peak load conditions. Battery dispatch helps reduce net system load during DR event periods.
6. **EV Managed Charging (Bring Your Own Charger [BYOC]):** ENO offers a BYOC program that rewards customers for shifting their EV charging load to off-peak hours. This program would be open to all EV customers with Level 2 chargers.

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

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

- **Characterize the Market:** Segment ENO's customer base into customer classes eligible to participate in DR programs.
- **Develop Baseline Projections:** Develop baseline projections for customer count and peak demand over the 20-year forecast period.
- **Characterize DR Options:** Define DR program options and map these to applicable customer classes.
- **Develop Model Inputs for Potential and Cost Estimates:** Develop participation, load reduction, and cost assumptions that feed the DRSim model.
- **Analyze Cases:** Estimate DR potential and associated implementation costs for the Low case and High case relative to the Reference case.

4.1 Market Characterization for DR Potential Assessment

Market characterization was the first step in the DR potential assessment process. Table 22 presents the different levels of market segmentation for the DR potential assessment, which are based on Guidehouse's examination of ENO's rate schedules, and the customer segments established in the EE potential study. The team finalized the market segmentation for the DR potential assessment in consultation with ENO.

The methodology Guidehouse used to segment the market at these levels is described below. Government customers are included as part of the C&I sector. As in prior studies, savings potential from streetlighting is not included in this study.

Table 22. Market Segmentation for DR Potential Assessment

Level	Description
Level 1: Sector	• Residential • C&I • EVs

Level 2: Customer Class	• Residential
	• C&I customers by size based on maximum demand values:
	  o Small C&I: <= 100 kW maximum demand
	  o Large C&I: >100 kW maximum demand
	• EVs

Level 3: Customer Segment	• Residential
	• C&I customer segments
	  o Colleges/Universities
	  o Healthcare
	  o Industrial/Warehouse

Level	Description
	- Lodging - Office – Large - Office – Small - Other - Restaurants - Retail – Food - Retail – Non-Food - Schools - EVs

Source: Guidehouse

Guidehouse first segmented customers into residential and C&I. Electric Vehicles (EVs) were considered as its own sector and segment. For residential, the team combined single-family and multifamily customers into a single residential category because DR program and pricing offers are typically not distinguished by dwelling type. Furthermore, there is no distinction between IQ and market rate residential program participants.

Next, Guidehouse segmented C&I customers into two sizes (small and large based on a 100 kW maximum demand threshold) and further segmented these into customer segments.[37] This cutoff value was determined in consultation with ENO and is aligned to ENO's EE programs when there is a specific offer to the small business segment. To determine the size cutoff, the team requested 2022 account-level maximum billed demand data from ENO. 2022 was chosen as the base year because it was the most recent year with a fully complete and verified dataset. However, the account-level maximum demand data was not available as part of this study's data request. Therefore, Guidehouse used the segment-level small/large split from the 2021 potential study.

The team mapped the SIC codes associated with individual accounts to customer segments in the analysis, which is aligned with the segmentation used for the EE analysis in the current study. Then, the team used the split of customers into small and large C&I by customer segment, as previously described, to get small and large C&I customer count splits within each segment. These splits were then used to develop a customer count and sales forecast by customer class and segment for the DR study. This segmentation is necessary because the type of DR program offer varies by customer size.

4.1.1 Baseline Projections

4.1.1.1 Customer Count Projections

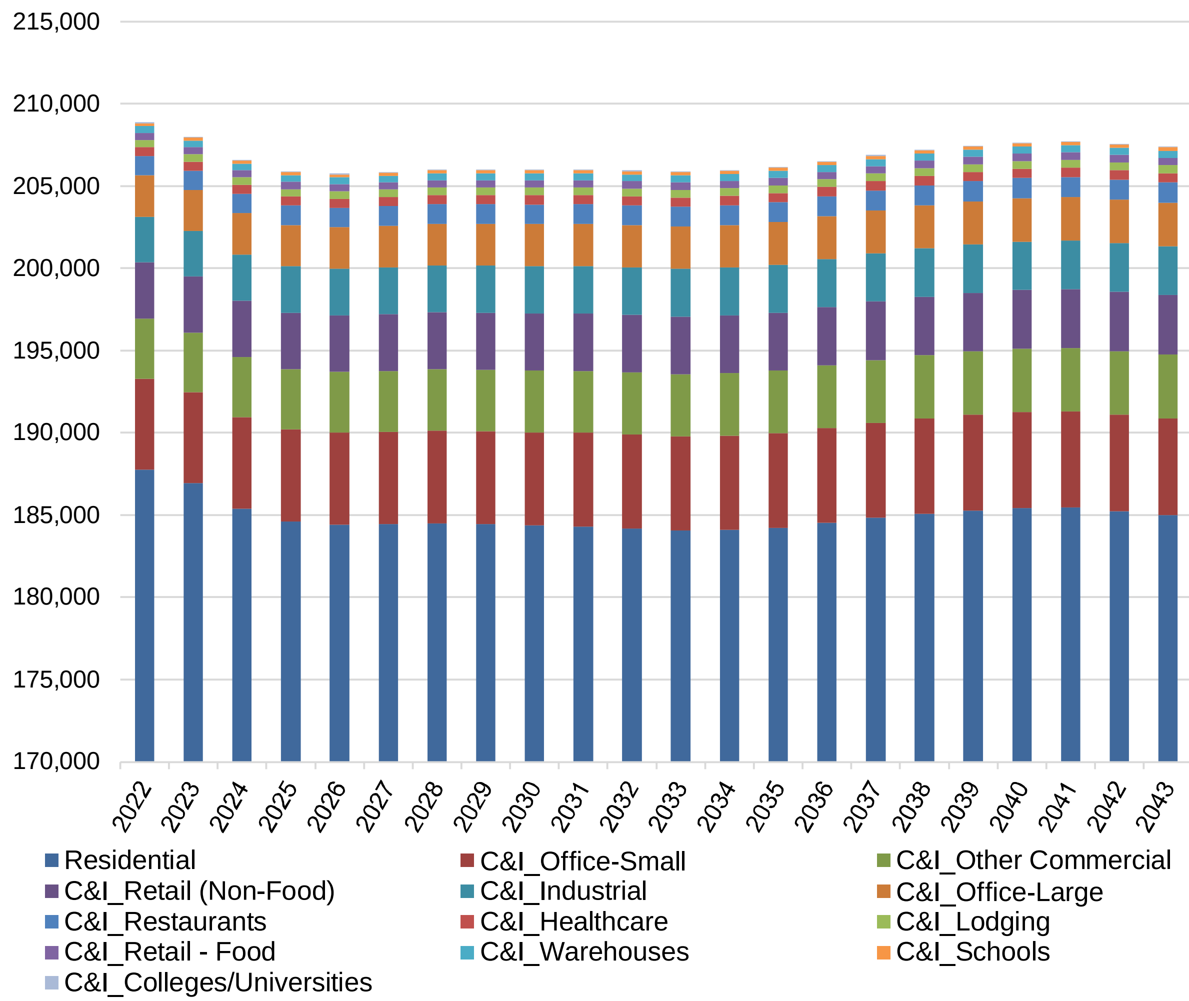
Guidehouse applied the split by customer size and segment, as previously described, to the aggregate count forecast by revenue class to produce a customer count forecast by customer class and segment, as described in Table . Commercial, industrial, and government account

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

count forecasts are all combined into C&I count forecasts. The residential sector is kept in aggregate because there is no further segmentation needed for the DR analysis. The underlying assumption in the account count projections is that the split by size and segment within C&I remains the same as the base year (2022) split. This simplifying assumption needs to be made because segment-level account count forecast is not available from ENO.

Figure 21 shows the aggregate customer count forecast by segment only, summed across all customer classes.

Figure 21. Customer Count Projections for DR Potential Assessment



Source: Guidehouse

4.1.1.2 Peak Demand Projections

The approach for developing disaggregate baseline peak demand projections (peak demand projections net of EE) by customer class, segment, and end-use is described here:

1. **Define peak period:** The first step in developing peak demand projections is to define the peak period. This study considered only DR potential for summer peak reduction. Guidehouse used the 8760 system load data to develop the load duration curve and

identified the top 40 system load hours that fit within MISO's defined peak period. Per MISO's business practice manual, "… the expected peak occurs during the summer (June through August) during the hours from 2:00 p.m. through 6:00 p.m."[38] Guidehouse included only the top 40 weekday hours within this window, which is the typical limit for calling summer DR events.

2. **Disaggregate sales forecast by customer class and customer segment:** Guidehouse developed the disaggregate sales forecast by customer class and segment using the same approach previously described for account count projections. The 2022 (base year) sales data by segment is aligned with the data used for EE analysis (obtained by mapping the 2022 SIC code-level sales from ENO to study segment). The size split for sales (small and large C&I) is aligned with the account count size split previously described. The disaggregate sales by size and segment for 2022 is applied to the sales projections by revenue class for forecast years to develop sales projections by size and segment for C&I customers (the underlying assumption is that the 2022 split of sales by C&I segments applies to the rest of the forecast years because the sales forecast from ENO is only at the revenue class level). Residential sales data is treated in aggregate as there is no further segmentation of the residential sector in the DR analysis.

3. **Use 8760 load profiles by revenue class to calculate coincident peak load factors:** Guidehouse received 8760 load profiles by revenue class (residential, commercial, industrial, government) from ENO for 2021 and 2022. Based on the peak period definition, the team calculated the coincident peak load factors according to Equation 5:

Equation 5. Coincident Peak Load Factor

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

As the analysis in the study is done by residential and C&I customer in aggregate, Guidehouse aggregated the hourly demand data for commercial, industrial, and government and determined the coincident peak load factor in aggregate for commercial, industrial, and government revenue classes to obtain C&I peak load factor.

Guidehouse calculated average coincident peak load factors for residential and C&I customers for each year (2021 and 2022) and took the average of the two load factors. Table 23 shows the individual years and aggregate coincident peak load factors at the system level and for residential and C&I sectors.

Table 23. Coincident Peak Load Factors

Year	System/Sector	Peak Load Factor
2021	System	0.710
	Residential	0.627
	C&I	0.793
2022	System	0.604

[38] Midcontinent Independent System Operator, *Business Practices Manual*, Demand Response, Manual No. 026, effective date October 1, 2023, page 20.

Year	System/Sector	Peak Load Factor
	Residential	0.699
	C&I	0.694
Average (2021 and 2022)	**System**	**0.66**
	Residential	**0.66**
	C&I	**0.74**

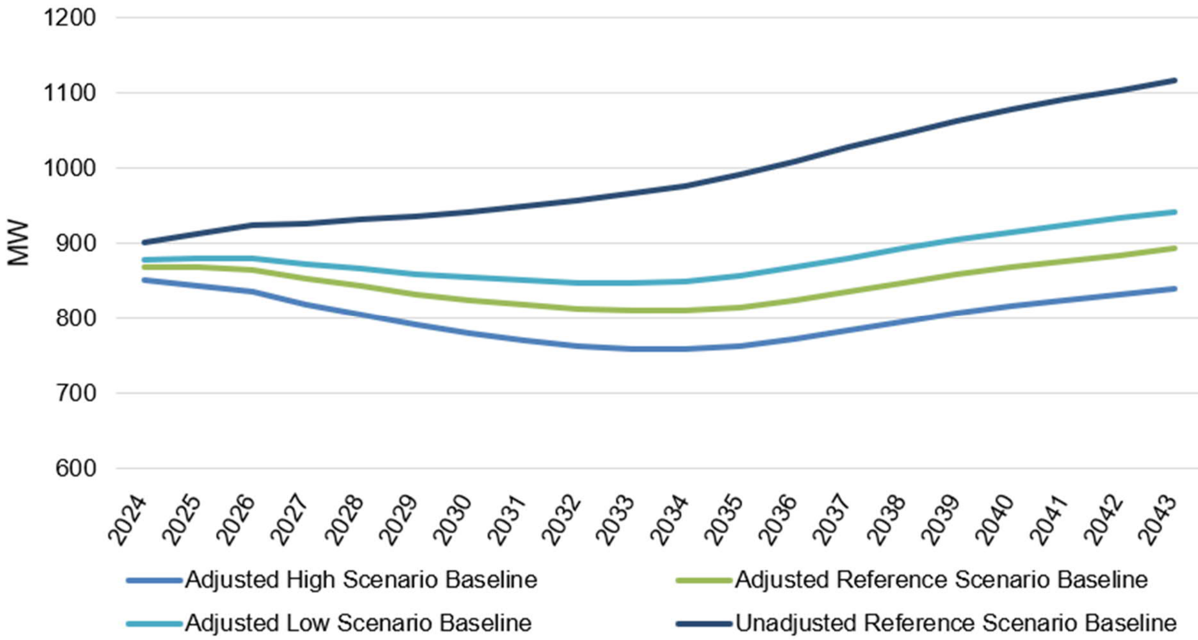
Source: Guidehouse

4. **Apply coincident peak load factors to disaggregate sales projections to estimate peak demand by customer class and segment:** Guidehouse applied the average coincident peak load factors by customer class and segment, developed in step 3 to the disaggregate sales projections by customer class and segment (described in step 2) to develop average coincident summer peak demand projections by customer class and segment. The peak demand by customer class and segment developed through this approach includes only residential, commercial, industrial, and government revenue classes and does not include EVs as the sales used as a starting point to develop the peak demand did not include charging energy consumption.
5. **Develop end-use shares in peak demand:** The DR potential assessment for C&I customers requires end-use breakdown of the peak demand (because the unit savings from DR for C&I are specified as "% of enduse load"). Therefore, Guidehouse needed to develop end-use shares in peak demand. The team referred to the National Renewable Energy Laboratory (NREL) ComStock data[39] for buildings in the region that use the New Orleans International Airport weather station., The ComStock data provides load profiles for different C&I building types. The team mapped the study segments to NREL's building types and used the peak period definition (described in step 1) to determine end-use shares in peak demand for the different C&I segments and building types. Only commercial and government revenue class loads are disaggregated by end use. Industrial segment load is kept at the total facility level and is not disaggregated by end use.
6. **Adjust baseline load for DR potential estimation with EE achievable potential estimates:** As EE leads to permanent load reductions in the baseline load, the baseline load for DR needs to be adjusted with EE potential estimates. Figure 22 shows the disaggregate peak demand projections before and after EE adjustments. The team used the EE savings forecasts for the Reference, Low, and High EE scenarios to develop corresponding baseline peak demand projections for these three scenarios for DR potential analysis. The "unadjusted Reference case baseline" represents the bottom-up disaggregate peak demand projections by customer class and segment, developed through the previously described steps. This projection is adjusted with the EE achievable potential estimates for all three cases (Reference, Low, and High) to derive the downward sloping "adjusted baseline" projections for all three cases. Figure 22 indicates that the baseline peak demand projections progressively decline over time with higher penetration of EE. As Figure 22 illustrates, the baseline demand net of Energy Efficiency is lower in the High case than in the Reference case due to higher energy

[39] https://comstock.nrel.gov/

efficiency savings in High than in Reference. Conversely, for the Low case, the baseline demand for DR is higher than Reference since the energy efficiency savings in Low are lower than in the Reference case, which in turn leads to higher baseline demand for DR.

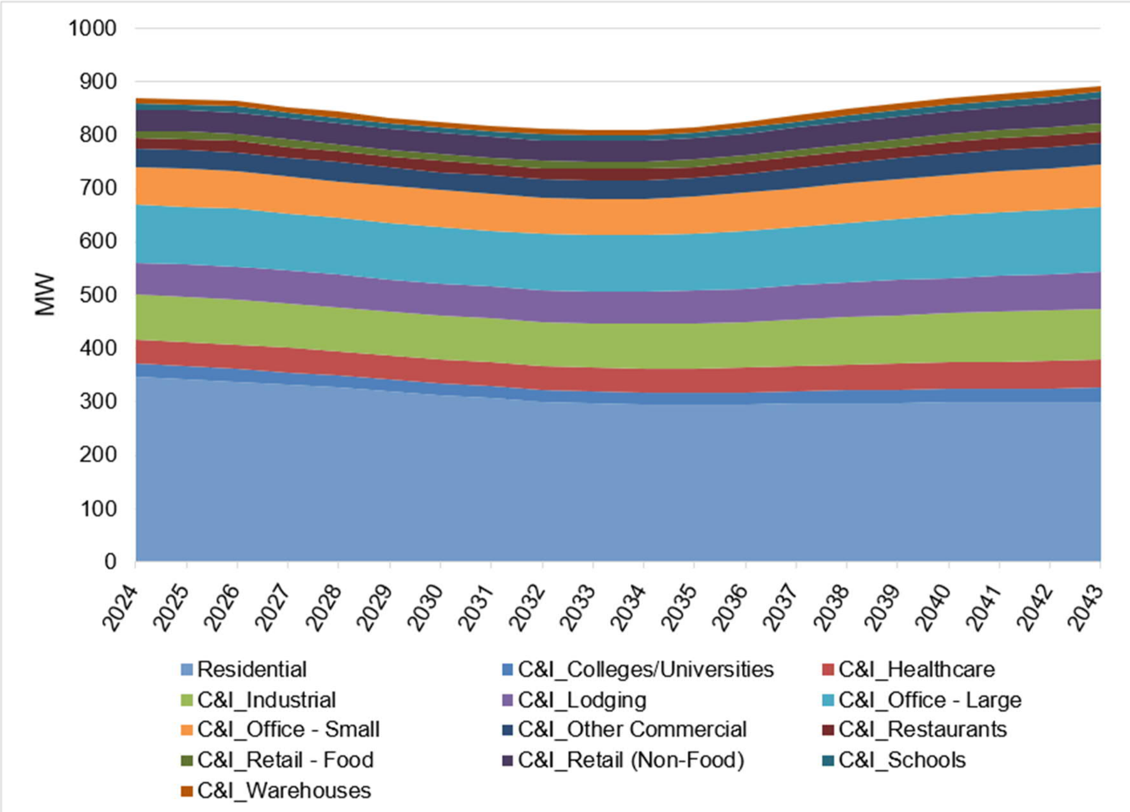
Figure 22. Peak Demand Forecast Comparisons



Source: Guidehouse

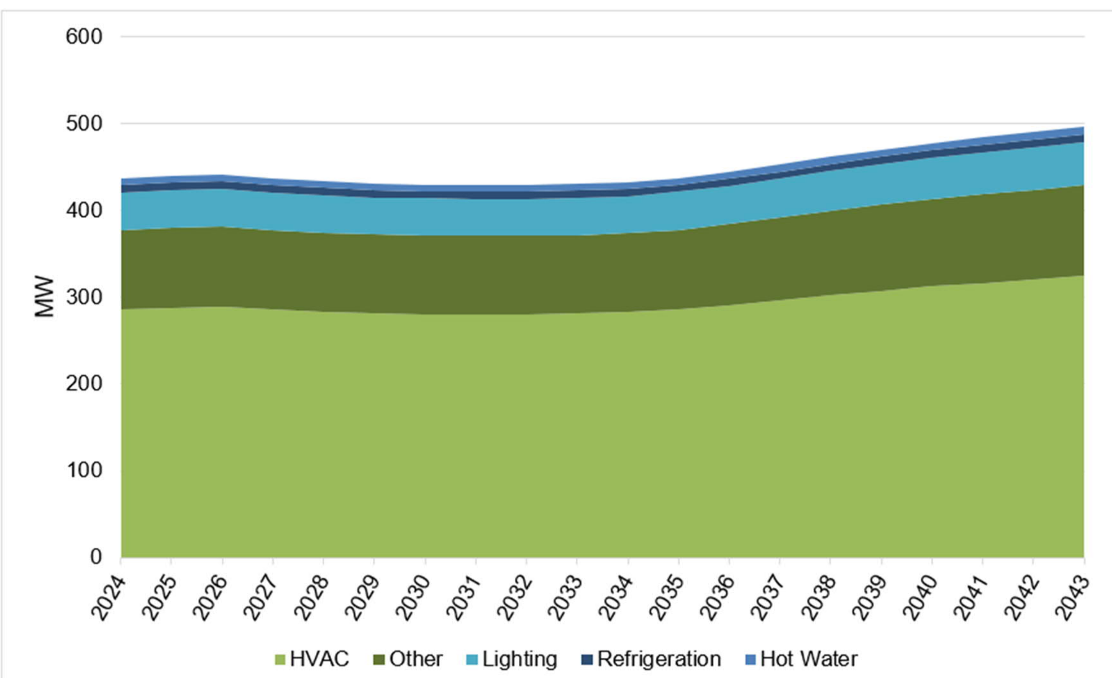
Figure 23 shows the disaggregate peak demand projections by customer segment. Figure 24 shows the disaggregate C&I peak demand by end use for the Reference case, derived from all six steps previously described. The disaggregate peak demand projections establish the foundation for DR potential estimates.

Figure 23. Peak Load Forecast by Customer Segment (MW)



Source: Guidehouse

Figure 24. Peak Load Forecast by End Use for C&I Customers (MW)



Source: Guidehouse

4.2 Descriptions of DR Options

Once the baseline peak demand projections were developed, the team characterized different types of DR options that could be used to reduce peak demand. Table 24 summarizes the DR options included in the analysis. The DR options represent ENO's current DR program offers and those that are commonly deployed in the industry. These programs also align with the Council's IRP rules, which state that DR programs should include those "… enabled by the deployment of advanced meter infrastructure, including both direct load control and DR pricing programs for both Residential and Commercial customer class."

Table 24. Summary of DR Options

DR Option	Characteristics	Eligible Customer Classes	Targeted End Use or Technology
DLC[40] • Thermostat for space cooling • Switch for water heating	Control of cooling load using smart thermostat; control of water heating load using a load control switch	Residential	Cooling, water heating
C&I Curtailment • Manual • Auto-DR enabled	Firm capacity reduction commitment with pay-for-performance ($/kW) based on nominated amount or actual performance	Large C&I	Various load types including HVAC, lighting, refrigeration, and industrial process loads (based on facility type)
Dynamic pricing[41] • Without enabling technology • With enabling technology	Voluntary opt-in dynamic pricing offer, such as CPP	All customer classes	All
BTMS • Standalone battery storage	Dispatch of BTM batteries for load reductions during peak demand periods	Residential[42]	Batteries
EV managed charging (BYOC)	BYOC program that will reward customers for shifting their EV charging load to off-peak hours	EVs	Light Duty Vehicles with L2 chargers

[40] DLC represents the smart thermostat-based EasyCool program offered by ENO to residential customers (switch-based option considered for water heater control).

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

[42] The DR potential assessment from BTM batteries only considered residential batteries. No battery forecast was available from ENO. Guidehouse used the NEM forecast data to project residential BTM batteries paired with solar. However, for C&I, there was no basis to develop battery forecasts and therefore this analysis did not consider DR potential from BTM batteries for C&I customers. Future potential studies could consider this update as and when C&I BTM battery forecast data is available.

DR Option	Characteristics	Eligible Customer Classes	Targeted End Use or Technology
PTR	Opt-in offer that provides a $/kWh rebate to customers for energy reduced during DR events	Residential Small C&I	All

Source: Guidehouse

Each DR option was segmented into several DR suboptions, each of which was tied to a specific end use or control strategy. Table 25 summarizes this segmentation. Detailed descriptions of the different types of DR options follow.

Table 25. Segmentation of DR Options into DR Suboptions

DR Option	DR Suboption	Eligible Customer Classes
DLC	Switch-Water Heating	Residential
	Thermostat-Central AC (CAC)/HP (BYOT)	
	Thermostat-HVAC (BYOT)	
C&I Curtailment	Curtailment-Manual HVAC Control	Large C&I
	Curtailment-Auto-DR HVAC Control	
	Curtailment-Standard Lighting Control	
	Curtailment-Advanced Lighting Control	
	Curtailment-Water Heating Control	
	Curtailment-Refrigeration Control	
	Curtailment-Compressed Air	
	Curtailment-Fans/Ventilation	
	Curtailment-Industrial Process	
	Curtailment-Pumps	
	Curtailment-Other	
Dynamic Pricing (CPP)	Dynamic pricing with enabling tech	Residential, Small C&I, Large C&I
	Dynamic pricing without enabling tech	
BTMS	BTMS-Battery Storage	Residential
PTR	PTR	Residential, Small C&I
EV Managed Charging (BYOC)	EV Managed Charging (BYOC)	Residential (LDVs)

Source: Guidehouse

4.2.1 DLC

This program controls water heating and cooling loads for residential customers using either a DLC device (switch for water heaters only) or a PCT. For AC control, this option represents the EasyCool BYOT program that ENO offers to residential customers. Table 26 summarizes the DLC program characteristics considered in this study.

Table 26. DLC Programs Characteristics

Item	Description
Program Name	DLC
Program Description	• Under space cooling control, this program represents the EasyCool BYOT program in which residential customers purchase and install qualifying connected thermostats on their own or via the ES Online Marketplace and voluntarily enroll these devices in the program. • Switch-based electric water heating load control apply only to residential customers, where ENO would switch off the water heating load during event hours using smart switches. This program is not currently offered by ENO.
Purpose/Trigger	DLC events will be called primarily to meet capacity shortfalls during summer, triggered primarily by a high day-ahead temperature forecast.
Key Program Design Parameters	• Events will be called during peak demand periods in summer (June 1 through September 30), only on non-holiday weekdays • Smart thermostat-based option[43] o Maximum 15 events called during summer o Enrolled customers receive upfront $50 incentive payment, per device, at the time of enrollment, plus $25 each season they participate, starting in the second year they remain enrolled; customers can earn incentives for up to two devices o Eligible thermostats listed in the EasyCool program site o Event notification varies by thermostat provider o Load reduction achieved through a max. 4-degree temperature offset o Event window: 12 p.m. to 8 p.m. o Max. event duration: 4 hours o Customers can opt-out any time at the thermostat, mobile device, or web app • Customers may be precooled prior to an event taking place o Water heating control characteristics (program currently does not exist)
Participation Eligibility	• Residential customers with CAC and HPs • Residential customers with electric water heaters.
Dependent Technology and Metering	**Technology:** Switches control water heating. Smart thermostats control CAC or HPs. **Metering:** Standard meter (no interval meter required). The program can use data loggers on a sample of participants to record interval usage for measurement and verification.

Source: Guidehouse

4.2.2 C&I Curtailment

The C&I curtailment program modeled in the potential assessment represents the ES Large Commercial DR program that ENO currently offers.[44] Under this program, ENO contracts with a DR service provider to deliver a fixed amount of load reduction. Enrolled participants nominate a certain amount of load reduction. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (expressed as $/kW-year) for being on call. Participants are paid based on performance when DR events are called. Only customers with greater than or equal to 100 kW demand qualify for enrollment. Once enrolled, customers are required to fulfill the nominated amount of load reduction when DR events are called. A specific site could curtail a variety of end-use loads depending on the types of business processes. Table 27 describes the C&I curtailment program characteristics considered in this study.

Table 27. C&I Curtailment Program Characteristics

Item	Description
Program Name	C&I Curtailment[45]
Program Description	The Large Commercial DR program (DR program) is a voluntary program that pays incentives to C&I customers for reducing a specified level of load reduction through onsite load reduction equipment. Customers receive fixed $/kW-yr. payment for being on call to deliver load reductions when DR events take place. When DR events are called, customers are paid based on the actual kilowatts reduced during an event against their baseline load. This program is currently being administered by a third party. Participating sites enrolled in the program curtail a variety of end uses (e.g., HVAC, water heating, lighting, refrigeration, process loads), depending on the business type.
Purpose/Trigger	DR events could be triggered by operating, reliability, or economic purposes.[46]
Key Program Design Parameters	• Events will be called during peak demand periods in summer (June 1 through September 30), only on non-holiday weekdays; additionally, events may be called at other times outside the summer season. • Event notification: 24 hours. prior to event via text and email • Incentive: $50/kW for summer; $10/kW for non-summer • There are no performance penalties for opting out at any time before or during an event
Participation Eligibility	Large C&I customers with greater than 100 kW peak demand

[43] Energy Smart, EasyCool, https://enrollmythermostat.com/faqs/entergyno/.
[44] Energy-Smart-Entergy-Large-Commercial-Automated-Demand-Response-Brochure-May-2022-Web.pdf (energysmartadr.com)
[45] Represents the Energy Smart Large Commercial DR program currently offered by ENO.
[46] This study estimates summer peak reduction potential only from this program.

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

Source: Guidehouse

4.2.3 Dynamic Pricing

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

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

The CPP offer requires AMI meters for settlement purposes. Hence, the rate offer is tied to AMI deployment. This study assumes that ENO offers the CPP rate from 2023 onward to account for lead time for rate design and approval before launching the program. Table 28 describes the dynamic pricing program characteristics considered in this study.

Table 28. Dynamic Pricing Program Characteristics

Item	Description
Program Name	Dynamic Pricing
Program Description	Opt-in CPP offer to all customers with a 6:1 critical peak to off-peak price ratio
Purpose/Trigger	• Events are primarily called for economic purposes (high market prices)

Item	Description
	• Events can be called during both summer and winter months • Current study estimates potential for summer peak reduction
Key Program Design Parameters	• Event window: May 1 to September 30 during summer; October 1 to April 30 during winter • Event notification is typically day-ahead • Average event duration assumed to be 4 hours; no more than one event is called in a day; calling events for more than 2 consecutive days may lead to customer dissatisfaction and disenrollment • Annual maximum event hours set at 80-100 hours
Participation Eligibility	All customers
Dependent Technology and Metering	All customers need smart meters for settlement purposes

Source: Guidehouse

4.2.4 BTMS

The Bring Your Own Battery (BYOB) program is offered by ENO with Honeywell. It targets residential customers with existing solar-connected smart battery systems and connects the battery systems to the Enbala Concerto distributed energy resource management system (DERMS) platform currently being used by Honeywell to administer the Large Commercial DR program. Table 29 describes the BTMS program characteristics.

Table 29. BTMS Program Characteristics

Item	Description
Program Name	BTMS
Program Description	BYOB program that targets residential customers with solar-connected battery systems. Batteries are dispatched to address ENO's grid needs and participants are incentivized for allowing ENO to control their batteries and export energy.
Purpose/Trigger	Events are called any time of the year to meet grid needs. Events could be triggered by emergency or reliability needs, economic purposes, and to fulfill operating reserve requirements (spin, non-spin, regulation).
Key Program Design Parameters	• Summer: May 1 to September 30 during summer (current); however, batteries can be dispatched year-round • Average event duration: 2-3 hours per event • Event notification is typically day-ahead or 1-2 hours ahead[47]

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

Item	Description
	• Number of annual events: Can go considerably higher than other programs/technologies because batteries are highly dispatchable; o ENO's proposed pilot is designed to call no more than 15-20 events with a duration between 2-3 hours per event.[48] o However, in future, ENO may be able to dispatch batteries for greater duration than what is specified in the pilot, similar to the MA utilities.[49]
Participation Eligibility	• Residential NEM customers (customers with solar)
Dependent Technology and Metering	All customers need PV-tied batteries with grid interconnection.

Source: Guidehouse

4.2.5 EV Managed Charging – BYOC Program

This passive managed charging program incentivizes customers for off-peak charging. The objective of the program is to shift EV load to off-peak hours, when demands on the electric system are lowest. BYOC leverages existing investments in AMI smart meter infrastructure to monitor customer EV charging behavior. The program is open to any make or model of EV using any Level 2 charger. Sagewell, in coordination with ENO, will recruit, enroll, monitor charging, and issue incentives to participating EV drivers in ENO territory. The pilot will enroll up to 350 participants each year, with cumulative totals of 350 and 750, EVs across the two PYs 2023-24.

This program does not reduce overall kilowatt-hour consumption but can have a significant impact on distribution system health and save ENO customers money by enabling ENO to procure energy at lower off-peak hour costs. EV charging, particularly at 10 kW and above, can negatively impact neighborhood-level power quality and may overload transformers. While immediate transformer failures or damage due to overloading are rare, shortened transformer life can result from frequent overloading and increase the utility operating costs due to premature equipment replacement. Because BYOC effectively shifts high charging rate EV load to off-peak hours every day, it mitigates potential infrastructure stress and can improve neighborhood power quality. Table 30 describes the BYOC program characteristics.

Table 30. BYOC Program Characteristics

Item	Description
Program Name	BYOC
Program Description	ENO provides incentives to customers to shift their EV charging from peak to off-peak periods. All customers with Level 2 chargers are eligible.

[48] "Filing of Entergy New Orleans LLC's Request for Approval of a Demand Response Battery Storage Pilot Program for Program Year 12", March 9, 2022.
[49] National Grid's Connected Solutions sets the maximum number of events at 60, https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-madailydispatchflyer.pdf.

Item	Description
Purpose/Trigger	Events are called any time of the year to meet grid needs. Events could be triggered by emergency or reliability needs, economic purposes, to fulfill operating reserve requirements (spin, non-spin, regulation), and to help address local distribution constraints with progressive increase in EV charging load.
Key Program Design Parameters	This program is not event based. Customers are incentivized to shift their EV charging from peak to off-peak periods.
Participation Eligibility	All vehicles with Level 2 chargers
Dependent Technology and Metering	AMI needed for monitoring of charging and for incentive calculation

Source: Guidehouse

4.2.6 PTR Program

This program represents ENO's planned opt-in PTR offer to residential customers. Per ENO's current pilot design, ENO can call events year-round (limited to a certain maximum number of events) and provide a $/kWh rebate on the amount of energy reduced during events over a customer's baseline energy use.[50] The customer participation pathway for this program is designed to integrate with existing customer engagement and behavioral EE customer offerings and includes customer engagement through email and SMS text messaging. Email communications will notify customers when events are imminent and provide clear recommendations and share tips on actions to reduce energy use during events. Participants also are informed at the end of the event, notifying customers that the event has ended, and an email at the end of the season that informs participants on the amount of energy saved and the incentives earned. Table 31 describes the PTR program characteristics.

Table 31. PTR Program Characteristics

Item	Description
Program Name	PTR
Program Description	ENO provides customers with a $/kWh rebate for reducing energy during events, capped at $50 per year. Enrolled customers receive pre-event, during, and post-event alerts that remind and guide them to behaviorally shift or reduce their variable electric loads to help earn their total potential incentive.
Purpose/Trigger	Events are called any time of the year to meet grid needs. Events could be triggered by emergency or reliability needs, economic purposes, and to fulfill operating reserve requirements (spin, non-spin, regulation).

[50] 2023-2025 Energy Smart DR Plan; Energy Smart, Reduce your energy usage and earn up to $50 cash with the Peak Time Rebate Pilot, https://www.energysmartnola.info/peak-time-rebate-pilot/#:~:text=Reduce%20your%20energy%20usage%20and,periods%20of%20high%20electricity%20usage.

Item	Description
Key Program Design Parameters	• Event duration: Max. of 4 hours • Event notification: 24-72 hours in advance via email • Number of annual events: Max. of 15 events
Participation Eligibility	• Residential – all customers (currently being offered) • Small C&I customers (not currently being offered)
Incentives	• $/kWh incentive with up to a maximum of $50 per year
Dependent Technology and Metering	AMI for baseline energy and reduction measurement

Source: Guidehouse

4.3 Key Assumptions for DR Potential and Cost Estimation

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

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

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

Equation 6. DR Technical Potential

$$\begin{aligned}\textit{Technical Potential}_{\textit{DR Sub Option},\textit{End Use},\textit{Year}} \\ = \textit{Eligible Load}_{\textit{DR Sub Option},\textit{Segment},\textit{End Use},\textit{Year}} \\ * \textit{Unit Impact}_{\textit{DR Sub Option},\textit{Segment},\textit{Year}}\end{aligned}$$

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

Equation 7. DR Achievable Potential

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

In addition to the potential estimates, the team developed annual and levelized costs by DR option and suboption. Guidehouse subsequently assessed the cost-effectiveness of each suboption and DR option in aggregate. Developing annual and levelized costs involves itemizing various cost components, such as program development costs, equipment costs, participant marketing and recruitment costs, annual program administration costs, technology lifetimes, and a discount rate. Table 32 summarizes the variables Guidehouse used to calculate DR potential and its associated costs in this analysis. These variables are discussed further in the following subsections.

Table 32. Key Variables for DR Potential and Cost Estimates

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

Source: Guidehouse

4.3.1 Participation Assumptions and Hierarchy

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

Participation assumptions are developed as "% of eligible customers":

- For the EasyCool program, eligible customers are those with CAC/HP and electric water heating.
- For the BYOT option within DLC, the DR team obtained smart thermostat penetration from the EE study and used that data to inform total number of eligible customers for the BYOT program. The team applied participation assumptions to these eligible customers.

- Residential customers not enrolled in DLC participate in PTR.

- For the C&I curtailment program, for commercial customers with HVAC control, only automated DR is considered based on ENO's current Large Commercial DR program offer. Therefore, customers with EMSs that can be preprogrammed to execute curtailment strategies in response to DR event signals are eligible to participate. In this case, the DR team obtained EMS saturation projections from the EE analysis and used that information to establish eligibility in C&I curtailment DR program participation. In addition to HVAC control using Auto-DR, the analysis also assessed potential available from other end uses such as lighting, water heating, and industrial loads.

  Large C&I customers who are not enrolled in the C&I Curtailment program are eligible to enroll in dynamic pricing.

- Small C&I customers are eligible to enroll in either PTR or Dynamic Pricing.

- For Dynamic Pricing, Guidehouse assumed that the CPP rate is offered to customers once AMI is deployed. Customers not enrolled in DLC, C&I Curtailment, and PTR (based on customer class) are eligible for Dynamic Pricing.

- For the BTMS program, only customers with BTM batteries tied to solar PV can participate and therefore participation in the DR program is tied to battery adoption projections.

- For EV managed charging, customers with Level 2 chargers are eligible; this does not overlap with any of the other DR options.

Table 33 presents the participation hierarchy for this study, whereby achievable participation estimates are applied to eligible customers only. The participation hierarchy presented here is a well-tested approach that has been followed in DR potential studies in other jurisdictions. The participation hierarchy helps avoid double counting of potential through common load participation across multiple programs and is necessary to arrive at an aggregate potential estimate for the entire portfolio of DR programs.

Table 33. Program Hierarchy to Account for Participation Overlaps

Customer Class	DR Options	Eligible Customers
Residential	DLC - Thermostat	Customers with CAC or HPs controlled using smart thermostats
	DLC - Switch	For water heating control: customers with electric water heating
	PTR	Customers not enrolled in DLC
	Dynamic Pricing	Customers not enrolled in DLC and PTR
	BTMS	NEM customers with BTM batteries
	EV Managed Charging	All customers with Level 2 chargers
Small C&I	PTR	All customers
	Dynamic Pricing	Customers not enrolled in PTR
Large C&I	C&I Curtailment	All customers
	Dynamic Pricing	Customers not enrolled in C&I curtailment

Source: Guidehouse

The Low and High scenarios for DR assumed lower and higher participation levels in DR programs than the Reference Case. The Low scenario assumed lower incentive levels than what was assumed for the Reference case and consequently lower levels of program participation. The High scenario similarly assumed higher levels of incentive than the Reference case and consequently higher participation levels in DR. The degree of change in participation with respect to incentives is based on data available from other jurisdictions. For dynamic pricing, which does not have any incentive level associated with it since it is a rate-based offer, the High and Low scenarios assumed higher and lower marketing efforts than the Reference case, which in turn lead to changes in enrollment levels for dynamic pricing when compared with the Reference case.

4.3.2 Unit Impact Assumptions

The unit impacts specify the amount of load that could be reduced during a DR event by customers enrolled in a DR program. Unit impacts differ by suboption because these are tied to specific end uses and control strategies. Unit impacts can be specified either directly as kilowatt reduction per participant or as percentage of enrolled load (as "% of end use" for some sub-options or as "% of total load" for other suboptions): [51]

- DLC suboptions (for smart thermostat) use kilowatt reduction per thermostat and per participant values based on EasyCool program evaluation
- C&I curtailment suboptions use percentage of the enduse load or total facility load
- PTR uses load reduction per participant based on Plan information

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

- Dynamic pricing uses a percentage of the total facility load
- BTMS uses load reduction per battery based on pilot data
- EV managed charging uses charging load reduction per vehicle based on Plan information

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

4.3.3 Cost Assumptions

Guidehouse developed itemized cost assumptions for each DR option to calculate annual program costs and levelized costs for each option. These assumptions also feed the cost-effectiveness calculations in this study. For DR options which represent ENO's current and planned program/pilot activities, cost assumptions are sourced from the program/pilot cost data provided by ENO. These cost assumptions are broadly categorized into incentive and non-incentive costs. The proportion of incentive and non-incentive costs is based on program/pilot data provided by ENO. For new DR options, such as Dynamic Pricing, Guidehouse developed itemized cost assumptions based on experiences from other jurisdictions.

In addition to the cost assumptions for DR options, the following variables feed the cost-effectiveness calculations in this study:

- **Nominal discount rate, societal discount rate,** and **inflation rate** are described in Appendix A
- **Transmission and distribution (T&D) line loss** of 4.4% (supplied by ENO)
- **Program life**, assumed to be 10 years for DLC, C&I curtailment, and BTMS and 20 years for dynamic pricing

To assess the benefits associated with DR programs, Guidehouse used the avoided generation capacity projections provided by ENO. Guidehouse calculated benefit-cost ratios for the TRC and Utility Cost Test (UCT), consistent with the Council's IRP rules. The TRC benefit-cost ratios are used for screening for cost-effectiveness using a 1.0 benefit-cost ratio threshold.

5. EE Achievable Potential

This section provides the results of the EE achievable potential analysis.

5.1 Model Calibration

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

- Comparing forecast values by sector and end use, typically against historic achieved savings (e.g., program savings from 2020-2022) and savings for PY 13 (2023) as of Q3 2023. Although some studies indicate DSM potential models are calibrated to ensure first-year simulated savings precisely equal prior-year reported savings, Guidehouse notes that forcing such precise agreement may introduce errors into the modeling process by effectively masking the explanation for differences—particularly when the measures included may vary significantly. Additionally, there may be sound reasons for first-year simulated savings to differ from prior-year reported savings (e.g., a program is rapidly ramping up or savings estimates have changed). Although the team endeavored to achieve reasonable agreement between past results and forecast first-year results, the team's approach did not force the model to do so, providing confidence that the model is internally consistent.[52]

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

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

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

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

This calibration cycle was challenging as there have been significant shifts in measures. Through June 2023, residential lighting has been a large proportion of ENO programs. Going forward, ENO's portfolio will not have the relative low cost and highly cost-effective residential lighting savings due to federal standards. Therefore, in calibration, Guidehouse adjusted the historical reference points to address this shift. Furthermore, as of PY 10 (2020), ES program achievements in the C&I sector have been below the plan values. C&I program changes may be a result of the COVID-19 pandemic and other market impacts.

[52] Certain adjustments to historical data were made to address the market changes such as removing residential lighting from the portfolio, which impacts both savings and costs per unit saved.

5.2 Achievable Potential Cases

A key component of a potential study is determining the appropriate level to set measure incentives for each case. For ENO, the incentive-level strategy characterized is the percentage of incremental measure cost approach. This approach calculates measure-level incentives based on a specified percentage of incremental measure costs. For example, if the specified incentive percentage was 50% and a measure's incremental cost was $100, then the calculated incentive for that measure would be $50. Guidehouse used the percentages provided by ENO's program administrator, APTIM, by sector and end use. In all cases, a measure's incentive is capped at 100% of incremental measure cost and IQ measures are incentivized at 100% (except for the Low case).

Guidehouse ran multiple cases for achievable potential summarized in Table 34. The following subsections describe these approaches.

Table 34. Overview of Achievable Potential Cases

Case	Behavior Participation	Incentives	TRC Threshold	Purpose
Low	Reduced	50% of current levels	1.0	Dampened program efforts
Reference	Expected	Current levels	0.9	Align with historic program achievements
2% Savings	Aggressive	Increased, 10x current levels	0.75	Target 2% electricity savings in 2025
High	Aggressive	Aggressive, 100x current levels	None	Demonstrating effect from aggressive program rollout

Note: In all cases, a measure's incentive is capped at 100% of incremental measure cost and IQ measures are incentivized at 100% (except for the Low savings case).

Source: Guidehouse

5.2.1 Reference Case

Because the actual program results for the PY 10-12 (2020-2022) plan were lower than forecast and PY 13 (2023) savings also are tracking to lower levels, Guidehouse used the historical achievements as the focus of the Reference case. The Reference case is the calibrated case. All other cases use the calibrated parameters defined by the Reference case as described in Appendix D.

This Reference case reflects the PY 10-12 and existing PY 13 data which include the savings achieved and the program administrative costs on a dollar per kWh saved basis. Administrative costs on a dollar per kilowatt-hour (kWh)-saved basis are the same as the historic program expenditure and are carried through the other cases.

APTIM, the ES program implementer, provided the incentive structure which ranges from 15% to 100% of incremental measure costs dependent on sector and end use. The TRC measure screening threshold for all measures is 0.9, recognizing the fact that numerous viable measures implemented through Energy Smart meet or exceed this level. Behavior program roll out matches the existing program planned rollout for participants, with the home energy reports program expected to achieve up to 70% participation in future years.

5.2.2 2% Savings Case

The savings goal under this case is the Council's goal of 2% of ENO sales by PY 15, 2025. The incentives assume ten times the existing levels up to a maximum of 100% and estimated aggressive behavior program participation rollout plan. The TRC measure screening threshold is relaxed to 0.75 from 0.9.

5.2.3 Low Case

The Low case uses the same inputs as the Reference case, except for lower levels of behavior program participation rollout. Incentives are set to 50% of current (or Reference case) levels.

5.2.4 High Case

The High case assumes higher incentives at 100 times the Reference case (up to 100% of incremental measure cost) and no change in administrative cost levels, on a dollar per kilowatt-hour-saved basis. Model assumptions use the same aggressive behavior program rollout for all sectors as used in the 2% savings case. There is no TRC measure screening threshold, as every measure is passed on to the achievable potential analysis.

5.3 Achievable Potential Results

Achievable potential values are termed annual incremental potential—they represent the incremental new potential available in each year. The total cumulative annual potential over the time period is the sum of each year's annual incremental achievable potential.[53] Economic potential can be thought of as a reservoir of cost-effective potential[54] from which programs can draw over time. Achievable potential represents the draining of that reservoir, the rate of which is governed by several factors including the lifetime of measures (for ROB technologies), market effectiveness, incentive levels, and customer willingness to adopt, among others. If the cumulative achievable potential ultimately reaches the economic potential, it will signify that all economic potential in the reservoir has been drawn down or harvested. However, achievable potential levels rarely reach the full economic potential level due to a variety of market and customer constraints that inhibit full economic adoption.[55]

All tables and figures that follow in this section (except for Section 5.3.1) present the potential savings for the Reference case only. Details for other cases have been prepared and are available.

[53] Cumulative potential for calculating reduction as a percentage of sales uses a value that does not double count savings. For example, the home energy reports behavior measure has a one-year life. However, subsequent savings in future years may not be new savings.

[54] Cost-effectiveness threshold is based on a TRC threshold. There were measures that were passed with TRC ratios below the set threshold where it was reasonable to assume that the measure is important to program implementation or included in past program delivery.

[55] Constraints on achievable potential that inhibit realization of the full economic potential include the rate at which homes and businesses will adopt efficient technologies, as well as the word of mouth and marketing effectiveness for the technology. If a technology already has high saturation at the beginning of the study, it may theoretically be possible to fully saturate the market and achieve 100% of the economic potential for that technology.

5.3.1 Achievable Potential by Case

As explained in Section 3.4.3, the achievable potential analysis was modeled with four cases. The cases are based on the incremental measure cost capping and shown in Table 35.

Table 35. Incentive Setting and Behavioral Program Participation by Case

Program Type	Reference	2% Savings	Low	High
Res Incentives	Based on historical values	10x Reference	50% of Reference	100x Reference
C&I Incentives				
Behavioral Participation	Planned rollout	High forecast	Low forecast	High forecast

Source: Guidehouse

Table 36 and Table 37 shows the incremental annual energy and peak demand potential for each case for WACC and Societal discount rate, respectively.

Table 36. Incremental Annual Achievable Potential by Case (WACC)

Year	Electricity (GWh)				Peak Demand (MW)			
	Reference	2%	High	Low	Reference	2%	High	Low
2024	70	98	119	49	19	25	30	14
2025	79	110	133	57	23	29	35	17
2026	84	114	138	61	25	33	38	19
2027	85	115	138	63	28	36	41	21
2028	89	117	141	66	30	39	45	24
2029	91	117	139	68	32	41	47	26
2030	89	114	135	68	34	42	48	27
2031	86	108	127	66	33	41	46	28
2032	79	99	115	62	32	38	43	27
2033	73	89	102	58	29	34	39	25
2034	65	78	88	53	26	29	34	23
2035	56	67	76	47	22	25	29	20
2036	50	58	65	42	19	20	24	18
2037	45	50	57	37	16	17	21	15
2038	40	44	51	34	14	14	18	13
2039	36	39	46	31	12	12	16	11
2040	34	37	44	28	11	11	15	10
2041	32	34	41	25	10	10	14	9
2042	30	32	38	23	9	10	13	8
2043	29	31	37	22	9	9	12	7

Source: Guidehouse analysis

Table 37. Incremental Annual Achievable Potential by Case (Societal)

Year	Electricity (GWh)				Peak Demand (MW)			
	Reference	2%	High	Low	Reference	2%	High	Low
2024	85	102	119	60	21	27	30	16
2025	85	115	133	68	23	31	35	19
2026	90	120	138	70	26	35	38	21
2027	92	121	138	71	29	38	41	23
2028	98	125	142	75	32	42	45	25
2029	99	123	139	75	34	44	47	27
2030	99	120	135	75	35	45	48	28
2031	96	114	127	73	35	44	46	29
2032	90	104	115	69	34	41	43	28
2033	82	94	102	64	31	37	39	26
2034	76	82	88	59	28	32	34	24
2035	67	70	76	54	24	27	29	21
2036	59	61	65	48	21	23	24	19
2037	53	53	57	45	18	19	21	16
2038	48	47	51	40	16	17	18	14
2039	44	43	46	36	14	15	16	12
2040	41	40	44	34	13	14	15	11
2041	38	38	41	31	12	12	14	9
2042	35	36	38	28	11	12	13	8
2043	33	34	37	28	10	11	12	8

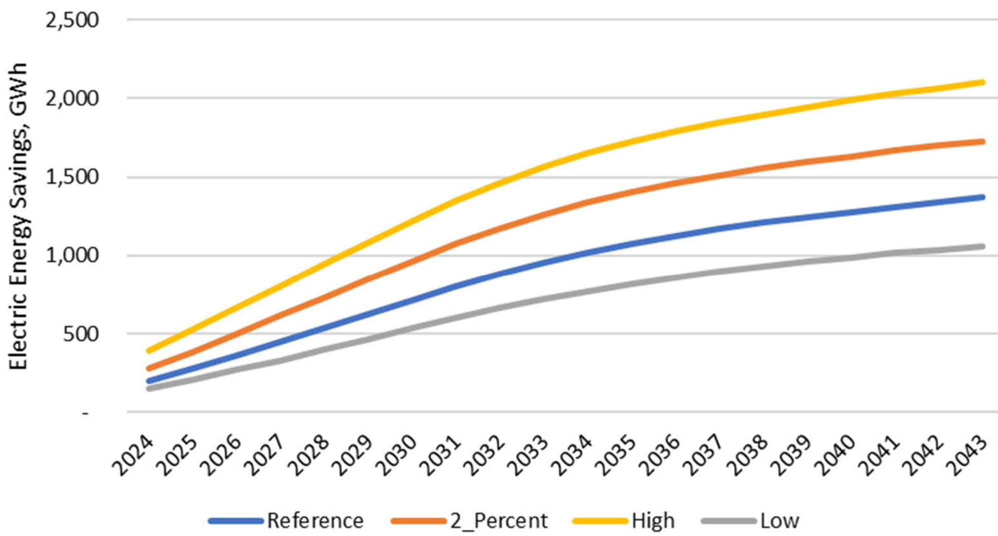
Source: Guidehouse analysis

Figure 25 and Figure 26 show the cumulative annual electric energy and peak demand savings for each case using the WACC. The range of savings increases over the 20-year period, with the Low case more than 1,000 GWh and the High case twice as large, with the pace of savings slowing by 2031 due to increasing saturation of existing set of measures. Each case has marked differences in the program design, i.e., changes in ENO-influenced parameters, including incentive level setting and behavioral program rollout.[56]

In comparison, the 2043 cumulative GWh and MW savings by discount rate is provided in Table 38. Discount rate for the high case does not impact the overall results since the high case has no cost-effectiveness threshold for the economic potential.

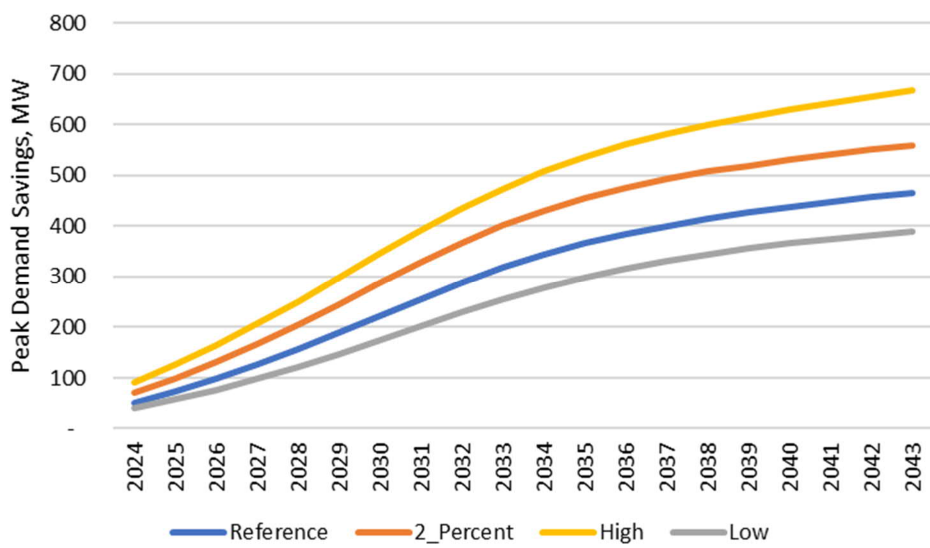
[56] Incentive levels influence the customer payback period, which results in a change in the payback acceptance curve influencing the market share potential of the energy efficient option. The payback acceptance curves for ENO were developed based on the results of customer surveys for a Midwest utility previously conducted by Guidehouse in 2015.

Figure 25. Cumulative Annual Achievable Electricity Potential by Case (GWh) (WACC)



Source: Guidehouse analysis

Figure 26. Cumulative Annual Achievable Peak Demand Potential by Case (MW) (WACC)



Source: Guidehouse analysis

Table 38. Cumulative 2043 Achievable Potential by Case, by Discount Rate

Discount Rate	Reference	2% Savings	High	Low
		Annual Energy Savings (GWh/year)		
WACC	1,370	1,729	2,105	1,060
Societal	1,563	1,858	2,106	1,221
		Peak Demand Savings (MW)		
WACC	466	560	668	389
Societal	499	616	668	411

Source: Guidehouse analysis

Table 39 shows the incremental annual achievable electricity potential as a percentage of ENO's total sales for each case using the WACC and Societal discount rate for the cost-effectiveness analysis. The 2% savings case, which targets achieving 2% by 2025, was based on calibrated adoption parameters based on the Reference case. As a result, the portfolio target with the WACC discount rate for saving at least 2% of sales shifts to 2027 through 2029. The 2% savings case, as well as the High case, falls below 2% in later years because most of the measures will be adopted, depleting the available potential in the future years.

This study only includes known, market-ready, quantifiable measures without introducing new measures in later years. However, over the lifetime of EE programs, new technologies and innovative program interventions could result in additional cost-effective energy savings. Therefore, the need to periodically revisit and reanalyze the potential forecast is necessary.

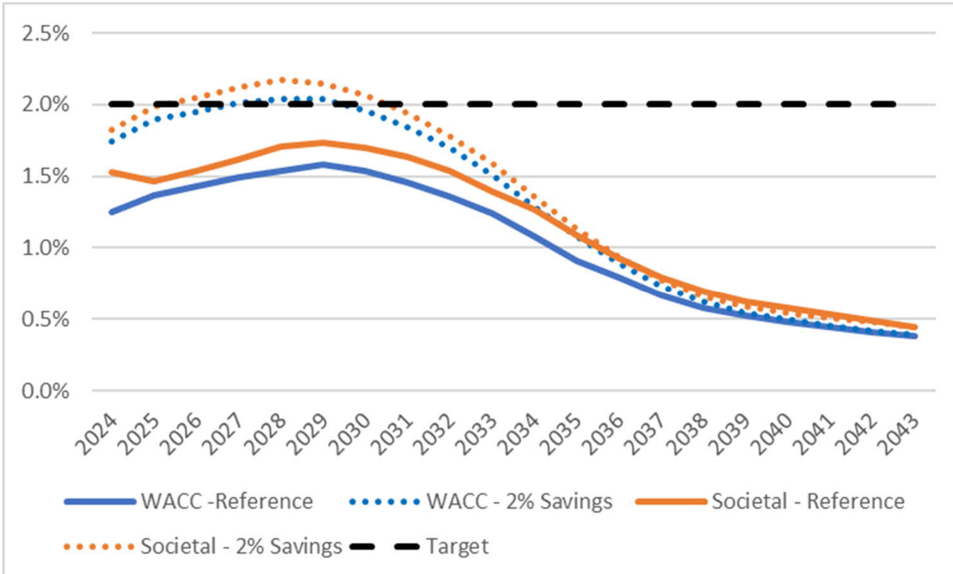
Table 39. Incremental Annual Achievable Electricity Potential, Percentage (%) of Sales (GWh) by Case by Discount Rate

	WACC				Societal			
Year	**Reference**	**2% Savings**	**High**	**Low**	**Reference**	**2% Savings**	**High**	**Low**
2024	1.25%	1.74%	2.11%	0.87%	1.53%	1.83%	2.11%	1.07%
2025	1.37%	1.90%	2.30%	0.99%	1.47%	1.99%	2.30%	1.18%
2026	1.43%	1.95%	2.34%	1.05%	1.54%	2.05%	2.34%	1.20%
2027	1.49%	2.01%	2.42%	1.11%	1.62%	2.12%	2.42%	1.24%
2028	1.54%	2.04%	2.44%	1.16%	1.71%	2.17%	2.46%	1.31%
2029	1.58%	2.04%	2.43%	1.20%	1.73%	2.15%	2.42%	1.31%
2030	1.54%	1.96%	2.32%	1.18%	1.70%	2.07%	2.32%	1.29%
2031	1.46%	1.84%	2.16%	1.14%	1.63%	1.94%	2.16%	1.24%
2032	1.36%	1.70%	1.97%	1.08%	1.54%	1.78%	1.97%	1.19%
2033	1.24%	1.51%	1.72%	0.99%	1.40%	1.59%	1.72%	1.09%
2034	1.08%	1.29%	1.46%	0.89%	1.26%	1.36%	1.46%	0.98%
2035	0.91%	1.08%	1.21%	0.77%	1.09%	1.13%	1.21%	0.88%
2036	0.79%	0.89%	1.00%	0.66%	0.93%	0.94%	1.00%	0.76%
2037	0.67%	0.73%	0.82%	0.57%	0.80%	0.77%	0.82%	0.68%
2038	0.58%	0.62%	0.70%	0.50%	0.70%	0.66%	0.70%	0.60%
2039	0.52%	0.54%	0.62%	0.44%	0.63%	0.59%	0.62%	0.53%
2040	0.48%	0.50%	0.58%	0.40%	0.58%	0.54%	0.58%	0.48%
2041	0.44%	0.45%	0.54%	0.35%	0.53%	0.50%	0.54%	0.44%
2042	0.41%	0.42%	0.50%	0.32%	0.49%	0.48%	0.50%	0.40%
2043	0.38%	0.39%	0.47%	0.29%	0.45%	0.44%	0.47%	0.38%

Source: Guidehouse analysis

Figure 27 provides the percentage of sales results when using WACC and societal discount rate. In these results, the portfolio savings achieve at least 2% of sales in 2025 through 2030 in the 2% case with societal discount rate. For both the WACC and societal discount rate analysis, the latter years (after 2035) converge as the market is saturated.

Figure 27. Incremental Annual Achievable Electricity Potential, Percentage (%) of Sales by Reference and 2% Savings Case by Discount Rate



Source: Guidehouse analysis

The total, administrative, and incentive costs for each case are provided in Table 40 and Table 41 for each year of the study period for WACC and Societal discount rate, respectively. It is important to note the differences in these cases as compared with the savings achieved. Administrative spending is relatively consistent between the cases, while incentive spending varies between the cases, with higher spending correlated to higher savings. The differences in discount rate are reflected by a larger portfolio with more measure cost-effective.

Table 40. Achievable Potential using WACC, Annual Investment by Case (million $)[57]

	Total Investment				Incentives				Administrative Costs			
Year	**Ref.**	**2%**	**High**	**Low**	**Ref.**	**2%**	**High**	**Low**	**Ref.**	**2%**	**High**	**Low**
2024	$11	$32	$81	$6	$6	$25	$71	$2	$5	$8	$10	$4
2025	$13	$37	$98	$7	$7	$28	$87	$2	$6	$9	$11	$5
2026	$15	$39	$104	$8	$8	$29	$91	$2	$7	$10	$12	$5
2027	$16	$41	$107	$8	$9	$30	$95	$3	$7	$10	$13	$6
2028	$18	$42	$115	$9	$10	$32	$101	$3	$8	$11	$13	$6
2029	$19	$43	$116	$10	$11	$32	$102	$3	$8	$11	$14	$7

57 Totals may not sum due to rounding.

	Total Investment				Incentives				Administrative Costs			
2030	$20	$43	$117	$10	$11	$32	$103	$4	$9	$11	$14	$7
2031	$20	$42	$113	$11	$11	$31	$100	$4	$8	$11	$13	$7
2032	$19	$39	$105	$10	$11	$29	$93	$4	$8	$10	$12	$7
2033	$17	$36	$95	$10	$10	$27	$85	$4	$7	$9	$11	$6
2034	$15	$31	$86	$10	$9	$23	$76	$4	$6	$8	$9	$6
2035	$12	$26	$75	$9	$7	$20	$67	$3	$5	$7	$8	$5
2036	$11	$22	$67	$8	$6	$16	$60	$3	$5	$6	$7	$5
2037	$9	$18	$59	$7	$5	$14	$54	$3	$4	$5	$6	$4
2038	$8	$15	$54	$6	$4	$11	$49	$3	$4	$4	$5	$4
2039	$7	$13	$50	$6	$4	$9	$45	$2	$3	$3	$4	$3
2040	$6	$11	$47	$5	$3	$8	$43	$2	$3	$3	$4	$3
2041	$5	$10	$44	$4	$3	$7	$40	$2	$2	$3	$4	$3
2042	$5	$8	$41	$4	$2	$6	$38	$2	$2	$2	$3	$2
2043	$4	$8	$39	$4	$2	$6	$36	$2	$2	$2	$3	$2
Total	**$250**	**$558**	**$1,613**	**$152**	**$139**	**$415**	**$1,439**	**$56**	**$111**	**$143**	**$174**	**$96**

Source: Guidehouse analysis

Table 41. Achievable Potential using Societal, Annual Investment by Case (million $)[58]

	Total Investment				Incentives				Administrative Costs			
Year	**Ref.**	**2%**	**High**	**Low**	**Ref.**	**2%**	**High**	**Low**	**Ref.**	**2%**	**High**	**Low**
2024	$14	$38	$81	$7	$8	$30	$71	$3	$7	$8	$10	$5
2025	$15	$44	$98	$9	$8	$34	$87	$3	$7	$10	$11	$6
2026	$17	$47	$103	$9	$9	$37	$91	$3	$8	$10	$12	$6
2027	$19	$50	$107	$10	$10	$39	$94	$3	$8	$11	$13	$6
2028	$21	$53	$115	$11	$12	$41	$101	$4	$9	$12	$13	$7
2029	$22	$54	$115	$11	$13	$42	$102	$4	$9	$12	$14	$7

58 Totals may not sum due to rounding.

	Total Investment				Incentives				Administrative Costs			
2030	$23	$55	$117	$12	$14	$43	$103	$4	$10	$12	$14	$8
2031	$24	$54	$113	$12	$14	$42	$100	$4	$10	$12	$13	$8
2032	$23	$50	$105	$12	$14	$40	$93	$4	$9	$11	$12	$7
2033	$21	$47	$95	$11	$13	$37	$84	$4	$8	$10	$11	$7
2034	$20	$42	$85	$11	$12	$33	$76	$4	$8	$9	$9	$6
2035	$18	$36	$75	$10	$11	$29	$67	$4	$7	$7	$8	$6
2036	$16	$32	$67	$9	$10	$26	$60	$4	$6	$6	$7	$5
2037	$14	$28	$59	$9	$9	$23	$53	$4	$5	$5	$6	$5
2038	$12	$25	$53	$8	$8	$20	$48	$4	$5	$4	$5	$5
2039	$11	$22	$49	$7	$7	$18	$45	$3	$4	$4	$4	$4
2040	$10	$21	$47	$7	$6	$17	$43	$3	$4	$4	$4	$4
2041	$9	$19	$43	$6	$6	$16	$40	$3	$3	$3	$4	$3
2042	$8	$18	$40	$6	$5	$15	$37	$3	$3	$3	$3	$3
2043	$7	$17	$38	$6	$5	$14	$35	$3	$3	$3	$3	$3
Total	**$325**	**$750**	**$1,605**	**$183**	**$193**	**$595**	**$1,431**	**$70**	**$132**	**$155**	**$174**	**$113**

Source: Guidehouse analysis

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

Guidehouse calculated TRC ratios for each measure based on the present value of benefits and costs (as defined by the numerator and denominator, respectively) over each measure's life. Avoided costs, discount rates, and other key data inputs used in the TRC calculation are presented in Appendix A.8. Effects of free ridership and spillover are not present in the results from this study, so the team did not apply an NTG factor. Providing gross savings results will allow the utility to easily apply updated NTG assumptions in the future and allow for variations in NTG assumptions by reviewers.

The TRC ratios for these cases are provided by year in Table 42. All cases are cost-effective except for the High case where the TRC screening is not used in the achievable potential calculation. The large increases in incentives for the High case do not impact the cost-effectiveness. Increasing incentives do not necessarily translate to a lower TRC because incentives are considered a transfer cost. However, higher incentives may make higher cost measures more attractive to end users and spur their adoption. Thus, where incentives increase as a percentage of measure cost, TRC ratios can be lower even though incentives are not part of the TRC calculation.

One of the screening criteria in the potential analysis is for the measures to pass the TRC test. A handful of measures with a TRC < 1.0 were included in the analysis. As a result, the portfolio is still cost-effective. Typically, the more aggressive the portfolio, the lower the TRC, as more lower cost-effective measures are added and administrative efforts increase to address more services to the market.

Table 42 provides the TRC for each case and for each discount rate. Guidehouse calculated the ratio for both the WACC and the societal discount rate. The results with the societal discount rate also use the lower discount rate for the economic screening.

Table 42. Portfolio TRC Test Ratios, Achievable Potential, by Case and by Discount Rate

Year	Reference		2% Savings		High		Low	
Discount Rate	**WACC**	**Societal**	**WACC**	**Societal**	**WACC**	**Societal**	**WACC**	**Societal**
2024	1.57	1.96	1.33	1.73	0.71	0.89	2.04	2.40
2025	1.63	2.24	1.35	1.76	0.69	0.88	2.06	2.51
2026	1.69	2.34	1.40	1.81	0.72	0.92	2.12	2.73
2027	1.73	2.41	1.44	1.86	0.75	0.96	2.15	2.88
2028	1.79	2.50	1.51	1.93	0.76	0.99	2.20	3.03
2029	1.87	2.57	1.60	1.98	0.79	1.03	2.28	3.19
2030	1.92	2.61	1.68	2.02	0.80	1.05	2.36	3.24
2031	1.98	2.61	1.77	2.05	0.82	1.07	2.44	3.28
2032	2.02	2.59	1.86	2.05	0.83	1.08	2.53	3.26
2033	2.00	2.55	1.93	2.02	0.82	1.08	2.62	3.21
2034	2.02	2.42	2.00	1.98	0.80	1.05	2.71	3.11
2035	2.06	2.32	2.06	1.92	0.78	1.02	2.79	2.93
2036	2.09	2.20	2.10	1.85	0.75	0.98	2.72	2.80
2037	2.06	2.09	2.06	1.78	0.71	0.94	2.34	2.51
2038	2.09	1.99	2.08	1.72	0.68	0.90	2.20	2.38
2039	2.11	1.92	2.07	1.67	0.66	0.87	2.08	2.26
2040	2.17	1.89	2.11	1.66	0.64	0.84	2.13	2.18
2041	2.20	1.85	2.12	1.63	0.63	0.83	2.13	2.09
2042	2.22	1.84	2.13	1.61	0.62	0.82	2.15	2.03
2043	2.21	1.85	2.15	1.59	0.62	0.81	2.18	1.85
2024-2043	1.78	2.31	1.51	1.86	0.72	0.95	2.16	2.80

Source: Guidehouse analysis

5.3.2 Achievable Potential by Sector

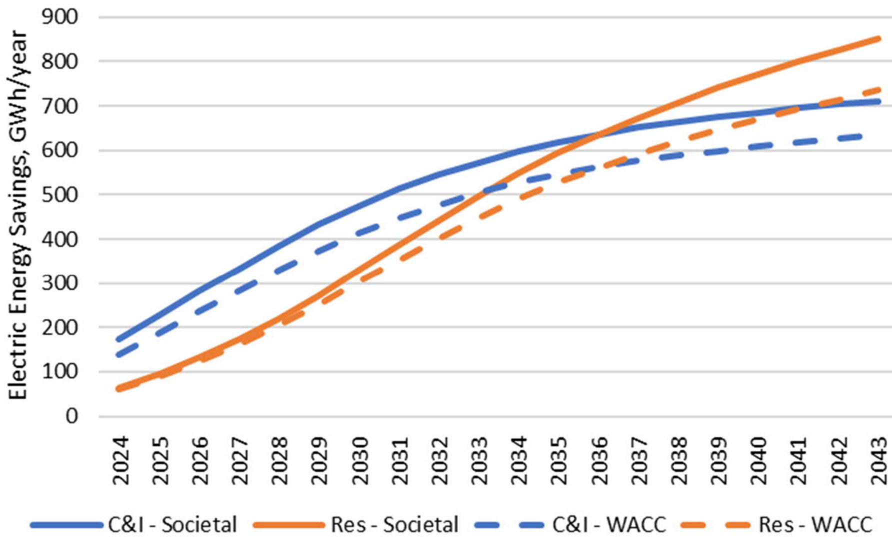
Table 43 provides the incremental achievable electric energy savings by sector for the Reference case. The Residential savings grow through 2031 and then start declining as technologies saturate, but level off. The C&I savings grow for the first 3 years and then gradual decline through to 2043. Breakdown of the residential sector into market rate and income qualified customers is provided in Appendix 7.4B.

Table 43. Incremental Annual Achievable Electric Savings (GWh) Potential by Sector, Reference Case

Year	Res - WACC	C&I - WACC	Res - Societal	C&I - Societal
2024	25.4	44.8	27.0	58.4
2025	29.1	49.8	31.2	54.0
2026	33.5	50.2	36.2	54.1
2027	38.3	46.9	41.6	50.7
2028	43.0	45.9	47.1	51.3
2029	47.1	43.6	52.0	47.2
2030	49.9	39.5	55.7	42.9
2031	50.8	34.7	57.5	38.0
2032	49.4	29.7	56.9	32.7
2033	45.9	26.7	54.3	27.7
2034	41.9	22.7	50.5	25.2
2035	36.9	19.0	46.1	20.7
2036	34.3	16.1	41.9	17.4
2037	31.0	13.9	38.2	14.7
2038	28.0	12.0	35.1	12.6
2039	25.7	10.7	32.5	11.1
2040	24.1	10.2	30.3	10.7
2041	22.7	9.1	28.4	9.5
2042	21.6	8.3	26.6	8.6
2043	20.9	7.7	25.3	7.9

Figure 28 shows the cumulative annual achievable electricity potential by sector for the Reference case, which is calibrated based on the historical ENO portfolio performance. In following the existing drop-off for the C&I savings, the forecast shows that C&I savings increases initially until market penetration of efficiency levels off.

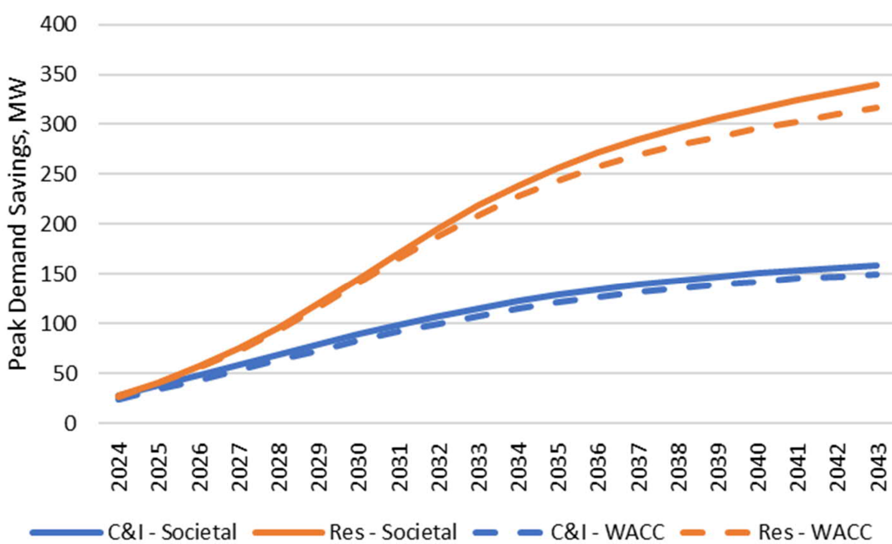
Figure 28. Cumulative Annual Achievable Electric Savings (GWh) Potential by Sector, Reference Case



Source: Guidehouse analysis

Figure 29 shows the cumulative annual achievable peak demand potential by sector for the Reference case.

Figure 29. Cumulative Annual Achievable Peak Demand (MW) Potential by Sector, Reference Case



Source: Guidehouse analysis

Table 44 shows the cumulative annual achievable electricity potential as a percentage of ENO's total sales for each sector for the Reference case. The residential sector accounts for a larger percentage than the C&I sector. Changing the discount rate increases the residential sector more than the commercial sector energy efficiency impacts.

Table 44. Cumulative Annual Achievable Electricity Potential by Sector, Percentage of Sales, Reference Case (%, GWh)

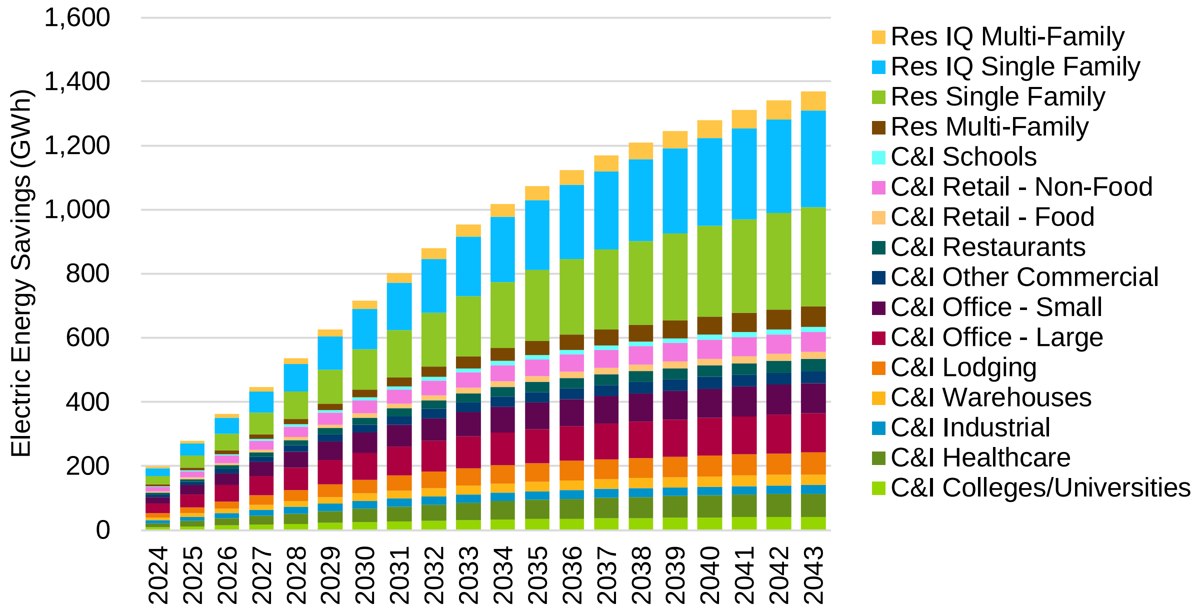
	WACC			Societal		
Year	**Total**	**Res**	**C&I**	**Total**	**Res**	**C&I**
2024	3.6%	2.7%	4.2%	4.3%	2.8%	5.3%
2025	4.9%	4.0%	5.6%	5.8%	4.2%	6.8%
2026	6.4%	5.4%	7.0%	7.3%	5.8%	8.3%
2027	7.9%	7.1%	8.4%	8.9%	7.6%	9.8%
2028	9.4%	9.0%	9.7%	10.6%	9.7%	11.3%
2029	11.0%	11.0%	11.0%	12.4%	11.9%	12.7%
2030	12.5%	13.2%	12.1%	14.1%	14.3%	13.9%
2031	14.0%	15.4%	13.1%	15.7%	16.8%	14.9%
2032	15.3%	17.5%	13.9%	17.2%	19.2%	15.9%
2033	16.6%	19.4%	14.7%	18.6%	21.5%	16.7%
2034	17.7%	21.2%	15.3%	19.9%	23.7%	17.4%
2035	18.6%	22.7%	15.8%	21.0%	25.5%	17.9%
2036	19.3%	24.0%	16.2%	21.9%	27.2%	18.3%
2037	20.0%	25.2%	16.5%	22.7%	28.6%	18.7%
2038	20.6%	26.2%	16.8%	23.4%	29.9%	19.0%
2039	21.1%	27.1%	17.1%	24.0%	31.1%	19.2%
2040	21.6%	28.0%	17.3%	24.6%	32.2%	19.4%
2041	22.0%	28.8%	17.5%	25.1%	33.2%	19.6%
2042	22.5%	29.5%	17.6%	25.6%	34.2%	19.8%
2043	22.8%	30.3%	17.8%	26.1%	35.1%	19.9%

Source: Guidehouse analysis

5.3.3 Achievable Potential by Customer Segment

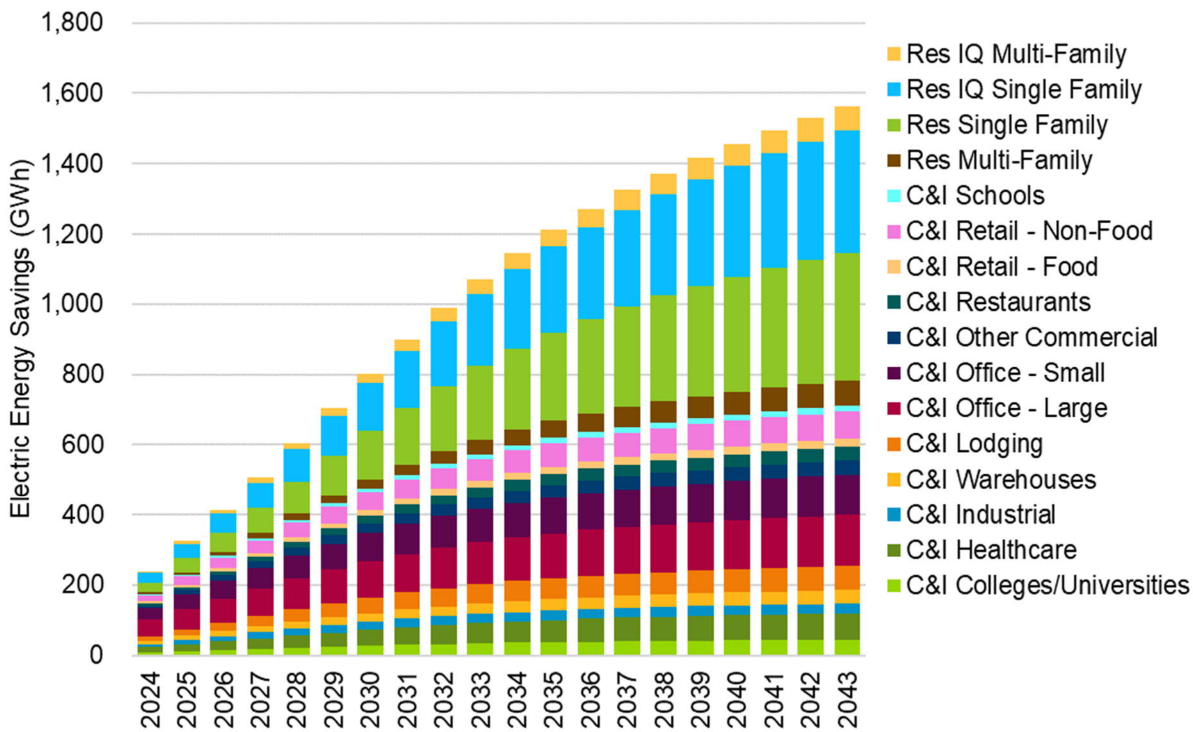
Figure 30 and Figure 31 shows the cumulative annual achievable electric energy potential by customer segment for the Reference case by WACC and Societal discount rate, respectively. The potential which grows from 200 GWh in 2024 to almost 1,400 GWh in 2043 for the WACC. The Societal discount rate case shows a larger growth over time but the same relative distribution across segments. Single-family (IQ and non-IQ) homes make up the largest residential segment, while large and small offices contribute the most savings to the C&I sector.

Figure 30. Reference Case Cumulative Annual Achievable Energy Savings Potential by Customer Segment, WACC



Source: Guidehouse analysis

Figure 31. Reference Case Cumulative Annual Achievable Energy Savings Potential by Customer Segment, Societal



Source: Guidehouse analysis

5.3.4 Achievable Potential by End Use

Figure 32 and Figure 33 show the percentage Reference case achievable potential by end use for the residential and C&I sectors in 2030 for WACC, respectively. The lighting interior for C&I only and HVAC end use for both sectors have the largest potential. The high HVAC end use savings contribution are associated with envelope and systems that affect both heating and cooling. ENO has a relatively high penetration of electric heating, which contributes to this factor even though New Orleans experiences rather low heating degree days and high cooling degree days. The total facility end use are for holistic measures, such as the behavior program.

Figure 32. Residential Achievable Electricity Potential by End Use, Reference Case, 2030 (%), WACC

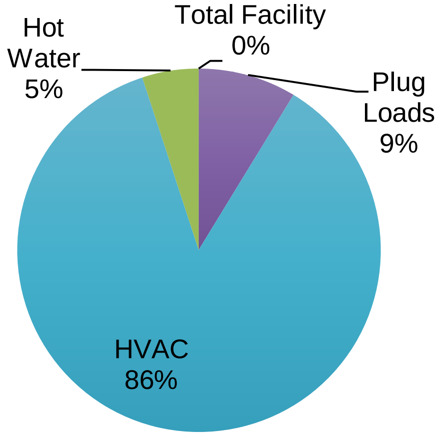
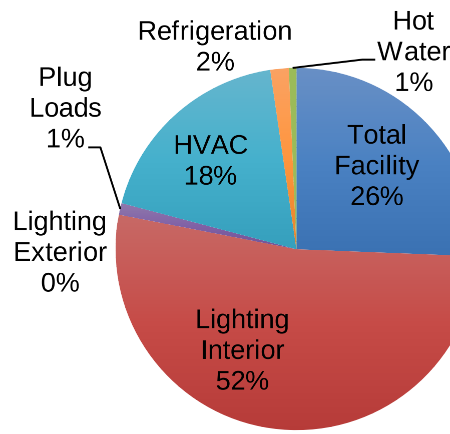


Figure 33. C&I Achievable Electricity Potential by End Use, Reference Case, 2030 (%), WACC



Source: Guidehouse analysis

Figure 34 and Figure 35 show the percentage Reference case achievable potential by end use for the residential and C&I sectors in 2030 using the societal discount rate. The discount rate slightly shifts the impacts to more plug loads as a percentage of sector level savings for the Societal discount rate.

Figure 34. Residential Achievable Electricity Potential by End Use, Reference Case, 2030 (%), Societal

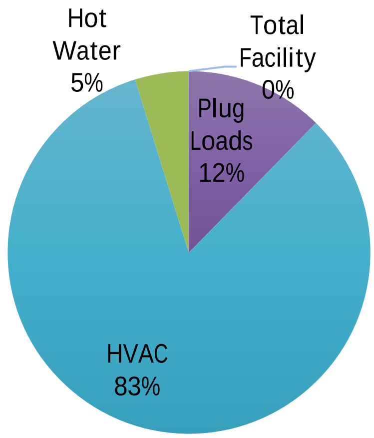
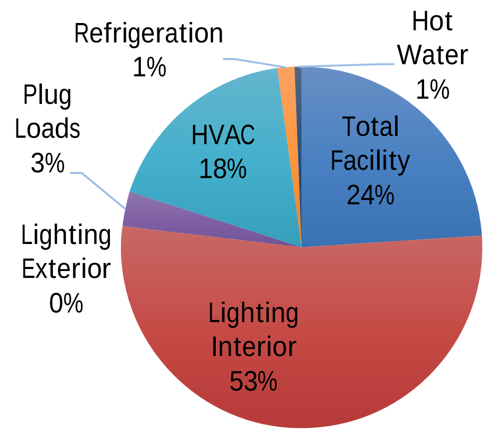


Figure 35. C&I Achievable Electricity Potential by End Use, Reference Case, 2030 (%), Societal



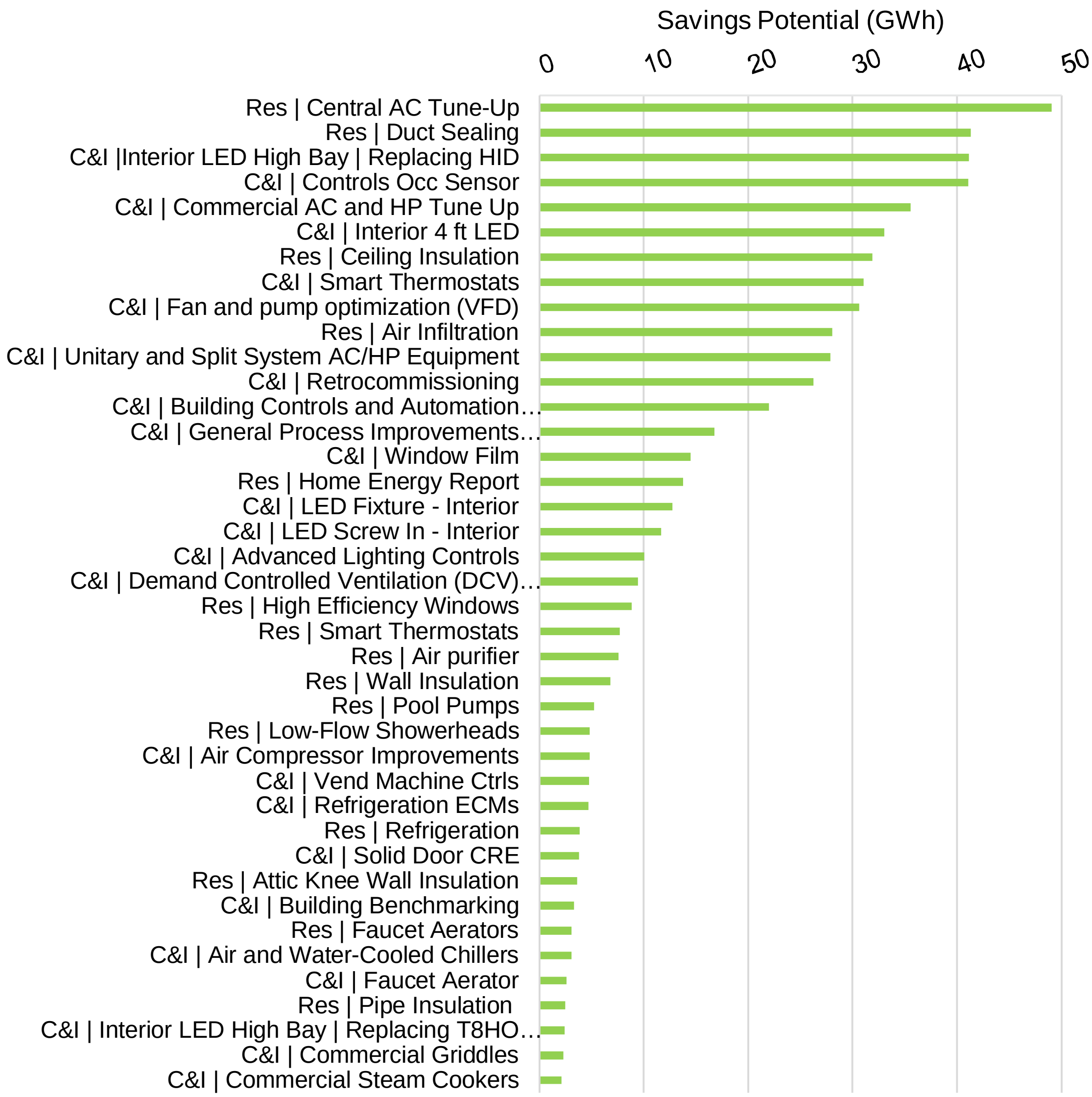
Source: Guidehouse analysis

5.3.5 Achievable Potential by Measure

Figure 36 and Figure 37 show the top 40 measures contributing to the cumulative achievable electricity savings potential in 2030 for WACC and Societal discount rate, respectively. For the WACC, interior high bay LEDs and occupancy sensor controls in the C&I sector provide the most savings, followed by AC and HP tune-up, 4-foot LEDs, and smart thermostats. For the Societal discount rate, C&I sector occupancy controls, retrocommissioning, and interior high bay LEDs are the top three measures. The order of largest measure has shifted.

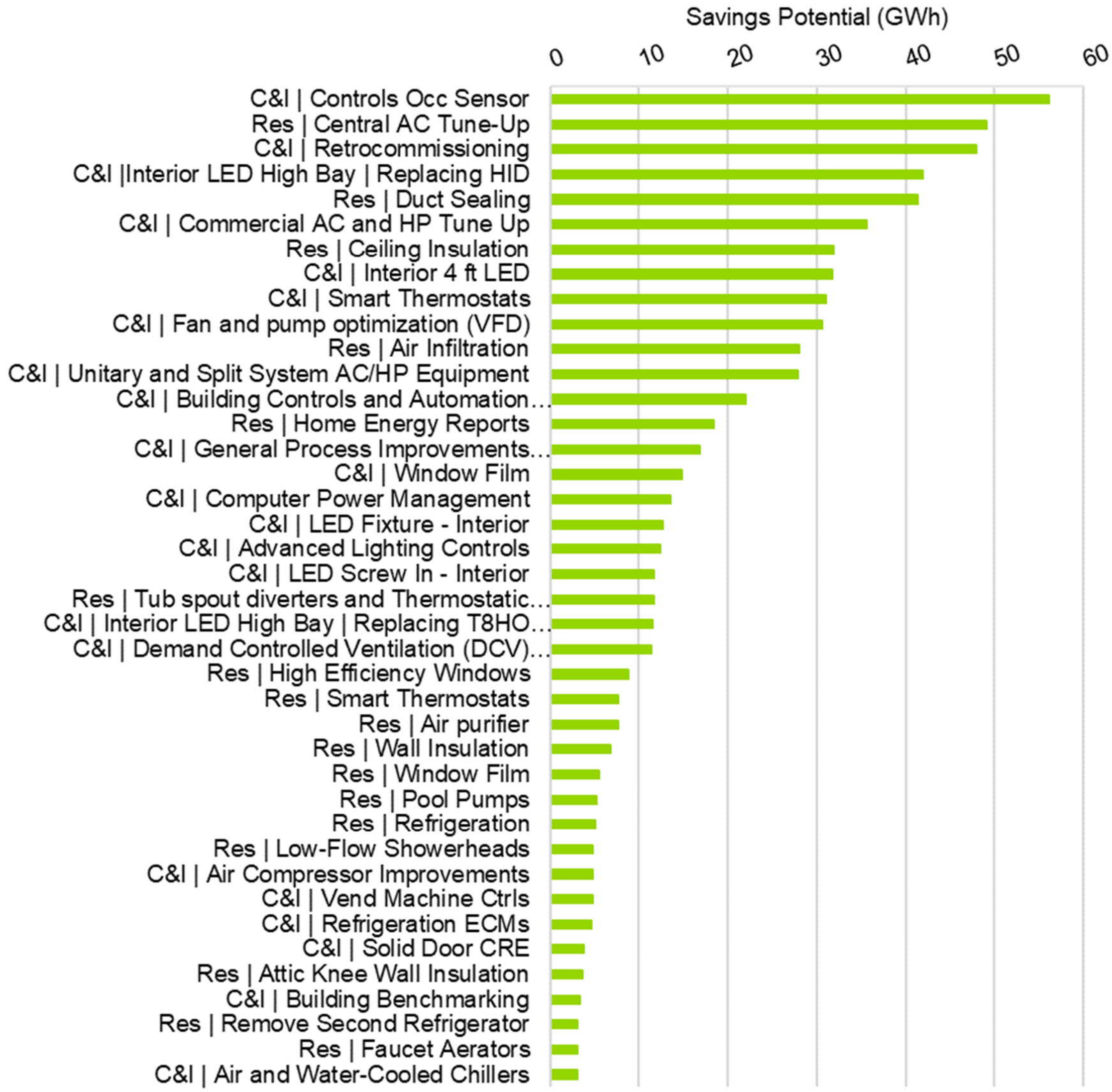
Central AC tune-up and duct sealing contribute the most residential sector savings in 2030 for the WACC. For societal discount rate, the order of highest residential savings has not changed. Home energy reports do not show up as the savings do not accumulate year over year and must be renewed with program intervention.

Figure 36. Cumulative Achievable Potential, Reference Case, 2030 Electricity Savings (GWh) – Top 40 Measures, WACC



Source: Guidehouse analysis

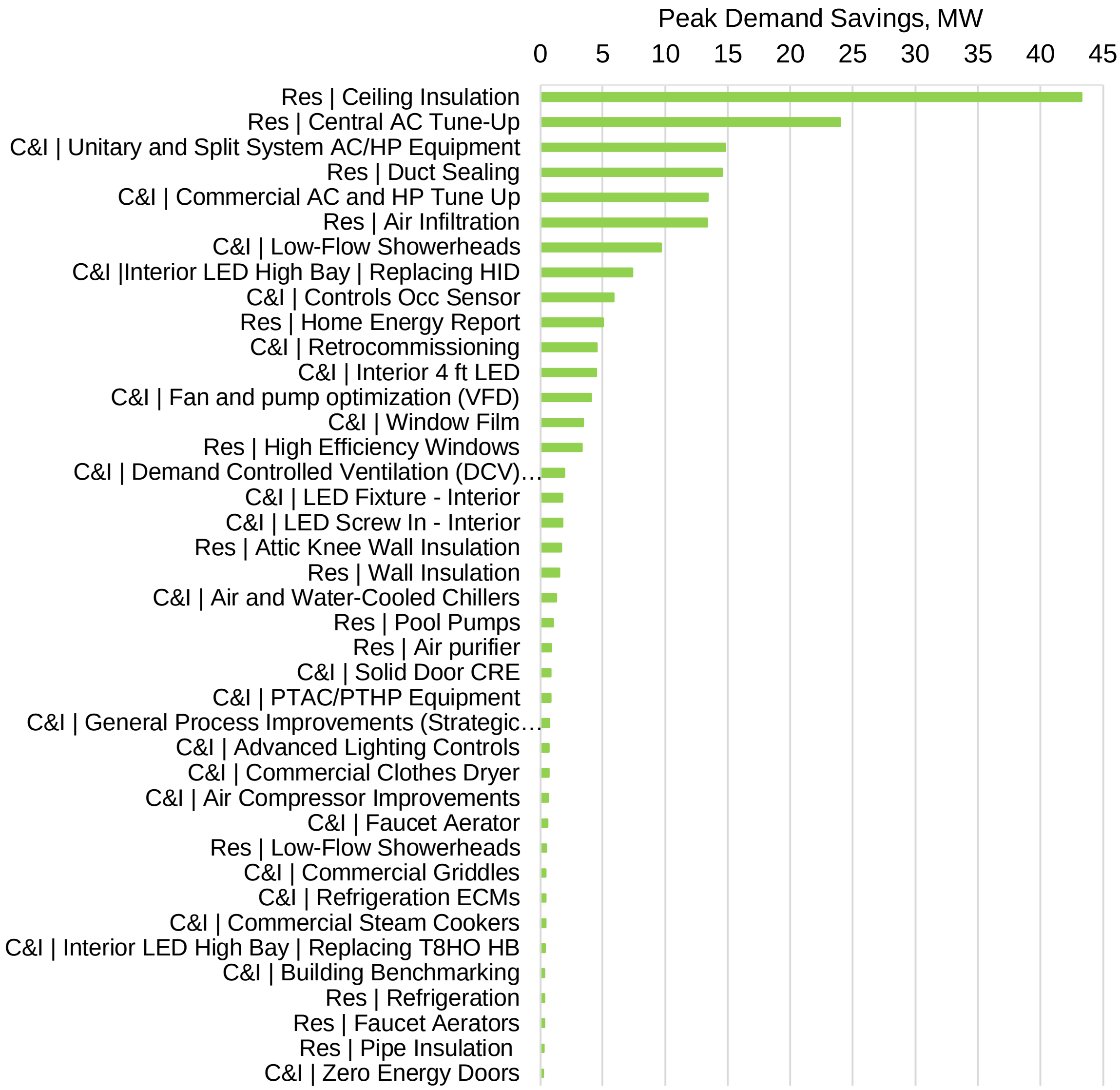
Figure 37. Cumulative Achievable Potential, Reference Case, 2030 Electricity Savings (GWh) – Top 40 Measures, Societal



Source: Guidehouse analysis

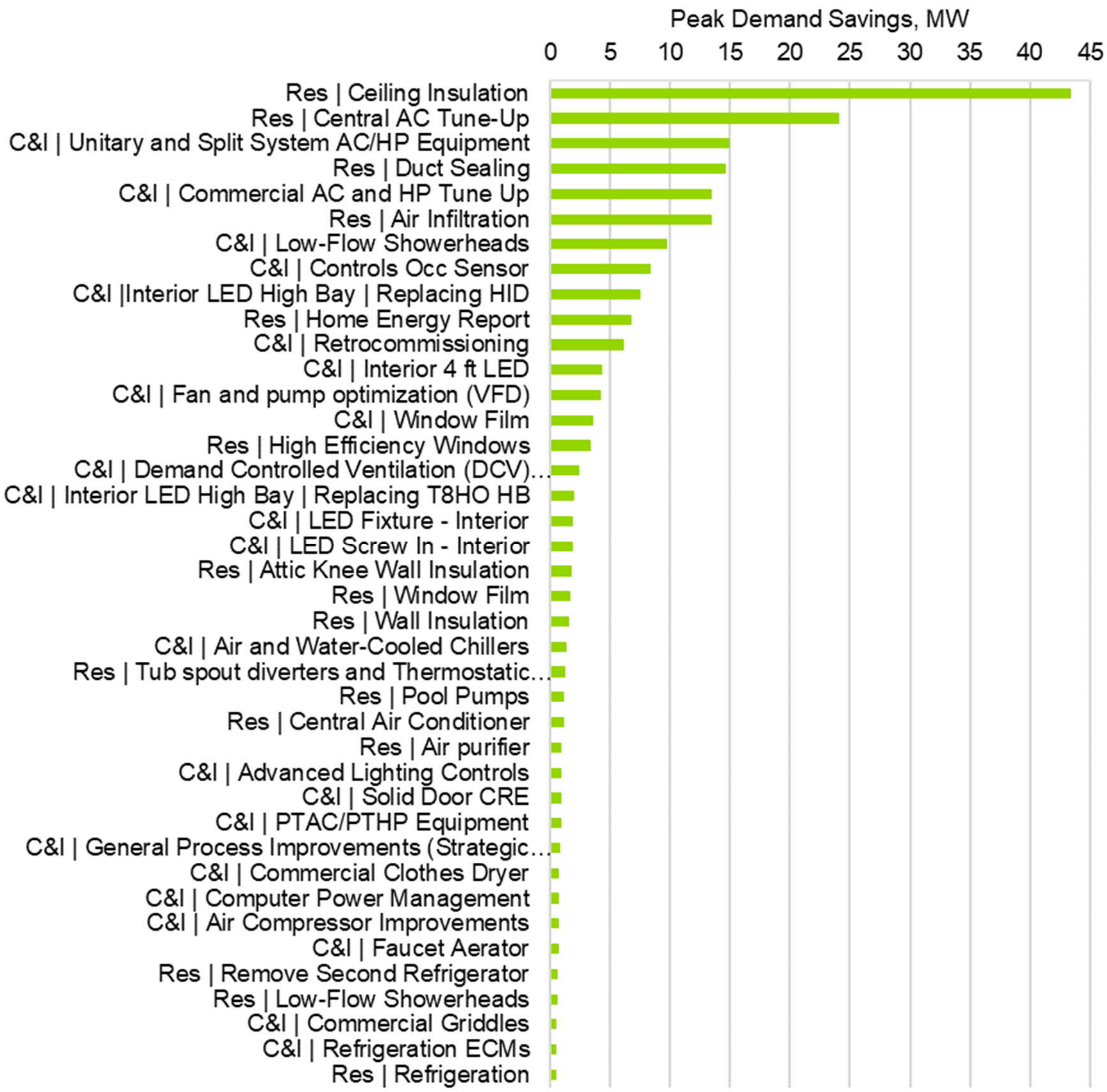
Figure 38 and Figure 39 show the top 40 measures contributing to the cumulative achievable peak demand potential in 2030 for the Reference savings case with WACC and Societal discount rate, respectively. The top measures are different than those listed for electric energy. Residential sector ceiling insulation and CAC tune-ups are the highest demand savings. For the C&I sector, the highest savings are unitary and split system AC/HP equipment. There is no difference in the top few measures between the discount rates, however, measures with less demand impact vary in contribution between the two cases. These measures' unit energy and peak demand savings are sourced from the TRM version 7.0.

Figure 38. Cumulative Achievable Potential, Reference Case, 2030 Peak Demand Savings (MW), Reference Case, WACC – Top 40 Measures



Source: Guidehouse analysis

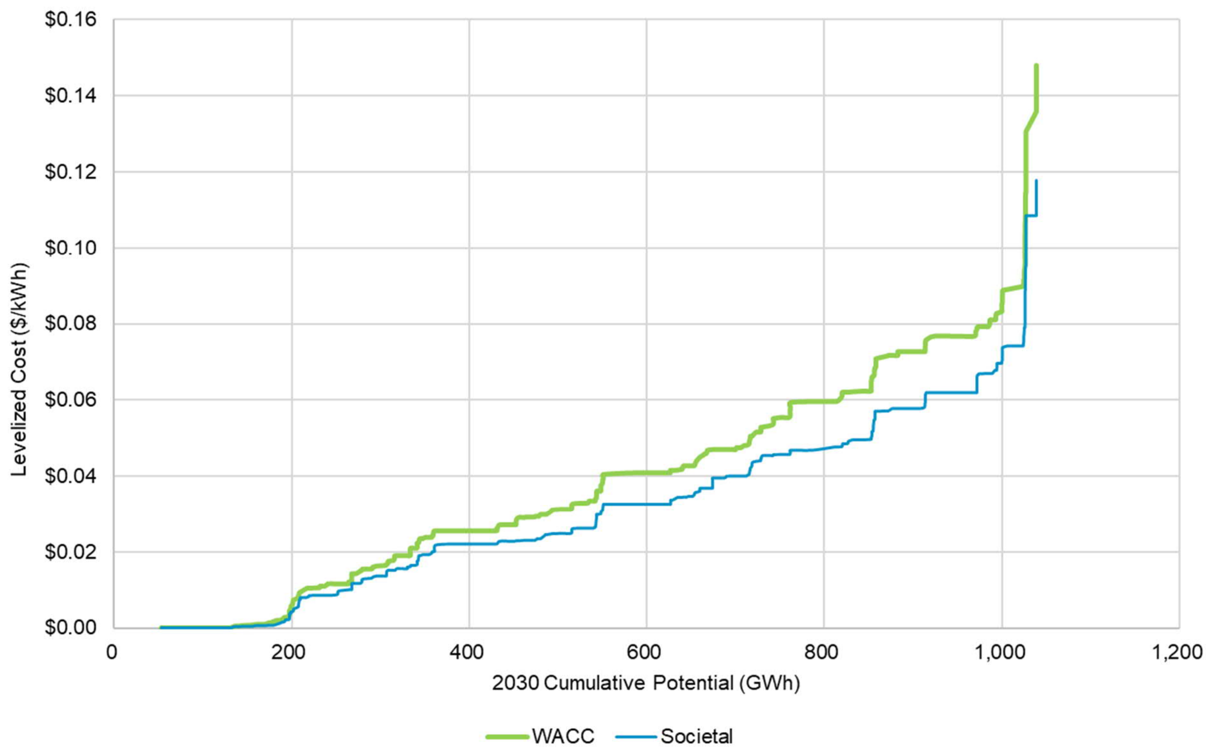
Figure 39. Cumulative Achievable Potential, Reference Case, 2030 Peak Demand Savings (MW), Reference Case, Societal – Top 40 Measures



Source: Guidehouse analysis

Figure 35 provides a supply curve of savings potential versus the levelized cost of savings in $/kWh for all measures considered in the study. The achievable potential levels out at about $0.09/kWh for WACC and $0.07 for Societal; incremental savings above this level become costlier.

Figure 40. Achievable Electricity Potential, Supply Curve (GWh/year) vs. Levelized Cost ($/kWh), 2030

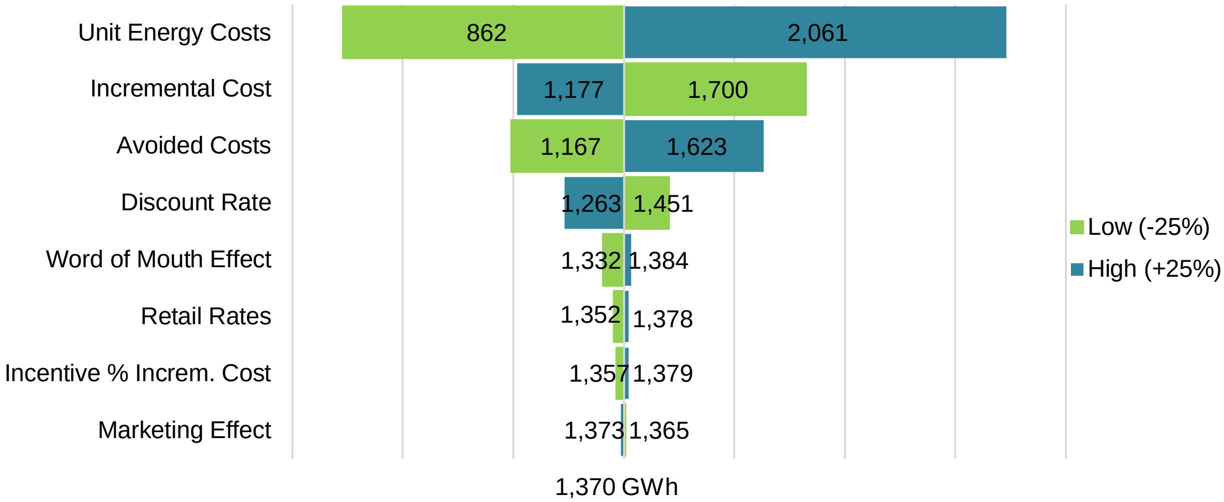


Source: Guidehouse analysis

5.3.6 Achievable Potential Sensitivity Analysis

Figure 41 shows a sensitivity analysis of the effect on electricity savings potential that results from varying the most influential factors by +/- 25%. Table 45 shows the percentage change to the cumulative energy savings potential for each sensitivity parameter in 2043. Unit energy savings have the largest impact, followed by incremental costs, avoided costs, and word of mouth effect. Such understandings are critical to evaluating related policy decisions and informing effective program design.

Figure 41. Cumulative Annual Achievable Electricity Potential, 2043, Sensitivity to Key Variables, WACC



Source: Guidehouse analysis

Table 45. Percentage Change to Cumulative Annual Electricity Potential, 2043, with 25% Parameter Change, WACC

Parameter	Low (-25%)	High (+25%)
Unit Energy Costs	-37%	51%
Incremental Cost	24%	-14%
Avoided Costs	-15%	18%
Discount Rate	6%	-8%
Word of Mouth Effect	-3%	1%
Incentive % Incremental Cost	-1%	1%
Retail Rates	-1%	1%
Marketing Effect	0.2%	-0.4%

Source: Guidehouse analysis

6. DR Achievable Potential

This chapter presents the DR achievable potential and cost results based on the approach described in Section 4. DR program delivery is agnostic to residential segmentation between income qualified and market rate. As such, the potential is reported only for the residential sector as a whole.

6.1 Cost-Effectiveness Results

This section presents cost-effectiveness results by DR option and suboption based on the TRC test. Guidehouse also calculated the cost-effectiveness results based on UCT.

6.1.1 Cost-Effectiveness Assessment Results

Table 46 shows benefit-cost ratios calculated for the different DR options based on TRC and UCT. It also shows the ratios using the two different discount rates used in the study – weighted average cost of capital (WACC) and societal discount rate. There are minimal changes in the benefit-cost ratios between the TRC and SCT results using WACC and societal discount rate respectively – the benefit-cost ratios are slightly greater using the societal discount rate, but the cost-effectiveness screening of the DR options does not result in a change to the achievable potential.

Switch-based water heating under DLC, Peak Time Rebate, and EV Managed Charging are the only three options that are not cost-effective.[59] The TRC benefit-cost ratios are greater than the UCT benefit-cost ratios since incentives are not included as a cost in TRC. Dynamic pricing has the same ratio for TRC and UCT since there are no incentive costs considered in dynamic pricing.

Based on data made available by ENO, the only benefit stream captured by the TRC test is the avoided cost of generation capacity. ENO does not currently have a way to value avoided T&D capacity nor for reliability or resource adequacy. These cost-effectiveness results would improve if avoided T&D capacity benefits also were included in the cost-effectiveness assessment. Only cost-effective DR options are shown in the achievable potential results in subsequent sections.

Table 46. Reference Case Benefit-Cost Ratios by DR Options

DR Option	TRC B/C Ratio	UCT B/C Ratio	SCT B/C Ratio
Dynamic Pricing	4.75	4.75	5.31
BTMS - Battery Storage	3.18	1.00	3.18
C&I Curtailment	3.16	1.21	3.16
DLC-Thermostat-Res	1.63	0.91	1.63
DLC-Switch-Water Heating	0.39	0.33	0.40
Peak Time Rebate	0.70	0.47	0.70
EV Managed Charging	0.57	0.43	0.57

Source: Guidehouse

[59] ENO is piloting Peak Time Rebate. The analysis assumed incentive levels that the pilot currently offers. Based on that, PTR benefit-cost assessment shows that the option is not cost-effective.

As described in Section 4.3, in addition to the Reference case, Guidehouse modeled potential results for Low and High cases. For these cases, the team adjusted assumed participation levels and incentive amounts to determine the impacts on the DR achievable potential. The screening of cost-effective options does not change for the High and Low scenarios when compared with the Reference case, however the B/C ratios are different.

6.2 Achievable Potential Results

This section presents cost-effective achievable potential results by DR option, suboption, customer class and segment.[60] The discount rate change from WACC to societal does not impact the results as discussed above. Therefore, only one set of savings are provided for DR potential.

6.2.1 Achievable Potential by DR Option

Figure 42 summarizes the cost-effective achievable potential by DR option for the Reference case. Figure 43 shows the cost-effective achievable potential as a percentage of ENO's peak demand. Achievable peak demand reduction potential is estimated to grow from 15 MW in 2024 to 75 MW in 2043. Cost-effective achievable potential makes up approximately 8.4% of ENO's peak demand in 2043. The team made several key observations:

- C&I Curtailment has the greatest cost-effective achievable potential: 51% share of total cost-effective potential in 2043. C&I Curtailment potential grows rapidly starting from 14.9 MW in 2024. This growth is calibrated to evaluated programs and implementation plan values before 2026. Beginning in 2026, C&I Curtailment follows the S-shaped ramp assumed for the program over a 5-year period. By 2031, the program attains a steady participation level with 26 MW of cost-effective potential, which increases slightly to 38.3 MW in 2043.

- DLC-Thermostat-Res has a 22% share of the total cost-effective achievable potential in 2043. The potential for this measure grows from 5.7 MW in 2024 to 16.6 MW in 2043. DLC-Switch-Water Heating is not cost-effective and does not contribute to achievable potential.

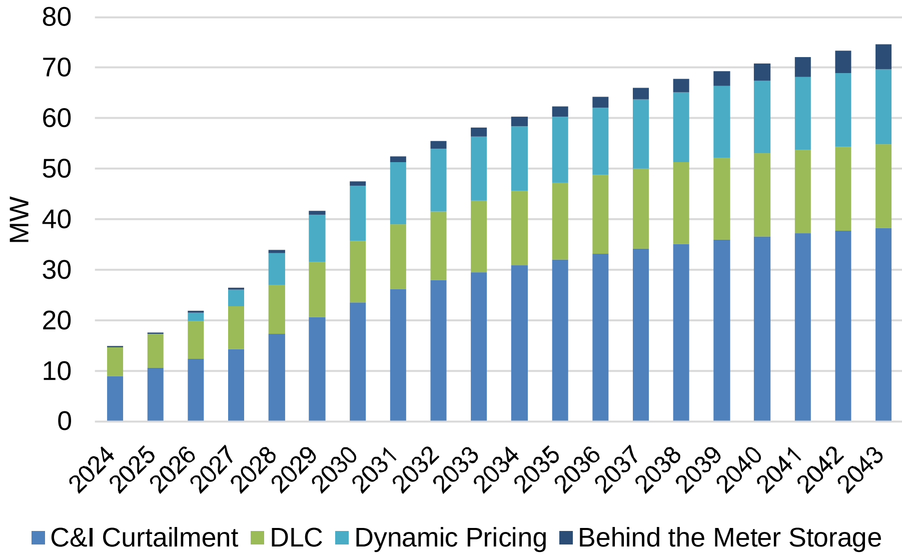
- Dynamic Pricing has a 20% share of the total cost-effective achievable potential in 2043. The dynamic pricing offer is assumed to begin in 2026 since ENO would need lead time to design and file a CPP tariff and have that approved to start offering it to customers. The program ramps up over a 5-year period (2026-2030) until it reaches a value of 12 MW. From then on, potential slowly increases from 1.6 MW in 2026 to 14.8 MW in 2043.

- BTMS contributes the remainder of the 7% share of the total cost-effective achievable potential in 2043. This program uses a linear ramp to reach steady state by 2033 and increases in residential battery count grows from 0.2 MW in 2024 to 4.9 MW in 2043.

DLC switch-based water heating, EV Managed Charging and Peak Time Rebate are not cost-effective, so do not contribute toward DR achievable potential.

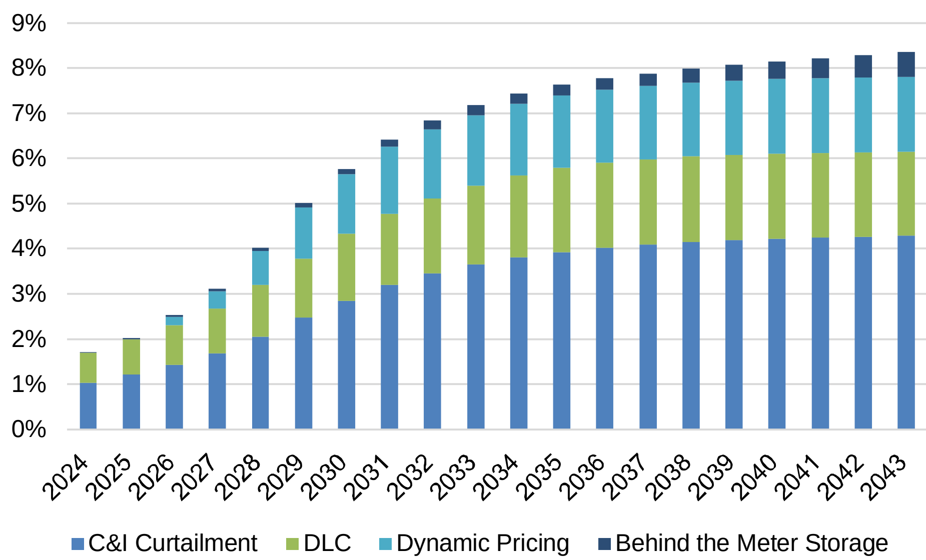
[60] Results for all DR options are presented in the Excel Results file.

Figure 42. Summer Peak Achievable Potential by DR Option (MW)



Source: Guidehouse analysis

Figure 43. Summer DR Achievable Potential by DR Option (% of Peak Demand)



Source: Guidehouse analysis

6.2.2 Achievable Potential by Case

Guidehouse developed DR potential estimates for three different cases. These cases are based on the DR program incentive levels:

- **Reference case:** Reflects DR program participation based on incentives at levels that match current programs (e.g., ENO's Smart EasyCool program) and industry best practice.

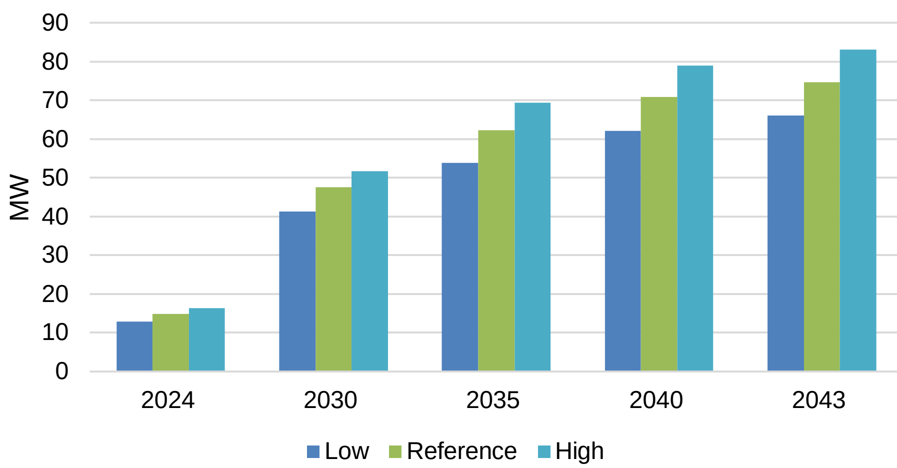
- **Low case:** Assumes incentives are 50% lower than in the Reference case. This drives program participation down and results in lower implementation costs.
- **High case:** Assumes incentives are 50% higher than in the Reference case. This drives program participation up and results in higher implementation costs.

The changes in participation with incentives are drawn on data presented in the California Demand Response Potential Study conducted by the Lawrence Berkeley National Lab.[61]

For dynamic pricing, which does not consider incentives since it is based on CPP rate offer, higher and lower participation levels in the High and Low scenarios than the Reference case are associated with variations in marketing effort, which affects program enrollment. The High case assumed 20% higher marketing costs than the Reference case while the Low case assumed 20% lower marketing costs than the Reference case.

Figure 44 and Figure 45 show the achievable potential results in terms of MW and percentage of peak demand by case, respectively. Under the Reference case, the achievable potential makes up approximately 8.4% of ENO's peak load in 2043. Under the Low and High cases, the achievable potential represents approximately 7.0% and 9.9% of ENO's peak demand in 2043, respectively.

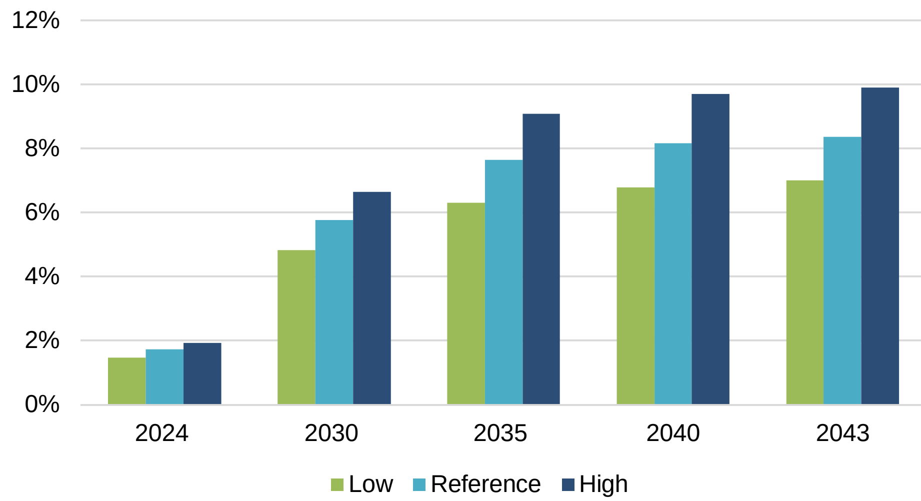
Figure 44. Summer DR Achievable Potential by Case (MW)



Source: Guidehouse analysis

[61] 2025 California Demand Response Potential Study. We also used data available in the Phase 4 California Demand Response Potential Study draft report, which has not yet been publicly released.

Figure 45. Summer DR Achievable Potential by Case (% of Peak Demand)



Source: Guidehouse analysis

6.2.3 Achievable Potential by DR Suboption

This section presents the breakdown of cost-effective potential by DR suboption. Each suboption is tied to a specific control technology and/or end use. Any suboption that is tied to a control technology is tied to the penetration of that technology in the market. This penetration trajectory is informed by saturation values from the EE potential study.

Figure 51 summarizes the cost-effective achievable potential by DR option for the Reference case. Guidehouse had the following key observations:

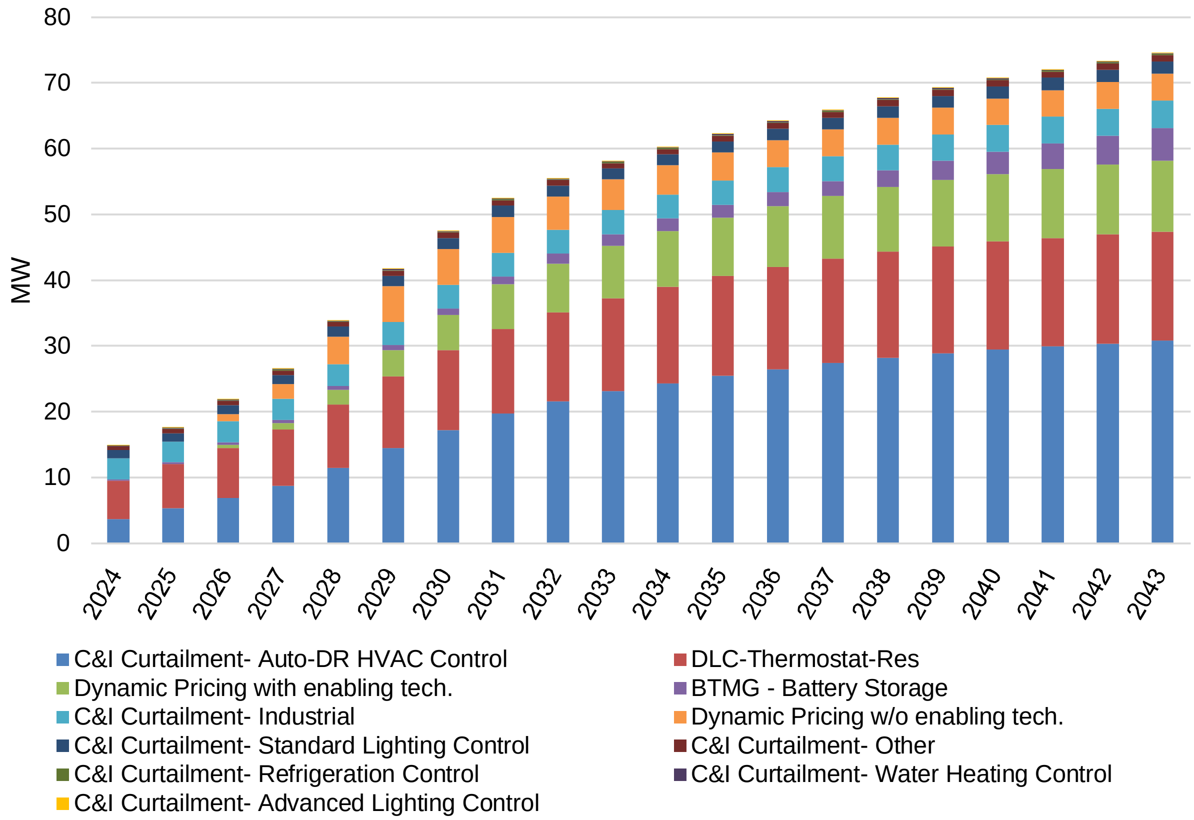
- Most of the C&I Curtailment reductions are associated with Auto-DR HVAC control, which reaches 30.8 MW or 41% of the total cost-effective potential in 2043. Other C&I Curtailment suboptions total to contribute 10% of the total cost-effective potential in 2043. Overall, C&I Curtailment options are projected to reach 38.3 MW by 2043.

- Only direct control of HVAC loads under the DLC-Thermostat suboption is cost-effective (and not water heating). This suboption makes up about 22% of the total cost-effective achievable potential in 2043 at 16.6 MW.

- Dynamic pricing makes up 20% of the total cost-effective achievable potential in 2043. Potential from customers with enabling technology in the form of thermostats/energy management systems is more than two times higher than that from customers without enabling technology—10.7 MW versus 4.1 MW in 2043.

- Batteries are projected to reach 4.9 MW of savings or 7% of the total cost-effective potential in 2043.

Figure 46. Summer DR Achievable Potential by DR Suboption



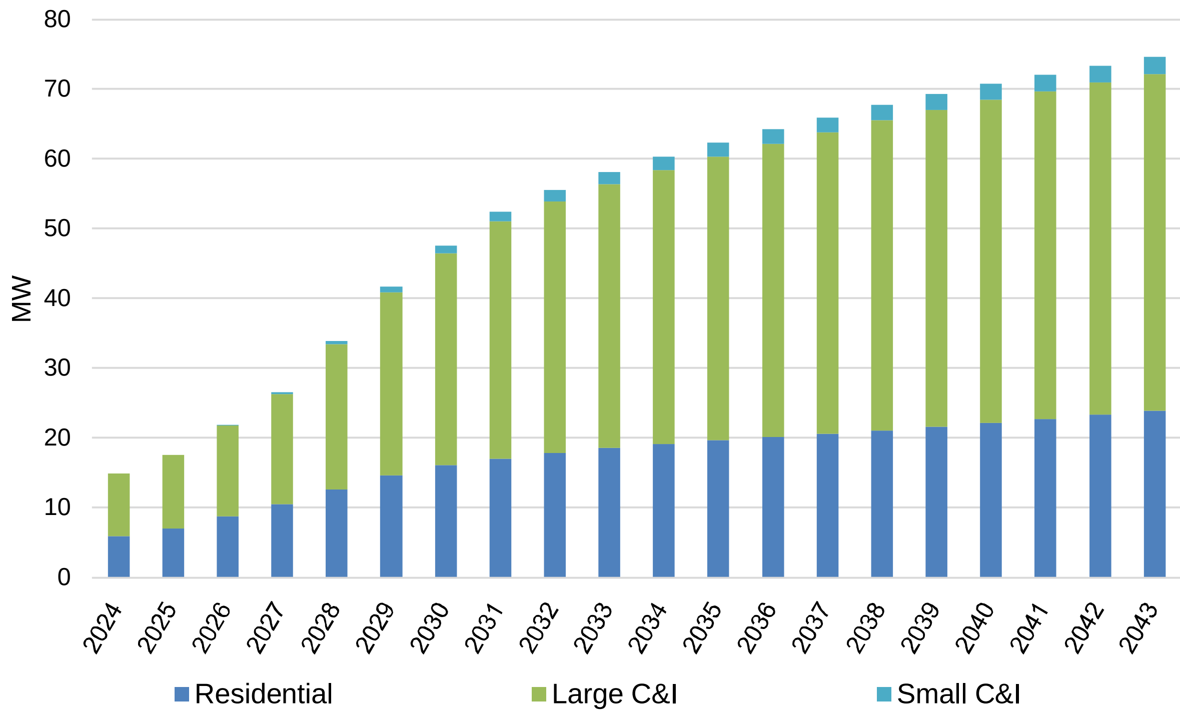
Source: Guidehouse analysis

6.2.4 Achievable Potential by Customer Class

This section presents the breakdown of cost-effective potential by customer class. The three customer classes included in the study are residential, small C&I, and large C&I. Figure 52 summarizes the cost-effective achievable potential by customer class for the Reference case. The team had the following key observations:

- Potential from residential customers makes up 32% (24 MW) of the total cost-effective achievable potential in 2043. C&I customers make up the remaining 68%.
- Potential from large C&I customers makes up 65% (48.2 MW) of the total cost-effective achievable potential in 2043. C&I curtailment with auto-DR HVAC control makes up 41% at 30.8 MW.
- Potential from small C&I customers makes up 3% (2.5 MW) of the total cost-effective achievable potential in 2043. This potential comes from Dynamic Pricing with enabling tech, the only cost-effective suboption for the small C&I customer class.

Figure 47. Summer DR Achievable Potential by Customer Class (MW)



Source: Guidehouse analysis

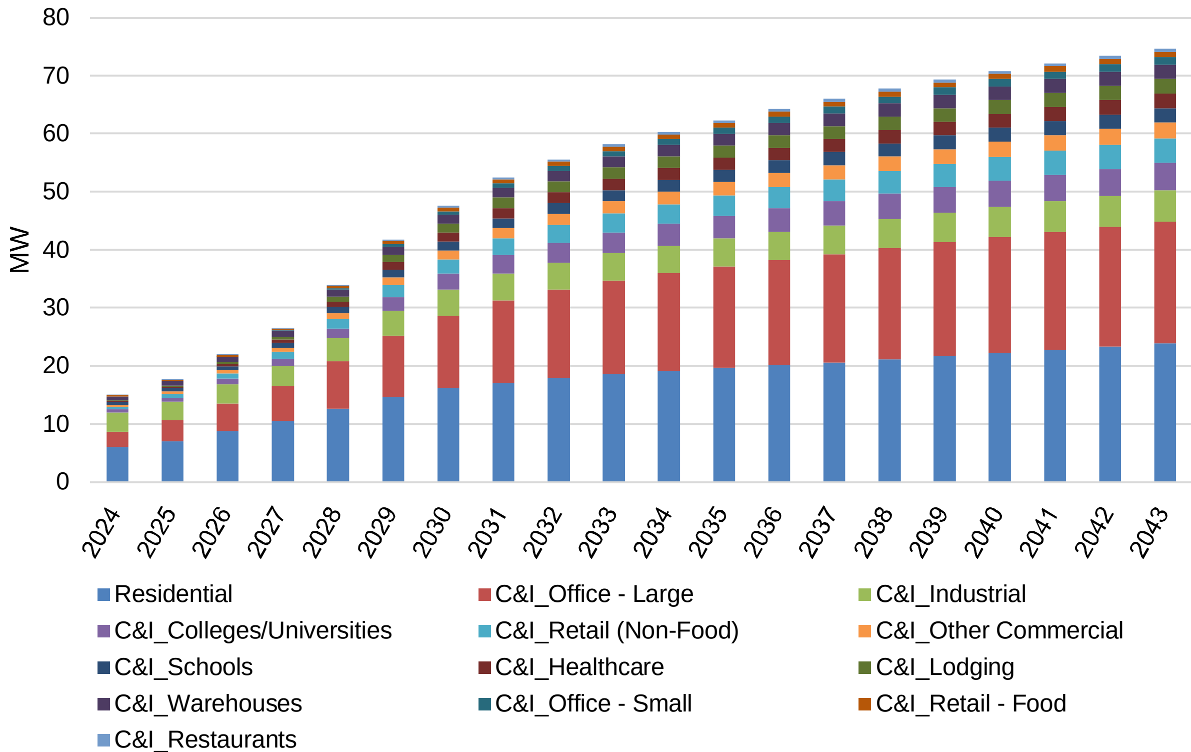
6.2.5 Achievable Potential by Customer Segment

This section presents the breakdown of cost-effective potential by customer segment. As previously discussed in the DR methodology section, these segments align with those included in the EE potential study. Guidehouse combined single family and multifamily customers into a single residential category because DR program and pricing offers are typically not distinguished by dwelling type. Government customers are included as part of the C&I sector. Savings potential analysis from streetlighting is not included in this study.

Figure 48 summarizes the cost-effective achievable potential by customer segment for the Reference case. Guidehouse had the following key observations:

- Potential from C&I customers primarily comes from large offices, which make up 28% (20.9 MW) of the total cost-effective achievable potential in 2043. This is followed by retail, colleges/universities, and industrial customers, which each make up between 5% and 7% of the total cost-effective achievable DR potential in 2043—4.2 MW, 4.7 MW, and 5.4 MW, respectively.
- All other C&I segments make up about 21% of the cost-effective achievable potential in 2043, which is 15.5 MW.

Figure 48. Summer DR Achievable Potential by Customer Segment



Source: Guidehouse analysis

6.3 Program Costs Results

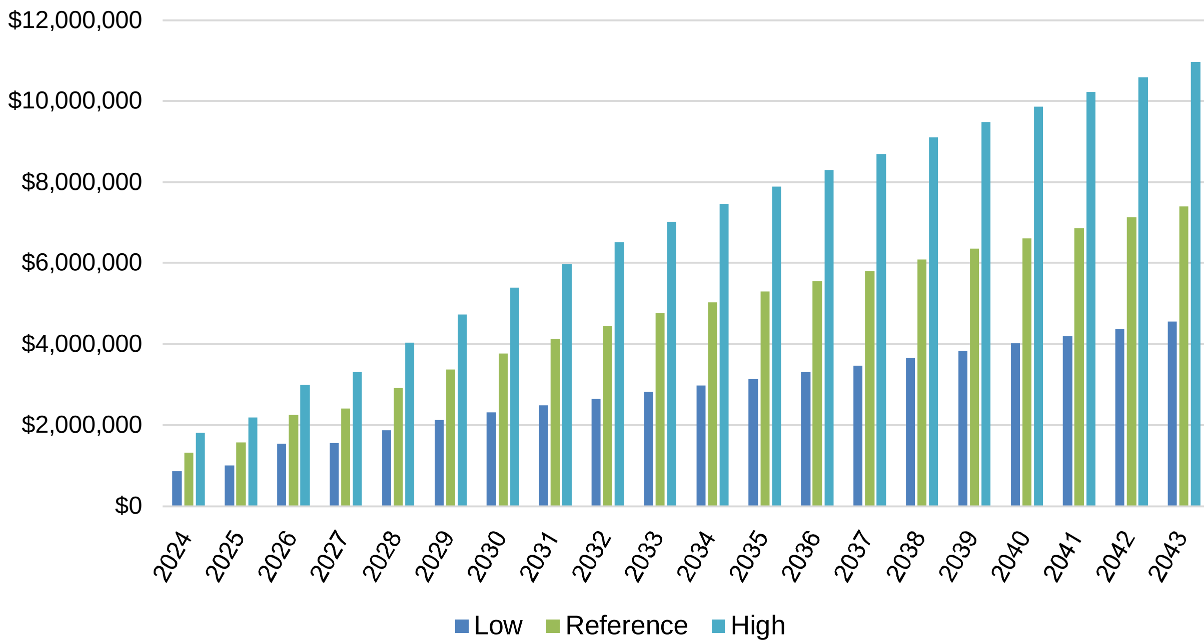
This section presents annual program costs by case and DR option.

6.3.1 Annual Costs by Case

Figure 49 shows annual implementation costs for the entire cost-effective DR portfolio by case. These costs represent the estimated total annual costs that ENO is likely to incur to realize the potential values discussed in Section 6.2. Relative to the Reference case, costs are lower and higher in the Low and High cases, respectively, due to varied incentive levels paid to customers and due to variations in marketing costs for dynamic pricing.[62]

[62] The cost results by case for all DR options is provided in the Excel Results file.

Figure 49. Annual DR Portfolio Costs by Case



Source: Guidehouse analysis

6.3.2 Annual Costs by DR Option

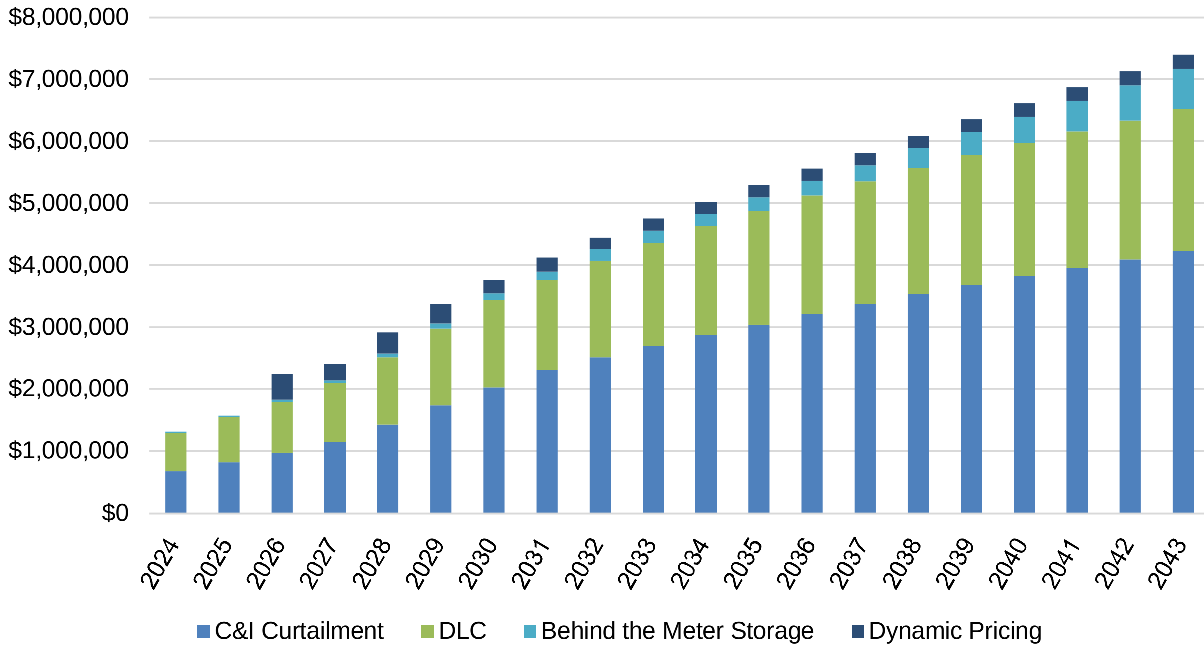
Figure 45 summarizes the annual program costs by DR option. The team observed the following:

- The program costs for DLC increase steadily from 2024 to 2043. Costs fluctuate in accordance with program participation, which is tied in part to thermostat market penetration, until it reaches its final value of $2.3 million in 2043.
- The program costs for C&I curtailment increase steadily from 2024 to 2031 until the program is fully ramped up. Costs steadily climb with program participation until it reaches its final value of $4.2 million in 2043.
- Dynamic pricing program costs are relatively high during its initial ramp up between 2026 and 2031, and then drop in 2032 when the program is fully ramped up. There is a spike in dynamic pricing costs attributed to the program development cost in 2026, which is when the ramp for this program begins. By 2030, 90% of the program is ramped up, so the incremental cost to recruit new customers is lower in 2031. Beyond 2031, costs remain low and relatively steady.
- Annual BTMS program costs increase steadily from 2024 to 2033 in line with the linear participation ramp during those years. When steady-state participation is reached, the annual rate of costs climbs with residential battery participation until it reaches its final value of $0.7 million in 2043.

Costs for the DR options that are not cost-effective (DLC-water heating, EV Managed Charging, and Peak Time Rebate) are not included in Figure 50.[63]

[63] Cost results for all DR Options are included in the Excel Results file.

Figure 50. Reference Case Annual Program Costs by DR Option

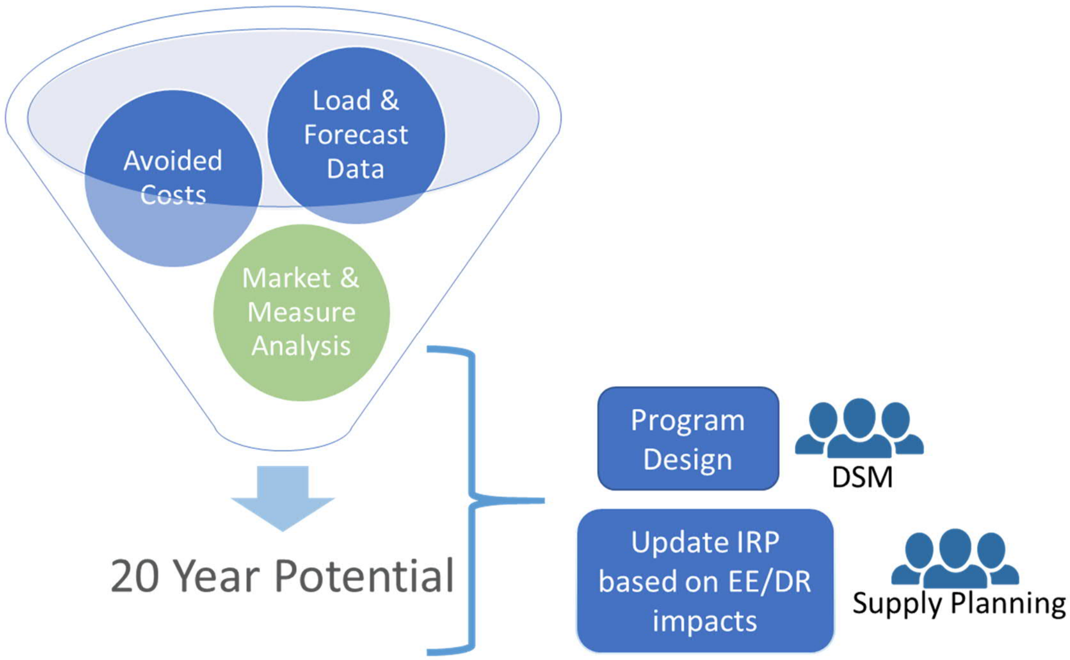


Source: Guidehouse analysis

7. Conclusions and Next Steps

Figure 50 illustrates the data inputs and outputs of the potential study, most notably for IRP and program planning.

Figure 51. Integrating Potential Study Outputs to IRP and DSM Planning



Source: Guidehouse

7.1 Benchmarking the Results to Previous Study

The team benchmarked the study results against the 2021 study and identified how the results could be used in ENO's 2024 IRP. The 2021 and 2024 potential studies leveraged the same methodology and similar data sources, however, there are key differences between the results of the two studies, aside from data updates. Table 47 provides a review of the key fields that have changed and their impact on potential.

Table 47. Key Study Input Differences

Field Type	Difference from Previous Study	Impact Potential
Building Stock (household count; 1000s sf for CI)	Res: Decrease ~5% starting in 2024 C&I: Decrease ~4% until 2025, then remain steady. Value is tied to kWh sales	Impacts of code changes could be influencing average household energy consumption Decrease technical potential
kWh Sales	Res: Steady C&I: Decrease ~3%	Large drop in one C&I account confirmed by ENO Decrease technical potential

Field Type	Difference from Previous Study	Impact Potential
kWh Avoided Cost	Decrease; this cycle is 85% of the value of last cycle in terms of present value for a measure life of 20 years	In initial years, there is a an increase and then a subsequent decrease of the BP23 Annual Load Weighted OpCo avoided energy costs (Nominal $/MWh) compared to the 2021 study. Avoided energy cost embeds price of carbon – last cycle used a separate price of carbon as an additional benefit in 2026 and beyond – ~4.2% reduction in benefits compared to last cycle. For BP23, carbon starts in 2036. Decrease economic potential and risks overall portfolio cost-effectiveness
kW Avoided Cost	Increase	118% of the value in the last cycle since BP24 uses a combustion turbine with hydrogen co-firing capability. Helps for summer peaking measures (HVAC)
Discount Rate	WACC: Decrease 7.09% to 6.86% New Societal (3%) cost analysis	Increases value of future stream of benefits Using a societal discount rate increases value to DSM
Variable Program Cost	Increase for Res; decrease for CI	Lighting removed from Residential Hinders cost-effectiveness for Res

Source: Guidehouse

EE

The differences in results and projected achievable potential between the 2021 and 2024 studies were driven in part by the following changes in methodology and approach:

- Calibration targets differed for the two studies:
  - The 2021 study used the planned targets for savings from the PY10-12 implementation plan, with a 2% savings goal for 2025.
  - The 2024 study used the actual savings and budget from PY 10-12 (2020-2022) and performance to date for PY 13 (2023). Underperformance was seen in the C&I sector across the years 2020-2023 and was consistent with results in other jurisdictions, based on Guidehouse's research.
- Different assumptions on planned rollout for home energy reports and savings percentage of consumption (from 1.3% in 2021 to 0.8% 2024)
- Updated data on residential saturation and density using the 2022 ENO RASS data

- Updates to commercial saturation values based on year-over-year program data (for measures where data was available)
- Changes in federal residential lighting standards, eliminating any residential lighting end use potential
- Updates in the TRM from version 4.0 to version 7.0, resulting in many changes in residential measure assumptions including those reflecting updated state building code changes
- Removal of behavior programs that do not show any promise for implementation or significant savings in the ENO service area, or in other utility territories

DR

The 2024 and 2021 DR analysis differed in the following ways:

- Current peak definition for MISO is slightly altered from the one used in the 2021 study in defining the peak period for calling DR programs.
- Added new DR options to the analysis (EV Managed Charging and Peak Time Rebate)
- Used historical program implementation data for Smart Thermostats and for C&I Curtailment and pilot program information from ENO’s most recent activities. There has been growth in residential and C&I program participation compared with the data from 3 years ago.
- Updated BTM battery projections and assumed all batteries are paired with solar for the DR analysis, with battery projections tied to solar projections.
- Updated data on the penetration of smart thermostat data and for other control technologies based on the EE analysis.

7.2 IRP

The potential study provides forecast savings inputs for use in the IRP modeling. These inputs are provided by sector, segment, and end use because each combination of these items is mapped to a load shape . Each measure is mapped to one or more DSM programs. Guidehouse then developed a load shape representative of each DSM program. The DSM program load shape represents the aggregate hourly energy savings for the group of measures included in the program over the 20-year planning period. These load shapes are what define the hourly usage profiles for the DSM program portfolio. The data is aligned with the Council’s IRP rules, which request that the data supplied include a description of each demand side resource considered, including a description of resource expected penetration levels by year, hourly load reduction profiles for each DSM program, results shown using both the utility’s WACC and the societal discount rate, and results of all four standard cost-effectiveness tests were calculated.

7.3 Program Planning

DSM potential studies are inherently different from DSM program portfolio designs. The long-term achievable potential identified for a 20-year period through this study is different from the short-term savings potential that would be identified through a DSM program portfolio design effort targeting a 3-year period. However, programmatic design (such as delivery methods and marketing strategies) will have implications for the overall savings goals and projected cost.

As mentioned, near-term savings potential, actual achievable goals, and program costs for a measure-level implementation will vary from the savings potential and costs estimated in this long-term study. This potential study is one element to consider in program design, along with historical program participation and current market conditions (with the team members on the ground):

- Significant savings potential exists in promoting retrocommissioning, occupancy sensor controls, and interior high bay and 4-foot LEDs for the C&I sector.
- There is high potential in O&M (residential duct sealing and AC tune-up) and behavior-type programs such as home energy reports in the residential sector.
- There is significant DR potential with large C&I customers from both C&I Curtailment (with increased adoption of DR-enabling control technologies) and dynamic pricing. Residential sector contribution from smart thermostat DLC is projected to grow progressively with increasing adoption of smart thermostats along with contribution from dynamic pricing.

7.4 Further Research

Finally, the potential study identified data gaps in characterizing ENO's market and measures. This is common for most utilities; however, for ENO to have more accurate potential estimates and information to support DSM planning, there is ENO-specific data that could support this end goal:

- Baseline and saturation studies for non-residential (C&I) such as an end use and technology survey
- Customer payback acceptance analysis or other market adoption study specific to the ENO service area either via customer survey, Delphi panel of regional stakeholders, or other method
- Exploration of behavior program opportunities in the ENO service territory

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

- Review and update the TRM for high impact measures especially those that have changed values from one evaluation cycle to another to understand the differences over time
- Consider including dynamic pricing options as the AMI rollout is completed
- Analyze the merits of time of day usage as it aligns to grid-based energy resources and their associated costs; peak savings may have a very different valuation in addressing the time of day of the savings versus an annualized avoided cost
- Explore cost-effective opportunities, pricing structures, and research on additional benefits to BTM, including battery storage.

A. EE Detailed Methodology

Appendix A includes the various data inputs, definitions, assumptions, and analysis needed for the potential analysis.

A.1 End-Use Definitions

Table 48. Description of End Uses

Segment	End Use	Definition
Residential	Total Facility	Consumption of all electric end uses in aggregate
	Lighting Interior	Overhead lights, lamps, etc.
	Lighting Exterior	Spotlighting, security lights, holiday/seasonal lighting, etc.
	Plug Loads	Large/small appliances including ovens, refrigerators, freezers, clothes washers, etc. Televisions, computers and related peripherals, and other electronic systems
	HVAC	All cooling, including both CAC and room or portable AC; all heating, including both primary heating and supplementary heating; motor drives associated with heating and cooling
	Water Heating	Heating of water for domestic hot water use
	Other	Miscellaneous loads
C&I	Total Facility	Consumption of all electric end uses in aggregate
	Lighting Interior	Overhead lights, lamps, etc. (main building and secondary buildings)
	Lighting Exterior	Spotlighting, security lights, holiday/seasonal lighting, etc. (main building and secondary buildings)
	Plug Loads	Computers, monitors, servers, printers, copiers, and related peripherals
	HVAC	All cooling equipment, including chillers and direct expansion cooling; all heating equipment, including boilers, furnaces, unit heaters, and baseboard units; motor drives associated with heating and cooling
	Refrigeration	Refrigeration equipment including fridges, coolers, and display cases
	Water Heating	Hot water boilers, tank heaters, and others
	Other	Miscellaneous loads including elevators, gym equipment, and other plug loads

Source: Guidehouse

A.2 Residential Sector

The following sections detail the approach used to determine electricity consumption by segment, the approach used to estimate end-use proportions, and the resulting residential household stock. To do so, Guidehouse needed to determine three pieces of information:

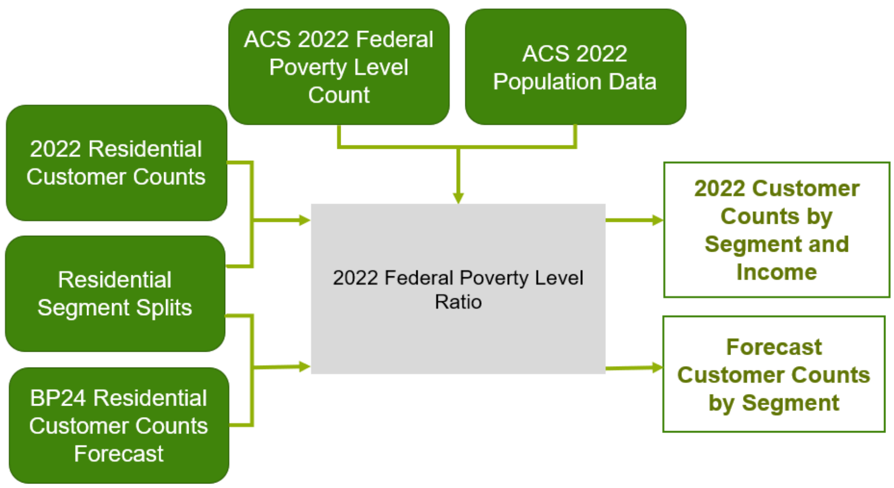
- Base year and forecast stock
- Base year and forecast total consumption

- Base year and forecast consumption by end use

1. Base Year and Forecast Residential Stock

Figure 52 outlines Guidehouse's approach to determining the base year and forecast residential stock. As a part of the 2024 report, Guidehouse needed to disaggregate values for IQ and market rate residential customers. Guidehouse used 2022 American Census Survey data,[64] along with data provided by ENO to calculate the proportion of residential counts for each income level according to ENO's IQ definition of less than 200% of the Federal Poverty Level.[65]

Figure 52. Residential Stock Base Year and Reference Case Approach



Source: Guidehouse

To define the base year residential sector inputs, Guidehouse determined the total base year stock using ENO's number of households in the class breakdown. Guidehouse needed to divide this total into single-family and multifamily segments. To do so, Guidehouse used the class breakdown from analysis of the 2022 RASS data provided by ENO and multiplied these splits by the total base year stock. To define the forecast residential sector inputs, Guidehouse used the same class breakdown from analysis of the 2022 RASS data and multiplied these splits by the total residential customer counts in the BP24 sales forecast.

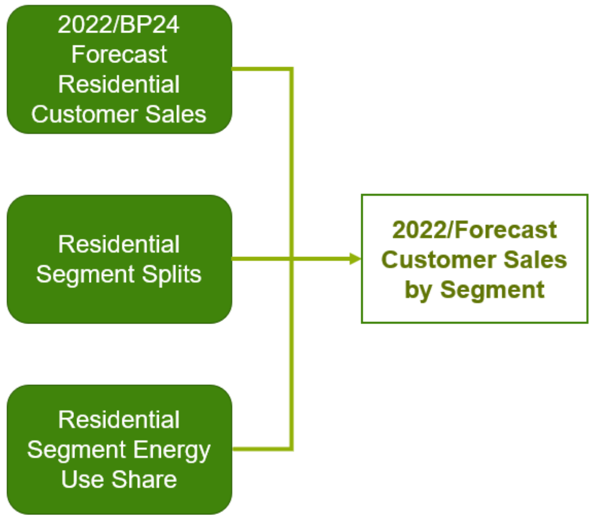
2. Base Year and Forecast Total Consumption

Figure 53 outlines Guidehouse's approach to determining the base year and forecast residential sales.

[64] https://data.census.gov/table/ACSST1Y2022.S1701?q=Federal+Poverty+level+in+New+Orleans+2022

[65] The Federal Poverty Level can be defined by total income per household and depends on the number of residents living in that house. Guidehouse research used base year values and definitions for its analysis: https://www.healthcare.gov/glossary/federal-poverty-level-fpl/.

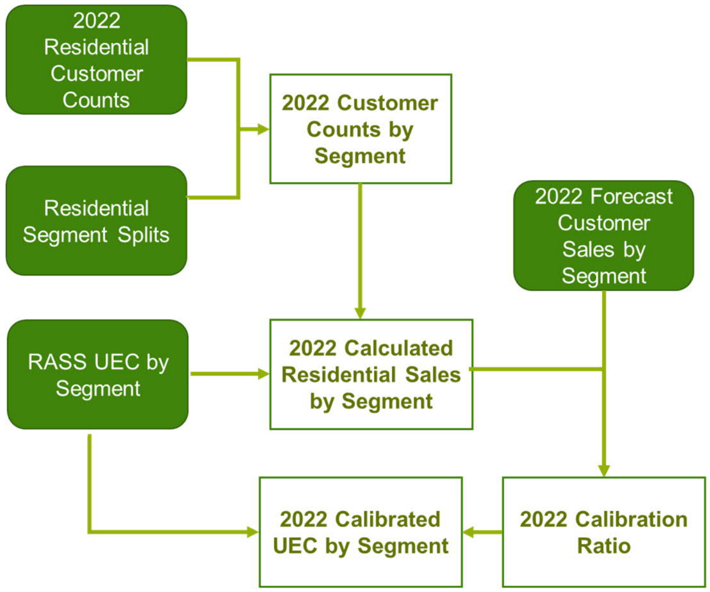
Figure 53. Base Year and Forecast Residential Sales Approach



Source: Guidehouse

Base year sales used the 2022 reported sales provided by ENO. Guidehouse calculated the residential UEC using analysis of the 2022 ENO RASS data by segment level and calibrated using the stock and sales by household split for an adjusted UEC. Therefore, the total 2022 stock times the adjusted UEC equals the total residential sales for 2022. Figure 54 and Table 49 provide the flow diagram of the analysis and results, respectively.

Figure 54. Base Year Calibrated UEC by Residential Segment



Source: Guidehouse

Table 49. 2022 Unit Energy Consumption (kWh/Account)

Building Segment	RASS 2022 UEC	Calibrated UEC
Single-Family	15,235	13,686
Multifamily	9,349	8,398

Source: Guidehouse analysis

3. Base Year and Forecast Consumption by End Use

To disaggregate the total residential consumption for single-family and multifamily customers to the end-use level, Guidehouse relied on end-use proportions used in the 2021 study.[66] Guidehouse calculated the proportion of energy used by each end use (e.g., this proportion of the consumption is a percentage of the total segment-level consumption). Guidehouse derived these proportions using Guidehouse DOE's EnergyPLUS prototypical models with adjustments to reflect ENO building stock and other Guidehouse adjustments based on lessons learned across utility jurisdictions. Guidehouse assumed the end-use proportions were constant across the forecast period. This assumption has minimal impact to the overall potential because all the residential sector savings calculations are not dependent on end-use consumption proportions except for behavioral measures. Table 50 shows the resulting end-use proportions by residential end use, which is an overall percentage of each household.

Table 50. Residential End Use Proportion (% of whole building kWh)

End Use	Percentage
Hot Water	4.4%

[66] The 2022 RASS provided by ENO included no data concerning end-use proportions. Guidehouse used the previous study methodology.

End Use	Percentage
HVAC	47.8%
Lighting Exterior	3.1%
Lighting Interior	19.4%
Plug Loads	25.3%
Total	**100.0%**

Source: Guidehouse analysis

A.3 C&I Sector

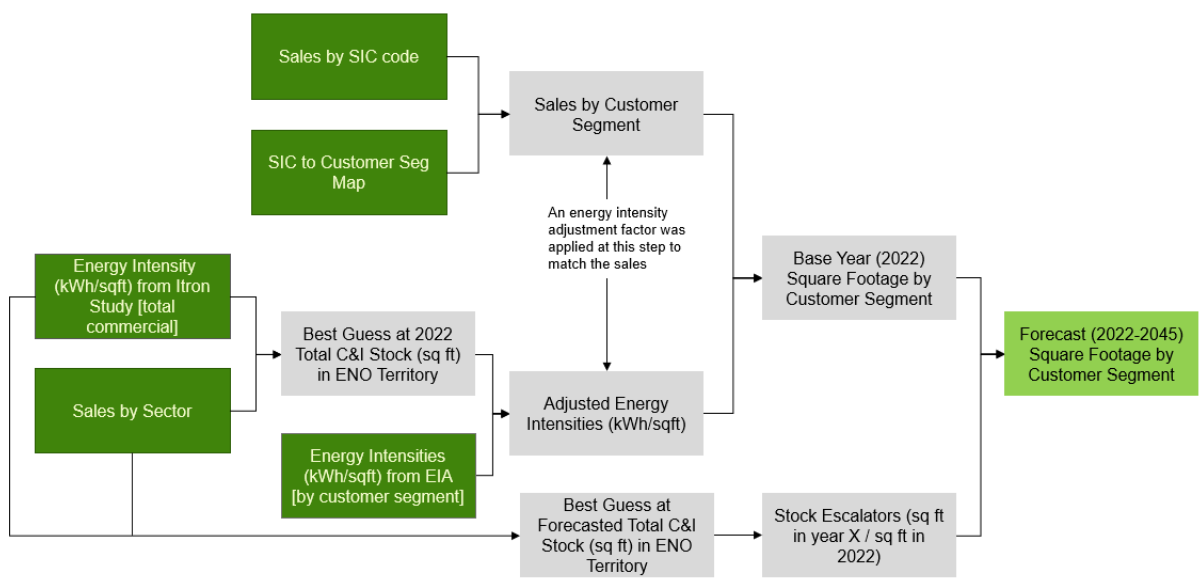
The following sections describe the detailed approach used to determine electricity consumption by segment, the approach used to estimate end-use proportions, and the resulting C&I stock. Guidehouse needed to determine two pieces of information:

- Base year and forecast stock and total consumption
- Base year and forecast consumption by end use

1. Base Year and Forecast C&I Stock and Total Consumption

Figure 55 outlines Guidehouse's approach to determining the base year and forecast C&I stock.

Figure 55. C&I Base Year and Forecast Approach



Source: Guidehouse

To define the base year C&I sector stock inputs, Guidehouse began with customer-level billing data, which included customers' SIC codes and 2022 annual consumption. This data came in three datasets: commercial, industrial, and governmental. Guidehouse used a mapping of SIC codes to customer segments derived as part of the 2018 study. By joining the mapping file to each of the three consumption datasets, Guidehouse aggregated the 2022 consumption to the customer segment level for each of the commercial, industrial, and governmental subsectors. ENO also provided 2022 total consumption for each of the commercial, industrial, and governmental subsectors in the class breakdown dataset.

To estimate square footage from segment-level energy usage, Guidehouse developed segment-level energy intensities (kWh/square foot). Guidehouse began with segment-level intensities from US EIA.[67] Table 51 shows the mapping of segments in the EIA intensity data to the segments of this study.

Table 51. C&I EUI Segments to Study Segment Mappings

EIA Principal Building Activity	Study Segment
Education	Colleges/Universities and Schools
Health Care	Healthcare
Buildings with Manufacturing	Industrial/Warehouses
Lodging	Lodging
Office	Office – Large and Office – Small
Public Assembly	Other Commercial
Food Service	Restaurants
Food Sales	Retail – Food
Mercantile	Retail – Non-Food

Source: Guidehouse analysis

For the non-industrial segments, Guidehouse used overall commercial sector intensities from Itron to adjust the segment-level intensities from EIA. To do so, Guidehouse calculated the best estimate of overall square footage in the commercial sector by dividing total 2022 sales by the Itron intensity. Guidehouse then calculated an adjustment factor by dividing the best estimate of total stock by the sum of the segment-level stock derived from EIA intensities. Guidehouse multiplied the adjustment factor by the segment-level EIA intensities to produce final segment-level EIA intensities that average out to the Itron overall intensity. For industrial, Guidehouse used the EIA intensity directly as the final intensity for the industrial segment. Finally, Guidehouse divided the segment-level base year sales (kWh) by the adjusted segment-level intensities (kWh/square feet) to calculate segment-level stock (square feet) in the base year.

Guidehouse used the base year segment-level stock as the foundation for the stock forecast (2024-2043). For the non-industrial segments, Guidehouse used the BP24 sales forecast divided by the Itron sector-level intensity forecasts to calculate forecast stock (square feet) for the C&I sector as a whole. Guidehouse used this stock forecast to establish escalation factors (square feet in year X/square feet in 2022) for the C&I stock forecast. In doing so, the escalators account for assumed DSM over time for both the sales and intensity. For the industrial segment, Guidehouse used the BP24 sales forecast to calculate escalation factors. Once derived, Guidehouse multiplied the escalation factors by the base year segment-level stock to calculate the segment-level stock forecast.

2. Base Year and Forecast Consumption by End Use

To disaggregate the total C&I consumption for each segment to the end-use level, Guidehouse relied on end-use proportions used in the 2021 study. Guidehouse calculated the proportion of

[67] Table C.20 Electricity consumption and conditional energy intensity by climate zone. Guidehouse used the hot/very hot climate zone designation. https://www.eia.gov/consumption/commercial/data/2018/ce/xls/c20.xlsx

energy used by each end use (e.g., this proportion of the consumption is X% of the total consumption). Guidehouse derived these proportions using Guidehouse's DOE EnergyPLUS prototypical models with adjustments to reflect ENO building stock and other Guidehouse adjustments based on lessons learned across utility jurisdictions. Guidehouse assumed the end-use proportions were constant across the forecast period. This assumption has minimal impact to the overall potential because most of the commercial sector savings calculations (except for behavioral) are independent from end-use consumption proportions. Table 52 shows the resulting end-use proportions by C&I end use, which is an overall percentage of each building type segment consumption.

Table 52. C&I Reference Case End-Use Proportions Forecast (% of kWh)

Segment	End Use	2022-2043
Colleges/Universities	Hot Water	1.5%
	HVAC	55.0%
	Lighting Exterior	2.7%
	Lighting Interior	25.4%
	Plug Loads	14.2%
	Refrigeration	1.2%
	Total Facility	**100.0%**
Healthcare	Hot Water	1.2%
	HVAC	52.0%
	Lighting Exterior	0.8%
	Lighting Interior	21.0%
	Plug Loads	24.5%
	Refrigeration	0.5%
	Total Facility	**100.0%**
Industrial/Warehouses	Hot Water	12.6%
	HVAC	44.2%
	Lighting Exterior	1.6%
	Lighting Interior	33.2%
	Plug Loads	5.4%
	Refrigeration	3.1%
	Total Facility	**100.0%**
Lodging	Hot Water	25.3%
	HVAC	32.3%
	Lighting Exterior	1.2%
	Lighting Interior	15.9%
	Plug Loads	24.5%
	Refrigeration	0.8%
	Total Facility	**100.0%**
Office - Large	Hot Water	0.4%
	HVAC	49.3%

Segment	End Use	2022-2043
	Lighting Exterior	0.2%
	Lighting Interior	31.1%
	Plug Loads	19.1%
	Total Facility	**100.0%**
Office - Small	Hot Water	0.4%
	HVAC	50.5%
	Lighting Exterior	0.2%
	Lighting Interior	30.3%
	Plug Loads	18.6%
	Total Facility	**100.0%**
Other Commercial	Hot Water	6.8%
	HVAC	30.5%
	Lighting Exterior	0.9%
	Lighting Interior	13.7%
	Plug Loads	44.5%
	Refrigeration	3.6%
	Total Facility	**100.0%**
Restaurants	Hot Water	5.2%
	HVAC	37.0%
	Lighting Exterior	4.5%
	Lighting Interior	7.4%
	Plug Loads	42.7%
	Refrigeration	3.2%
	Total Facility	**100.0%**
Retail - Food	Hot Water	0.1%
	HVAC	24.8%
	Lighting Exterior	1.2%
	Lighting Interior	22.4%
	Plug Loads	11.5%
	Refrigeration	40.1%
	Total Facility	**100.0%**
Retail (Non-Food)	Hot Water	11.0%
	HVAC	33.5%
	Lighting Exterior	3.0%
	Lighting Interior	44.3%
	Plug Loads	5.0%
	Refrigeration	3.2%
	Total Facility	**100.0%**
Schools	Hot Water	2.0%

Segment	End Use	2022-2043
	HVAC	57.1%
	Lighting Exterior	2.6%
	Lighting Interior	23.9%
	Plug Loads	13.3%
	Refrigeration	1.1%
	Total Facility	**100.0%**

Source: Guidehouse analysis

A.4 Measure List and Characterization Assumptions

Guidehouse developed the measure list and characterizations based on internal expertise, ENO-specific data, the New Orleans TRM version 7.0, and secondary sources where necessary. The measure characterization is provided in a separate workbook.

A.5 Avoided Costs and Cost-Effectiveness

Guidehouse input several cost-related inputs to determine the cost-effectiveness of measures over the study period. This section details those inputs.

Avoided Energy Costs

ENO provided the BP23[68] avoided costs through 2067 in nominal dollars. Guidehouse projected these costs over the remainder of the study period plus the longest measure life (25 years) using 2% inflation rate starting in 2043 to input into the model. Figure 56 shows the avoided energy cost projections or forecast locational marginal prices in nominal dollars.

[68] BP23 refers to the vintage of a set of planning and modeling assumptions. At the time of this study, BP24 values were available for avoided capacity, but not yet avoided energy. Therefore, BP23 was the latest assumption set of avoided energy values available.

Figure 56. ENO BP 23 Avoided Energy Cost Projections

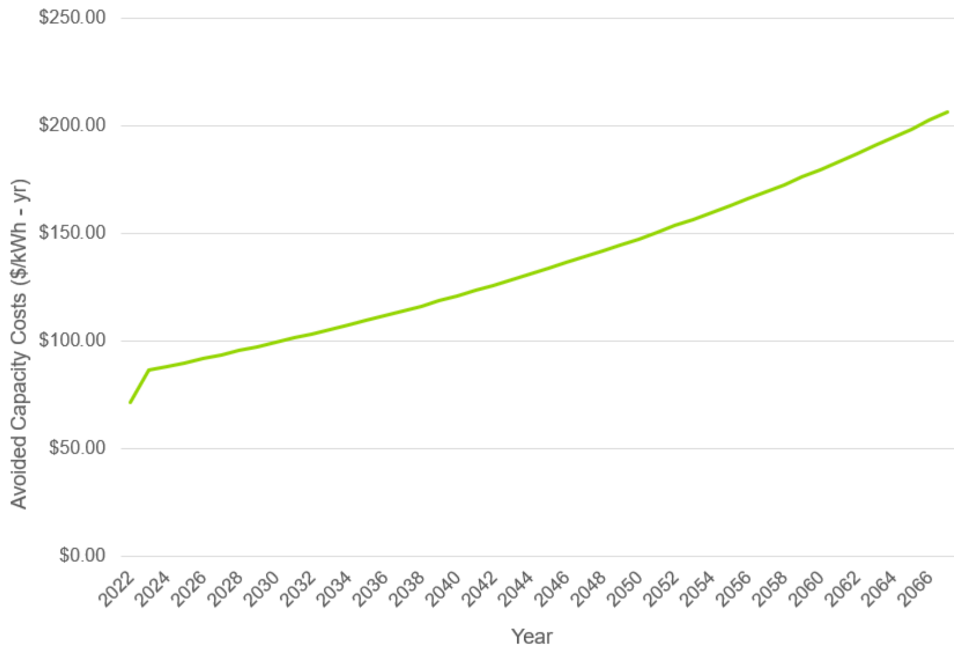
- CO2 price is lower in BP23. The CO2 price did not start until 2035 in BP23 and started in 2026 in BP20, which was used in the 2021 IRP potential study.
- The big driver is the amount of solar added in BP23. BP23 projects almost twice the amount of solar being added to the MISO market as compared to BP20, which has the effect of driving LMPs lower.
- Carbon costs are embedded in the BP23 values.

Avoided Capacity Cost

ENO provided the BP24[69] avoided capacity costs through 2052 in nominal dollars. Guidehouse projected these costs over the remainder of the study period plus the longest measure life (15 years) using a 2% inflation rate starting in 2053 to input into the model. Figure 57 shows these costs over the study period in nominal dollars.

[69] BP24 refers to the vintage of a set of business planning and modeling assumptions used by ENO. At the time of this study, BP24 was the latest assumption set available for avoided capacity costs.

Figure 57. ENO BP24 Avoided Capacity Projections



Source: Guidehouse

A.6 Cost-Effectiveness Calculations

The potential analysis uses two forms of cost-effectiveness calculations. The TRC test is for utility cost-effectiveness. There also is the PCT, which is mostly addressed by calculating the participant payback period instead of the benefit-cost ratio for the PCT. This section describes these tests, the inputs, and how they are used for the potential study.

TRC Test

The TRC test is a benefit-cost metric that measures the net benefits of EE measures from the combined stakeholder viewpoint of the utility (or program administrator) and the customers. The TRC benefit-cost ratio is calculated in the model using Equation 8.

Equation 8. Benefit-Cost Ratio for TRC Test

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

Where:

- PV( ): The present value calculation that discounts cost streams over time
- Avoided Costs: The monetary benefits resulting from electric energy and capacity savings—e.g., avoided costs of infrastructure investments and avoided fuel (commodity costs) due to electric energy conserved by efficient measures
- Technology Cost: The incremental equipment cost to the customer
- Admin Costs: The administrative costs incurred by the utility or program administrator

Guidehouse calculated TRC ratios for each measure based on the present value of benefits and costs over each measure's life. Free ridership's effects are not present in the results from this study, so the team did not apply an NTG factor. Providing gross savings results will allow ENO to easily apply updated NTG assumptions in the future and allow for variations in NTG assumptions.

The administrative costs are included when reporting sector-specific or portfolio-wide cost-effectiveness. However, they are not included at the measure level for economic potential screening. For this screening, the focus is to identify measures that are cost-effective on the margin prior to assessing effects for the achievable potential where administrative costs are considered depending on the amount and level of programmatic spend.

Participant Payback Period

Guidehouse calculates the customer payback period to assess customer potential to implement the energy-saving action. The payback period is used to assess customer acceptance and adoption of the measure. Additional details are described in Section 4.3. The payback period is calculated after the incentive is applied to the measure cost. Equation 9 demonstrates the calculation.

Equation 9. Participant Payback Period

$$\boldsymbol{Payback} = \frac{\boldsymbol{Annual\ kWh\ Saved}\ \times \boldsymbol{Annualized\ Retail\ Rate}\ \left(\$/_{\boldsymbol{kWh}}\right)}{\boldsymbol{Incremental\ Measure\ Cost} - \boldsymbol{Incentive}}$$

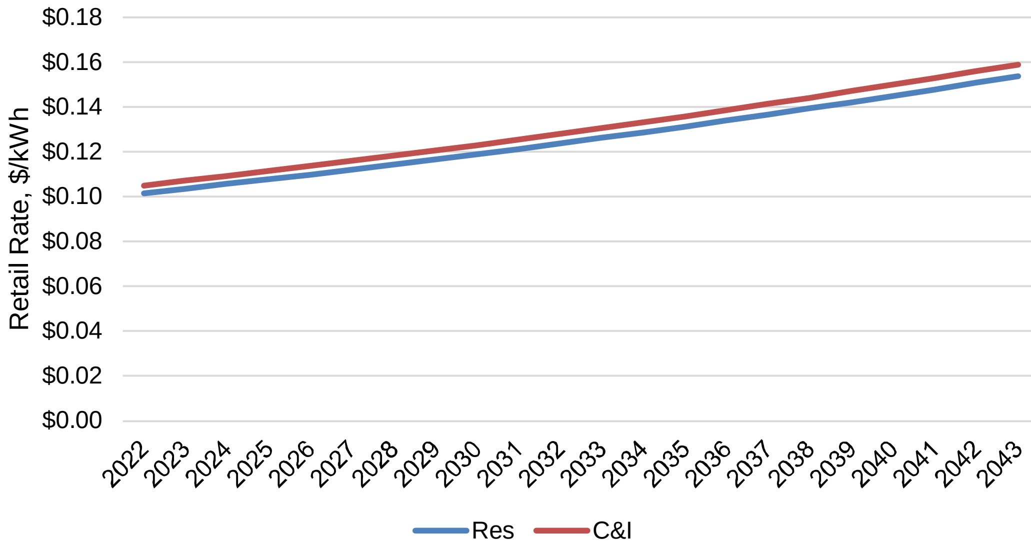
Where:

- Annual kWh Saved: Calculated for each measure and segment (as appropriate)
- Annualized Retail Rate: The overall cost a customer pays per kilowatt-hour consumed (see Appendix A.7)
- Incremental Measure Costs: The costs the participant would pay (without an incentive) to implement the measure; in ROB and NEW, depending on the measure, the difference in the cost of the efficiency and standard equipment is used instead of the full cost of installation (material and labor costs)
- Incentives: The incentive costs paid for a customer's out of pocket costs to be reduced

A.7 Retail Rates

Customer economics is a primary driver of EE measure adoption, so Guidehouse used a forecast of electric retail rates for each sector to estimate achievable energy and demand potential. Because ENO did not have a forecast of retail rates readily available, the team calculated the retail rates based on historic sales. ENO provided 2021 - August 2023 (revenue ($) and sales (kWh) by rate class and rate schedule, as well as customer counts by rate class and rate schedule. For each rate schedule, Guidehouse divided revenue by sales to calculate an average rate ($/kWh). Then, for each sector (residential and non-residential), Guidehouse calculated an average rate ($/kWh) weighted by the number of customers on each rate schedule. Guidehouse then assumed the rates would increase with inflation, or 2% per year shown in Figure 58.

Figure 58. Electricity Retail Rate Forecast: 2022-2043



Source: Guidehouse analysis

A.8 Other Key Input Assumptions

As Table 53 shows, Guidehouse used the discount rates provided by ENO and an inflation rate consistent with the utility's planning.

Table 53. Potential Study Assumptions

Variable Name	Percentage
Discount Rate (WACC)	6.86%
Discount Rate (Societal)	3.00%
Inflation Rate	2.00%

Source: ENO

B. Residential Segment Level Results

The Guidehouse team analyzed the residential segment for the 2024 Study by market rate and income qualified customers. The market characterization details are provided in Table 15 and Appendix A.2. Guidehouse concluded that the Residential sector is composed of 48% income qualified and 52% market rate customers. The incentive structure for income qualified measures is at 100% of measure costs for all cases, except for the Low case.

Table 54 and Table 55 provide the incremental energy savings for WACC and Societal discount rates, respectively. The savings split is almost even despite the income qualified sector being almost 5% smaller. Since the High case does not differentiate by housing segment for the incentive levels, the savings potential between income qualified and market rate reflects the difference in population size.

Table 54. Income Qualified vs. Market Rate by Case Incremental Energy Savings (GWh/year), WACC

	Income Qualified				Market Rate			
Year	Reference	2% Savings	High	Low	Reference	2% Savings	High	Low
2024	12.6	15.0	17.2	7.9	12.8	15.6	18.8	8.2
2025	14.5	17.5	20.2	9.2	14.6	18.2	22.2	9.5
2026	16.8	20.5	23.8	10.8	16.7	21.2	26.2	11.0
2027	19.2	23.7	27.6	12.5	19.1	24.5	30.3	12.7
2028	21.6	27.0	31.1	14.2	21.4	27.9	34.2	14.5
2029	23.7	29.9	34.1	15.9	23.4	30.9	37.5	16.2
2030	25.1	32.0	36.0	17.2	24.9	33.1	39.6	17.6
2031	25.4	32.9	36.4	18.1	25.4	34.1	40.1	18.6
2032	24.5	32.3	35.0	18.3	24.9	33.5	38.6	18.9
2033	22.6	30.2	32.3	18.0	23.3	31.4	35.5	18.8
2034	20.4	27.2	28.8	17.0	21.5	28.4	31.6	17.9
2035	17.8	23.8	25.1	15.5	19.1	25.0	27.5	16.5
2036	16.5	20.6	22.0	13.8	17.8	21.7	24.0	14.9
2037	14.8	17.7	19.3	12.2	16.2	18.8	21.0	13.2
2038	13.4	15.5	17.2	10.7	14.6	16.6	18.7	11.7
2039	12.3	13.9	15.7	9.5	13.4	14.9	17.0	10.2
2040	11.5	12.7	14.6	8.5	12.6	13.7	15.8	9.1
2041	10.9	11.9	13.7	7.7	11.8	12.8	14.9	8.1
2042	10.3	11.2	12.9	7.1	11.2	12.1	14.0	7.3
2043	10.0	10.8	12.5	7.0	10.9	11.7	13.6	7.2

Source: Guidehouse analysis

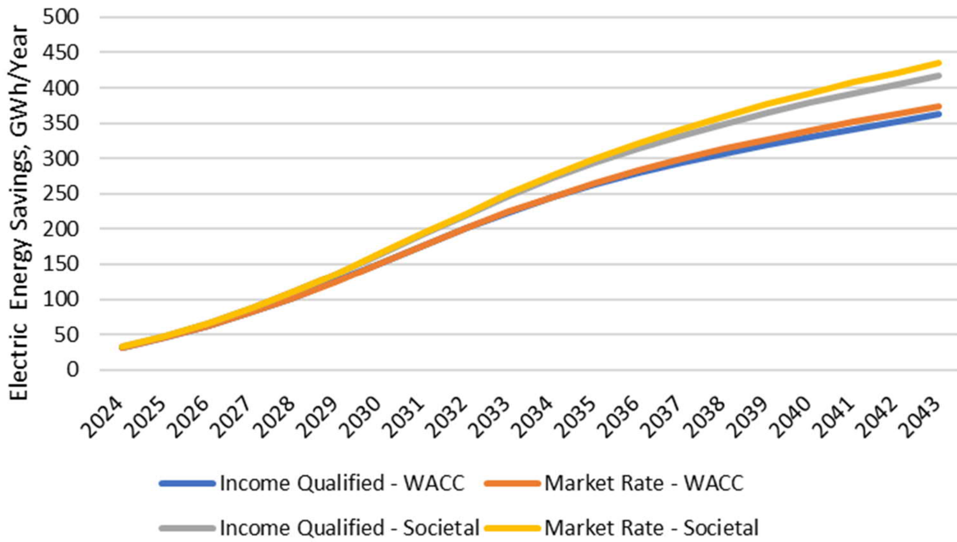
Table 55. Income Qualified vs. Market Rate by Case Incremental Energy Savings (GWh/year), Societal

	Income Qualified				Market Rate			
Year	Reference	2% Savings	High	Low	Reference	2% Savings	High	Low
2024	13.4	16.2	17.2	8.0	13.7	17.0	18.9	8.3
2025	15.5	19.1	20.3	9.3	15.7	19.9	22.2	9.6
2026	18.1	22.6	23.9	10.9	18.1	23.5	26.2	11.2
2027	20.8	26.2	27.6	12.7	20.8	27.2	30.4	12.9
2028	23.6	29.8	31.2	14.4	23.5	30.9	34.3	14.7
2029	26.0	32.9	34.2	16.1	26.0	34.1	37.6	16.4
2030	27.8	35.0	36.1	17.8	27.9	36.3	39.7	18.2
2031	28.6	35.7	36.5	18.8	28.9	37.1	40.2	19.4
2032	28.1	34.6	35.1	19.2	28.8	36.0	38.7	19.8
2033	26.6	32.1	32.3	18.8	27.7	33.5	35.6	19.6
2034	24.5	28.8	28.9	17.8	26.0	30.2	31.7	18.8
2035	22.2	25.2	25.2	16.7	23.9	26.5	27.6	17.9
2036	20.1	21.9	22.0	15.2	21.8	23.2	24.1	16.4
2037	18.2	19.2	19.3	14.6	20.0	20.4	21.1	15.9
2038	16.7	17.0	17.2	13.3	18.3	18.2	18.7	14.5
2039	15.5	15.4	15.7	12.1	17.0	16.6	17.0	13.2
2040	14.5	14.3	14.6	11.2	15.9	15.4	15.8	12.1
2041	13.6	13.5	13.7	10.5	14.8	14.5	14.9	11.1
2042	12.7	12.7	12.9	9.8	13.9	13.7	14.0	10.3
2043	12.1	12.3	12.5	9.9	13.2	13.3	13.6	10.3

Source: Guidehouse analysis

Figure 59 provides the cumulative energy savings by residential market rate customers versus income qualified segments. The market rate has a slightly higher savings forecast in the latter years.

Figure 59. Reference Case – Market Rate vs. Income Qualified Cumulative Energy Savings, GWh



Source: Guidehouse analysis

Table 56 and Table 57 provide the total program costs (incentives and administrative costs) for the income qualified versus market rate residential segments for WACC and Societal discount rates, respectively. The combined total of these values equal the residential sector costs.

Table 56. Program Costs for Income Qualified versus Market Rate Residential Segments, WACC ($millions)

	Income Qualified				Market Rate			
Year	Reference	2% Savings	High	Low	Reference	2% Savings	High	Low
2024	$2.4	$3.8	$10.4	$1.0	$1.8	$3.5	$11.9	$0.9
2025	$3.1	$4.9	$13.1	$1.3	$2.3	$4.5	$15.0	$1.2
2026	$4.0	$6.3	$16.5	$1.7	$3.0	$5.8	$19.0	$1.5
2027	$5.0	$7.9	$19.9	$2.0	$3.7	$7.3	$22.9	$1.9
2028	$6.0	$9.6	$23.1	$2.5	$4.5	$8.9	$26.6	$2.3
2029	$6.9	$11.2	$25.7	$2.9	$5.2	$10.4	$29.7	$2.6
2030	$7.6	$12.5	$27.6	$3.3	$5.7	$11.7	$31.9	$3.0
2031	$7.8	$13.2	$28.4	$3.6	$6.0	$12.5	$32.8	$3.3
2032	$7.5	$13.3	$27.6	$3.7	$5.9	$12.6	$31.9	$3.5
2033	$6.8	$12.5	$25.7	$3.8	$5.5	$12.1	$29.6	$3.6
2034	$5.9	$11.3	$23.4	$3.7	$4.9	$11.0	$26.8	$3.5
2035	$4.8	$9.6	$20.6	$3.4	$4.1	$9.5	$23.4	$3.3
2036	$4.2	$8.0	$18.2	$3.1	$3.8	$7.9	$20.5	$3.0
2037	$3.4	$6.4	$15.9	$2.7	$3.2	$6.4	$17.8	$2.6
2038	$2.8	$5.1	$14.0	$2.4	$2.7	$5.2	$15.6	$2.2

	Income Qualified				Market Rate			
Year	Reference	2% Savings	High	Low	Reference	2% Savings	High	Low
2039	$2.3	$12.6	$2.1	$2.1	$2.3	$4.2	$13.9	$1.9
2040	$1.9	$11.5	$1.8	$1.8	$1.9	$3.5	$12.6	$1.6
2041	$1.6	$10.5	$1.6	$1.6	$1.7	$3.0	$11.5	$1.3
2042	$1.4	$9.5	$1.5	$1.5	$1.4	$2.6	$10.3	$1.1
2043	$1.2	$8.9	$1.4	$1.4	$1.3	$2.3	$9.7	$1.1

Source: Guidehouse analysis

Table 57. Program Costs for Income Qualified versus Market Rate Residential Segments, Societal ($millions)

	Income Qualifed				Market Rate			
Year	Reference	2% Savings	High	Low	Reference	2% Savings	High	Low
2024	$2.7	$5.4	$10.4	$1.1	$2.1	$5.2	$11.9	$1.0
2025	$3.5	$7.1	$13.1	$1.3	$2.7	$6.9	$15.0	$1.2
2026	$4.5	$9.3	$16.5	$1.7	$3.5	$9.1	$18.9	$1.6
2027	$5.7	$11.6	$19.9	$2.1	$4.5	$11.3	$22.9	$1.9
2028	$6.9	$13.9	$23.0	$2.5	$5.4	$13.6	$26.6	$2.3
2029	$8.0	$16.0	$25.6	$2.9	$6.3	$15.6	$29.6	$2.7
2030	$8.8	$17.6	$27.5	$3.4	$7.1	$17.2	$31.8	$3.2
2031	$9.3	$18.4	$28.2	$3.7	$7.7	$18.2	$32.7	$3.5
2032	$9.2	$18.3	$27.4	$3.9	$7.8	$18.1	$31.7	$3.7
2033	$8.7	$17.3	$25.5	$4.0	$7.6	$17.3	$29.4	$3.8
2034	$8.0	$15.9	$23.1	$3.9	$7.2	$16.0	$26.5	$3.7
2035	$7.1	$14.1	$20.3	$3.7	$6.6	$14.3	$23.2	$3.6
2036	$6.2	$12.5	$17.9	$3.4	$6.1	$12.9	$20.3	$3.3
2037	$5.5	$10.9	$15.6	$3.4	$5.5	$11.4	$17.5	$3.3
2038	$4.8	$9.7	$13.7	$3.1	$5.0	$10.1	$15.3	$3.0
2039	$4.3	$8.6	$12.2	$2.8	$4.5	$9.1	$13.5	$2.7
2040	$3.9	$7.9	$11.2	$2.6	$4.1	$8.4	$12.3	$2.5
2041	$3.5	$7.2	$10.2	$2.4	$3.7	$7.7	$11.2	$2.2
2042	$3.1	$6.5	$9.2	$2.3	$3.3	$7.0	$10.0	$2.0
2043	$2.8	$6.2	$8.7	$2.4	$3.0	$6.7	$9.4	$2.2

Source: Guidehouse analysis

C. Achievable Potential Modeling Methodology

This appendix demonstrates Guidehouse's approach to calculating achievable potential, which is fundamentally more complex than calculating technical or economic potential.

The critical first step in the process to accurately estimate achievable potential is to simulate market adoption of energy efficient measures. The team's approach to simulating the adoption of energy efficient technologies for purposes of calculating achievable potential can be broken down into the following two strata:

1. Calculation of the dynamic approach to equilibrium market share
2. Calculation of the equilibrium market share

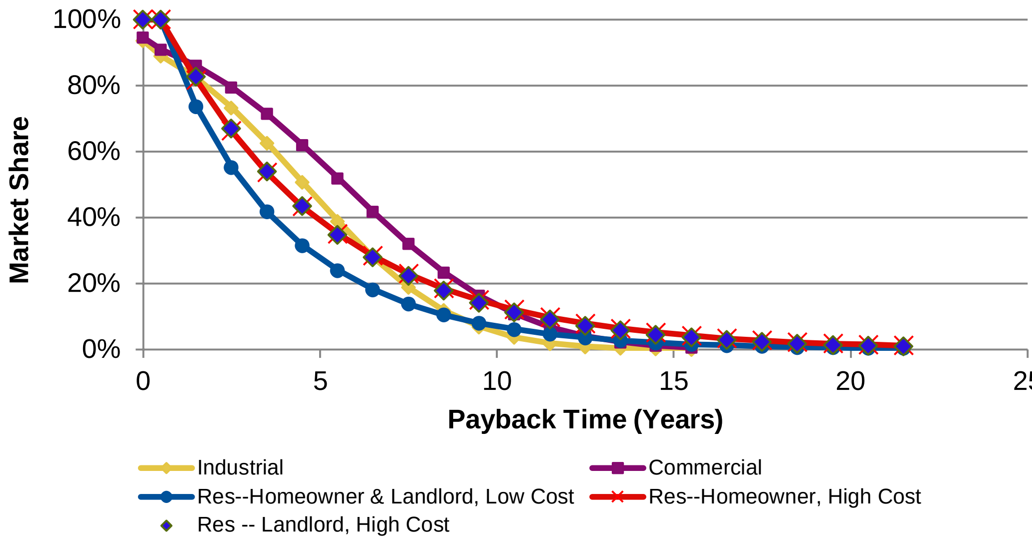
Calculation of Dynamic Equilibrium Market Share

The equilibrium market share can be thought of as the percentage of individuals choosing to purchase a technology, provided those individuals are fully aware of the technology and its relative merits (e.g., the energy- and cost-saving features of the technology). For energy efficient technologies, a key differentiating factor between the base technology and the efficient technology includes the energy and cost savings associated with the efficient technology. That additional efficiency often comes at a premium in initial cost. In efficiency potential studies, equilibrium market share is often calculated as a function of the payback time of the efficient technology relative to the inefficient technology. While such approaches have limitations, they are nonetheless directionally reasonable and simple enough to permit estimation of market share for the dozens or even hundreds of technologies that are often considered in potential studies.

Guidehouse uses equilibrium payback acceptance curves that were developed using primary research it conducted in the Midwest US.[70] To develop these curves, the team surveyed 400 residential, 400 commercial, and 150 industrial customers. These surveys presented decision makers with numerous choices between technologies with low upfront costs but high annual energy costs and measures with higher upfront costs but lower annual energy costs. Guidehouse conducted statistical analysis to develop the set of curves shown in Figure 60, which were leveraged in this study. Though ENO-specific data is not currently available to estimate these curves, Guidehouse considers that the nature of the decision-making process is such that the data developed using these surveyed customers represents the best data available for this study at this time. Furthermore, as the previous two potential study cycles were followed up with Council-sponsored studies, there has been a unique situation where different methodologies and data collection efforts were tested and compared against each other in the same jurisdiction and year of study. This unique situation specifically includes different approaches to assess customer affinity to adoption. As the results between the Guidehouse study and the other consultants' reports were aligned in the final adoption forecast, Guidehouse does not believe that these older datasets will mislead the analysis.

[70] A detailed discussion of the methodology and findings of this research is contained in the *Demand Side Resource Potential Study*, prepared for Kansas City Power and Light, August 2013.

Figure 60. Payback Acceptance Curves



Source: Guidehouse, 2015

Because the payback time of a technology can change over time, as do technology costs or energy costs, the equilibrium market share also can evolve. The equilibrium market share is recalculated for every time-step within the market simulation to ensure the dynamics of technology adoption considers this effect. The term equilibrium market share is a bit of an oversimplification and a misnomer, as it can itself change over time and is never truly in equilibrium. It is used nonetheless to facilitate understanding of the approach.

Calculation of the Approach to Equilibrium Market Share

The team used two approaches to calculate the approach to equilibrium market share (i.e., how quickly a technology reaches final market saturation): one for new technologies or those being modeled as a retrofit (a.k.a. discretionary) measures, and one for technologies simulated as ROB (i.e., lost opportunity) measures.[71] The following sections summarize each approach at a high level.

Retrofit/New Technology Adoption Approach

Retrofit and new technologies employ an enhanced version of the classic Bass diffusion model[72,73] to simulate the S-shaped approach to equilibrium commonly observed for technology adoption. Figure 61 illustrates the causal influences underlying the Bass model. In this model, achievable potential flows to adopters through two primary mechanisms: adoption from external influences such as program marketing/advertising, and adoption from internal influences including word of mouth. Figure 54 illustrates the fraction of the population willing to adopt is estimated using the payback acceptance curves.

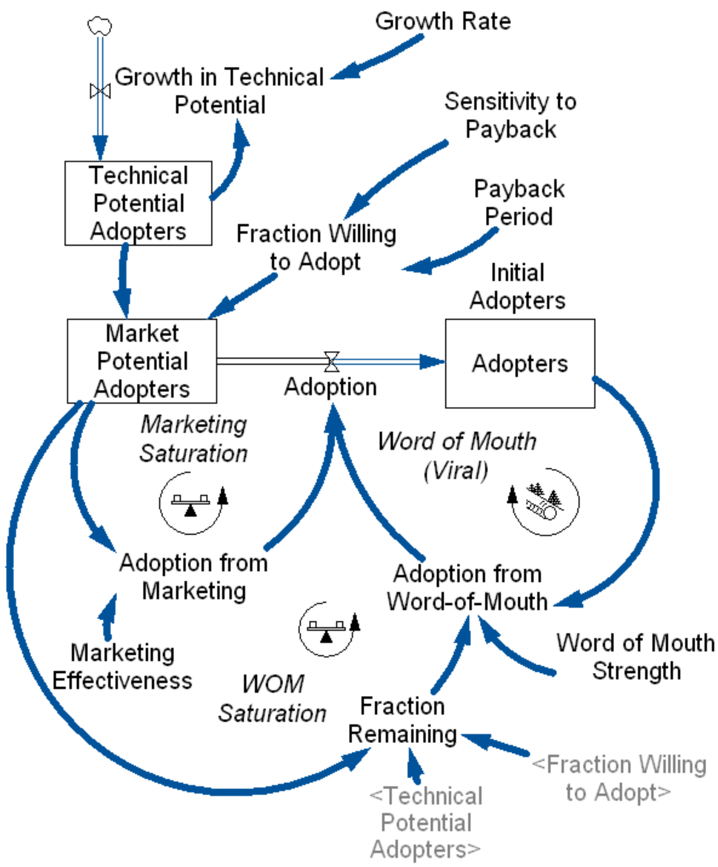
[71] Each of these approaches can be better understood by visiting Guidehouse's technology diffusion simulator, available at: http://forio.com/simulate/Guidehousesimulations/technology-diffusion-simulation.

[72] Frank Bass, 1969, "A new product growth model for consumer durables," *Management Science* 15 (5): p215–227.

[73] John D. Sterman, Business Dynamics: Systems Thinking and Modeling for a Complex World, Irwin McGraw-Hill, 2000. p. 332.

The marketing effectiveness and external influence parameters for this diffusion model are typically estimated upon the results of case studies where these parameters were estimated for dozens of technologies.[74] Additionally, the calibration process permits adjusting these parameters as warranted (e.g., to better align with historic adoption patterns within the ENO market). Recognition of the positive or self-reinforcing feedback generated by the word of mouth mechanism is evidenced by increasing discussion of concepts like social marketing and the term viral, which has been popularized and strengthened by social networking sites such as Facebook and YouTube. However, the underlying positive feedback associated with this mechanism has been part of the Bass diffusion model of product adoption since its inception in 1969.

Figure 61. Stock/Flow Diagram of Diffusion Model for New Products and Retrofits



Source: Guidehouse, 2015

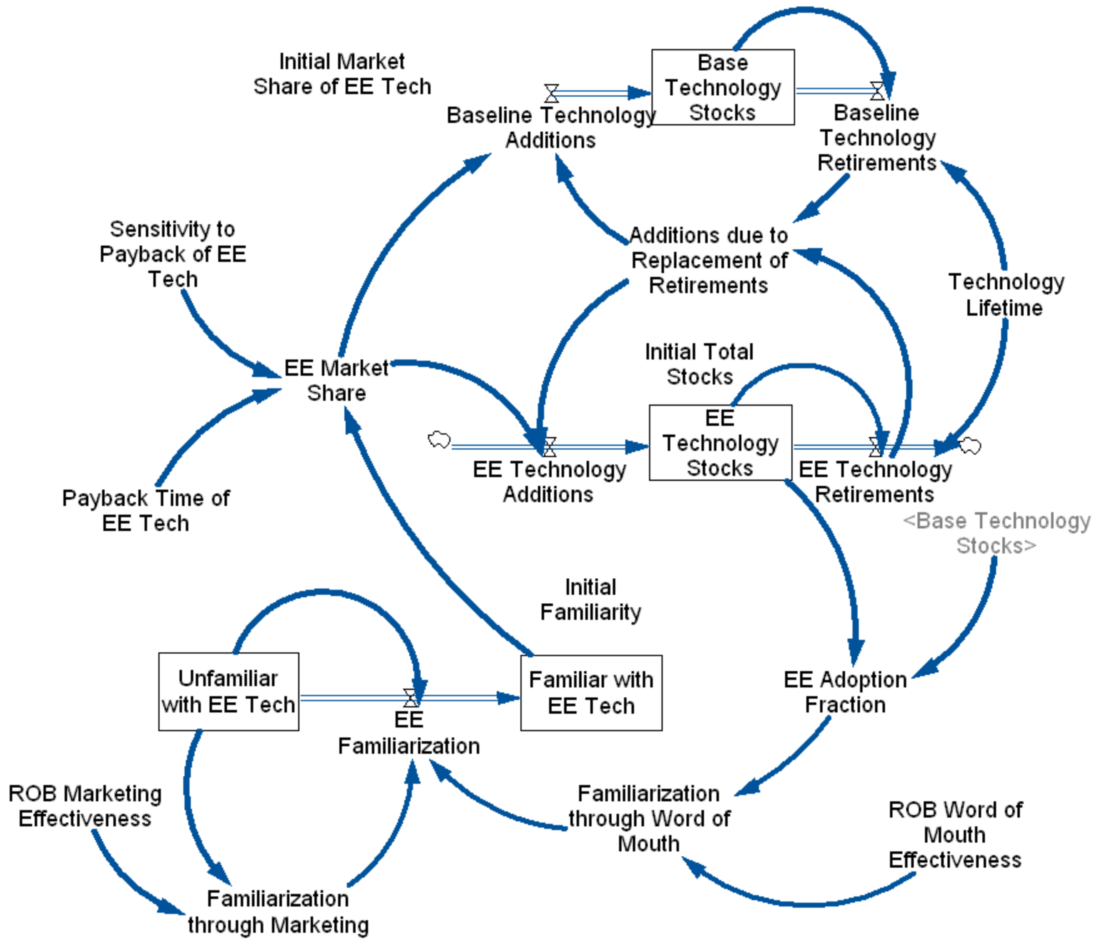
ROB Technology Adoption Approach

The dynamics of adoption for ROB technologies are more complicated than for new/retrofit technologies because it requires simulating the turnover of long-lived technology stocks. To account for this, the DSMSim model tracks the stock of all technologies, both base and efficient,

[74] See Mahajan, V., Muller, E., and Wind, Y. (2000). *New Product Diffusion Models.* Springer. Chapter 12 for estimation of the Bass diffusion parameters for dozens of technologies. This model uses the median value of 0.365 for the word of mouth strength in the base case. The Marketing Effectiveness parameter was assumed to be 0.04, representing a somewhat aggressive value that exceeds the most likely value of 0.021 (75th percentile value is 0.055) per Mahajan 2000.

and explicitly calculates technology retirements and additions consistent with the lifetime of the technologies. Such an approach ensures that technology churn is considered in the estimation of achievable potential, as only a fraction of the total stock of technologies are replaced each year, which affects how quickly technologies can be replaced. A model that endogenously generates growth in the familiarity of a technology, analogous to the Bass approach, is overlaid on the stock tracking model to capture the dynamics associated with the diffusion of technology familiarity. Figure 62 illustrates a simplified version of the model employed in DSMSim.

Figure 62. Stock/Flow Diagram of Diffusion Model for ROB Measures



Source: Guidehouse, 2015

D. Calibration

Forecasting is the inherently uncertain process of estimating future outcomes by applying a model to historical and current observations. As with all forecasts, the Guidehouse results cannot be empirically validated *a priori* because there is no future basis against which one can compare simulated versus actual results. Even though all future estimates are untestable at the time they are developed, forecasts can still warrant confidence when historical observations can be shown to reliably correspond with generally accepted theory and models.

“Calibration” refers to the standard process of adjusting model parameters such that model results align with observed data. Calibration provides the forecaster and stakeholders with a degree of confidence that simulated results are reasonable and reliable. Calibration is intended to achieve three main purposes:

- Anchor the model in actual market conditions and ensure the bottom-up approach to calculating potential can replicate previous market conditions;
- Establish a realistic starting point from which future projections are made; and
- Account for varying levels of market barriers and influences across different types of technologies.

The Guidehouse approach applies general market and consumer parameters to forecast technology adoption. There are often reasons why markets for certain end uses or technologies behave differently than the norm—both higher and lower. Calibration offers a mechanism for using historical observations to account for these differences.

The calibration process is not a regression of savings or spending (i.e., it does not draw a future trend line of savings based on past program accomplishments). Rather, calibration develops parameters that describe the customer decision-making process and the velocity of the market based on recent history. Once these parameters are set, the model uses them as a starting point for the forecast period.

For the 2024 IRP study, the team calibrated the ENO model based on historical program and market data from 2020 through 2022 and 2023 achievements to date for EE measures. Program accomplishments prior to 2020 were judged by the Guidehouse team as too different in terms of the measures offered by programs and the baselines set by code or policy. For the calibration, any new measures or programmatic aspects not applicable in the historical years were removed from the analysis to optimize the model compatibility to the historical period. For the DR analysis, the program participation was calibrated to historical program achievements for DR options that represent DR programs ENO currently offers.

Necessity of Calibration

In evaluative statistical models, calibration is called regression, and goodness of fit is typically the main focus because the models are usually simple. In situations of complex dynamics and non-linearity (as in this study), model sophistication and adequacy can become the main focus. However, grounding the model in observation remains equally necessary. The ability of a forecast to reasonably simulate observed data affords credibility and confidence to forecast estimates.

Although data supports all underlying parameters in the model, much of the data is at an aggregate level that can be inadequate to forecast differences across the various classes of technologies and end uses. The incentive costs are a good example of this effect. The model uses incentives to forecast customer purchase tendencies (thus their adoption of technologies) based on the upfront and lifetime cost factors for which customers have self-reported their importance. The incentive inputs read into the model are provided at the sector and end use level, yet calibration allows the Guidehouse team to scale up and down these inputs to better match historical market activity.

Calibration is not an optional exercise in modeling. One might suggest that the average customer data should be sufficient to make a reliable aggregated forecast. Nevertheless, two important non-linearities compel a more granular parameterization:

- Program portfolios are not evenly composed across end uses. Straight averaging of customer willingness and awareness may not lead to reliable total savings and costs calculations due to unevenness of adoption of technologies.

- The dynamics in the model regarding the timing of adoption can become incompatible with the remaining potential indicated by program achievements. For example, if the forecast results were not calibrated for LED lighting in the residential sector, the saturation may remain inaccurately low in early years and indicate a larger remaining potential in future years. Calibrating upward may increase potential in the early years but decrease potential in later years. Without the calibration, the model adoption would imply that in the absence of utility program intervention, residential LED lighting would have historically had much lower adoption. Calibration allows us to capture these program influences to reflect more accurately remaining potential.

The team treats the calibrated results as the most basic set of interpretable results from which to develop alternate cases.

Interpreting Calibration

Calibration can constrain achievable potential for certain end uses when aligning model results with past EE portfolio accomplishments. Although calibration provides a reasonable historical basis for estimating future achievable potential, past program achievements may not capture the potential because of structural changes in future programs or changes in consumer values. Calibration can be viewed as holding constant certain factors that might otherwise change future program potential, such as:

- Consumer values and attitudes toward energy efficient measures
- Market barriers associated with different end uses
- Program efficacy in delivering measures
- Program spending constraints and priorities

Allowing changing values and shifting program characteristics would likely cause deviations from achievable potential estimates when calibrating to past program achievements.

Does calibrating to historical data constrain the future forecast? In a strictly numeric sense, yes. If a certain end use is calibrated downward or upward, then future adoption and its timing are affected. Nevertheless, this should not be interpreted as “calibration constrains the level of adoption thought possible.” Rather, calibration provides a more accurate estimate of the rate of technology turnover in the market, current state of customer willingness, market barriers, program characteristics, and remaining adoption potential.

One interpretation is that the calibration process creates a floor for the remaining potential. Market barriers, customer attitudes, and program efficacy generally move in the direction of improvement.

Implementing Calibration

The process primarily seeks to develop a set of consumer decision and market parameters that represent recent history. Once developed, these parameters are used as the starting point for the model's stock turnover algorithms and consumer decision algorithms. Developing these parameters requires historical market data. The model uses 2020-2022 program data (gross savings and program spending data) and performs a backcast to fit model parameters such that historical achievements are generally matched.

The Guidehouse team calibrated by reviewing the EE portfolio data from 2020 through 2022 to assess how the market has reacted to program offerings in the past. This method calibrated gross program savings in the model to gross program savings in the 2020-2022 period. After reviewing the gross savings calibration, the Guidehouse team additionally calibrated on the resulting program cost to further tune the incentive levels offered to each end use. In some cases, the first calibration step of gross savings matched the historical gross savings, but the resulting program costs may have been significantly different. This result implies the model overpredicts or underpredicts the sensitivity of customers to rebates. The Guidehouse team further tuned the incentive levels (within their specified caps under each case). Changing incentives would result in a change in gross savings, so an iterative process of adjusting factors to calibrate gross savings and program budget was needed in some cases.

For some sectors and end uses, this primary calibration method was not possible because program offerings and the market have significantly changed. When the primary calibration method was not possible, a secondary method was used that focused on tuning saturation and penetration rates of the end use as a whole to market data. For example, the 2022 RASS provides data on the saturation of technologies. This saturation is a more reliable calibration target because it seeds the model with an accurate starting point to assess the potential for future high efficiency savings.

To execute calibration, the Guidehouse team adjusted model parameters and compared the back cast of the model against historical program data. Guidehouse made individual adjustments to four key levers (listed in Table 58 primarily at the sector and end use levels until achieving a reasonable match with historical data. In some cases where a specific technology witnessed adoption at unexpectedly high or low levels, the team adjusted these levers at the technology level; adjusting at the end use level in these cases would cause the entire end use to undershoot or overshoot the historical program targets.

Table 58. Calibration Levers

Lever	Drivers and Impact on Model Results
Awareness	• Increasing initial awareness shortens the time required for a measure to reach 100% consumer awareness and accelerates adoption. • Increasing marketing strength increases the adoption rate of technologies in the nascent stage (i.e., having low initial consumer awareness). • Increasing word of mouth strength increases the adoption rate of technologies in the mid to later stages of adoption (i.e., having medium to high consumer awareness).
Willingness	• Increasing incentive levels increases adoption, budget, and savings. • Overriding a technology's cost-effectiveness allows it to be considered for adoption (otherwise, non-cost-effective measures are not considered in achievable potential). • Adjusting the weighted utility adjusts the attractiveness of a technology relative to the others in its competition. • Adjusting the consumer-implied discount rate can account for non-cost-related market barriers that may be higher or lower than normal.
Stock Turnover	• Adjusting turnover rates allows the model to better reflect real-world market dynamics. The model assumes technologies turn over based on EUL. However, the real velocity of the market and turnover dynamics are not this perfect or exact.
Adoption	• Adjusting adoption by end use enables better alignment of the model's backcast with limited historic program data.

Source: Guidehouse

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-23-01**

APPENDIX E

MACRO INPUTS WORKBOOK

HIGHLY SENSITIVE
PROTECTED MATERIALS

INTENTIONALLY OMITTED

DECEMBER 2024

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-23-01**

APPENDIX F

ENTERGY NEW ORLEANS, LLC TECHNICAL MEETING MATERIALS

DECEMBER 2024

Leslie M. LaCoste
Counsel – Regulatory
Entergy Services, LLC
504-576-4102 | llacost@entergy.com
6**39 Loyola Avenue, New Orleans, LA 70113**

October 26, 2023

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

Re: **2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**
Docket No. UD-23-01

Dear Ms. Johnson:

Entergy New Orleans, LLC ("ENO" or the "Company") respectfully submits the Presentation for Technical Meeting #1 in the above referenced Docket. As a result of the remote operations of the Council's office related to COVID-19, ENO submits this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you or the Council otherwise directs. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

Should you have any questions regarding the above, I may be reached at (504) 576-4102. Thank you for your assistance with this matter.

Sincerely,

Leslie M. LaCoste

LML/jlc
Enclosures
cc: Official Service List (Public Version *via email)*

November 9, 2023

ENO 2024 IRP Technical Meeting #1

Docket UD-23-01

Goals and Agenda of Technical Meeting #1

As described in the Initiating Resolution (R-23-254), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to discuss inputs, assumptions, Planning Scenarios, and Planning Strategies with a view towards reaching consensus on the Scenarios and Strategies to be used in developing the 2024 IRP. Scenarios and Strategies are to be finalized no later than at Technical Meeting #3.

- The Initiating Resolution notes several additional topics that will inform the discussion of Scenarios and Strategies, including the use of manual portfolios, the treatment of early resource retirements, and the parameters of energy-based analysis as an alternative to capacity-based optimization.
- ENO will facilitate a discussion on these topics and present its proposals for reference and alternative Planning Scenarios and its proposed least-cost and RCPS/Council Policy Planning Strategies.
- ENO expects that the Intervenors will elect to provide a Stakeholder Scenario and Strategy for the 2024 IRP, as they did for the 2021 cycle. To the extent the Intervenors have discussed the requested parameters of the Stakeholder Scenario and Strategy among themselves, they can present their initial designs.

Given the substance and detail involved in these topics, and the importance of ensuring all parties have the opportunity to participate in the discussions, an additional, interim Technical Meeting may be necessary between this one and Technical Meeting #2. If so, it will be scheduled as soon as practical.

01 2024 IRP Planning Objectives and Analytical Framework

Key Resource Planning Objectives

- ENO's resource planning process is based on a set of principles designed to reliably meet customer power needs at the lowest reasonable cost while reducing emissions, improving reliability and resilience performance, and minimizing customer risk exposure. While the landscape within the electric utility industry is changing, these principles remain the consistent factors underpinning our long-term planning strategy.

- The IRP plays an important role in the iterative process of planning ENO's future resource portfolio by providing a comprehensive and transparent look at long-term themes and tendencies that may affect resource planning decisions.

- This strategy provides the flexibility for ENO to respond and adapt to a constantly shifting utility landscape and customer demand.

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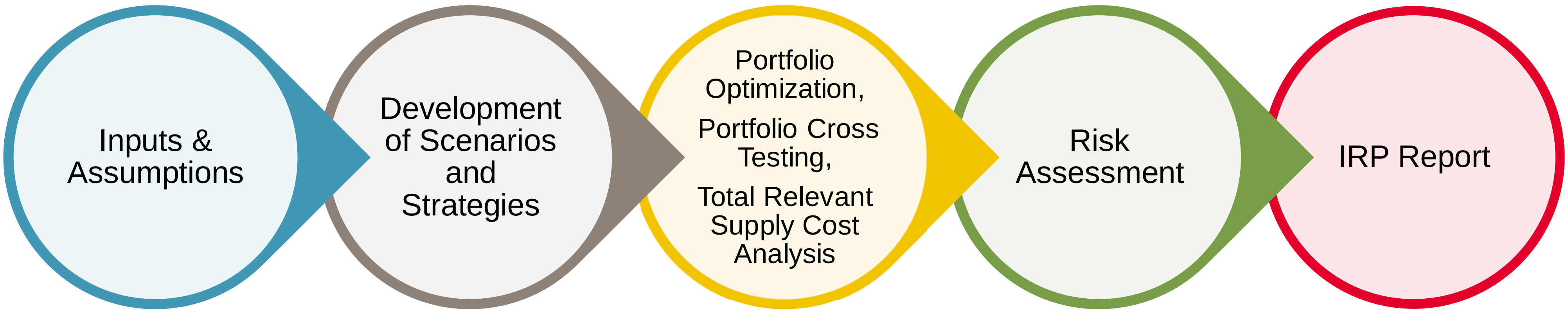
Path to the 2024 IRP Report



Assessment of Portfolio Performance Across Scenarios

- Portfolios developed for each Scenario/Strategy combination will be tested across all other Scenarios to assess risk across key variables that differentiate the scenarios
- The total relevant supply cost of each of the Scenario/Portfolio combinations represents the present value of incremental fixed and net variable costs to customers
- IRP resolution requires additional risk assessment for identified least-cost portfolios to estimate P10/P50/P90 cost

Illustrative - actual scenarios and portfolio combinations TBD

Portfolios / Scenarios	Strategy 1 (Least Cost)	Strategy 2 (But For RCPS)	Strategy 3 (RCPS Compliance)
Scenario A	R_{A1}	R_{A2}	R_{A3}
Scenario B	R_{B1}	R_{B2}	R_{B3}
Scenario C	R_{C1}	R_{C2}	R_{C3}

Notes:
1. "R" refers to Long Term Capacity Expansion (LTCE) created portfolios for specific Scenario/Strategy combination
2. Colored entries illustratively represent proposed portfolios subject to cross-testing under all scenarios and additional risk assessment

02 Inputs and Assumptions

Inputs and Assumptions

Reliability Need	Supply Side and Demand Side Resources	Economic & Financial
• Peak load and total energy load forecast w/ sensitivities • Long-term reserve margin requirements and MISO seasonal reserve margins • Capacity accreditation for thermal and non-thermal resources	• Existing fleet capability • Resource deactivation assumptions • Technology Assessment (capital and operating costs, performance) • Continued use of DSM	• Inflation rates • Discount rates • Fuel and emissions price forecasts (eg. gas, coal, nuclear, NOx, CO_2) • Federal tax credits • Capacity value

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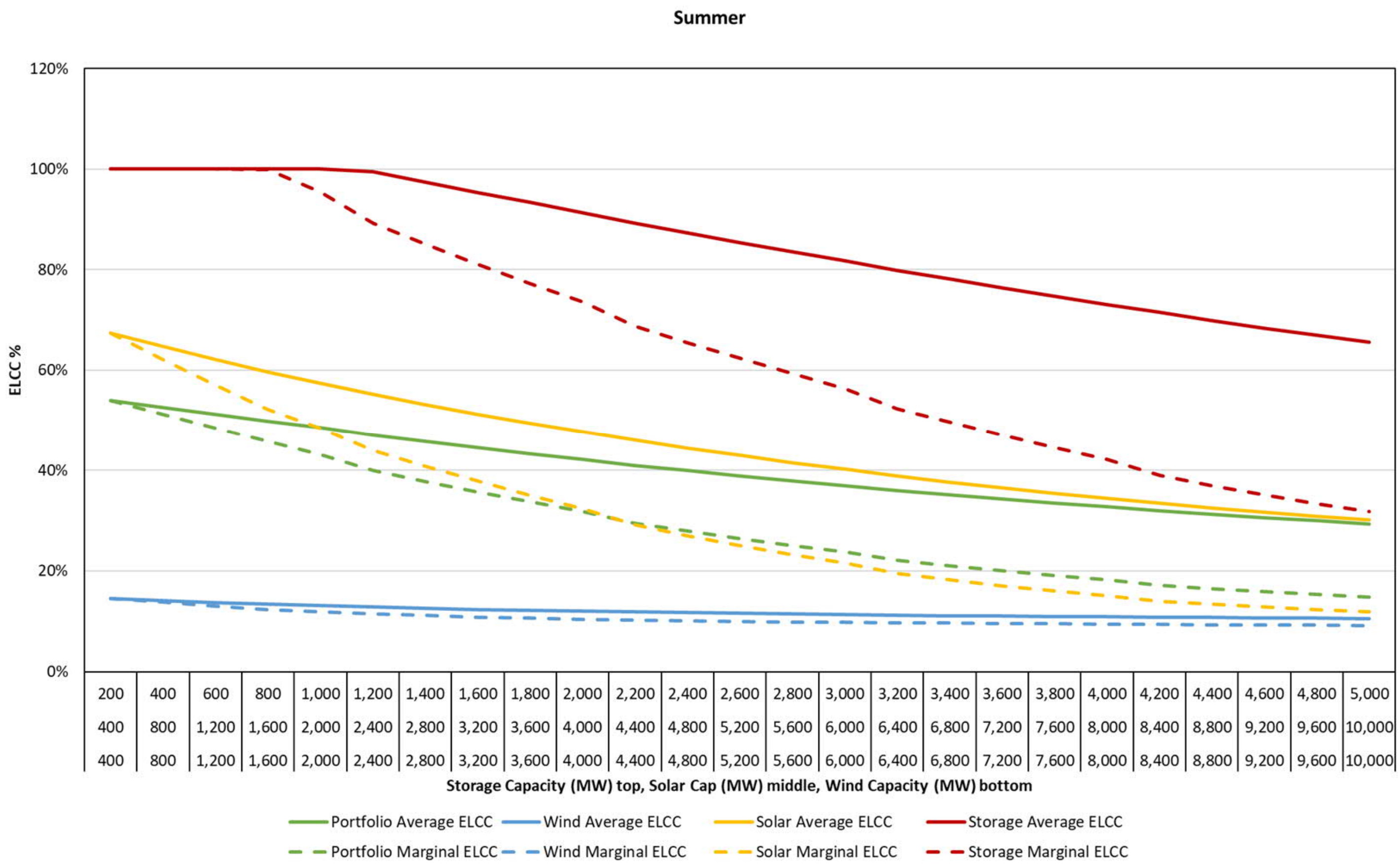
2024 IRP Inputs and Assumptions

Input/Assumption	MISO Market Modeling	Portfolio Development	Total Relevant Supply Costs
Planning Scenarios	✓	✓	✓
Gas Price Forecast	✓	✓	✓
CO2 Price Forecast	✓	✓	✓
Load Forecast	✓	✓	✓
Planning Strategies		✓	✓
Capacity Value		✓	✓
Supply-Side Resource Alternative Costs		✓	✓
ENO’s Long-Term Capacity Need		✓	✓
DSM Potential Study Results		✓	✓
Input Sensitivities			✓

Effective Load Carrying Capability ("ELCC") Study

- Entergy engaged Astrapé consulting to perform a comprehensive ELCC study to inform IRP inputs
- Sample results for summer for a select portfolio of MISO South solar, wind, and four-hour storage are depicted below



Seasonal Accredited Capacity (SAC) for Thermal Resources

- Thermal resource accreditation is heavily based on historic unit availability during max gen events and other tight supply hours that occurred in the prior 3 years.
  - 80% of accreditation is based on availability during tight margin hours (Tier 2), 20% based on all other hours (Tier 1)
- Resource performance is measured by a resource's hourly real time offers, so planned outages (without a granted exemption) and forced outages will negatively impact a unit's accreditation.
- Generation resources with a lead time greater than 24 hours that are not online during tight supply hours will be considered unavailable during Tier 2 hours for accreditation purposes.
- The approved SAC methodology only applies to thermal resources. MISO is currently conducting a stakeholder process to develop a new non-thermal (wind, solar, battery, etc.) accreditation methodology.

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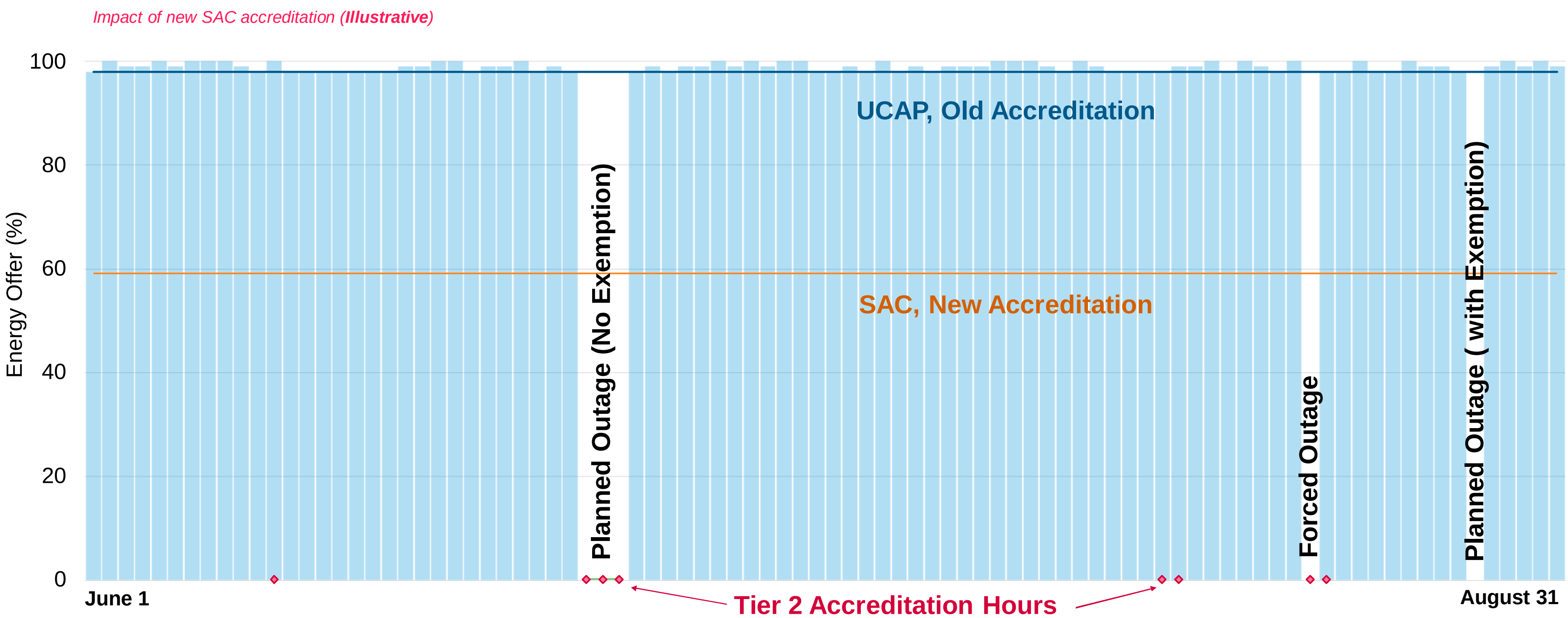
SAC vs UCAP - Example



UCAP is only impacted by forced outages
SAC is impacted by forced outages, derates, and non-exempt planned outages (80% weight on Tier 2 hours)

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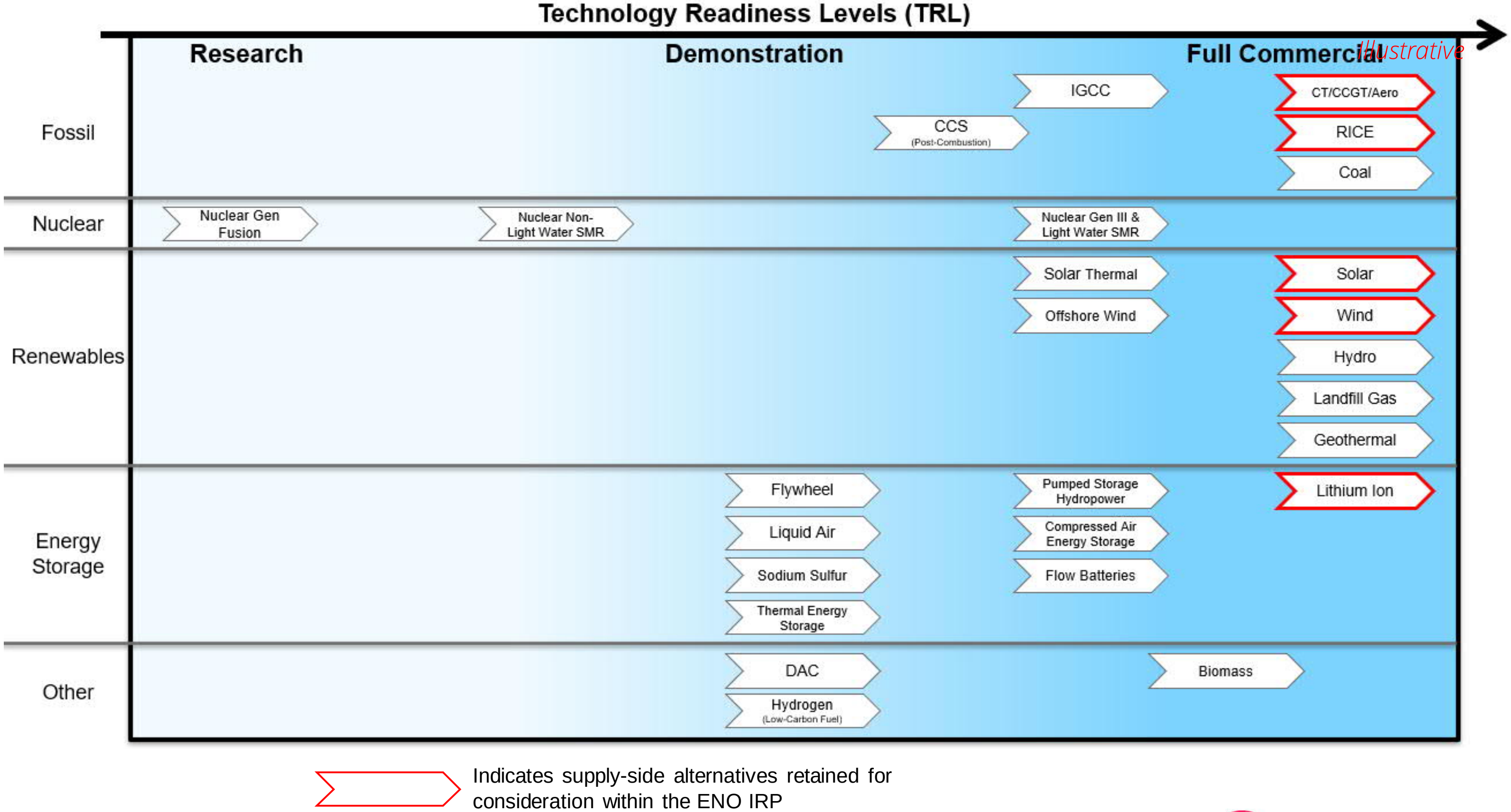
03 Resource Options

Illustrative Supply-Side Resource Alternatives

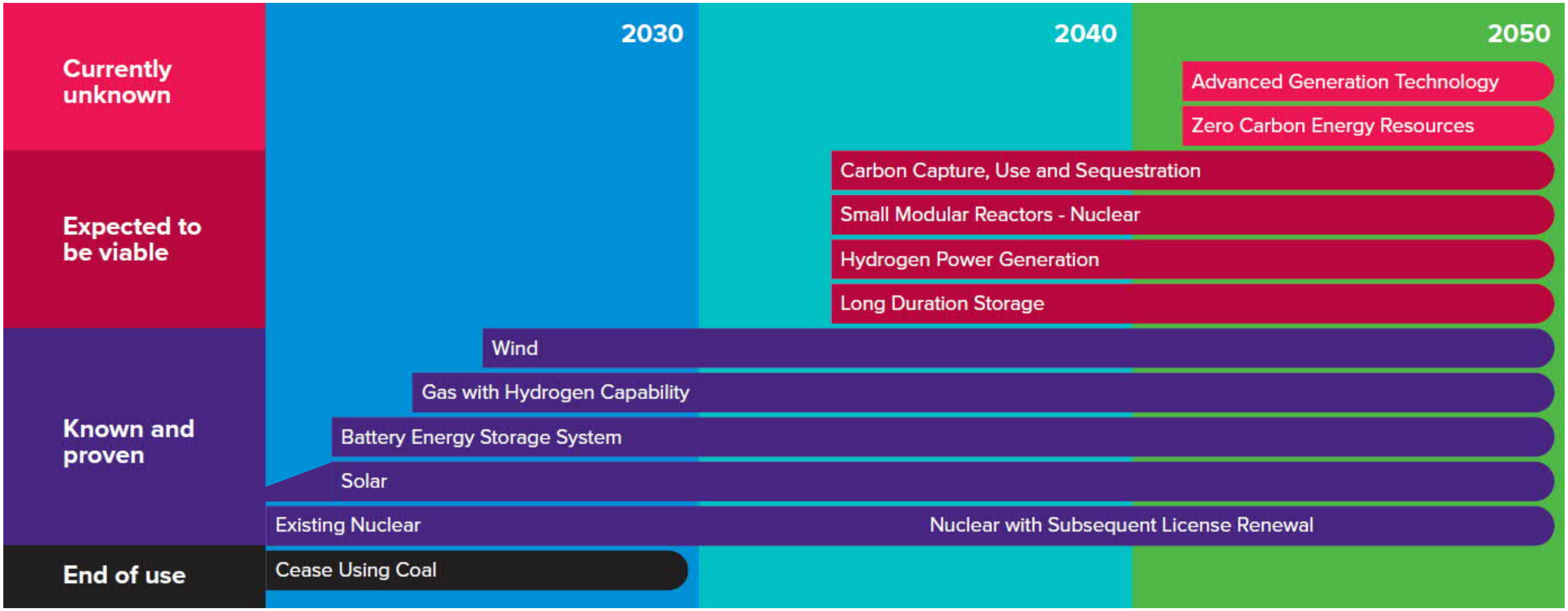
The technology evaluation includes:

- Survey supply side resource alternatives
- Retain subset of alternatives based on:
  - technology maturity
  - economics
  - reliability
  - environmental impact
  - geographic feasibility



Illustrative pathway to zero carbon emissions

Technology evolution and integration assumptions



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Demand Side Management Potential Studies

- ENO has contracted with Guidehouse to develop its 2024 DSM Potential Study
  - Long term (2024-2043) EE and DR Potential in Orleans Parish
- Study results to be structured into input cases for use in Aurora
- ENO study to produce multiple input cases including one modeling potential to achieve the Council's 2% DSM savings goal
- Each input case will be run using two different discount rates to assess cost effectiveness:
  - ENO's after-tax WACC of 6.86%; and
  - A discount rate of 3.0% that aligns with the rate used by ADM Associates in its Societal Cost Test evaluation of the Energy Smart program
- To the extent feasible, DSM Studies will use BP2024 inputs
- Each Planning Strategy will require an assigned DSM Input Case
- DSM Studies due to be filed February 1, 2024

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04 ENO Proposed Planning Scenarios

Development of Planning Scenarios

In order to reasonably account for a broad range of uncertainty, the ENO IRP takes a scenario-based approach. In this approach, Planning Scenarios are developed that represent different combinations of outcomes of many variables and reasonably bookend the range of potential outcomes.

Major areas of uncertainty that are considered:

- Sales and load growth
- Customer usage trends
- Natural gas price trends
- Market unit life assumptions
- Federal tax credits
- Emissions price trends
- Generation capital cost forecasts
- MISO market reforms

For each scenario, the AURORA Capacity Expansion Model selects (i.e., outputs) a 20-year resource portfolio for each associated Planning Strategy that is economically optimal for ENO under that set of circumstances.

2024 IRP Proposed Planning Scenarios

	Scenario 1 – Reference	Scenario 2 – Clean Air Act Section 111 Compliance	Scenario 3 – For Stakeholder Consideration
Peak Load & Energy Growth	• Reference	• Reference	• High
Natural Gas Prices	• Reference	• Reference	• High
MISO Coal Deactivations	• All ETR coal by 2030 • All MISO coal aligns with MTEP Future 2 (36 year life)	• All ETR coal by 2030 • All MISO coal by 2030	• All ETR coal by 2030 • All MISO coal aligns with MTEP Future 3 (30 year life)
MISO Natural Gas CC Deactivations	• 45 year life	• NGCC by 2035	• 35 year life
MISO Natural Gas Other Deactivations	• 36 year life	• Steam gas EGUs by 2030	• 30 year life
Carbon Tax Scenario	• Reference Cost	• Reference Cost	• High Cost
Renewable Capital Cost	• Reference Cost	• Reference Cost	• Low Cost
Narrative	• Assumptions align with the 2024 Business Plan case. • Moderate amount of industrial growth forecasted which would drive the need for new development	• Entergy and utilities across MISO deactivate existing units early to be compliant with proposed changes to Clean Air Act Section 111(d) • New resources built would comply with proposed changes to 111(b)	• High energy growth from both industrial and residential sectors forecasted. • Renewable cost assumed to be low due to more efficient supply chain

05 ENO Proposed Planning Strategies

2024 IRP Proposed Planning Strategies

	Strategy 1	Strategy 2	Strategy 3	Strategy 4
Description	Least Cost Planning	But For RCPS	RCPS Compliance	Stakeholder Strategy
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals	TBD
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.	TBD
DSM Input Case	Reference Case	2% Program Case	2% Program Case	TBD
Manual Portfolio	TBD	TBD	TBD	TBD
Sensitivity	TBD	TBD	TBD	TBD

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Supplemental Analysis to Capacity Expansion Optimization

Manual Portfolios and Sensitivity Cases

- Early Unit Retirements
- Policy Goal Achievement (e.g., RCPS)

Energy-based Analysis

06

Timeline

Timeline

Event	Current Deadline	Status
Public Meeting #1	August 23, 2023	✓
Technical Meeting #1	November 9, 2023	✓
DSM Potential Studies Due	February 1, 2024	
Mardi Gras	February 13, 2024	
Stakeholders provide their Scenario and Strategy	Before Technical Meeting 2	
Technical Meeting #2—Discuss Final ENO and Stakeholder Scenarios and Strategies	February 20-March 1, 2024	
Deadline for Council policies to be included in optimization	April 15, 2024	
Technical Meeting #3—Finalize Strategies and DSM Input Case Assignments; DSM input files for modeling due; initial Scorecard discussion	May 1-May 14, 2024	
Technical Meeting #4—Downselection of Portfolios for Cross Testing; finalize Scorecard; initial discussion of Energy Smart budgets and goals	September 23-October 4, 2024	
2024 IRP Report filed	**December 13, 2024**	
Public Meeting #2 (ENO & SPO Present)	January 21-31, 2025	
Public Meeting #3 (Council receives public comment)	February 18-28, 2025	
Technical Meeting #5—Energy Smart PY16-18 programs and implementation plan	February 18-28, 2025	
Mardi Gras	March 4, 2025	
Intervenor Comments on Final IRP	March 10, 2025	
ENO Reply Comments	April 28, 2025	
Advisor Report	June 2, 2025	
Energy Smart Implementation Plan Filing for PY 16-18	June 16, 2025	

Leslie M. LaCoste
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504-576-4102 | llacost@entergy.com
6**39 Loyola Avenue, New Orleans, LA 70113**

February 15, 2024

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

Re: **2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**
Docket No. UD-23-01

Dear Ms. Johnson:

Entergy New Orleans, LLC ("ENO" or the "Company") respectfully submits the Presentation for Technical Meeting #2 in the above referenced Docket. As a result of the remote operations of the Council's office related to COVID-19, ENO submits this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you or the Council otherwise directs. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

Should you have any questions regarding the above, I may be reached at (504) 576-4102. Thank you for your assistance with this matter.

Sincerely,

Leslie M. LaCoste

LML/jlc
Enclosures
cc: Official Service List (Public Version *via email)*

February 29, 2024

ENO 2024 IRP
Technical Meeting #2

Docket UD-23-01

Goals and Agenda of Technical Meeting #2

Goals

As described in the Initiating Resolution (R-23-254), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to continue discussions regarding Planning Scenarios and Planning Strategies with a goal towards reaching consensus on the Scenarios and Strategies to be used in developing the 2024 IRP. Scenarios and Strategies are to be finalized by Technical Meeting #3 in early May 2024.

Agenda

1. Further Discussion of ENO Proposed Planning Scenarios and Strategies
   - Discussion of Intervenor Scenario and Strategy (if applicable)
2. BP24 Supply Side Alternatives
   - Technology Costs
3. Inputs and Assumptions (Tech Meeting #1 Follow-ups)
   - Macro-Inputs Workbook (HSPM)
   - Hydrogen POV
   - Load Forecast Discussion
4. Modeling Methodology (Tech Meeting #1 Follow-ups)
   - Energy-based Modeling
   - Stochastic Modeling
5. Timeline and Next Steps

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01

Proposed Planning Scenarios and Strategies

2024 IRP Proposed Planning Scenarios

	Scenario 1 – Reference	Scenario 2 – Clean Air Act Section 111 Compliance	Scenario 3 – For Stakeholder Consideration
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1. See MISO Futures Report Series 1A for additional detail

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2024 IRP Proposed Planning Strategies

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Manual Portfolio	TBD	TBD	TBD	TBD
Sensitivity	TBD	TBD	TBD	TBD

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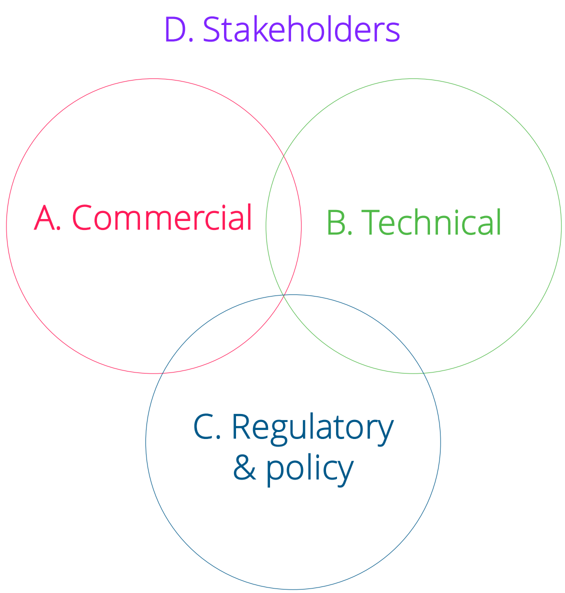
02 BP24 Supply Side Alternatives

Technology Assessment: Four Lenses

As part of an on-going process, Entergy evaluates existing, new and emerging technologies to meet supply- side resource needs



A. Commercial
What are a technology's cost and market indicators?

B. Technical
What are the operational, environmental, and internal capability factors associated with a specific technology?

C. Regulatory & policy
How do regulatory bodies and federal + state policies encourage or disincentivize deployment?

D. Stakeholders
How does the technology deliver on the needs and expectations of our four key stakeholders? Customers, Communities, Employees, and Shareholders

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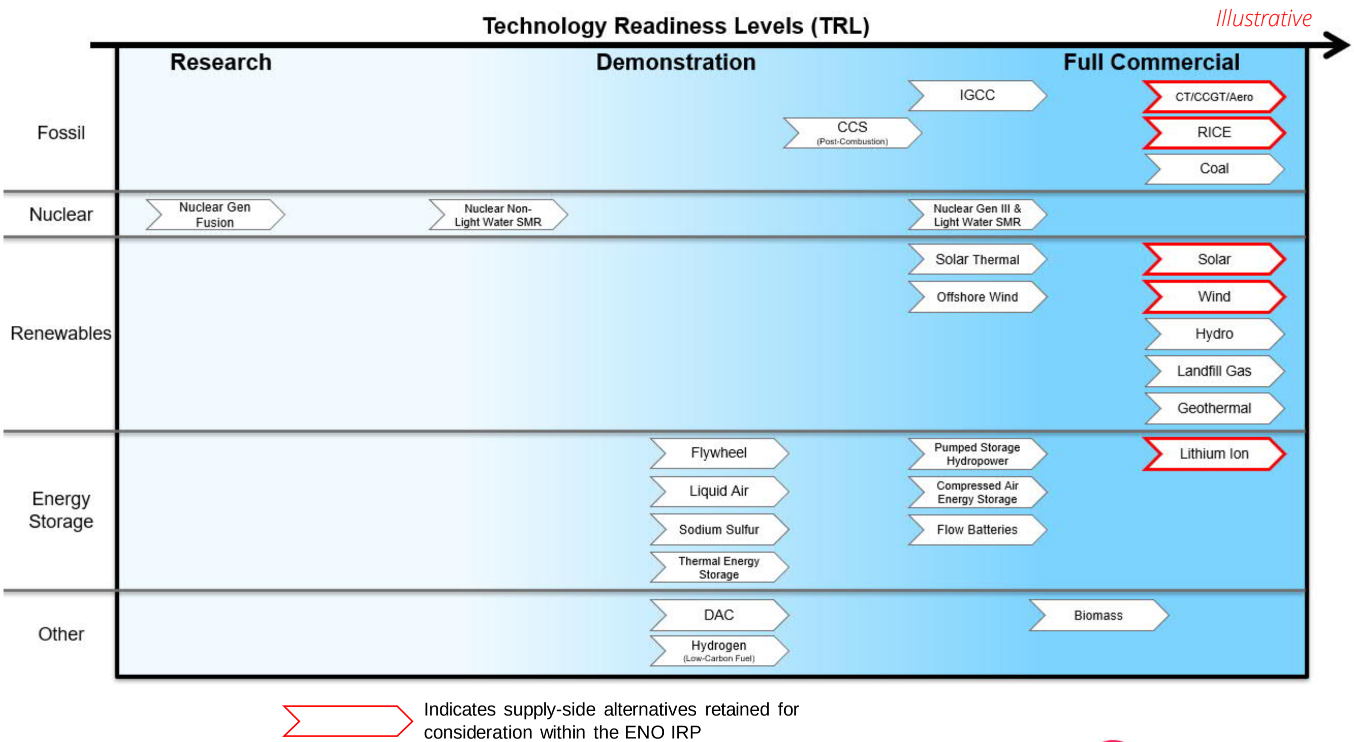
Identified Supply-Side Resource Alternatives

- **STORAGE (BESS)**
  - Lithium-Ion (4-hr)
- **GAS (H2 capable 30%)**
  - Aeroderivative CT
  - CCGT (1x1 w/DF)
  - CCGT (2x1) w/o DF
  - Frame CT
  - RICE
- **WIND**
  - On-shore MISO South
- **SOLAR**
  - Solar Bifacial
- **HYBRID**
  - Solar & BESS

Illustrative Supply-Side Resource Alternatives

The technology evaluation includes:

- Survey supply side resource alternatives
- Retain subset of alternatives based on:
  - technology maturity
  - economics
  - reliability
  - environmental impact
  - geographic feasibility



Cost: Thermal Resources

Technology	Installed Capital Cost Nominal [2023$/kWac]	Fixed O&M L. Real [2023$/kW-yr.]	Variable O&M L. Real [2023$/MWh]
CT	$1,134	$6.76	$8.65
CCGT (1x1) w/ duct firing	$1,296	$12.58	$4.97
CCGT (2x1)	$1,349	$10.90	$5.16
Aeroderivative CT	$3,277	$32.99	$9.39
RICE	$1,998	$34.48	$14.03

1. Sources: Sargent & Lundy, Burns & McDonnell, NREL, EPRI, and Entergy Capital Projects
2. Excludes transmission interconnection costs

Performance: Thermal Resources

Technology	Summer Net Maximum Capacity [MW]	Full HHV Summer Heat Rate [Btu/kWh]	Life [Yr.]	H2 Capable (%)
CT	408	9,450	30	30%
CCGT (1x1) w/ duct firing	729	6759	30	30%
CCGT (2x1)	1,216	6,308	30	30%
Aeroderivative-CT	89.9	9,703	30	30%
RICE	129	8,440	30	25%

Sources: Sargent & Lundy, Entergy Capital Projects

Cost: Renewable and Storage Resources

Technology	Installed Capital Cost Nominal [2023$/kWac]	Fixed O&M L. Real [2023$/kW-yr.]
Utility-Scale Solar	$1,866	$13.10
Hybrid: Solar + BESS	$2,950	$19.02
On-shore Wind, MISO South	$2,010	$42.63
Storage (4hr, Li-Ion)[4]	$2,332	$14.79

1. Sources: S&P Global, Wood Mackenzie, EPRI, NREL, Entergy Power Development
2. There are no variable costs assumed to be incurred
3. Excludes transmission interconnection costs
4. BESS Installed Capital Cost includes 10% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by an additional 10% augmentation every five years (year 6, 11, and 16). This corresponds to a degradation rate of 2% of BESS capacity per year.

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Performance: Renewable and Storage Resources

Technology	Max Summer Capacity [MW-ac]	Assumed Capacity Factor [%]	Life [Yr.]	DC:AC Ratio [%]	Degradation [%]
Utility-Scale Solar	100MW	24.8%[1]	30	1.3	0.5% per year
Hybrid: Solar + BESS	100MW 50MW/200MWh	24.8%	30 (Solar) / 20 (BESS)	1.3	0.5% per year (Solar only)
On-shore Wind, MISO South	100 - 200 MW	30.9%[2]	30	n/a	n/a
Storage (4hr, Li-Ion)	50MW / 200MWh	n/a	20	n/a	Degradation negated by Augmentation

1.Solar resources assume a 0.3% improvement in capacity factor in each subsequent year installed. Therefore, the capacity factor for solar resources installed in the second year of the outlook improve from 25.68% to 25.75%.
2.Wind resources assume a 0.1% improvement in capacity factor in each subsequent year installed.
3. Hybrid resources will be modeled in Aurora as stand-alone solar with the option to add a coupled storage at a discounted cost

Sources: EPRI, Entergy Power Development

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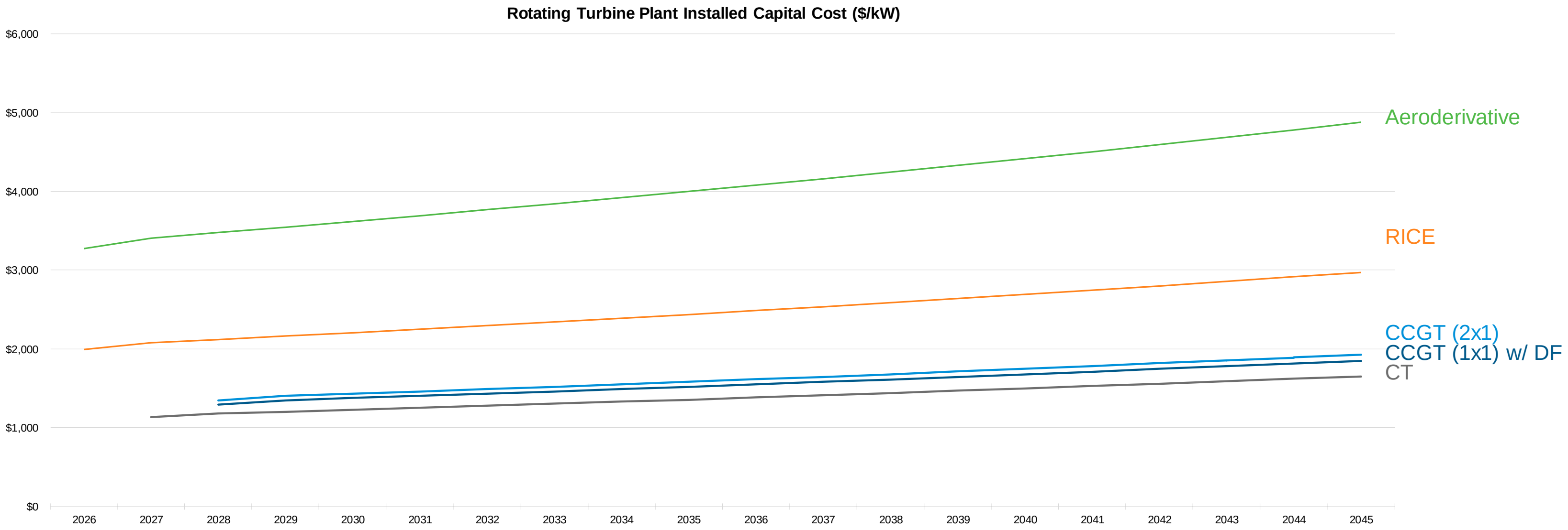
Financial Assumptions

Evaluation Components	
Long Term Inflation Rate Assumption	2.0%
Inflation Reduction Act Tax Credits	•Solar and Wind resources: $30/MWh (2026$, assumes full PTC rate) •Storage resources: 30% ITC (assumes full ITC rate) •Tax Credit Phase-out is assumed (100% through 2035, 75% in 2036, 50% in 2037, 0% in 2038 and beyond)

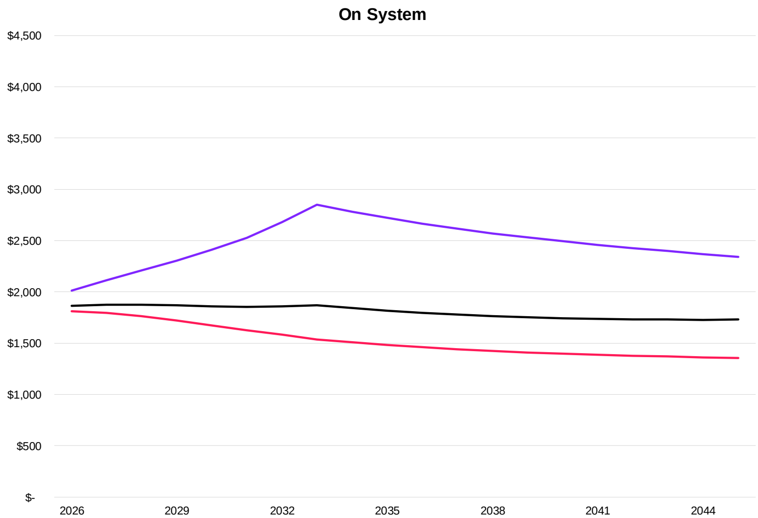
Rotating Turbine Plant Long-Term Cost Projections

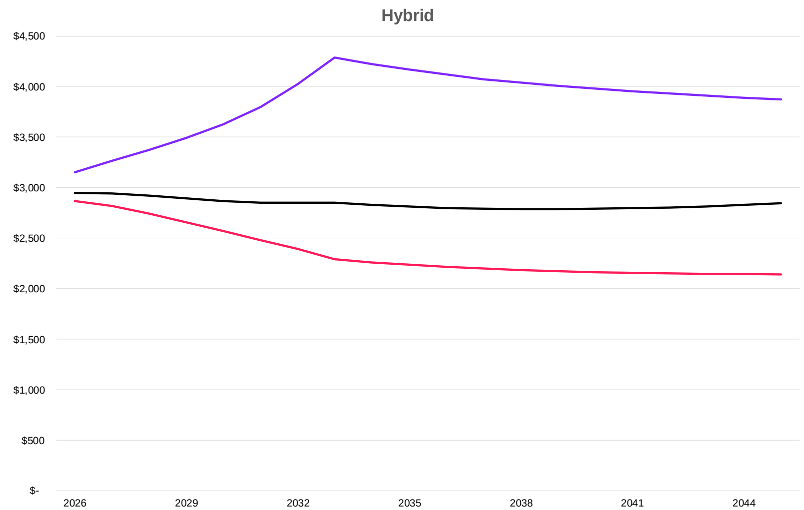


Solar Long Term Cost Projections

Costs below reflect installed capital cost ($/kW-ac)

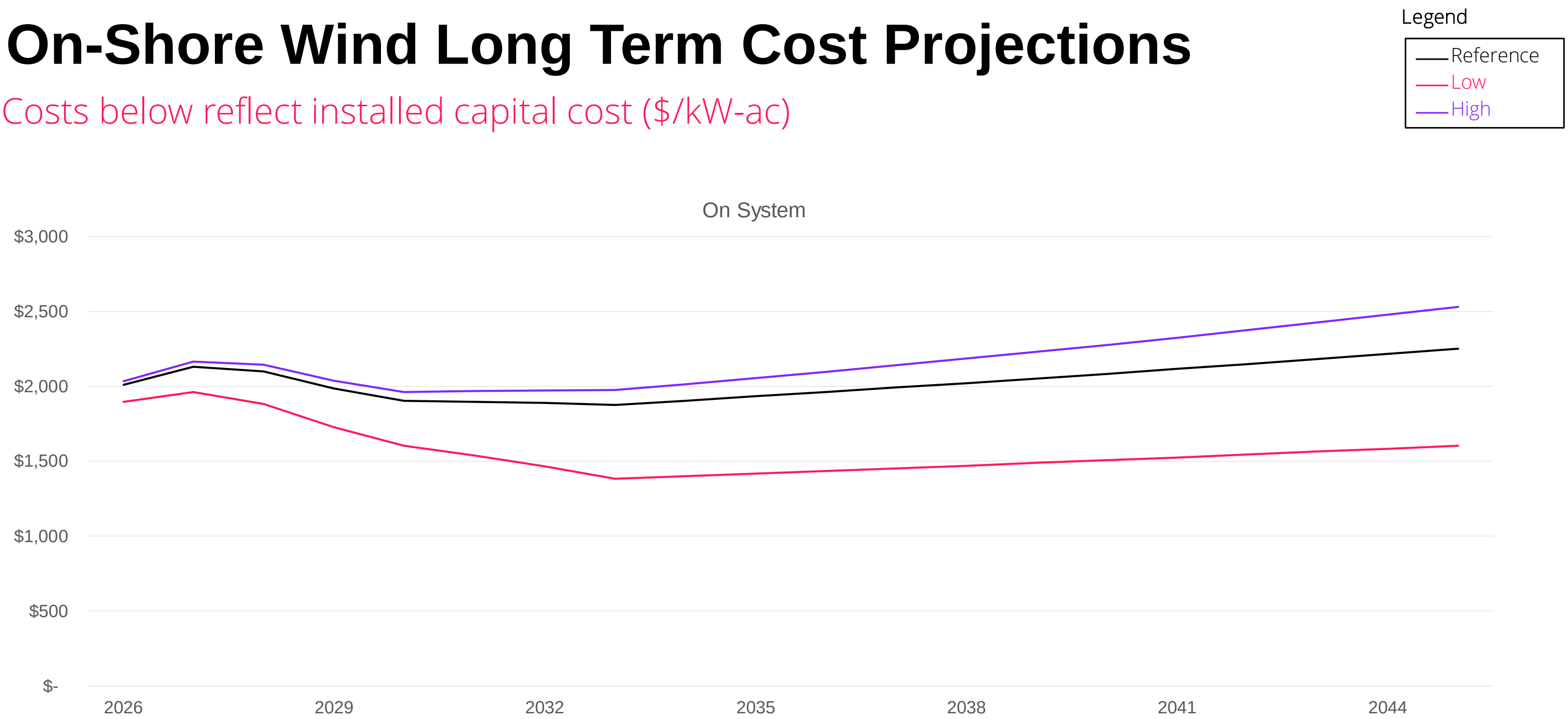
Legend
Reference
Low
High





On-Shore Wind Long Term Cost Projections

Costs below reflect installed capital cost ($/kW-ac)



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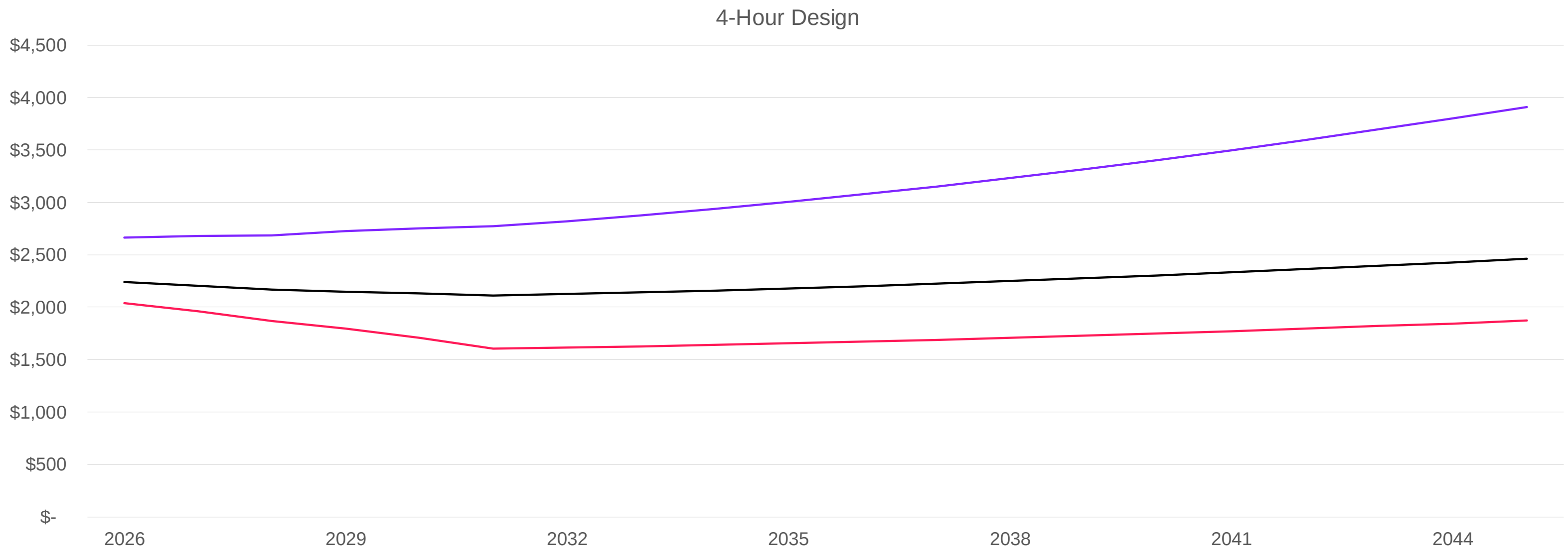
BESS Long Term Cost Projections

Costs below reflect installed capital cost ($/kW-ac)

Legend

- Reference
- Low
- High



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Transmission Interconnection Adders

Excluding Transmission Network Upgrades

New POI Cost

Project Size (MW)	Cost ($ millions)	Description
X<399 MW	15	(115,138,161 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)
399≤X≤799	20	(230 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)
X>799	50	(500 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)

Brownfield POI Cost

Project Size (MW)	Cost ($ millions)	Description
X<399 MW	5	(115,138,161 kV) = POI Add node to existing substation
399≤X≤799	7	(230 kV) = POI Add node to existing substation
X>799	10	(500 kV) = POI Add node to existing substation

Generation Interconnection cost:

- Cost required for collector station and power conversion equipment. Includes electrical infrastructure from generation unit to Transmission Point of Interconnection ("POI").

Transmission Interconnection cost:

- Cost required for Transmission to build POI substation, transmission line work, and remote end coordination.
- **Excludes:**
  - Network Resource Interconnection Service (NRIS)
  - External Resource Interconnection Service (ERIS)
  - Interconnection Service (IS) = NRIS + NRIS Local + ERIS
  - Off-system upgrades

- All interconnection cost will be project specific and are generalized for ease of estimating purposes. This chart covers many typical options and is meant to be used as guidance.

Example Use:

- NEW POI Solar Facility
  100MW Solar New Build – New POI @ 230kV
  + $20M for Transmission Interconnection Cost. ($200/kW)
- New POI Natural Gas Facility
  1,216 MW CCGT – New POI @ 230kV
  3 Interconnections @ 230kV
  (2 CTG + 1STG)
  + $34M (20+7+7) for Transmission Interconnection Cost. ($28/kW)

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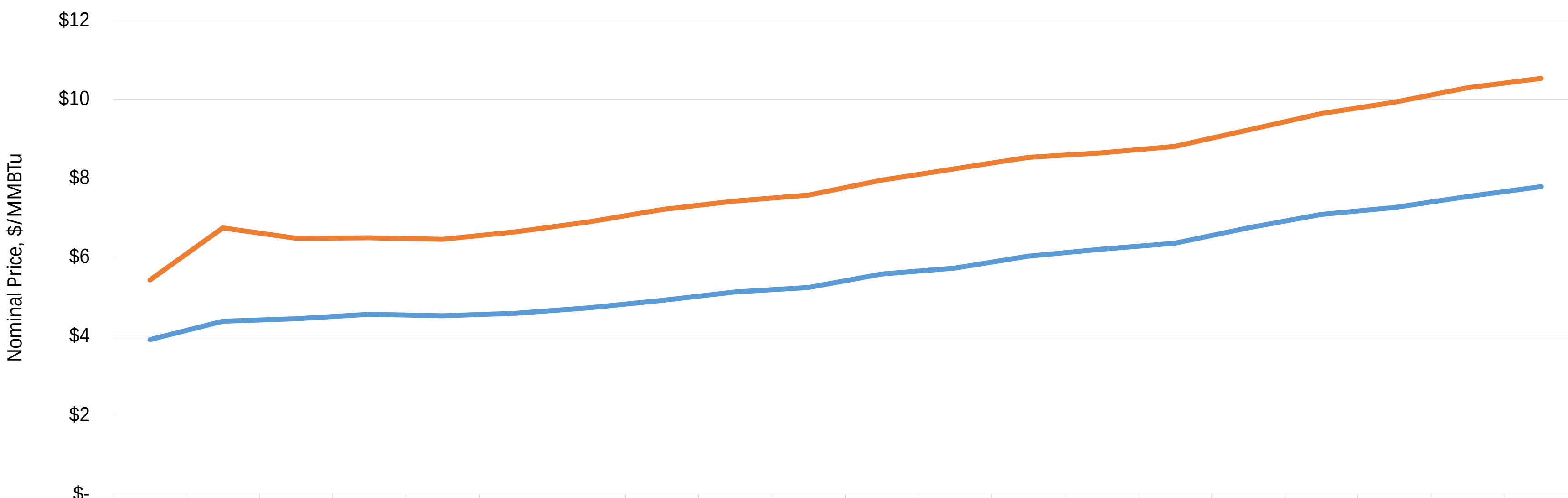
03

Inputs and Assumptions

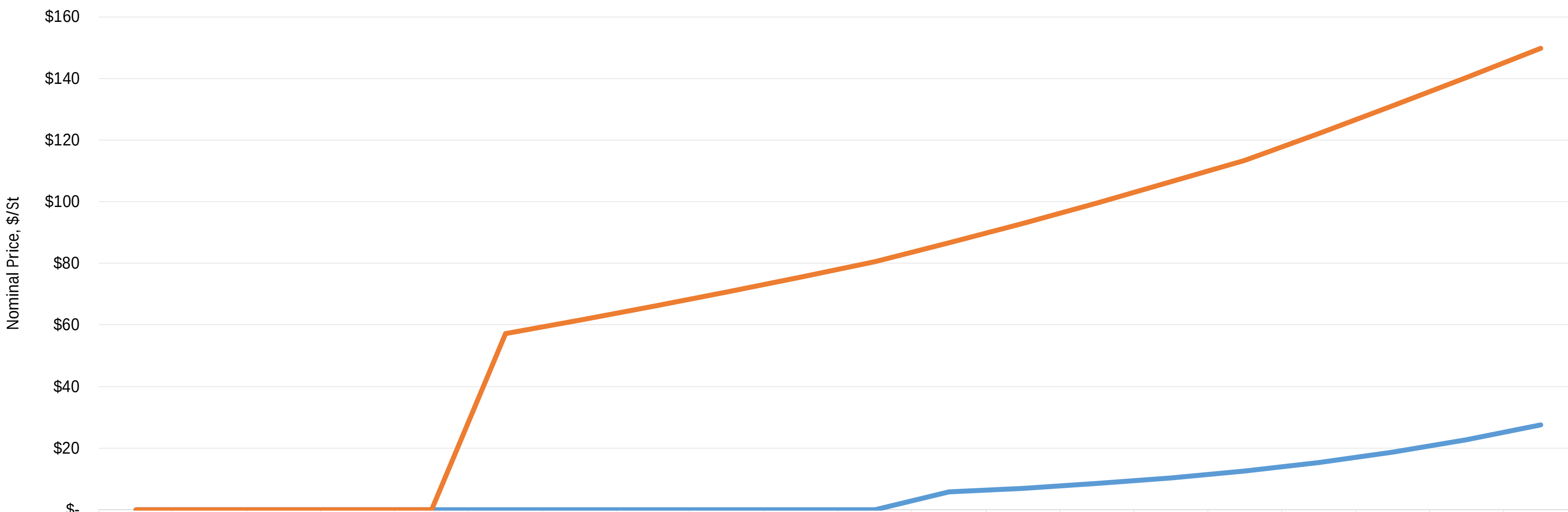
Henry Hub Gas Price Forecast



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Reference	$3.92	$4.38	$4.43	$4.55	$4.51	$4.57	$4.71	$4.90	$5.11	$5.23	$5.57	$5.72	$6.03	$6.20	$6.35	$6.75	$7.09	$7.26	$7.54	$7.79
High	$5.43	$6.74	$6.48	$6.48	$6.45	$6.64	$6.89	$7.21	$7.42	$7.57	$7.95	$8.23	$8.52	$8.65	$8.81	$9.22	$9.64	$9.93	$10.28	$10.54

Year

CO2 Price Forecast



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Reference	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$5.72	$6.97	$8.48	$10.32	$12.56	$15.29	$18.61	$22.65	$27.57
High	$-	$-	$-	$-	$-	$57.12	$61.48	$65.99	$70.66	$75.49	$80.49	$86.63	$92.99	$99.57	$106.38	$113.42	$122.08	$131.04	$140.31	$149.90

Year

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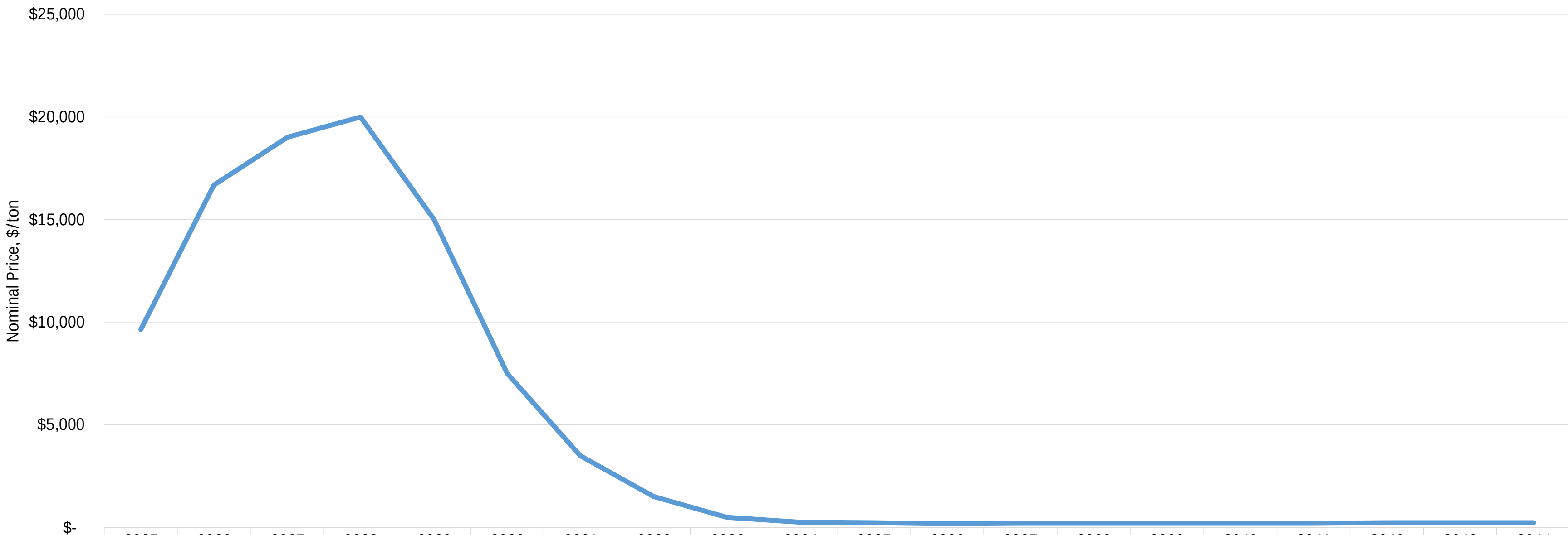
Louisiana Seasonal NOX Price



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Price	$9,643	$16,682	$19,000	$20,000	$15,000	$7,500	$3,500	$1,500	$500	$250	$225	$200	$204	$208	$212	$216	$221	$225	$230	$234

Year

1. NOx is only applied in summer months

Hydrogen focus: create optionality in near term, infrastructure grown in long term

Hydrogen utilization in the power generation sector has near term items that can be addressed to preserve optionality while long term challenges are addressed.

Near term focus: Entergy is incorporating **design considerations that do not prevent hydrogen optionality** in the future if market considerations and infrastructure align

Long term challenges facing the industry that need to be addressed for large scale consumption by the power generation sector **include:**

Pipelines

- 100% burning power gen consumption is beyond what can be supported with today's pipeline infrastructure
- New 2x1 CCGTs could consume well over 1,000 tonnes / day of hydrogen at 100% capacity factor & 100% H2 burn

Storage

- Cavern storage is needed
- Storage addresses reliability and load following needs for power generation

Production

- Growth of electrolysis production is needed
- Hydrogen pathway in the EPA Clean Air Act Section 111 proposal limited to green hydrogen given the lifecycle emissions requirements

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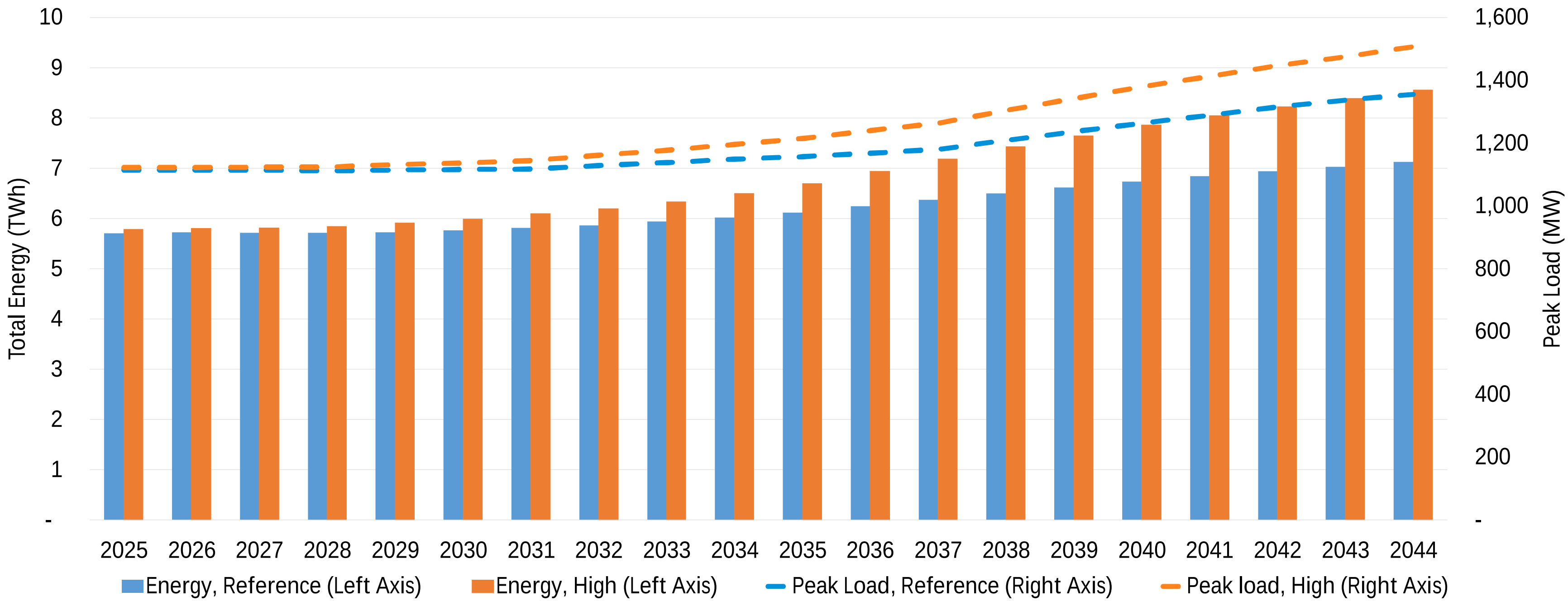
ENO Peak Load & Energy Forecast



1. Peak Load is Non-Coincident

ENO Load Forecast – Process

Entergy New Orleans develops electricity consumption forecasts through 2050.

The forecasts are developed using statistical models and a bottom-up approach by class – Residential, Commercial, Industrial, and Governmental – to estimate the total electricity consumption volumes. The volumes are developed considering several elements including:

- Historical consumption levels, numbers of customers, temperatures, and estimates of end-use consumption (heating, cooling, other)
- Energy efficiency – organic and company-sponsored
- Future changes in population/households and end-use Individual customer information for identified large industrial customers

Adjustments are made to reflect other expectations including future levels of EV adoption, building or process electrification, and behind-the-meter solar adoption.

Monthly consumption volumes are used to estimate peak loads and allocated across hourly profiles.

ENO Load Forecast Levers

	Item	Load Forecast: Reference Case	Load Forecast: Low Growth Sensitivity	Load Forecast: High Growth Sensitivity
Traits	**Policy and Other Traits**		Decreased Res/Com growth due to: Slower EV adoption, Higher levels of EE Reduced industrial load	Increased Res/Com growth due to: Higher building electrification, Accelerated EV and Solar adoption, Increases in industrial load
Expectations	**Peaks**	Reference (BP24)	Lower	Higher
	Energy	Reference (BP24)	Lower	Higher
Inputs	**BTM Solar**	Reference (BP24)	Reference	Higher
	Electric Vehicles (EVs)	Reference (BP24)	Lower	Higher
	Electrification	Reference (BP24)	Lower	Higher
	Organic EE and OpCo DSM	Reference (BP24)	Higher	Lower
	Customer Growth (Res & Com)	Reference (BP24)	Lower	Higher
	Refinery Utilization (Trends opposite EVs)	Reference (BP24)	Higher (opposite of EVs)	Lower (opposite of EVs)

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04

Modeling Methodology

Methodology Slide

Previous IRP Process

Step 1

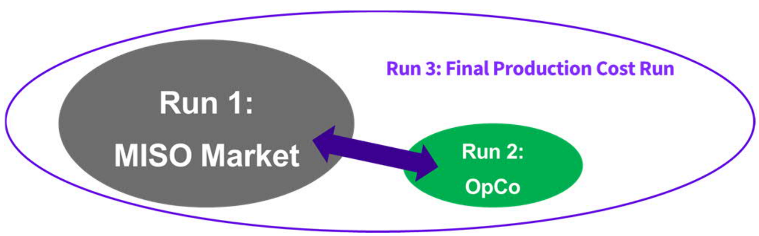
- Run MISO Market Long Term Capacity Expansion (LTCE)

Step 2

- LMP from Step 1 used to create pricing for a single Market Resource to represent a market transaction point for OpCo LTCE

Step 3

- MISO and OpCo capacity expansion result combined for final production cost run

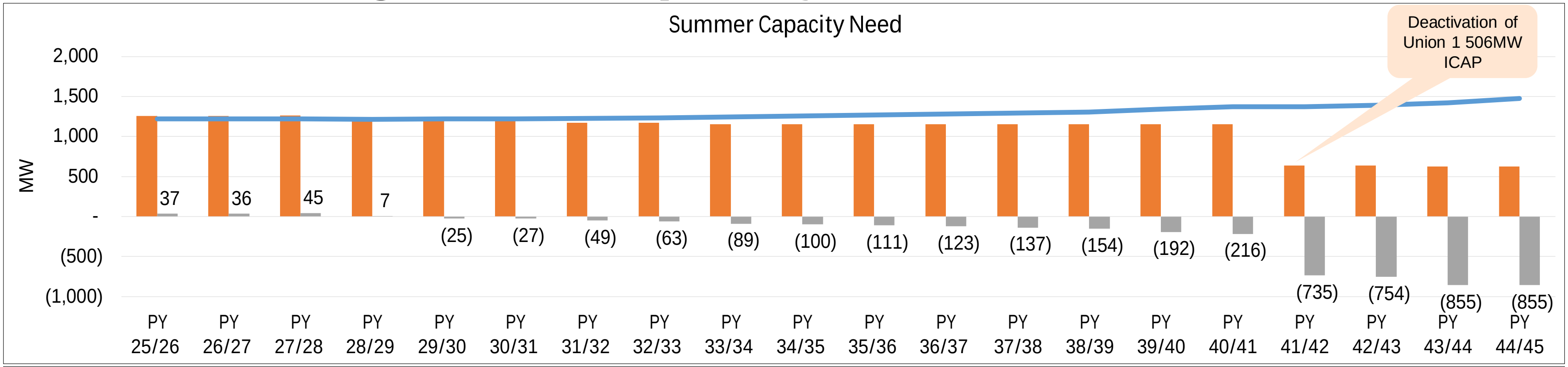


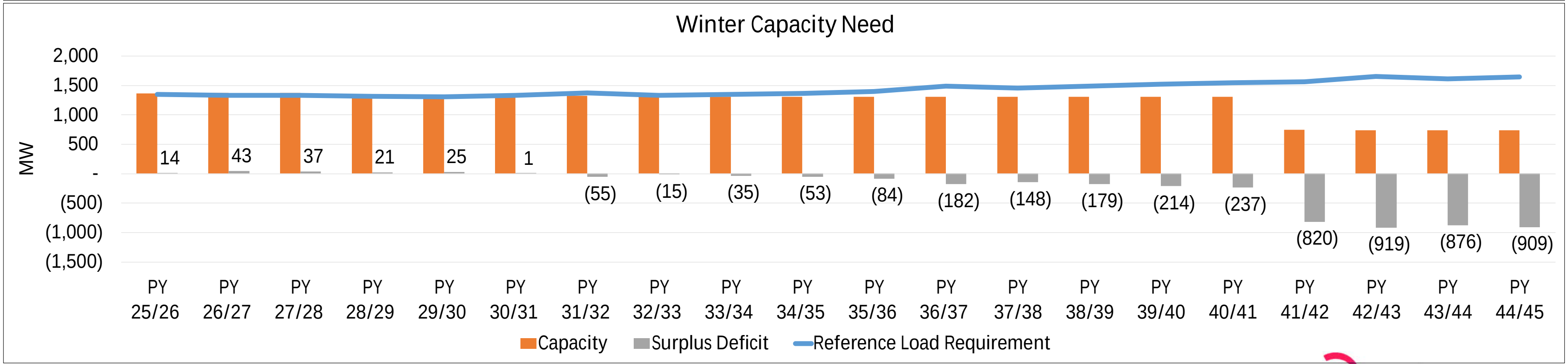
New IRP Process

Step 1

- LTCE run for both MISO Market and OpCo simultaneously
- No separate production cost run needed
- Seasonal capacity expansion construct

ENO's Long-Term Capacity Need





1. Planning Year (PY) defined as June of the first year through May of the following year
2. Reserve Margin for summer and winter seasons are 7.4% and 25.5% respectively
3. Capability based on BP24 SAC and includes owned resources, affiliate PPAs, third party PPAs, LMRs, and the two planned resources 2025 ENO Solar & Sherwood Battery

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Energy-Based Modeling

The Aurora capacity expansion function allows the user to input target reserve margins as well as maximum and minimum reserve margins to provide the software flexibility to choose the most economic resources (considering energy revenue) without over constraining the solution to precisely meet the target reserve margin.

ENOL proposes to use this flexibility to improve ‘energy-based modeling’ while still maintaining target reserve margins (as contemplated by the 2024 IRP Initiating Resolution), based on MISO’s summer and winter PRMs.

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Stochastic Modeling

- In the prior IRP, stochastic analysis was performed on four portfolios:
  - Scenario 1, Strategy 1
  - Scenario 1, Strategy 2
  - Manual Portfolio 1a
  - Manual Portfolio 3a

- The analysis developed additional CO_2 and natural gas price inputs to inform 400 additional production cost simulations for each portfolio, producing a distribution of total relevant supply cost for each portfolio

- ENO proposes a similar method for the current IRP cycle, with potential tweaks to improve simulation time without affecting robustness of results
  - Subset of portfolios subject to stochastic analysis to be determined

05

Timeline

Timeline

Event	Current Deadline	Status
Public Meeting #1	August 23, 2023	✓
Technical Meeting #1	November 9, 2023	✓
DSM Potential Studies Due	February 1, 2024	✓
Mardi Gras	February 13, 2024	✓
Stakeholders provide their Scenario and Strategy	Before Technical Meeting 2	
Technical Meeting #2—Discuss Final ENO and Stakeholder Scenarios and Strategies	February 29, 2024	
Deadline for Council policies to be included in optimization	April 15, 2024	
Technical Meeting #3—Finalize Strategies and DSM Input Case Assignments; DSM input files for modeling due; initial Scorecard discussion	May 1-May 14, 2024	
Technical Meeting #4—Downselection of Portfolios for Cross Testing; finalize Scorecard; initial discussion of Energy Smart budgets and goals	September 23-October 4, 2024	
2024 IRP Report filed	**December 13, 2024**	
Public Meeting #2 (ENO & SPO Present)	January 21-31, 2025	
Public Meeting #3 (Council receives public comment)	February 18-28, 2025	
Technical Meeting #5—Energy Smart PY16-18 programs and implementation plan	February 18-28, 2025	
Mardi Gras	March 4, 2025	
Intervenor Comments on Final IRP	March 10, 2025	
ENO Reply Comments	April 28, 2025	
Advisor Report	June 2, 2025	
Energy Smart Implementation Plan Filing for PY 16-18	June 16, 2025	

CERTIFICATE OF SERVICE
UD-23-01

I hereby certify that I have served the required number of copies of the foregoing pleading upon all other known parties of this proceeding individually and/or through their attorney of record or other duly designated individual.

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New Orleans, Louisiana, this 15th day of February, 2024

Leslie LaCoste

____
Leslie M. LaCoste

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April 23, 2024

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

Re: **2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**
Docket No. UD-23-01

Dear Ms. Johnson:

Entergy New Orleans, LLC ("ENO" or the "Company") respectfully submits the Presentation for Technical Meeting #3 in the above referenced Docket. As a result of the remote operations of the Council's office related to COVID-19, ENO submits this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you or the Council otherwise directs. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

Should you have any questions regarding the above, I may be reached at (504) 576-4102. Thank you for your assistance with this matter.

Sincerely,

Leslie M. LaCoste

LML/jlc
Enclosures
cc: Official Service List (Public Version *via email)*

May 7, 2024

ENO 2024 IRP Technical Meeting #3

Docket UD-23-01

Goals and Agenda of Technical Meeting #3

Goals

As described in the Initiating Resolution (R-23-254), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to finalize the Planning Scenarios and Planning Strategies to be used in developing the 2024 IRP. All IRP inputs are to be locked down by May 17, 2024. There will also be a discussion of the Guidehouse DSM Potential Study and the draft Scorecard.

Agenda

1. Discussion of Proposed Stakeholder Scenario and Strategy
2. Technical Meeting #2 Follow-Ups
3. Review of Guidehouse DSM Study results
4. Initial Discussion of Scorecard Metrics – Initial discussion, starting from 2021 Scorecard

01

Proposed Planning Scenarios and Strategies

2024 IRP Proposed Planning Scenarios

	Scenario 1 – Reference	Scenario 2 – Clean Air Act Section 111 Compliance	Scenario 3 – Stakeholder Scenario
Peak Load & Energy Growth	• Reference	• Reference	• High
Natural Gas Prices	• Reference	• Reference	• High
MISO Coal Deactivations[1]	• All ETR coal by 2030 • All MISO coal aligns with MTEP Future 2 (36 year life)	• All ETR coal by 2030 • All MISO coal by 2030	• All ETR and MISO coal by 2030
MISO Natural Gas CC Deactivations	• 45 year life	• NGCC by 2035	• Deactivated by 2035
MISO Natural Gas Other Deactivations	• 36 year life	• Steam gas EGUs by 2030	• Deactivated by 2035
Carbon Tax Scenario	• Reference Cost	• Reference Cost	• High Cost
Renewable Capital Cost	• Reference Cost	• Reference Cost	• Low Cost
Narrative	• Assumptions align with the 2024 Business Plan case. • Moderate amount of industrial growth forecasted which would drive the need for new development	• Entergy and utilities across MISO deactivate existing units early to be compliant with proposed changes to Clean Air Act Section 111(d) • New resources built would comply with proposed changes to 111(b)	• High energy growth from both industrial and residential sectors forecasted. • Renewable cost assumed to be low due to more efficient supply chain

1. See MISO Futures Report Series 1A for additional detail

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2024 IRP Proposed Planning Strategies

	Strategy 1	Strategy 2	Strategy 3	Strategy 4
Description	Least Cost Planning	But For RCPS	RCPS Compliance	Stakeholder Strategy— Accelerated Grid Cleaning
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals	800 MW of renewables by 2030, including 200 MW of BTM solar and 55 MW of IFOM Community Solar; high load growth driven by EVs and electrification
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.	Accelerate achievement of RCPS goals using local generation and PPAs to increase portfolio of solar, storage, and wind
DSM Input Case	WACC, Reference Case	WACC, 2% Program Case	WACC, 2% Program Case	Societal Discount Rate, High Case
Optimized Portfolio	Yes	Yes	Yes	No
Manual Portfolio	Early Deactivation of Union 1 in 2032 Early Deactivation of Union 1 in 2035	N/A	N/A	Yes

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Questions

- Follow-up from Technical Meeting #2

- Additional Questions

02

DSM Potential Study

Potential Calculation Methodology

- **Technical Potential** – total energy savings assuming all installed measures can immediately be replaced with the efficient measure

- **Economic Potential (EE Only)** – assumes same immediate replacement, but only using measures that pass cost-effectiveness testing
  - Total Resource Cost (TRC) test used at different levels in the 2024 study

- **Achievable Potential** – economic potential modified to account for measure adoption rates and the diffusion of technology through the market

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Overview of 2024 DSM Potential Study

For EE, Guidehouse developed four input cases of achievable potential:

- **Reference**—Assumes current incentive levels and expected behavior participation; aligns with historical program achievement; uses historical program admin costs on a $/kWh basis; 0.9 TRC threshold
- **2% Savings**—Aligns to 2% savings goal by 2025 instead of historical savings achievement; assumes increased incentives (10X Reference case, up to 100% of incremental cost) and aggressive behavioral participation; 0.75 TRC threshold
- **Low**—Same inputs as Reference; incentives are set to 50% of Reference case levels.
- **High**—Same inputs as Reference assumes increased incentives (100X Reference case, up to 100% of incremental cost); no TRC threshold so all measures are passed through

For Demand Response, Guidehouse developed three input cases:

- **Reference**—Reflects participation based on incentives that match current programs and industry best practice
- **Low**—Assumes incentives 50% lower than the Reference case
- **High**—Assumes incentives 50% higher than Reference case

All DSM and DR cases were run using two different discount rates—ENO's WACC and a 3% societal discount rate.

Key EE Findings—2024 DSM Potential Study

Findings

1. Over 20 year time period, lower potential savings in the Reference and Low Cases, but higher potential savings in the 2% and High cases in the 2024 study as compared to the 2021 study
2. Costs are $71M lower in the Reference Case in the 2024 study as compared to the 2021 study. Costs are significantly higher in the 2% and High cases
3. Top Measures: Residential A/C Tune-Up and Duct sealing; Commercial Occupancy Sensor and A/C and Heat Pump Tune-Up

Drivers

- **Calibration targets**
  - The 2021 study used planned targets for savings from the PY10-12 implementation plan, including a 2% savings goal for 2025.
  - The 2024 study used the actual savings and budget from PY10-12 and performance to date for PY13. Underperformance was seen in the C&I sector, consistent with results in other jurisdictions.
- **Assumptions on home energy reports**
  - Planned savings associated with the behavioral program were reduced
  - Savings percentage of consumption reduced
- **Updated data from the 2022 Residential Appliance Saturation Study**
- **Updated commercial saturation values**
- **EISA standards incorporated**
- **Updated TRM version**
- **Behavioral programs that did not show promise for kWh savings in the ENO area were removed**

Incremental Potential GWh Savings and MW Reduction by Year

Year	Electric Energy (GWh)			
	Reference Case	2% Savings Case	High Case	Low Case
2024	70	98	119	49
2028	89	117	141	66
2033	73	89	102	58
2038	40	44	51	34
2043	29	31	37	22

Year	Total Investment				Incentives				Administrative Costs			
	Ref.	**2%**	**High**	**Low**	**Ref.**	**2%**	**High**	**Low**	**Ref.**	**2%**	**High**	**Low**
2024	$11	$32	$81	$6	$6	$25	$71	$2	$5	$8	$10	$4
2028	$18	$42	$115	$9	$10	$32	$101	$3	$8	$11	$13	$6
2033	$17	$35	$95	$10	$10	$27	$85	$4	$7	$9	$11	$6
2038	$8	$15	$54	$6	$4	$11	$49	$3	$4	$4	$5	$4
2043	$4	$8	$39	$4	$2	$6	$36	$2	$2	$2	$3	$2
20-Year Total	**$250**	**$558**	**$1613**	**$152**	**$139**	**$415**	**$1,439**	**$56**	**$111**	**$143**	**$174**	**$96**

Note: Values in $ millions

Incremental Potential GWh Savings by Year as a Percentage of Total Annual Sales

Year	Reference Case	2% Savings Case	High Case	Low Case
2024	1.25%	1.74%	2.11%	0.87%
2028	1.54%	2.04%	2.44%	1.15%
2033	1.24%	1.51%	1.72%	0.99%
2038	0.58%	0.62%	0.70%	0.50%
2043	0.38%	0.39%	0.47%	0.29%

Incremental Potential GWh Savings by Year in the 2024 and 2021 DSM Potential Studies

	2024 DSM Potential Study			
	Reference Case	2% Case	Low Case	High Case
2024	70	98	49	119
2028	89	117	67	141
2033	73	89	58	102
2038	40	44	34	51
2043	29	31	22	37
Total (MW)	1242	1551	960	1830

	2021 DSM Potential Study			
	Reference Case	2% Case	Low Case	High Case
2021	79	89	77	93
2025	103	119	101	126
2030	96	115	96	123
2035	65	86	66	94
2040	50	73	51	81
Total (MW)	1302	1344	1299	1359

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Incremental Potential Peak Demand Reduction (MW) by Year in the 2024 and 2021 DSM Potential Studies

	2024 DSM Potential Study Peak Demand Reduction			
	Reference Case	2% Case	Low Case	High Case
2024	19	25	14	30
2028	30	39	24	45
2033	29	34	26	39
2038	14	14	13	18
2043	9	9	7	12
Total (MW)	433	515	362	608

	2021 DSM Potential Study Peak Demand Reduction			
	Reference Case	2% Case	Low Case	High Case
2021	21	22	20	23
2025	25	26	25	26
2030	24	25	25	26
2035	17	18	17	18
2040	12	13	12	13
Total (MW)	408	429	409	432

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Key DR Findings—2024 DSM Potential Study

Findings

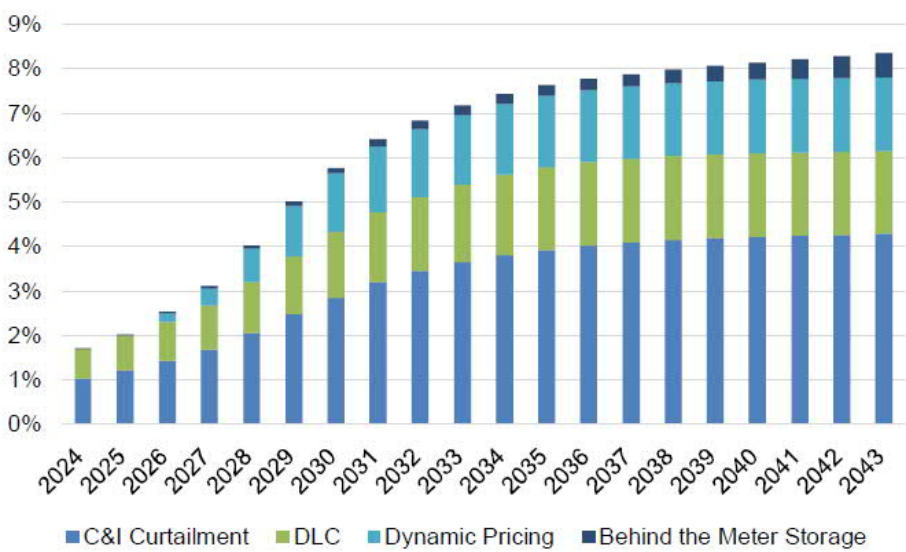
1. Peak demand reduction potential through DR programs ramps up slower in the 2024 study, but reaches higher levels in the outer years
2. Top DR Options: C&I Curtailment (51%); Residential Thermostat DLC (22%); Dynamic Pricing (20%); BTM Storage (7%)

Drivers

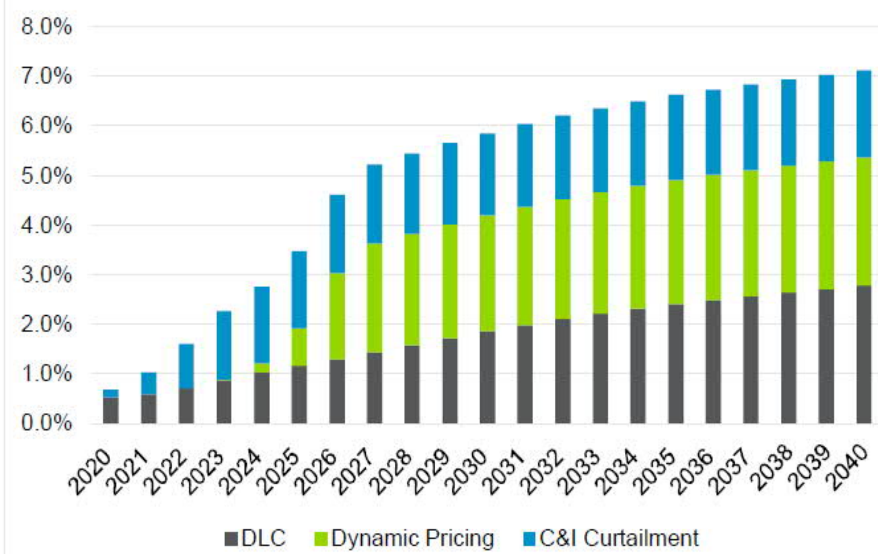
- MISO slightly changed the definition of peak
- Added new DR options
  - EV Managed Charging and Peak Time Rebate
- Used data from ENO's current DR programs
- Updated Behind-the-Meter battery storage projections
  - Assumed batteries are paired with solar
  - Updated data on penetration of smart thermostats and other control technologies

Peak Achievable Potential (% of peak demand) by DR Option in the 2024 and 2021 Potential Studies

2024 DSM Potential Study



2021 DSM Potential Study



Questions

- Follow-up from Technical Meeting #2
- Additional Questions

03

Proposed Scorecard Metrics

Scorecard Parameters and Descriptions

Utility Cost (Portfolio optimization in AURORA model)	
Expected Value	The average total relevant supply cost of Portfolios across Scenarios and relative to other optimized Portfolios (all Scenarios are weighted equally)
Utility Costs Impacted on ENO's Revenue Requirements	
Net present Value of Revenue Requirements	The Total Relevant Supply Cost of the Portfolio in the Scenario it was optimized in
Nominal Portfolio Value (residential./other customer classes)	A sum of the initial 5 years of the planning period
Risk/Uncertainty	
Distribution of Potential Utility Costs	The standard deviation of total relevant supply cost across Scenarios divided by the expected value to get to a coefficient of variation
Range of potential utility costs	The sum of the total relevant supply cost upside and downside risk of Portfolios
Probability of high CO2 intensity	Probability of high CO2 intensity in the initial 5 years of the planning period
Probability of high groundwater usage	Probability of high groundwater usage in the initial 5 years of the planning period
Reliability	
Relative Loss of Load Expectation	The relative amount of perfect capacity added or subtracted to obtain the 0.1 Loss of Load Expectation target in the final year of the planning period
Flexible Resources	The total MW of ramp available in the final year of the planning period
Quick Start Resources	The total MW of quick start available in the final year of the planning period (Includes supply and demand side dispatchable resources)
Environmental Impact	
CO2 Intensity	The cumulative tons of CO2/GWh over the planning period
Groundwater usage	The cumulative percentage of energy generated by resources that use ground water
Land Usage	The cumulative acreage necessary for supply plan resources over the planning period
Consistency with City Policies/Goals	
Renewable and Clean Portfolio Standard (RCPS)	The average annual percent of a portfolios clean energy targeted to align with Schedule 3.A. of the RCPS.
Macroeconomic Impact to ENO	
Macroeconomic Factor (Jobs, local economy impacts)	DSM spending represents only quantifiable macroeconomic impact at this time. Future ability to evaluate/model DERs could provide additional basis for comparison.

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Scorecard Metrics

Scoring Parameters	Measure	A	B	C	D
Utility Cost (Portfolio optimization in AURORA model)					
Expected Value	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Utility Costs Impacted on ENO's Revenue Requirements					
Net present Value of Revenue Requirements	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Nominal Portfolio Value (residential./other customer classes)	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Risk/Uncertainty					
Distribution of Potential Utility Costs	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Range of potential utility costs	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Probability of high CO2 intensity	1-100% Grading Scale	<33%	>33%	>66%	=100%
Probability of high groundwater usage	1-100% Grading Scale	<33%	>33%	>66%	=100%
Reliability					
Relative Loss of Load Expectation	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Flexible Resources	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Quick Start Resources	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Environmental Impact					
CO2 Intensity	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Groundwater usage	1-100% Grading Scale	<33%	>33%	>66%	=100%
Land Usage	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Consistency with City Policies/Goals					
Renewable and Clean Portfolio Standard (RCPS)	1-(-15)% Grading Scale	100% Low Carbon	>66% Low Carbon	>33% Low Carbon	<33% Low Carbon
Macroeconomic Impact to ENO					
Macroeconomic Factor (Jobs, local economy impacts)	N/A	N/A	N/A	N/A	N/A

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04 Timeline

Timeline

Event	Current Deadline	Status
Public Meeting #1	August 23, 2023	✓
Technical Meeting #1	November 9, 2023	✓
DSM Potential Studies Due	February 1, 2024	✓
Mardi Gras	February 13, 2024	✓
Stakeholders provide their Scenario and Strategy	Before Technical Meeting 2	✓
Technical Meeting #2—Discuss Final ENO and Stakeholder Scenarios and Strategies	February 29, 2024	✓
Deadline for Council policies to be included in optimization	April 15, 2024	✓
Technical Meeting #3—Finalize Scenarios and Strategies and DSM Input Case Assignments; DSM input files for modeling due; initial Scorecard discussion	May 7, 2024	
IRP Inputs Finalized	**May 17, 2024**	
Complete portfolio development and results; circulate portfolios and workpapers to Parties	September 6, 2024	
Technical Meeting #4—Downselection of Portfolios for Cross Testing; finalize Scorecard; initial discussion of Energy Smart budgets and goals	September 23-October 4, 2024	
2024 IRP Report filed	**December 13, 2024**	
Public Meeting #2 (ENO & SPO Present)	January 21-31, 2025	
Public Meeting #3 (Council receives public comment)	February 18-28, 2025	
Technical Meeting #5—Energy Smart PY16-18 programs and implementation plan	February 18-28, 2025	
Mardi Gras	March 4, 2025	
Intervenor Comments on Final IRP	March 10, 2025	
ENO Reply Comments	April 28, 2025	
Advisor Report	June 2, 2025	
Energy Smart Implementation Plan Filing for PY 16-18	June 16, 2025	

CERTIFICATE OF SERVICE
UD-23-01

I hereby certify that I have served the required number of copies of the foregoing pleading upon all other known parties of this proceeding individually and/or through their attorney of record or other duly designated individual.

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New Orleans, Louisiana, this 15th day of February 2024

Leslie M. LaCoste

Kevin T. Boleware
Manager – Regulatory Affairs
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September 18, 2024

Via Electronic Delivery
Clerk of Council
City Hall, Room 1E09
1300 Perdido Street
New Orleans, Louisiana 70112

Re: CNO Docket No. UD-23-01 (2024 Triennial IRP)

Dear Clerk:

Attached please find Entergy New Orleans, LLC's ("ENO") Slide Deck for Technical Meeting #4 that is scheduled for Wednesday, October 2, 2024, at 10:00 a.m.

ENO submits this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you direct. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

If you have any questions, please do not hesitate to call me. Thank you for your courtesy and assistance with this matter.

Sincerely,

Kevin T. Boleware

Enclosures

cc: Official Service List UD-23-01 *(via electronic mail)*

October 2, 2024

ENO 2024 IRP
Technical Meeting #4

Docket UD-23-01

Goals and Agenda of Technical Meeting #4

Goals

The Initiating Resolution (R-23-254) contemplates several goals for this Technical Meeting:

- Review and discuss the Optimized Resource Portfolios selected through the Aurora capacity expansion modeling and reach consensus on the subset of portfolios to be carried through the total supply cost analysis and cross testing;
- Finalize the scorecard metrics presented at Technical Meeting #3; and
- Engage in an initial discussion regarding Energy Smart Program Years 16-18 (2026-2028).

Agenda

1. Optimized Resource Portfolio Discussion and Downselection
2. Risk Assessment Discussion
3. Scorecard Metrics Discussion
4. Energy Smart PY 16-18 Program Discussion
5. Timeline and Next Steps

Technical Meeting #3 (5/7/24)—Follow Ups

- Parties had further discussions regarding the parameters of the Stakeholder Strategy
- On 5/13/24, ENO proposed updates to the composition of the 500 MW Renewables Block required by the Stakeholder Strategy
- On 5/16/24, Greg Nichols from the City's Office of Resilience and Sustainability submitted a letter confirming that the proposed updates were acceptable to the Intervenors
- As required by the Initiating Resolution, the Planning Scenarios, Planning Strategies, and IRP Inputs were all finalized on 5/17/24
- ENO circulated the results of the Aurora modeling and initial total supply costs on 9/6/24

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01 Optimized Resource Portfolio Discussion and Downselection

2024 IRP—Planning Scenarios (Finalized 5/17/24)

	Scenario 1 – Reference	Scenario 2 – Clean Air Act Section 111 Compliance	Scenario 3 – Stakeholder Scenario
Peak Load & Energy Growth	• Reference	• Reference	• High
Natural Gas Prices	• Reference	• Reference	• High
MISO Coal Deactivations[1]	• All ETR coal by 2030 • All MISO coal aligns with MTEP Future 2 (36 year life)	• All ETR coal by 2030 • All MISO coal by 2030	• All ETR and MISO coal by 2030
MISO Natural Gas CC Deactivations[1]	• 45 year life	• NGCC by 2035	• Deactivated by 2035
MISO Natural Gas Other Deactivations[1]	• 36 year life	• Steam gas EGUs by 2030	• Deactivated by 2035
Carbon Tax Scenario	• Reference Cost	• Reference Cost	• High Cost
Renewable Capital Cost	• Reference Cost	• Reference Cost	• Low Cost
Narrative	• Assumptions align with the 2024 Business Plan case. • Moderate amount of industrial growth forecasted which would drive the need for new development	• Entergy and utilities across MISO deactivate existing units early to be compliant with proposed changes to Clean Air Act Section 111(d) • New resources built would comply with proposed changes to 111(b)	• High energy growth from both industrial and residential sectors forecasted. • Renewable cost assumed to be low due to more efficient supply chain

1. See MISO Futures Report Series 1A for additional detail

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2024 IRP—Planning Strategies (Finalized 5/17/24)

	Strategy 1	Strategy 2	Strategy 3	Strategy 4
Description	Least Cost Planning	But For RCPS	RCPS Compliance	Stakeholder Strategy— Accelerated Grid Cleaning
Resource Portfolio Criteria and Constraints	Meet long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio of supply and DSM resources	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs	Include a portfolio of DSM programs that meet the Council's stated 2% goal and determine remaining needs in compliance with RCPS policy goals	800 MW of renewables by 2030, including 200 MW of BTM solar and 55 MW of IFOM Community Solar; high load growth driven by EVs and electrification
Objective	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal.	Design a portfolio that includes a set of potential DSM programs intended to meet the Council's stated 2% goal. Excludes new resources that would not be RCPS compliant.	Accelerate achievement of RCPS goals using local generation and PPAs to increase portfolio of solar, storage, and wind
DSM Input Case	WACC, Reference Case	WACC, 2% Program Case	WACC, 2% Program Case	Societal Discount Rate, High Case
Optimized Portfolio	Yes	Yes	Yes	No
Manual Portfolio	Early Deactivation of Union 1 in 2032 Early Deactivation of Union 1 in 2035	N/A	N/A	Yes

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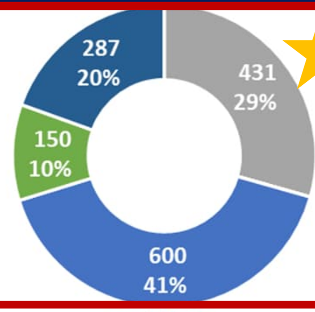
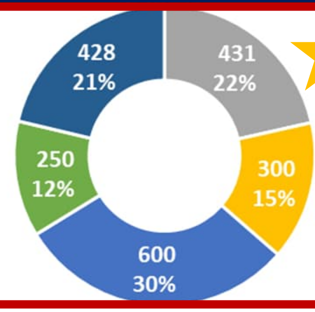
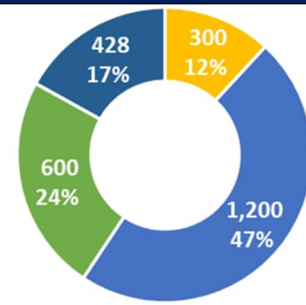
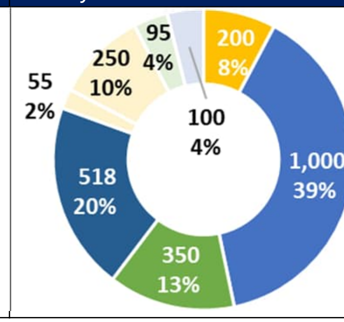
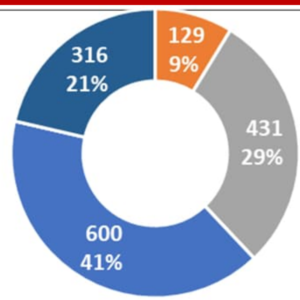
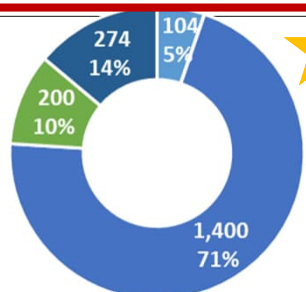
Capacity Expansion– Process and Observations

- For each Scenario and Strategy combination, portfolios are created in Aurora capacity expansion using constraints and assumptions
- Three Scenarios and four Strategies produced twelve optimized portfolios, plus two manual portfolios created under Scenario 1 / Strategy 1
- Stakeholders work together to narrow down the fourteen portfolios created in capacity expansion to no more than five to be cross-tested across the three Scenarios
  - Limiting to five necessary to maintain the IRP schedule
- The objective of portfolio downselection for cross-testing is to identify a diverse, representative range of potential portfolios, which when tested across each of the Scenarios will provide more information regarding how portfolios' total supply costs change under the different assumptions of the three Scenarios
- Portfolios incorporate combinations of renewables, storage, and DSM, with fossil resources selected in some cases

Portfolios proposed for downselection

- **Scenario 1 / Strategy 1** represents least cost planning with reference assumptions, including the current assumed deactivation of Union 1 in 2041.
- **Scenario 1 / Strategy 1, Manual Portfolio 1b** represents least cost planning with reference assumptions and an acceleration of the deactivation of Union 1 to 2035.
- **Scenario 1 / Strategy 2** provides an optimized portfolio with reference assumptions and a mix of different resource types.
- **Scenario 2 / Strategy 4** forces in solar, wind, and battery storage (500 MW total) by 2030 and DSM programs.
- **Scenario 3 / Strategy 3** provides a renewable-only resource selection with a mix of wind and battery capability. This portfolio selects the largest amount of capability given the high demand Scenario.

Scenario 1 (Reference) (ICAP MW)

	Strategy 1 Least Cost Planning DSM Optimized All Resources Available	Strategy 2 But for RCPS 2% DSM Program Forced In All Resources Available	Strategy 3 RCPS Compliance 2% DSM Program Forced In Only Renewable Resources Available	Strategy 4 Stakeholder Strategy Societal High DSM Program Forced In 500 MW Renewables Block Forced In Only Renewable Resources Available
Optimized Portfolios				
Manual Portfolio 1a: 2032 Union 1 Deactivation				
Manual Portfolio 1b: 2035 Union 1 Deactivation				

Strategy 1 – Optimized Portfolios:

Strategy 2 – Optimized Portfolios:

Strategy 3 – Optimized Portfolios:

Strategy 4 – Optimized Portfolios:

Manual Portfolio

Manual Portfolio 1a:

Manual Portfolio 1b:

★ Proposed portfolios for cross testing

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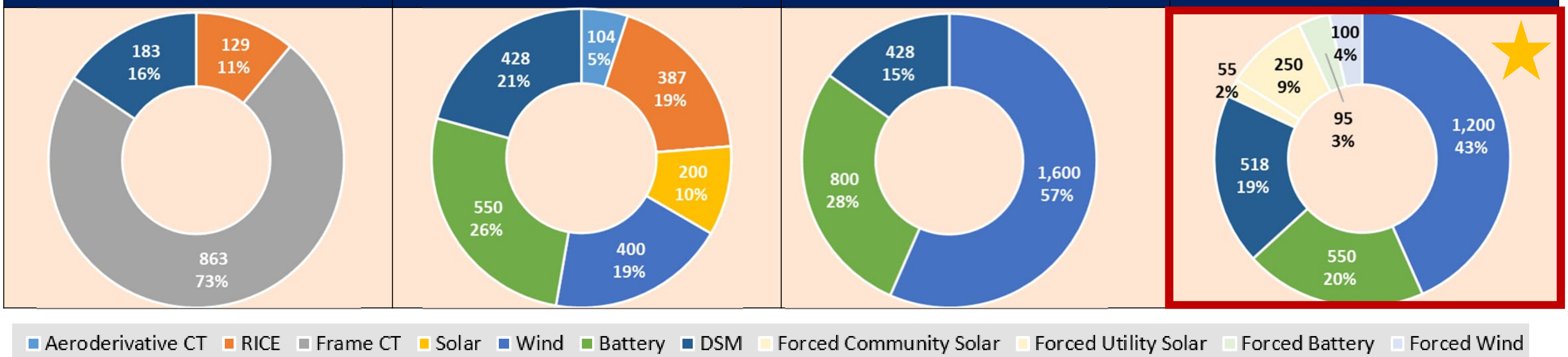
Aeroderivative CT | RICE | Frame CT | Solar | Wind | Battery | DSM | Forced Community Solar | Forced Utility Solar | Forced Battery | Forced Wind

Scenario 2 (Clean Air Act Section 111 Compliance) (ICAP MW)

Strategy 1 Least Cost Planning DSM Optimized All Resources Available	Strategy 2 But for RCPS 2% DSM Program Forced In All Resources Available	Strategy 3 RCPS Compliance 2% DSM Program Forced In Only Renewable Resources Available	Strategy 4 Stakeholder Strategy Societal High DSM Program Forced In 500 MW Renewables Block Forced In Only Renewable Resources Available

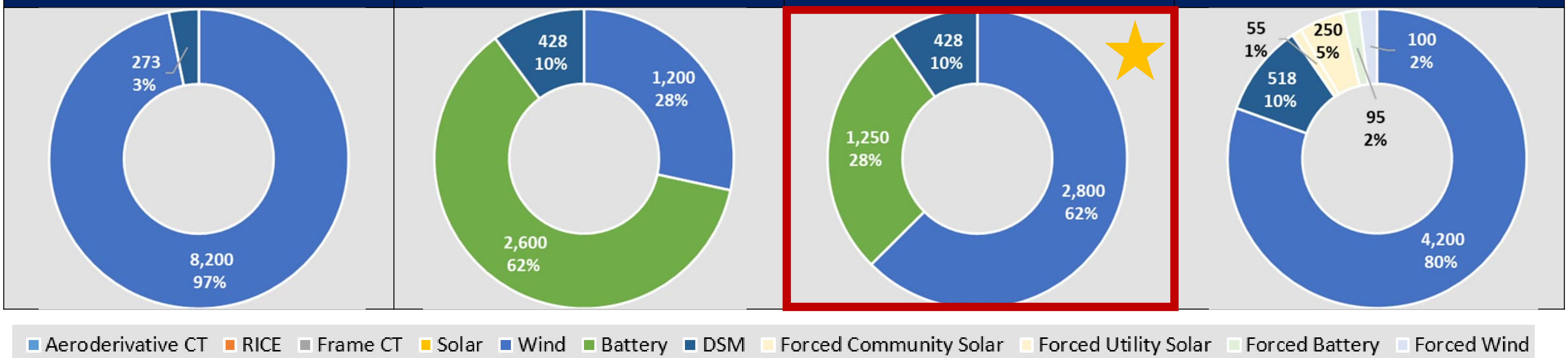


★ Proposed portfolios for cross testing

*All capacity stated in ICAP

Scenario 3 (Stakeholder Scenario) (ICAP MW)

Strategy 1	Strategy 2	Strategy 3	Strategy 4
Least Cost Planning DSM Optimized All Resources Available	But for RCPS 2% DSM Program Forced In All Resources Available	RCPS Compliance 2% DSM Program Forced In Only Renewable Resources Available	Stakeholder Strategy Societal High DSM Program Forced In 500 MW Renewables Block Forced In Only Renewable Resources Available

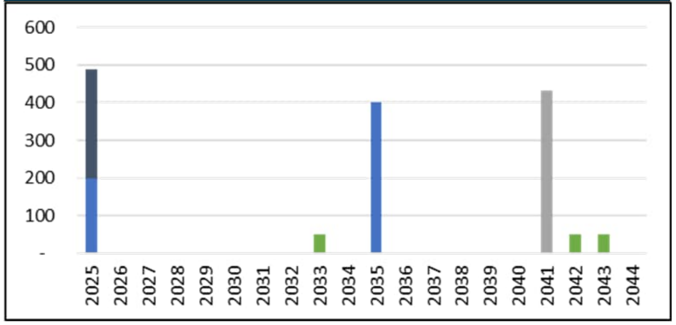


Proposed portfolios for cross testing

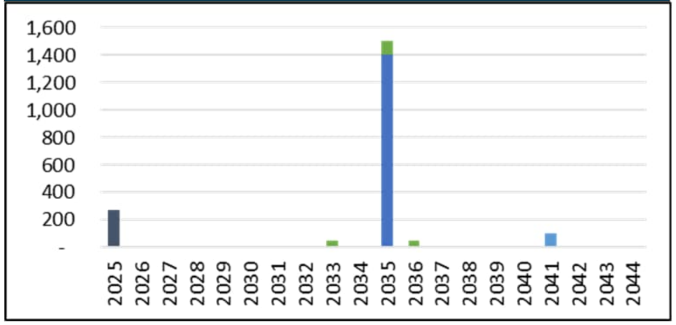
*All capacity stated in ICAP

Portfolios Proposed for Downselection - Build Timeline (ICAP MW)

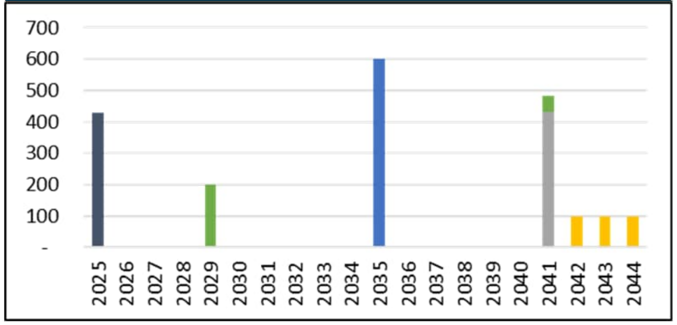
Scenario 1 Strategy 1



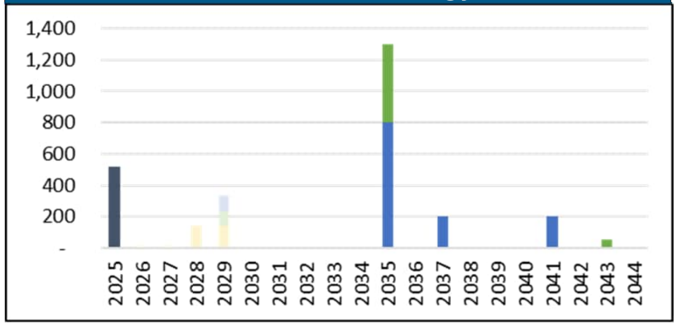
Scenario 1 Strategy 1 Manual 1b



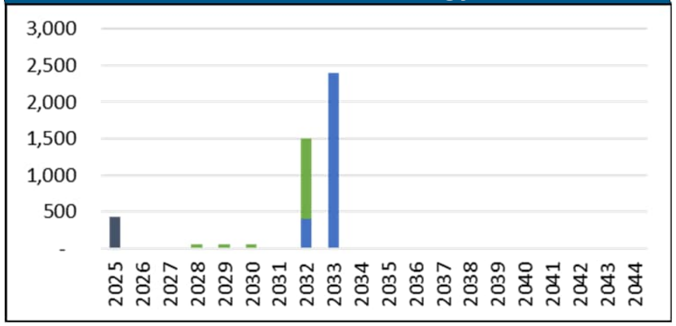
Scenario 1 Strategy 2



Scenario 2 Strategy 4



Scenario 3 Strategy 3



Aeroderivative CT | RICE | Frame CT | Solar | Wind | Battery | DSM | Forced Community Solar | Forced Utility Solar | Forced Battery | Forced Wind

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02 Risk Assessment

Stochastic Analysis

The stochastic risk assessment gives an indication of the variability of a Portfolio's costs as underlying assumptions change.

The Company proposes performing the stochastic analysis on gas price & CO_2 price assumptions for all of the proposed portfolios for downselection on Slide 7.

03

Proposed Scorecard Metrics

Scorecard Parameters and Descriptions

Utility Cost (Portfolio optimization in AURORA model)	
Expected Value	The average total relevant supply cost of Portfolios across Scenarios and relative to other optimized Portfolios (all Scenarios are weighted equally)
Utility Costs Impacted on ENO's Revenue Requirements	
Net present Value of Revenue Requirements	The Total Relevant Supply Cost of the Portfolio in the Scenario in which it was optimized
Nominal Portfolio Value (residential./other customer classes)	A sum of the initial 5 years of the planning period
Risk/Uncertainty	
Distribution of Potential Utility Costs	The standard deviation of total relevant supply cost across Scenarios divided by the expected value to get to a coefficient of variation
Range of potential utility costs	The sum of the total relevant supply cost upside and downside risk of Portfolios
Probability of high CO2 intensity	Probability of high CO2 intensity in the initial 5 years of the planning period
Probability of high groundwater usage	Probability of high groundwater usage in the initial 5 years of the planning period
Reliability	
Relative Loss of Load Expectation	The relative amount of "perfect capacity" added or subtracted to obtain the 0.1 Loss of Load Expectation target in the final year of the planning period
Flexible Resources	The total MW of ramp available in the final year of the planning period
Quick Start Resources	The total MW of quick start available in the final year of the planning period (Includes supply and demand side dispatchable resources)
Environmental Impact	
CO2 Intensity	The cumulative tons of CO2/GWh over the planning period
Groundwater usage	The cumulative percentage of energy generated by resources that use ground water
Land Usage	The cumulative acreage necessary for supply plan resources over the planning period
Consistency with City Policies/Goals	
Renewable and Clean Portfolio Standard (RCPS)	The average annual percent of a portfolio's clean energy targeted to align with Schedule 3.A. of the RCPS.
Macroeconomic Impact to ENO	
Macroeconomic Factor (Jobs, local economy impacts)	DSM spending represents only quantifiable macroeconomic impact at this time. Future ability to evaluate/model DERs could provide additional basis for comparison.

Scorecard Metrics

Scoring Parameters	Measure	A	B	C	D
Utility Cost (Portfolio optimization in AURORA model)					
Expected Value	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Utility Costs Impact on ENO's Revenue Requirements					
Net present Value of Revenue Requirements	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Nominal Portfolio Value (residential/other customer classes)	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Risk/Uncertainty					
Distribution of Potential Utility Costs	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Range of potential utility costs	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Probability of high CO2 intensity	1-100% Grading Scale	<33%	>33%	>66%	=100%
Probability of high groundwater usage	1-100% Grading Scale	<33%	>33%	>66%	=100%
Reliability					
Relative Loss of Load Expectation	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Flexible Resources	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Quick Start Resources	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Environmental Impact					
CO2 Intensity	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Groundwater usage	1-100% Grading Scale	<33%	>33%	>66%	=100%
Land Usage	1-10 Grading Scale	>7.5	7.5 - 5.01	5 - 2.51	≤ 2.50
Consistency with City Policies/Goals					
Renewable and Clean Portfolio Standard (RCPS)	1-(-15)% Grading Scale	100% Low Carbon	>66% Low Carbon	>33% Low Carbon	<33% Low Carbon
Macroeconomic Impact to City of NO					
Macroeconomic Factor (Jobs, local economy impacts)	N/A	N/A	N/A	N/A	N/A

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04

Energy Smart Program PY 16-18

Energy Smart PY 16-18—Implementation Plan Timeline

IRP Technical Meeting #4	October 2, 2024
Issue RFP for Third Party Administrator and Third Party Evaluator	October 2024
2024 IRP Report Filed	December 13, 2024
RFP Submission Deadline	December 2024
IRP Technical Meeting #5 (Energy Smart Design)	February 18-28, 2025
RFP selections and submission of Proposed TPA and TPE to Council	February 2025
Draft of Implementation Plan	May 16, 2025
Advisors' Report on 2024 IRP	June 2, 2025
Proposed Technical Conference	June 3, 2025
Implementation Plan Filing	June 16, 2025

Energy Smart PY 13-15— EE Program Matrix

Current Programs (PY 13-14)	**Proposed Programs (PY15)**
Home Performance w Energy Star	Home Performance w Energy Star
A/C Solutions	A/C Solutions
Retail Lighting and Appliances	A/C Solutions Income Qualified
Residential Behavioral	Retail Appliances
Income Qualified Weatherization	Retail Appliances Income Qualified
Multifamily Solutions	Multifamily Solutions
School Kits	Multifamily Solutions Income Qualified
Small C&I Solutions	Income Qualified Weatherization
Large C&I Solutions	Neighborhood-Based Delivery Pilot
New Construction	
Publicly Funded Institutions	Residential HVAC Midstream
	School Kits
	Residential Behavioral
	Small C&I Solutions
	Large C&I Solutions
	New Construction Code Compliance
	Publicly Funded Institutions

Energy Smart PY 13-15—DR Program Matrix

Proposed Programs (PY 15)	**Potential Programs (PY 16-18)**
Bring Your Own Thermostat	Bring Your Own Thermostat
Electric Vehicle Charging	Electric Vehicle Charging (Residential & Commercial)
Battery Storage (Residential & Small Commercial)	Battery Storage (Residential & Commercial)
Peak Time Rebate	Peak Time Rebate
Electric Vehicle Charging (Small Commercial Fleet)	Alternative Small C&I curtailment options offering two-way control
Critical Peak Pricing/ Dynamic Pricing	Electric Vehicle Charging (Commercial Fleet)
	Critical Peak Pricing/ Dynamic Pricing
	Direct Load Control – Water Heaters

Energy Smart PY 16-18 Topics to be Considered

- Continued focus on income qualified programming
- Energy efficiency goal
  - "The Council will consider setting the kWh saving targets for PYs 16-18 (2026-2028) based upon the outcome of the DSM potential studies performed in the 2024 IRP proceeding."*
- Demand Response goal and incentive mechanism
  - "The goal for PY16 and beyond shall also be evaluated as part of the Energy Smart Implementation plan for PYs 16-18 (2026-2028) based on registered DR Capacity for PY15 and based on actual kW savings for PY16 and beyond."**

1. * Council for the City of New Orleans Resolution R-23-553, December 14, 2023 at page 11
2. **Council for the City of New Orleans Resolution R-23-553, December 14, 2023 at page 12

05 Timeline

Timeline

Event	Current Deadline	Status
Public Meeting #1	August 23, 2023	✓
Technical Meeting #1	November 9, 2023	✓
DSM Potential Studies Due	February 1, 2024	✓
Mardi Gras	February 13, 2024	✓
Stakeholders provide their Scenario and Strategy	Before Technical Meeting 2	✓
Technical Meeting #2—Discuss Final ENO and Stakeholder Scenarios and Strategies	February 29, 2024	✓
Deadline for Council policies to be included in optimization	April 15, 2024	✓
Technical Meeting #3—Finalize Scenarios and Strategies and DSM Input Case Assignments; DSM input files for modeling due; initial Scorecard discussion	May 7, 2024	✓
IRP Inputs Finalized	**May 17, 2024**	✓
Complete portfolio development and results; circulate portfolios and workpapers to Parties	September 6, 2024	✓
Technical Meeting #4—Downselection of Portfolios for Cross Testing; finalize Scorecard; initial discussion of Energy Smart budgets and goals	October 2, 2024	
2024 IRP Report filed	**December 13, 2024**	
Public Meeting #2 (ENO & SPO Present)	January 21-31, 2025	
Public Meeting #3 (Council receives public comment)	February 18-28, 2025	
Technical Meeting #5—Energy Smart PY16-18 programs and implementation plan	February 18-28, 2025	
Mardi Gras	March 4, 2025	
Intervenor Comments on Final IRP	March 10, 2025	
ENO Reply Comments	April 28, 2025	
Advisor Report	June 2, 2025	
Energy Smart Implementation Plan Filing for PY 16-18	June 16, 2025	

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-23-01**

APPENDIX G

ANNUAL DSM VALUES

DECEMBER 2024

ENO IRP Appendix G - DSM

Annual Program Costs, $

Scenario 1 / Strategy 1

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	$ 6,172,239	$ 6,101,207	$ 5,550,225	$ 4,639,804	$ 3,583,878	$ 2,587,160	$ 1,771,014	$ 1,166,361	$ 748,113	$ 471,671	$ 294,225	$ 182,403	$ 112,733	$ 69,630	$ 43,077	$ 26,762	$ 16,753	$ 10,621	$ 6,867	$ 4,570
	HPwES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	HVAC	$ 838,667	$ 1,085,567	$ 1,362,848	$ 1,650,969	$ 1,916,105	$ 2,116,962	$ 2,204,923	$ 2,145,988	$ 1,951,131	$ 1,666,755	$ 1,339,612	$ 1,032,848	$ 764,649	$ 553,803	$ 396,970	$ 286,842	$ 206,460	$ 143,854	$ 109,352	$ 103,684
	Large C&I	$ 16,888,589	$ 16,551,568	$ 15,705,818	$ 15,643,380	$ 14,710,160	$ 13,876,683	$ 12,554,044	$ 11,092,689	$ 9,723,772	$ 8,520,386	$ 7,404,029	$ 6,581,067	$ 6,005,348	$ 5,466,437	$ 5,122,418	$ 5,014,602	$ 4,658,092	$ 4,413,553	$ 4,196,711	$ 3,212,870
	LI_MF	$ 2,491,998	$ 3,160,985	$ 3,915,431	$ 4,707,242	$ 5,441,253	$ 6,012,533	$ 6,305,837	$ 6,252,024	$ 5,874,376	$ 5,280,084	$ 4,599,284	$ 3,957,743	$ 3,415,495	$ 2,997,908	$ 2,693,922	$ 2,483,288	$ 2,335,201	$ 2,232,388	$ 2,174,236	$ 2,154,130
	Recycling	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Res Behavior	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Retail	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	School Kits	$ 38,444	$ 49,502	$ 62,027	$ 75,040	$ 86,853	$ 95,232	$ 97,985	$ 93,894	$ 83,481	$ 68,963	$ 53,289	$ 38,929	$ 27,218	$ 18,427	$ 12,198	$ 7,953	$ 5,133	$ 3,292	$ 2,103	$ 1,340
	Small C&I	$ 6,103,755	$ 6,080,824	$ 5,890,984	$ 5,980,564	$ 5,734,741	$ 5,500,280	$ 5,049,317	$ 4,513,002	$ 3,982,156	$ 3,494,458	$ 3,031,078	$ 2,676,188	$ 2,405,660	$ 2,161,029	$ 1,995,508	$ 1,924,138	$ 1,772,202	$ 1,667,697	$ 1,579,248	$ 1,186,446
	Subtotal Residential Energy Efficiency Programs	$ 3,369,109	$ 4,296,053	$ 5,340,306	$ 6,433,251	$ 7,444,210	$ 8,224,727	$ 8,608,745	$ 8,491,906	$ 7,908,989	$ 7,015,801	$ 5,992,185	$ 5,029,520	$ 4,207,362	$ 3,570,138	$ 3,103,090	$ 2,778,083	$ 2,546,795	$ 2,379,534	$ 2,285,691	$ 2,259,155
	Subtotal C&I Energy Efficiency Programs	$ 29,164,584	$ 28,733,599	$ 27,147,027	$ 26,263,749	$ 24,028,778	$ 21,964,123	$ 19,374,375	$ 16,772,052	$ 14,454,040	$ 12,486,516	$ 10,729,332	$ 9,439,658	$ 8,523,742	$ 7,697,097	$ 7,161,003	$ 6,965,502	$ 6,447,047	$ 6,091,871	$ 5,782,826	$ 4,403,886
	Subtotal Energy Efficiency Programs	$ 32,533,693	$ 33,029,652	$ 32,487,332	$ 32,697,000	$ 31,472,989	$ 30,188,850	$ 27,983,120	$ 25,263,958	$ 22,363,029	$ 19,502,317	$ 16,721,518	$ 14,469,178	$ 12,731,104	$ 11,267,234	$ 10,264,093	$ 9,743,585	$ 8,993,842	$ 8,471,405	$ 8,068,517	$ 6,663,041
Demand Response Program	BTMG - Battery Storage	$ 26,637	$ 34,827	$ 47,346	$ 62,422	$ 81,760	$ 106,482	$ 137,764	$ 177,756	$ 194,562	$ 201,795	$ 218,598	$ 236,741	$ 256,178	$ 313,376	$ 367,988	$ 428,687	$ 496,702	$ 570,398	$ 650,744	$ 715,071
	C&I Curtailment- Advanced Lighting Control	$ 1,088	$ 1,293	$ 1,395	$ 1,580	$ 1,768	$ 3,747	$ 4,781	$ 5,502	$ 6,069	$ 6,529	$ 6,947	$ 7,355	$ 7,740	$ 8,119	$ 8,467	$ 8,803	$ 9,114	$ 9,425	$ 9,739	$ 10,059
	C&I Curtailment- Auto-DR HVAC Control	$ 254,724	$ 338,716	$ 436,197	$ 580,960	$ 750,114	$ 909,917	$ 1,071,031	$ 1,199,182	$ 1,318,312	$ 1,425,659	$ 1,527,671	$ 1,627,424	$ 1,720,157	$ 1,809,227	$ 1,889,742	$ 1,966,229	$ 2,036,354	$ 2,105,657	$ 2,175,336	$ 2,247,849
	C&I Curtailment- Industrial	$ 250,921	$ 260,988	$ 269,107	$ 285,561	$ 302,229	$ 313,339	$ 324,119	$ 330,175	$ 337,303	$ 345,350	$ 355,833	$ 368,892	$ 382,869	$ 397,960	$ 412,541	$ 427,167	$ 441,064	$ 455,246	$ 469,817	$ 483,956
	C&I Curtailment- Other	$ 18,956	$ 20,055	$ 21,098	$ 23,301	$ 25,543	$ 26,871	$ 28,106	$ 28,631	$ 29,249	$ 29,947	$ 30,856	$ 31,989	$ 33,201	$ 34,509	$ 35,773	$ 37,042	$ 38,247	$ 39,477	$ 40,740	$ 41,966
	C&I Curtailment- Refrigeration Control	$ 7,981	$ 8,512	$ 9,036	$ 10,155	$ 11,294	$ 11,951	$ 12,555	$ 12,789	$ 13,066	$ 13,377	$ 13,783	$ 14,289	$ 14,831	$ 15,415	$ 15,980	$ 16,546	$ 17,085	$ 17,634	$ 18,199	$ 18,746
	C&I Curtailment- Standard Lighting Control	$ 104,178	$ 109,887	$ 115,267	$ 126,606	$ 138,136	$ 144,107	$ 150,090	$ 152,578	$ 155,648	$ 159,203	$ 163,926	$ 169,866	$ 176,249	$ 183,159	$ 189,844	$ 196,557	$ 202,939	$ 209,456	$ 216,154	$ 222,645
	C&I Curtailment- Water Heating Control	$ 7,436	$ 7,855	$ 8,250	$ 9,080	$ 9,925	$ 10,429	$ 10,899	$ 11,102	$ 11,342	$ 11,613	$ 11,965	$ 12,404	$ 12,874	$ 13,382	$ 13,872	$ 14,364	$ 14,831	$ 15,308	$ 15,798	$ 16,273
	DLC-Switch-Water Heating	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	DLC-Thermostat-Res	$ 481,846	$ 522,144	$ 582,092	$ 645,104	$ 711,030	$ 781,780	$ 766,089	$ 794,526	$ 824,417	$ 859,086	$ 896,016	$ 937,622	$ 980,366	$ 1,025,038	$ 1,071,460	$ 1,119,976	$ 1,168,889	$ 1,216,988	$ 1,267,682	$ 1,315,836
	Dynamic Pricing with enabling tech.	$ -	$ 110,373	$ 59,960	$ 86,451	$ 113,207	$ 116,999	$ 133,226	$ 125,315	$ 130,655	$ 134,327	$ 136,802	$ 139,600	$ 141,993	$ 144,647	$ 147,603	$ 150,552	$ 153,546	$ 156,640	$ 159,952	$ 162,894
	Dynamic Pricing w/o enabling tech.	$ -	$ 290,332	$ 187,237	$ 241,186	$ 198,907	$ 116,320	$ 110,279	$ 82,433	$ 78,843	$ 76,081	$ 73,979	$ 72,685	$ 71,759	$ 71,048	$ 70,645	$ 70,506	$ 70,473	$ 70,423	$ 70,805	$ 70,642
	EV Managed Charging	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Peak Time Rebate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Subtotal Demand Response Programs	$ 1,153,767	$ 1,704,983	$ 1,736,985	$ 2,072,406	$ 2,343,914	$ 2,541,942	$ 2,748,940	$ 2,919,991	$ 3,099,466	$ 3,262,968	$ 3,436,378	$ 3,618,868	$ 3,798,217	$ 4,015,879	$ 4,223,916	$ 4,436,429	$ 4,649,244	$ 4,866,653	$ 5,094,966	$ 5,305,939
	Total DSM Programs	$ 33,687,460	$ 34,734,635	$ 34,224,317	$ 34,769,405	$ 33,816,903	$ 32,730,793	$ 30,732,061	$ 28,183,949	$ 25,462,495	$ 22,765,285	$ 20,157,895	$ 18,088,046	$ 16,529,320	$ 15,283,114	$ 14,488,009	$ 14,180,014	$ 13,643,086	$ 13,338,058	$ 13,163,483	$ 11,968,979

Scenario 1 / Strategy 1 Manual 1b

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	$ 6,172,239	$ 6,101,207	$ 5,550,225	$ 4,639,804	$ 3,583,878	$ 2,587,160	$ 1,771,014	$ 1,166,361	$ 748,113	$ 471,671	$ 294,225	$ 182,403	$ 112,733	$ 69,630	$ 43,077	$ 26,762	$ 16,753	$ 10,621	$ 6,867	$ 4,570
	HPwES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	HVAC	$ 887,487	$ 1,149,810	$ 1,438,883	$ 1,733,460	$ 2,001,724	$ 2,196,683	$ 2,264,027	$ 2,171,225	$ 1,936,920	$ 1,617,922	$ 1,268,449	$ 954,804	$ 691,369	$ 492,127	$ 349,089	$ 252,093	$ 182,612	$ 128,234	$ 100,221	$ 99,929
	Large C&I	$ 16,888,589	$ 16,551,568	$ 15,705,818	$ 15,643,380	$ 14,710,160	$ 13,876,683	$ 12,554,044	$ 11,092,689	$ 9,723,772	$ 8,520,386	$ 7,404,029	$ 6,581,067	$ 6,005,348	$ 5,466,437	$ 5,122,418	$ 5,014,602	$ 4,658,092	$ 4,413,553	$ 4,196,711	$ 3,212,870
	LI_MF	$ 2,491,998	$ 3,160,985	$ 3,915,431	$ 4,707,242	$ 5,441,253	$ 6,012,533	$ 6,305,837	$ 6,252,024	$ 5,874,376	$ 5,280,084	$ 4,599,284	$ 3,957,743	$ 3,415,495	$ 2,997,908	$ 2,693,922	$ 2,483,288	$ 2,335,201	$ 2,232,388	$ 2,174,236	$ 2,154,130
	Recycling	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Res Behavior	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Retail	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	School Kits	$ 38,444	$ 49,502	$ 62,027	$ 75,040	$ 86,853	$ 95,232	$ 97,985	$ 93,894	$ 83,481	$ 68,963	$ 53,289	$ 38,929	$ 27,218	$ 18,427	$ 12,198	$ 7,953	$ 5,133	$ 3,292	$ 2,103	$ 1,340
	Small C&I	$ 6,103,755	$ 6,080,824	$ 5,890,984	$ 5,980,564	$ 5,734,741	$ 5,500,280	$ 5,049,317	$ 4,513,002	$ 3,982,156	$ 3,494,458	$ 3,031,078	$ 2,676,188	$ 2,405,660	$ 2,161,029	$ 1,995,508	$ 1,924,138	$ 1,772,202	$ 1,667,697	$ 1,579,248	$ 1,186,446
	Subtotal Residential Energy Efficiency Programs	$ 3,417,929	$ 4,360,296	$ 5,416,340	$ 6,515,742	$ 7,529,830	$ 8,304,448	$ 8,667,849	$ 8,517,143	$ 7,894,778	$ 6,966,968	$ 5,921,022	$ 4,951,477	$ 4,134,082	$ 3,508,462	$ 3,055,209	$ 2,743,333	$ 2,522,946	$ 2,363,914	$ 2,276,560	$ 2,255,399
	Subtotal C&I Energy Efficiency Programs	$ 29,164,584	$ 28,733,599	$ 27,147,027	$ 26,263,749	$ 24,028,778	$ 21,964,123	$ 19,374,375	$ 16,772,052	$ 14,454,040	$ 12,486,516	$ 10,729,332	$ 9,439,658	$ 8,523,742	$ 7,697,097	$ 7,161,003	$ 6,965,502	$ 6,447,047	$ 6,091,871	$ 5,782,826	$ 4,403,886
	Subtotal Energy Efficiency Programs	$ 32,582,513	$ 33,093,895	$ 32,563,367	$ 32,779,491	$ 31,558,608	$ 30,268,571	$ 28,042,225	$ 25,289,195	$ 22,348,818	$ 19,453,484	$ 16,650,354	$ 14,391,134	$ 12,657,824	$ 11,205,559	$ 10,216,212	$ 9,708,835	$ 8,969,993	$ 8,455,785	$ 8,059,386	$ 6,659,285
Demand Response Program	BTMG - Battery Storage	$ 16,511	$ 21,538	$ 29,375	$ 38,602	$ 50,539	$ 65,462	$ 84,941	$ 109,520	$ 117,087	$ 118,961	$ 128,957	$ 139,637	$ 151,152	$ 188,651	$ 221,768	$ 258,120	$ 298,412	$ 342,196	$ 389,833	$ 428,128
	C&I Curtailment- Advanced Lighting Control	$ 713	$ 844	$ 912	$ 1,033	$ 1,157	$ 2,427	$ 3,120	$ 3,609	$ 3,998	$ 4,314	$ 4,599	$ 4,873	$ 5,129	$ 5,377	$ 5,603	$ 5,820	$ 6,021	$ 6,221	$ 6,422	$ 6,629
	C&I Curtailment- Auto-DR HVAC Control	$ 254,724	$ 338,716	$ 436,197	$ 580,960	$ 750,114	$ 909,917	$ 1,071,031	$ 1,199,182	$ 1,318,312	$ 1,425,659	$ 1,527,671	$ 1,627,424	$ 1,720,157	$ 1,809,227	$ 1,889,742	$ 1,966,229	$ 2,036,354	$ 2,105,657	$ 2,175,336	$ 2,247,849
	C&I Curtailment- Industrial	$ 156,283	$ 163,066	$ 168,634	$ 179,417	$ 190,336	$ 197,706	$ 204,835	$ 208,946	$ 213,791	$ 219,176	$ 226,022	$ 234,405	$ 243,262	$ 252,727	$ 261,822	$ 270,946	$ 279,623	$ 288,483	$ 297,598	$ 306,421
	C&I Curtailment- Other	$ 19,858	$ 20,836	$ 21,746	$ 23,855	$ 26,008	$ 27,253	$ 28,430	$ 28,911	$ 29,526	$ 30,238	$ 31,186	$ 32,379	$ 33,661	$ 35,044	$ 36,375	$ 37,705	$ 38,961	$ 40,242	$ 41,557	$ 42,838
	C&I Curtailment- Refrigeration Control	$ 4,971	$ 5,318	$ 5,663	$ 6,380	$ 7,113	$ 7,541	$ 7,934	$ 8,094	$ 8,281	$ 8,490	$ 8,755	$ 9,080	$ 9,423	$ 9,789	$ 10,142	$ 10,495	$ 10,831	$ 11,174	$ 11,528	$ 11,869
	C&I Curtailment- Standard Lighting Control	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	C&I Curtailment- Water Heating Control	$ 4,631	$ 4,908	$ 5,170	$ 5,705	$ 6,250	$ 6,580	$ 6,888	$ 7,026	$ 7,189	$ 7,370	$ 7,600	$ 7,882	$ 8,180	$ 8,498	$ 8,804	$ 9,111	$ 9,402	$ 9,700	$ 10,007	$ 10,304
	DLC-Switch-Water Heating	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	DLC-Thermostat-Res	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Dynamic Pricing with enabling tech.	$ -	$ 110,373	$ 59,960	$ 86,451	$ 113,207	$ 116,999	$ 133,226	$ 125,315	$ 130,655	$ 134,327	$ 136,802	$ 139,600	$ 141,993	$ 144,647	$ 147,603	$ 150,552	$ 153,546	$ 156,640	$ 159,952	$ 162,894
	Dynamic Pricing w/o enabling tech.	$ -	$ 290,332	$ 187,237	$ 241,186	$ 198,907	$ 116,320	$ 110,279	$ 82,433	$ 78,843	$ 76,081	$ 73,979	$ 72,685	$ 71,759	$ 71,048	$ 70,645	$ 70,506	$ 70,473	$ 70,423	$ 70,805	$ 70,642
	EV Managed Charging	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Peak Time Rebate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Subtotal Demand Response Programs	$ 457,691	$ 955,933	$ 914,893	$ 1,163,589	$ 1,343,631	$ 1,450,206	$ 1,650,685	$ 1,773,037	$ 1,907,681	$ 2,024,616	$ 2,145,572	$ 2,267,965	$ 2,384,715	$ 2,525,008	$ 2,652,504	$ 2,779,484	$ 2,903,623	$ 3,030,736	$ 3,163,038	$ 3,287,573
	Total DSM Programs	$ 33,040,204	$ 34,049,828	$ 33,478,260	$ 33,943,079	$ 32,902,239	$ 31,718,777	$ 29,692,910	$ 27,062,232	$ 24,256,499	$ 21,478,100	$ 18,795,926	$ 16,659,100	$ 15,042,539	$ 13,730,567	$ 12,868,716	$ 12,488,319	$ 11,873,616	$ 11,486,522	$ 11,222,424	$ 9,946,858

Scenario 1 / Strategy 2

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	$ 5,870,526	$ 5,944,905	$ 5,554,326	$ 4,774,719	$ 3,790,663	$ 2,811,291	$ 1,978,996	$ 1,347,002	$ 903,385	$ 608,335	$ 419,202	$ 300,459	$ 227,473	$ 183,258	$ 156,785	$ 141,044	$ 131,093	$ 124,700	$ 120,190	$ 116,542
	HPwES	$ 3,532,987	$ 4,638,567	$ 5,933,975	$ 7,347,386	$ 8,747,501	$ 9,965,769	$ 10,789,282	$ 11,016,863	$ 10,606,916	$ 9,678,724	$ 8,373,743	$ 6,993,693	$ 5,659,156	$ 4,533,707	$ 3,654,532	$ 3,018,058	$ 2,541,882	$ 2,165,450	$ 1,956,676	$ 1,920,228
	HVAC	$ 887,487	$ 1,149,810	$ 1,438,883	$ 1,733,460	$ 2,001,724	$ 2,196,683	$ 2,264,027	$ 2,171,225	$ 1,936,920	$ 1,617,922	$ 1,268,449	$ 954,804	$ 691,369	$ 492,127	$ 349,089	$ 252,093	$ 182,612	$ 128,234	$ 100,221	$ 99,929
	Large C&I	$ 16,888,589	$ 16,551,568	$ 15,705,818	$ 15,643,380	$ 14,710,160	$ 13,876,683	$ 12,554,044	$ 11,092,689	$ 9,723,772	$ 8,520,386	$ 7,404,029	$ 6,581,067	$ 6,005,348	$ 5,466,437	$ 5,122,418	$ 5,014,602	$ 4,658,092	$ 4,413,553	$ 4,196,711	$ 3,212,870
	LI_MF	$ 3,487,842	$ 4,534,516	$ 5,752,139	$ 7,074,338	$ 8,373,302	$ 9,468,487	$ 10,150,323	$ 10,245,088	$ 9,700,913	$ 8,614,905	$ 7,187,638	$ 5,677,849	$ 4,281,529	$ 3,124,506	$ 2,239,172	$ 1,602,119	$ 1,158,208	$ 853,920	$ 659,385	$ 546,330
	Recycling	$ 131,202	$ 144,991	$ 159,914	$ 175,992	$ 193,230	$ 211,612	$ 231,093	$ 251,602	$ 273,032	$ 295,237	$ 318,034	$ 341,194	$ 364,450	$ 387,491	$ 409,975	$ 431,530	$ 451,767	$ 470,293	$ 486,723	$ 500,697
	Res Behavior	$ 1,624,876	$ 1,635,749	$ 1,647,069	$ 1,658,569	$ 1,668,944	$ 1,679,895	$ 1,691,784	$ 1,703,574	$ 1,715,575	$ 1,729,871	$ 1,746,040	$ 1,764,825	$ 1,785,277	$ 1,804,941	$ 1,823,668	$ 1,842,058	$ 1,858,826	$ 1,874,203	$ 1,889,747	$ 1,905,411
	Retail	$ 1,459,126	$ 1,774,420	$ 2,062,658	$ 2,290,270	$ 2,427,481	$ 2,500,517	$ 2,509,968	$ 2,436,343	$ 2,352,301	$ 2,332,743	$ 2,294,842	$ 2,316,983	$ 2,274,263	$ 2,220,447	$ 2,154,297	$ 2,098,716	$ 2,006,499	$ 1,863,358	$ 1,814,521	$ 1,907,534
	School Kits	$ 38,632	$ 49,744	$ 62,331	$ 75,407	$ 87,278	$ 95,698	$ 98,464	$ 94,354	$ 83,889	$ 69,300	$ 53,549	$ 39,120	$ 27,352	$ 18,517	$ 12,257	$ 7,991	$ 5,159	$ 3,309	$ 2,113	$ 1,346
	Small C&I	$ 6,103,755	$ 6,080,824	$ 5,890,984	$ 5,980,564	$ 5,734,741	$ 5,500,280	$ 5,049,317	$ 4,513,002	$ 3,982,156	$ 3,494,458	$ 3,031,078	$ 2,676,188	$ 2,405,660	$ 2,161,029	$ 1,995,508	$ 1,924,138	$ 1,772,202	$ 1,667,697	$ 1,579,248	$ 1,186,446
	Subtotal Residential Energy Efficiency Programs	$ 11,162,151	$ 13,927,798	$ 17,056,968	$ 20,355,422	$ 23,499,462	$ 26,118,660	$ 27,734,941	$ 27,919,048	$ 26,669,547	$ 24,338,702	$ 21,242,294	$ 18,088,469	$ 15,083,395	$ 12,581,737	$ 10,642,990	$ 9,252,564	$ 8,204,953	$ 7,358,768	$ 6,909,387	$ 6,881,476
	Subtotal C&I Energy Efficiency Programs	$ 28,862,871	$ 28,577,296	$ 27,151,127	$ 26,398,664	$ 24,235,563	$ 22,188,254	$ 19,582,357	$ 16,952,692	$ 14,609,313	$ 12,623,179	$ 10,854,309	$ 9,557,714	$ 8,638,481	$ 7,810,725	$ 7,274,711	$ 7,079,784	$ 6,561,387	$ 6,205,950	$ 5,896,149	$ 4,515,859
	Subtotal Energy Efficiency Programs	$ 40,025,022	$ 42,505,094	$ 44,208,095	$ 46,754,086	$ 47,735,025	$ 48,306,913	$ 47,317,299	$ 44,871,740	$ 41,278,860	$ 36,961,881	$ 32,096,603	$ 27,646,182	$ 23,721,876	$ 20,392,462	$ 17,917,701	$ 16,332,348	$ 14,766,340	$ 13,564,718	$ 12,805,536	$ 11,397,335
Demand Response Program	BTMG - Battery Storage	$ 26,637	$ 34,827	$ 47,346	$ 62,422	$ 81,760	$ 106,482	$ 137,764	$ 177,756	$ 194,562	$ 201,795	$ 218,598	$ 236,741	$ 256,178	$ 313,376	$ 367,988	$ 428,687	$ 496,702	$ 570,398	$ 650,744	$ 715,071
	C&I Curtailment- Advanced Lighting Control	$ 1,088	$ 1,293	$ 1,395	$ 1,580	$ 1,768	$ 3,747	$ 4,781	$ 5,502	$ 6,069	$ 6,529	$ 6,947	$ 7,355	$ 7,740	$ 8,119	$ 8,467	$ 8,803	$ 9,114	$ 9,425	$ 9,739	$ 10,059
	C&I Curtailment- Auto-DR HVAC Control	$ 424,487	$ 565,283	$ 728,588	$ 970,202	$ 1,250,541	$ 1,511,347	$ 1,769,648	$ 1,968,568	$ 2,148,284	$ 2,306,843	$ 2,456,975	$ 2,605,080	$ 2,744,413	$ 2,880,570	$ 3,005,139	$ 3,124,674	$ 3,234,970	$ 3,344,747	$ 3,455,632	$ 3,569,350
	C&I Curtailment- Industrial	$ 250,921	$ 260,988	$ 269,107	$ 285,561	$ 302,229	$ 313,339	$ 324,119	$ 330,175	$ 337,303	$ 345,350	$ 355,833	$ 368,892	$ 382,869	$ 397,960	$ 412,541	$ 427,167	$ 441,064	$ 455,246	$ 469,817	$ 483,956
	C&I Curtailment- Other	$ 18,956	$ 20,055	$ 21,098	$ 23,301	$ 25,543	$ 26,871	$ 28,106	$ 28,631	$ 29,249	$ 29,947	$ 30,856	$ 31,989	$ 33,201	$ 34,509	$ 35,773	$ 37,042	$ 38,247	$ 39,477	$ 40,740	$ 41,966
	C&I Curtailment- Refrigeration Control	$ 7,981	$ 8,512	$ 9,036	$ 10,155	$ 11,294	$ 11,951	$ 12,555	$ 12,789	$ 13,066	$ 13,377	$ 13,783	$ 14,289	$ 14,831	$ 15,415	$ 15,980	$ 16,546	$ 17,085	$ 17,634	$ 18,199	$ 18,746
	C&I Curtailment- Standard Lighting Control	$ 104,178	$ 109,887	$ 115,267	$ 126,606	$ 138,136	$ 144,107	$ 150,090	$ 152,578	$ 155,648	$ 159,203	$ 163,926	$ 169,866	$ 176,249	$ 183,159	$ 189,844	$ 196,557	$ 202,939	$ 209,456	$ 216,154	$ 222,645
	C&I Curtailment- Water Heating Control	$ 7,436	$ 7,855	$ 8,250	$ 9,080	$ 9,925	$ 10,429	$ 10,899	$ 11,102	$ 11,342	$ 11,613	$ 11,965	$ 12,404	$ 12,874	$ 13,382	$ 13,872	$ 14,364	$ 14,831	$ 15,308	$ 15,798	$ 16,273
	DLC-Switch-Water Heating	$ -	$ 1,882,660	$ 2,585,382	$ 5,843,472	$ 6,525,747	$ 4,242,509	$ 4,161,454	$ 2,376,583	$ 2,457,501	$ 2,523,656	$ 2,580,924	$ 4,548,644	$ 5,121,550	$ 8,211,021	$ 8,405,411	$ 5,605,350	$ 5,293,791	$ 3,289,125	$ 3,385,720	$ 1,489,197
	DLC-Thermostat-Res	$ 731,164	$ 818,130	$ 940,637	$ 1,080,423	$ 1,238,608	$ 1,417,763	$ 1,461,119	$ 1,563,807	$ 1,660,962	$ 1,753,014	$ 1,834,541	$ 1,909,595	$ 1,975,129	$ 2,034,669	$ 2,089,943	$ 2,143,356	$ 2,193,775	$ 2,240,173	$ 2,288,679	$ 2,339,472
	Dynamic Pricing with enabling tech.	$ -	$ 110,373	$ 59,960	$ 86,451	$ 113,207	$ 116,999	$ 133,226	$ 125,315	$ 130,655	$ 134,327	$ 136,802	$ 139,600	$ 141,993	$ 144,647	$ 147,603	$ 150,552	$ 153,546	$ 156,640	$ 159,952	$ 162,894
	Dynamic Pricing w/o enabling tech.	$ -	$ 303,389	$ 201,899	$ 260,565	$ 194,969	$ 97,709	$ 89,443	$ 69,822	$ 65,292	$ 61,941	$ 59,641	$ 58,169	$ 59,038	$ 59,934	$ 60,872	$ 61,763	$ 62,571	$ 63,226	$ 64,057	$ 64,848
	EV Managed Charging	$ 450,200	$ 636,791	$ 830,310	$ 1,030,952	$ 1,238,920	$ 1,454,417	$ 1,948,077	$ 2,538,464	$ 3,306,190	$ 4,177,696	$ 5,137,313	$ 6,167,107	$ 7,251,628	$ 8,377,313	$ 9,533,592	$ 10,713,330	$ 11,910,430	$ 13,123,076	$ 14,353,701	$ 15,541,815
	Peak Time Rebate	$ 284,153	$ 652,545	$ 1,457,429	$ 2,129,600	$ 2,314,527	$ 2,514,484	$ 2,476,215	$ 2,522,476	$ 2,569,422	$ 2,619,509	$ 2,671,543	$ 2,727,097	$ 2,783,751	$ 2,841,016	$ 2,898,452	$ 2,956,307	$ 3,013,514	$ 3,068,493	$ 3,123,945	$ 3,181,094
	Subtotal Demand Response Programs	$ 2,307,201	$ 5,412,588	$ 7,275,703	$ 11,920,369	$ 13,447,173	$ 11,972,153	$ 12,707,498	$ 11,883,570	$ 13,085,544	$ 14,344,801	$ 15,679,649	$ 18,996,828	$ 20,961,443	$ 25,515,091	$ 27,185,477	$ 25,884,499	$ 27,082,579	$ 26,602,424	$ 28,252,875	$ 27,857,387
	Total DSM Programs	$ 42,332,223	$ 47,917,682	$ 51,483,798	$ 58,674,456	$ 61,182,198	$ 60,279,066	$ 60,024,796	$ 56,755,310	$ 54,364,404	$ 51,306,681	$ 47,776,252	$ 46,643,011	$ 44,683,319	$ 45,907,552	$ 45,103,178	$ 42,216,846	$ 41,848,919	$ 40,167,142	$ 41,058,411	$ 39,254,722

Scenario 2 / Strategy 4

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	$ 6,172,239	$ 6,101,207	$ 5,550,225	$ 4,639,804	$ 3,583,878	$ 2,587,160	$ 1,771,014	$ 1,166,361	$ 748,113	$ 471,671	$ 294,225	$ 182,403	$ 112,733	$ 69,630	$ 43,077	$ 26,762	$ 16,753	$ 10,621	$ 6,867	$ 4,570
	HPwES	$ 7,644,616	$ 9,952,191	$ 12,459,376	$ 14,964,293	$ 17,145,468	$ 18,721,304	$ 19,308,115	$ 18,601,695	$ 16,815,096	$ 14,432,221	$ 11,759,799	$ 9,367,346	$ 7,302,841	$ 5,708,787	$ 4,542,750	$ 3,752,068	$ 3,162,434	$ 2,682,726	$ 2,423,021	$ 2,393,852
	HVAC	$ 5,044,353	$ 6,791,929	$ 8,578,523	$ 10,265,134	$ 11,680,946	$ 12,865,206	$ 13,686,746	$ 13,899,831	$ 13,738,691	$ 13,530,855	$ 13,016,724	$ 12,644,081	$ 12,014,705	$ 11,396,485	$ 10,797,478	$ 10,296,037	$ 9,705,473	$ 8,962,993	$ 8,590,116	$ 8,751,230
	Large C&I	$ 41,495,855	$ 39,672,866	$ 36,792,584	$ 37,699,756	$ 34,911,154	$ 34,138,391	$ 31,437,716	$ 28,417,656	$ 25,679,207	$ 23,478,668	$ 21,273,265	$ 19,868,655	$ 18,475,671	$ 17,550,506	$ 17,080,195	$ 17,392,912	$ 16,526,465	$ 15,961,837	$ 15,378,672	$ 9,113,956
	LI_MF	$ 6,683,003	$ 8,667,688	$ 10,895,514	$ 13,185,881	$ 15,236,960	$ 16,703,961	$ 17,213,406	$ 16,520,083	$ 14,758,454	$ 12,341,831	$ 9,691,773	$ 7,283,014	$ 5,273,951	$ 3,738,637	$ 2,625,476	$ 1,861,889	$ 1,337,177	$ 971,064	$ 743,008	$ 621,840
	Recycling	$ 131,202	$ 144,991	$ 159,914	$ 175,992	$ 193,230	$ 211,612	$ 231,093	$ 251,602	$ 273,032	$ 295,237	$ 318,034	$ 341,194	$ 364,450	$ 387,491	$ 409,975	$ 431,530	$ 451,767	$ 470,293	$ 486,723	$ 500,697
	Res Behavior	$ 1,624,876	$ 1,635,749	$ 1,647,069	$ 1,658,569	$ 1,668,944	$ 1,679,895	$ 1,691,784	$ 1,703,574	$ 1,715,575	$ 1,729,871	$ 1,746,040	$ 1,764,825	$ 1,785,277	$ 1,804,941	$ 1,823,668	$ 1,842,058	$ 1,858,826	$ 1,874,203	$ 1,889,747	$ 1,905,411
	Retail	$ 3,291,093	$ 3,958,656	$ 4,478,174	$ 4,798,227	$ 4,876,178	$ 4,816,138	$ 4,633,586	$ 4,291,589	$ 3,954,135	$ 3,753,665	$ 3,527,729	$ 3,413,333	$ 3,225,994	$ 3,056,943	$ 2,907,835	$ 2,804,224	$ 2,655,226	$ 2,440,439	$ 2,358,542	$ 2,472,247
	School Kits	$ 38,444	$ 49,502	$ 62,027	$ 75,040	$ 86,853	$ 95,232	$ 97,985	$ 93,894	$ 83,481	$ 68,963	$ 53,289	$ 38,929	$ 27,218	$ 18,427	$ 12,198	$ 7,953	$ 5,133	$ 3,292	$ 2,103	$ 1,340
	Small C&I	$ 17,651,054	$ 17,891,780	$ 17,705,463	$ 18,540,581	$ 17,795,574	$ 17,279,647	$ 15,723,449	$ 13,796,165	$ 11,882,445	$ 10,217,898	$ 8,710,617	$ 7,648,565	$ 6,756,739	$ 6,152,682	$ 5,797,769	$ 5,772,650	$ 5,403,671	$ 5,166,157	$ 4,943,220	$ 2,871,226
	Subtotal Residential Energy Efficiency Programs	$ 24,457,587	$ 31,200,706	$ 38,280,597	$ 45,123,136	$ 50,888,580	$ 55,093,348	$ 56,862,715	$ 55,362,268	$ 51,338,463	$ 46,152,643	$ 40,113,388	$ 34,852,722	$ 29,994,436	$ 26,111,711	$ 23,119,379	$ 20,995,759	$ 19,176,037	$ 17,405,012	$ 16,493,261	$ 16,646,617
	Subtotal C&I Energy Efficiency Programs	$ 65,319,148	$ 63,665,853	$ 60,048,273	$ 60,880,142	$ 56,290,605	$ 54,005,198	$ 48,932,180	$ 43,380,182	$ 38,309,764	$ 34,168,237	$ 30,278,108	$ 27,699,622	$ 25,345,143	$ 23,772,818	$ 22,921,040	$ 23,192,324	$ 21,946,890	$ 21,138,615	$ 20,328,759	$ 11,989,752
	Subtotal Energy Efficiency Programs	$ 89,776,735	$ 94,866,559	$ 98,328,870	$ 106,003,278	$ 107,179,185	$ 109,098,546	$ 105,794,894	$ 98,742,450	$ 89,648,228	$ 80,320,880	$ 70,391,495	$ 62,552,344	$ 55,339,579	$ 49,884,528	$ 46,040,419	$ 44,188,083	$ 41,122,927	$ 38,543,627	$ 36,822,020	$ 28,636,369
Demand Response Program	BTMG - Battery Storage	$ 37,263	$ 48,775	$ 66,174	$ 87,719	$ 114,529	$ 149,211	$ 193,588	$ 249,803	$ 277,026	$ 290,130	$ 314,196	$ 340,293	$ 368,191	$ 445,504	$ 522,832	$ 609,766	$ 706,821	$ 812,375	$ 927,573	$ 1,019,501
	C&I Curtailment- Advanced Lighting Control	$ 1,704	$ 1,973	$ 2,103	$ 2,355	$ 2,612	$ 4,657	$ 5,607	$ 6,231	$ 6,733	$ 7,156	$ 7,565	$ 7,991	$ 8,409	$ 8,834	$ 9,233	$ 9,628	$ 9,997	$ 10,368	$ 10,745	$ 11,124
	C&I Curtailment- Auto-DR HVAC Control	$ 589,838	$ 779,801	$ 997,789	$ 1,319,795	$ 1,691,265	$ 2,034,483	$ 2,373,172	$ 2,631,788	$ 2,866,939	$ 3,075,011	$ 3,274,296	$ 3,473,476	$ 3,662,497	$ 3,848,430	$ 4,018,533	$ 4,181,799	$ 4,332,084	$ 4,481,799	$ 4,633,278	$ 4,788,346
	C&I Curtailment- Industrial	$ 345,012	$ 355,897	$ 364,049	$ 383,704	$ 403,898	$ 417,107	$ 430,313	$ 437,590	$ 446,894	$ 457,672	$ 472,020	$ 490,080	$ 509,478	$ 530,425	$ 550,566	$ 570,689	$ 589,706	$ 609,087	$ 629,001	$ 648,390
	C&I Curtailment- Other	$ 19,858	$ 20,836	$ 21,746	$ 23,855	$ 26,008	$ 27,253	$ 28,430	$ 28,911	$ 29,526	$ 30,238	$ 31,186	$ 32,379	$ 33,661	$ 35,044	$ 36,375	$ 37,705	$ 38,961	$ 40,242	$ 41,557	$ 42,838
	C&I Curtailment- Refrigeration Control	$ 10,974	$ 11,607	$ 12,224	$ 13,645	$ 15,094	$ 15,909	$ 16,668	$ 16,950	$ 17,311	$ 17,728	$ 18,284	$ 18,983	$ 19,735	$ 20,546	$ 21,326	$ 22,106	$ 22,843	$ 23,593	$ 24,365	$ 25,116
	C&I Curtailment- Standard Lighting Control	$ 143,139	$ 149,743	$ 155,826	$ 170,002	$ 184,480	$ 191,996	$ 199,635	$ 202,747	$ 206,873	$ 211,732	$ 218,277	$ 226,560	$ 235,477	$ 245,119	$ 254,394	$ 263,664	$ 272,426	$ 281,358	$ 290,538	$ 299,470
	C&I Curtailment- Water Heating Control	$ 10,224	$ 10,712	$ 11,160	$ 12,201	$ 13,264	$ 13,883	$ 14,470	$ 14,714	$ 15,027	$ 15,389	$ 15,872	$ 16,479	$ 17,132	$ 17,836	$ 18,513	$ 19,190	$ 19,829	$ 20,481	$ 21,151	$ 21,802
	DLC-Switch-Water Heating	$ -	$ 2,099,689	$ 2,909,879	$ 6,577,127	$ 7,414,197	$ 4,946,049	$ 4,893,231	$ 2,935,728	$ 3,030,528	$ 3,110,022	$ 3,179,626	$ 5,350,729	$ 5,988,511	$ 9,393,987	$ 9,615,070	$ 6,542,586	$ 6,206,499	$ 4,008,262	$ 4,121,342	$ 2,042,217
	DLC-Thermostat-Res	$ 1,020,350	$ 1,178,020	$ 1,395,948	$ 1,656,905	$ 1,964,221	$ 2,322,526	$ 2,484,470	$ 2,725,735	$ 2,953,048	$ 3,161,752	$ 3,340,929	$ 3,496,839	$ 3,627,005	$ 3,739,087	$ 3,838,169	$ 3,929,485	$ 4,012,999	$ 4,087,955	$ 4,163,857	$ 4,249,447
	Dynamic Pricing with enabling tech.	$ -	$ 107,807	$ 60,198	$ 94,051	$ 128,308	$ 134,418	$ 149,702	$ 139,045	$ 144,962	$ 148,524	$ 151,660	$ 154,162	$ 157,105	$ 159,752	$ 162,977	$ 166,051	$ 169,288	$ 172,492	$ 175,807	$ 178,953
	Dynamic Pricing w/o enabling tech.	$ -	$ 323,051	$ 216,507	$ 274,288	$ 182,535	$ 84,570	$ 73,885	$ 62,231	$ 56,354	$ 51,812	$ 48,503	$ 46,244	$ 44,881	$ 44,101	$ 43,809	$ 44,201	$ 45,723	$ 46,931	$ 48,105	$ 49,151
	EV Managed Charging	$ 494,300	$ 704,808	$ 923,136	$ 1,149,507	$ 1,384,146	$ 1,627,287	$ 2,184,642	$ 2,851,256	$ 3,718,194	$ 4,702,358	$ 5,786,048	$ 6,949,008	$ 8,173,781	$ 9,445,049	$ 10,750,870	$ 12,083,184	$ 13,435,105	$ 14,804,579	$ 16,194,357	$ 17,536,130
	Peak Time Rebate	$ 498,430	$ 1,017,408	$ 2,001,264	$ 2,758,006	$ 2,925,780	$ 3,129,257	$ 3,067,262	$ 3,124,605	$ 3,182,798	$ 3,244,870	$ 3,309,350	$ 3,378,177	$ 3,448,370	$ 3,519,321	$ 3,590,490	$ 3,662,180	$ 3,733,077	$ 3,801,232	$ 3,869,975	$ 3,940,797
	Subtotal Demand Response Programs	$ 3,171,093	$ 6,810,126	$ 9,138,003	$ 14,523,161	$ 16,450,337	$ 15,098,605	$ 16,115,075	$ 15,427,334	$ 16,952,212	$ 18,524,395	$ 20,167,812	$ 23,981,400	$ 26,294,232	$ 31,453,037	$ 33,433,158	$ 32,142,232	$ 33,595,359	$ 33,200,754	$ 35,151,650	$ 34,853,282
	Total DSM Programs	$ 92,947,828	$ 101,676,685	$ 107,466,873	$ 120,526,439	$ 123,629,522	$ 124,197,151	$ 121,909,969	$ 114,169,783	$ 106,600,439	$ 98,845,275	$ 90,559,307	$ 86,533,745	$ 81,633,811	$ 81,337,565	$ 79,473,576	$ 76,330,316	$ 74,718,287	$ 71,744,381	$ 71,973,670	$ 63,489,651

Scenario 3 / Strategy 3

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	$ 5,870,526	$ 5,944,905	$ 5,554,326	$ 4,774,719	$ 3,790,663	$ 2,811,291	$ 1,978,996	$ 1,347,002	$ 903,385	$ 608,335	$ 419,202	$ 300,459	$ 227,473	$ 183,258	$ 156,785	$ 141,044	$ 131,093	$ 124,700	$ 120,190	$ 116,542
	HPwES	$ 3,532,987	$ 4,638,567	$ 5,933,975	$ 7,347,386	$ 8,747,501	$ 9,965,769	$ 10,789,282	$ 11,016,863	$ 10,606,916	$ 9,678,724	$ 8,373,743	$ 6,993,693	$ 5,659,156	$ 4,533,707	$ 3,654,532	$ 3,018,058	$ 2,541,882	$ 2,165,450	$ 1,956,676	$ 1,920,228
	HVAC	$ 887,487	$ 1,149,810	$ 1,438,883	$ 1,733,460	$ 2,001,724	$ 2,196,683	$ 2,264,027	$ 2,171,225	$ 1,936,920	$ 1,617,922	$ 1,268,449	$ 954,804	$ 691,369	$ 492,127	$ 349,089	$ 252,093	$ 182,612	$ 128,234	$ 100,221	$ 99,929
	Large C&I	$ 16,888,589	$ 16,551,568	$ 15,705,818	$ 15,643,380	$ 14,710,160	$ 13,876,683	$ 12,554,044	$ 11,092,689	$ 9,723,772	$ 8,520,386	$ 7,404,029	$ 6,581,067	$ 6,005,348	$ 5,466,437	$ 5,122,418	$ 5,014,602	$ 4,658,092	$ 4,413,553	$ 4,196,711	$ 3,212,870
	LI_MF	$ 3,487,842	$ 4,534,516	$ 5,752,139	$ 7,074,338	$ 8,373,302	$ 9,468,487	$ 10,150,323	$ 10,245,088	$ 9,700,913	$ 8,614,905	$ 7,187,638	$ 5,677,849	$ 4,281,529	$ 3,124,506	$ 2,239,172	$ 1,602,119	$ 1,158,208	$ 853,920	$ 659,385	$ 546,330
	Recycling	$ 131,202	$ 144,991	$ 159,914	$ 175,992	$ 193,230	$ 211,612	$ 231,093	$ 251,602	$ 273,032	$ 295,237	$ 318,034	$ 341,194	$ 364,450	$ 387,491	$ 409,975	$ 431,530	$ 451,767	$ 470,293	$ 486,723	$ 500,697
	Res Behavior	$ 1,624,876	$ 1,635,749	$ 1,647,069	$ 1,658,569	$ 1,668,944	$ 1,679,895	$ 1,691,784	$ 1,703,574	$ 1,715,575	$ 1,729,871	$ 1,746,040	$ 1,764,825	$ 1,785,277	$ 1,804,941	$ 1,823,668	$ 1,842,058	$ 1,858,826	$ 1,874,203	$ 1,889,747	$ 1,905,411
	Retail	$ 1,459,126	$ 1,774,420	$ 2,062,658	$ 2,290,270	$ 2,427,481	$ 2,500,517	$ 2,509,968	$ 2,436,343	$ 2,352,301	$ 2,332,743	$ 2,294,842	$ 2,316,983	$ 2,274,263	$ 2,220,447	$ 2,154,297	$ 2,098,716	$ 2,006,499	$ 1,863,358	$ 1,814,521	$ 1,907,534
	School Kits	$ 38,632	$ 49,744	$ 62,331	$ 75,407	$ 87,278	$ 95,698	$ 98,464	$ 94,354	$ 83,889	$ 69,300	$ 53,549	$ 39,120	$ 27,352	$ 18,517	$ 12,257	$ 7,991	$ 5,159	$ 3,309	$ 2,113	$ 1,346
	Small C&I	$ 6,103,755	$ 6,080,824	$ 5,890,984	$ 5,980,564	$ 5,734,741	$ 5,500,280	$ 5,049,317	$ 4,513,002	$ 3,982,156	$ 3,494,458	$ 3,031,078	$ 2,676,188	$ 2,405,660	$ 2,161,029	$ 1,995,508	$ 1,924,138	$ 1,772,202	$ 1,667,697	$ 1,579,248	$ 1,186,446
	Subtotal Residential Energy Efficiency Programs	$ 11,162,151	$ 13,927,798	$ 17,056,968	$ 20,355,422	$ 23,499,462	$ 26,118,660	$ 27,734,941	$ 27,919,048	$ 26,669,547	$ 24,338,702	$ 21,242,294	$ 18,088,469	$ 15,083,395	$ 12,581,737	$ 10,642,990	$ 9,252,564	$ 8,204,953	$ 7,358,768	$ 6,909,387	$ 6,881,476
	Subtotal C&I Energy Efficiency Programs	$ 28,862,871	$ 28,577,296	$ 27,151,127	$ 26,398,664	$ 24,235,563	$ 22,188,254	$ 19,582,357	$ 16,952,692	$ 14,609,313	$ 12,623,179	$ 10,854,309	$ 9,557,714	$ 8,638,481	$ 7,810,725	$ 7,274,711	$ 7,079,784	$ 6,561,387	$ 6,205,950	$ 5,896,149	$ 4,515,859
	Subtotal Energy Efficiency Programs	$ 40,025,022	$ 42,505,094	$ 44,208,095	$ 46,754,086	$ 47,735,025	$ 48,306,913	$ 47,317,299	$ 44,871,740	$ 41,278,860	$ 36,961,881	$ 32,096,603	$ 27,646,182	$ 23,721,876	$ 20,392,462	$ 17,917,701	$ 16,332,348	$ 14,766,340	$ 13,564,718	$ 12,805,536	$ 11,397,335
Demand Response Program	BTMG - Battery Storage	$ 26,637	$ 34,827	$ 47,346	$ 62,422	$ 81,760	$ 106,482	$ 137,764	$ 177,756	$ 194,562	$ 201,795	$ 218,598	$ 236,741	$ 256,178	$ 313,376	$ 367,988	$ 428,687	$ 496,702	$ 570,398	$ 650,744	$ 715,071
	C&I Curtailment- Advanced Lighting Control	$ 1,088	$ 1,293	$ 1,395	$ 1,580	$ 1,768	$ 3,747	$ 4,781	$ 5,502	$ 6,069	$ 6,529	$ 6,947	$ 7,355	$ 7,740	$ 8,119	$ 8,467	$ 8,803	$ 9,114	$ 9,425	$ 9,739	$ 10,059
	C&I Curtailment- Auto-DR HVAC Control	$ 424,487	$ 565,283	$ 728,588	$ 970,202	$ 1,250,541	$ 1,511,347	$ 1,769,648	$ 1,968,568	$ 2,148,284	$ 2,306,843	$ 2,456,975	$ 2,605,080	$ 2,744,413	$ 2,880,570	$ 3,005,139	$ 3,124,674	$ 3,234,970	$ 3,344,747	$ 3,455,632	$ 3,569,350
	C&I Curtailment- Industrial	$ 250,921	$ 260,988	$ 269,107	$ 285,561	$ 302,229	$ 313,339	$ 324,119	$ 330,175	$ 337,303	$ 345,350	$ 355,833	$ 368,892	$ 382,869	$ 397,960	$ 412,541	$ 427,167	$ 441,064	$ 455,246	$ 469,817	$ 483,956
	C&I Curtailment- Other	$ 18,956	$ 20,055	$ 21,098	$ 23,301	$ 25,543	$ 26,871	$ 28,106	$ 28,631	$ 29,249	$ 29,947	$ 30,856	$ 31,989	$ 33,201	$ 34,509	$ 35,773	$ 37,042	$ 38,247	$ 39,477	$ 40,740	$ 41,966
	C&I Curtailment- Refrigeration Control	$ 7,981	$ 8,512	$ 9,036	$ 10,155	$ 11,294	$ 11,951	$ 12,555	$ 12,789	$ 13,066	$ 13,377	$ 13,783	$ 14,289	$ 14,831	$ 15,415	$ 15,980	$ 16,546	$ 17,085	$ 17,634	$ 18,199	$ 18,746
	C&I Curtailment- Standard Lighting Control	$ 104,178	$ 109,887	$ 115,267	$ 126,606	$ 138,136	$ 144,107	$ 150,090	$ 152,578	$ 155,648	$ 159,203	$ 163,926	$ 169,866	$ 176,249	$ 183,159	$ 189,844	$ 196,557	$ 202,939	$ 209,456	$ 216,154	$ 222,645
	C&I Curtailment- Water Heating Control	$ 7,436	$ 7,855	$ 8,250	$ 9,080	$ 9,925	$ 10,429	$ 10,899	$ 11,102	$ 11,342	$ 11,613	$ 11,965	$ 12,404	$ 12,874	$ 13,382	$ 13,872	$ 14,364	$ 14,831	$ 15,308	$ 15,798	$ 16,273
	DLC-Switch-Water Heating	$ -	$ 1,882,660	$ 2,585,382	$ 5,843,472	$ 6,525,747	$ 4,242,509	$ 4,161,454	$ 2,376,583	$ 2,457,501	$ 2,523,656	$ 2,580,924	$ 4,548,644	$ 5,121,550	$ 8,211,021	$ 8,405,411	$ 5,605,350	$ 5,293,791	$ 3,289,125	$ 3,385,720	$ 1,489,197
	DLC-Thermostat-Res	$ 731,164	$ 818,130	$ 940,637	$ 1,080,423	$ 1,238,608	$ 1,417,763	$ 1,461,119	$ 1,563,807	$ 1,660,962	$ 1,753,014	$ 1,834,541	$ 1,909,595	$ 1,975,129	$ 2,034,669	$ 2,089,943	$ 2,143,356	$ 2,193,775	$ 2,240,173	$ 2,288,679	$ 2,339,472
	Dynamic Pricing with enabling tech.	$ -	$ 110,373	$ 59,960	$ 86,451	$ 113,207	$ 116,999	$ 133,226	$ 125,315	$ 130,655	$ 134,327	$ 136,802	$ 139,600	$ 141,993	$ 144,647	$ 147,603	$ 150,552	$ 153,546	$ 156,640	$ 159,952	$ 162,894
	Dynamic Pricing w/o enabling tech.	$ -	$ 303,389	$ 201,899	$ 260,565	$ 194,969	$ 97,709	$ 89,443	$ 69,822	$ 65,292	$ 61,941	$ 59,641	$ 58,169	$ 59,038	$ 59,934	$ 60,872	$ 61,763	$ 62,571	$ 63,226	$ 64,057	$ 64,848
	EV Managed Charging	$ 450,200	$ 636,791	$ 830,310	$ 1,030,952	$ 1,238,920	$ 1,454,417	$ 1,948,077	$ 2,538,464	$ 3,306,190	$ 4,177,696	$ 5,137,313	$ 6,167,107	$ 7,251,628	$ 8,377,313	$ 9,533,592	$ 10,713,330	$ 11,910,430	$ 13,123,076	$ 14,353,701	$ 15,541,815
	Peak Time Rebate	$ 284,153	$ 652,545	$ 1,457,429	$ 2,129,600	$ 2,314,527	$ 2,514,484	$ 2,476,215	$ 2,522,476	$ 2,569,422	$ 2,619,509	$ 2,671,543	$ 2,727,097	$ 2,783,751	$ 2,841,016	$ 2,898,452	$ 2,956,307	$ 3,013,514	$ 3,068,493	$ 3,123,945	$ 3,181,094
	Subtotal Demand Response Programs	$ 2,307,201	$ 5,412,588	$ 7,275,703	$ 11,920,369	$ 13,447,173	$ 11,972,153	$ 12,707,498	$ 11,883,570	$ 13,085,544	$ 14,344,801	$ 15,679,649	$ 18,996,828	$ 20,961,443	$ 25,515,091	$ 27,185,477	$ 25,884,499	$ 27,082,579	$ 26,602,424	$ 28,252,875	$ 27,857,387
	Total DSM Programs	$ 42,332,223	$ 47,917,682	$ 51,483,798	$ 58,674,456	$ 61,182,198	$ 60,279,066	$ 60,024,796	$ 56,755,310	$ 54,364,404	$ 51,306,681	$ 47,776,252	$ 46,643,011	$ 44,683,319	$ 45,907,552	$ 45,103,178	$ 42,216,846	$ 41,848,919	$ 40,167,142	$ 41,058,411	$ 39,254,722

ENO IRP Appendix G - DSM

Annual Output, MWh

Scenario 1 / Strategy 1

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	83,262	102,491	119,640	134,042	144,329	151,941	157,058	160,774	162,290	163,536	164,314	165,381	165,168	165,314	165,397	165,888	165,579	165,637	165,613	166,032
	HPwES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	HVAC	6,944	9,705	13,096	17,141	21,679	26,650	31,739	36,639	40,872	44,433	47,176	49,381	50,758	51,769	52,429	52,897	53,278	53,362	53,491	53,662
	Large C&I	145,465	179,709	210,397	240,295	266,664	290,810	311,602	330,014	343,503	355,726	365,936	376,124	382,766	389,604	395,897	403,110	408,381	413,173	417,935	421,795
	LI_MF	15,301	21,444	29,006	38,037	48,157	59,250	70,642	81,687	91,345	99,687	106,392	112,086	116,046	119,277	121,754	123,809	125,624	126,614	127,688	128,848
	Recycling	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Res Behavior	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Retail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	School Kits	413	578	781	1,025	1,295	1,589	1,885	2,170	2,406	2,602	2,751	2,867	2,931	2,979	3,011	3,041	3,051	3,051	3,056	3,070
	Small C&I	65,287	82,337	98,647	115,346	130,749	145,358	158,187	169,414	177,623	184,816	190,624	196,266	199,605	202,919	205,866	209,275	211,740	213,879	215,917	217,347
	Subtotal Residential Energy Efficiency Programs	22,657	31,727	42,883	56,204	71,130	87,489	104,266	120,497	134,623	146,722	156,318	164,334	169,735	174,025	177,193	179,747	181,953	183,028	184,235	185,580
	Subtotal C&I Energy Efficiency Programs	294,013	364,536	428,684	489,683	541,742	588,108	626,848	660,202	683,415	704,079	720,874	737,772	747,538	757,837	767,160	778,273	785,700	792,689	799,465	805,174
	Subtotal Energy Efficiency Programs	316,670	396,263	471,567	545,886	612,872	675,597	731,114	780,698	818,038	850,800	877,192	902,106	917,273	931,863	944,353	958,020	967,652	975,716	983,700	990,754

Scenario 1 / Strategy 1 Manual 1b

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	83,262	102,491	119,640	134,042	144,329	151,941	157,058	160,774	162,290	163,536	164,314	165,381	165,168	165,314	165,397	165,888	165,579	165,637	165,613	166,032
	HPwES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	HVAC	7,243	10,145	13,709	17,952	22,691	27,847	33,068	38,019	42,207	45,646	48,221	50,250	51,462	52,335	52,890	53,281	53,583	53,654	53,759	53,916
	Large C&I	145,465	179,709	210,397	240,295	266,664	290,810	311,602	330,014	343,503	355,726	365,936	376,124	382,766	389,604	395,897	403,110	408,381	413,173	417,935	421,795
	LI_MF	15,301	21,444	29,006	38,037	48,157	59,250	70,642	81,687	91,345	99,687	106,392	112,086	116,046	119,277	121,754	123,809	125,624	126,614	127,688	128,848
	Recycling	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Res Behavior	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Retail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	School Kits	413	578	781	1,025	1,295	1,589	1,885	2,170	2,406	2,602	2,751	2,867	2,931	2,979	3,011	3,041	3,051	3,051	3,056	3,070
	Small C&I	65,287	82,337	98,647	115,346	130,749	145,358	158,187	169,414	177,623	184,816	190,624	196,266	199,605	202,919	205,866	209,275	211,740	213,879	215,917	217,347
	Subtotal Residential Energy Efficiency Programs	22,956	32,167	43,497	57,014	72,142	88,685	105,594	121,876	135,958	147,935	157,364	165,204	170,438	174,592	177,654	180,130	182,258	183,319	184,503	185,834
	Subtotal C&I Energy Efficiency Programs	294,013	364,536	428,684	489,683	541,742	588,108	626,848	660,202	683,415	704,079	720,874	737,772	747,538	757,837	767,160	778,273	785,700	792,689	799,465	805,174
	Subtotal Energy Efficiency Programs	316,969	396,703	472,181	546,697	613,884	676,794	732,442	782,078	819,372	852,014	878,237	902,975	917,977	932,429	944,814	958,403	967,957	976,008	983,968	991,008

Scenario 1 / Strategy 2

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	60,474	79,710	97,285	112,329	123,448	131,746	137,400	141,450	143,289	144,705	145,586	146,650	146,533	146,707	146,807	147,259	147,001	147,052	147,035	147,409
	HPwES	15,114	21,641	29,801	39,707	50,997	63,614	76,866	90,066	101,937	112,513	121,275	128,830	134,220	138,675	142,167	145,197	147,806	149,404	151,176	153,193
	HVAC	7,243	10,145	13,709	17,952	22,691	27,847	33,068	38,019	42,207	45,646	48,221	50,250	51,462	52,335	52,890	53,281	53,583	53,654	53,759	53,916
	Large C&I	145,465	179,709	210,397	240,295	266,664	290,810	311,602	330,014	343,503	355,726	365,936	376,124	382,766	389,604	395,897	403,110	408,381	413,173	417,935	421,795
	LI_MF	18,790	26,801	36,753	48,768	62,393	77,527	93,292	108,834	122,601	134,577	144,174	152,116	157,374	161,431	164,309	166,589	168,441	169,202	170,157	171,303
	Recycling	491	684	894	1,123	1,365	1,628	1,911	2,219	2,535	2,878	3,241	3,634	4,026	4,445	4,881	5,347	5,784	6,271	6,754	7,261
	Res Behavior	13,319	13,408	13,501	13,626	13,675	13,767	13,868	13,999	14,061	14,178	14,307	14,503	14,634	14,796	14,947	15,130	15,246	15,363	15,490	15,656
	Retail	6,346	8,401	10,691	13,173	15,648	18,175	20,673	23,126	25,345	27,608	29,821	32,140	34,208	36,288	38,273	40,292	42,083	43,586	45,136	46,889
	School Kits	413	578	781	1,025	1,295	1,589	1,885	2,170	2,406	2,602	2,751	2,867	2,931	2,979	3,011	3,041	3,051	3,051	3,056	3,070
	Small C&I	65,287	82,337	98,647	115,346	130,749	145,358	158,187	169,414	177,623	184,816	190,624	196,266	199,605	202,919	205,866	209,275	211,740	213,879	215,917	217,347
	Subtotal Residential Energy Efficiency Programs	61,715	81,658	106,130	135,374	168,064	204,145	241,562	278,434	311,092	340,002	363,790	384,339	398,854	410,950	420,477	428,876	435,994	440,532	445,528	451,288
	Subtotal C&I Energy Efficiency Programs	271,225	341,756	406,329	467,970	520,861	567,913	607,190	640,877	664,414	685,247	702,146	719,041	728,904	739,230	748,569	759,644	767,121	774,104	780,887	786,551
	Subtotal Energy Efficiency Programs	332,940	423,414	512,459	603,343	688,924	772,058	848,751	919,311	975,506	1,025,249	1,065,937	1,103,380	1,127,758	1,150,179	1,169,046	1,188,519	1,203,115	1,214,636	1,226,414	1,237,840

Scenario 2 / Strategy 4

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	83,262	102,491	119,640	134,042	144,329	151,941	157,058	160,774	162,290	163,536	164,314	165,381	165,168	165,314	165,397	165,888	165,579	165,637	165,613	166,032
	HPwES	19,237	27,058	36,697	48,213	61,061	75,101	89,448	103,300	115,262	125,559	133,806	140,839	145,713	149,798	153,039	155,937	158,380	160,026	161,800	163,868
	HVAC	12,720	18,204	24,976	32,990	41,856	51,523	61,505	71,296	80,158	88,302	95,420	102,100	107,520	112,471	116,840	120,875	124,707	127,646	130,638	133,810
	Large C&I	208,308	251,980	290,930	329,942	362,668	393,348	419,871	443,532	460,729	476,428	489,654	503,019	511,585	520,539	528,844	538,448	545,445	551,982	558,467	563,065
	LI_MF	22,984	32,275	43,718	57,382	72,622	89,219	106,066	122,164	135,841	147,283	156,076	163,206	167,697	171,170	173,623	175,623	177,178	177,928	178,812	179,934
	Recycling	755	948	1,157	1,387	1,629	1,892	2,174	2,484	2,799	3,142	3,505	3,899	4,289	4,709	5,144	5,611	6,048	6,535	7,017	7,525
	Res Behavior	13,319	13,408	13,501	13,626	13,675	13,767	13,868	13,999	14,061	14,178	14,307	14,503	14,634	14,796	14,947	15,130	15,246	15,363	15,490	15,656
	Retail	8,975	11,718	14,702	17,847	20,876	23,869	26,739	29,496	31,923	34,378	36,760	39,264	41,464	43,684	45,796	47,954	49,844	51,422	53,053	54,913
	School Kits	413	578	781	1,025	1,295	1,589	1,885	2,170	2,406	2,602	2,751	2,867	2,931	2,979	3,011	3,041	3,051	3,051	3,056	3,070
	Small C&I	92,565	114,850	136,261	158,531	178,518	197,654	214,432	229,083	239,640	248,849	256,252	263,407	267,468	271,561	275,202	279,480	282,498	285,198	287,748	289,433
	Subtotal Residential Energy Efficiency Programs	78,402	104,189	135,533	172,470	213,014	256,959	301,684	344,909	382,449	415,444	442,625	466,677	484,247	499,606	512,400	524,171	534,453	541,972	549,866	558,776
	Subtotal C&I Energy Efficiency Programs	384,135	469,320	546,831	622,515	685,515	742,944	791,361	833,389	862,658	888,813	910,220	931,806	944,220	957,414	969,443	983,816	993,523	1,002,817	1,011,828	1,018,530
	Subtotal Energy Efficiency Programs	462,536	573,509	682,365	794,985	898,528	999,903	1,093,045	1,178,298	1,245,108	1,304,257	1,352,844	1,398,484	1,428,467	1,457,020	1,481,843	1,507,986	1,527,976	1,544,789	1,561,694	1,577,306

Scenario 3 / Strategy 3

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	60,474	79,710	97,285	112,329	123,448	131,746	137,400	141,450	143,289	144,705	145,586	146,650	146,533	146,707	146,807	147,259	147,001	147,052	147,035	147,409
	HPwES	15,114	21,641	29,801	39,707	50,997	63,614	76,866	90,066	101,937	112,513	121,275	128,830	134,220	138,675	142,167	145,197	147,806	149,404	151,176	153,193
	HVAC	7,243	10,145	13,709	17,952	22,691	27,847	33,068	38,019	42,207	45,646	48,221	50,250	51,462	52,335	52,890	53,281	53,583	53,654	53,759	53,916
	Large C&I	145,465	179,709	210,397	240,295	266,664	290,810	311,602	330,014	343,503	355,726	365,936	376,124	382,766	389,604	395,897	403,110	408,381	413,173	417,935	421,795
	LI_MF	18,790	26,801	36,753	48,768	62,393	77,527	93,292	108,834	122,601	134,577	144,174	152,116	157,374	161,431	164,309	166,589	168,441	169,202	170,157	171,303
	Recycling	491	684	894	1,123	1,365	1,628	1,911	2,219	2,535	2,878	3,241	3,634	4,026	4,445	4,881	5,347	5,784	6,271	6,754	7,261
	Res Behavior	13,319	13,408	13,501	13,626	13,675	13,767	13,868	13,999	14,061	14,178	14,307	14,503	14,634	14,796	14,947	15,130	15,246	15,363	15,490	15,656
	Retail	6,346	8,401	10,691	13,173	15,648	18,175	20,673	23,126	25,345	27,608	29,821	32,140	34,208	36,288	38,273	40,292	42,083	43,586	45,136	46,889
	School Kits	413	578	781	1,025	1,295	1,589	1,885	2,170	2,406	2,602	2,751	2,867	2,931	2,979	3,011	3,041	3,051	3,051	3,056	3,070
	Small C&I	65,287	82,337	98,647	115,346	130,749	145,358	158,187	169,414	177,623	184,816	190,624	196,266	199,605	202,919	205,866	209,275	211,740	213,879	215,917	217,347
	Subtotal Residential Energy Efficiency Programs	61,715	81,658	106,130	135,374	168,064	204,145	241,562	278,434	311,092	340,002	363,790	384,339	398,854	410,950	420,477	428,876	435,994	440,532	445,528	451,288
	Subtotal C&I Energy Efficiency Programs	271,225	341,756	406,329	467,970	520,861	567,913	607,190	640,877	664,414	685,247	702,146	719,041	728,904	739,230	748,569	759,644	767,121	774,104	780,887	786,551
	Subtotal Energy Efficiency Programs	332,940	423,414	512,459	603,343	688,924	772,058	848,751	919,311	975,506	1,025,249	1,065,937	1,103,380	1,127,758	1,150,179	1,169,046	1,188,519	1,203,115	1,214,636	1,226,414	1,237,840

Annual Max, MW

Note: Values included for DR and EE are not including gross up for Transmission Losses and/or Reserve Margin

Scenario 1 / Strategy 1

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	14.81	18.24	21.30	23.80	25.70	27.04	27.94	28.53	28.89	29.12	29.26	29.34	29.40	29.43	29.45	29.46	29.47	29.47	29.47	29.48
	HPwES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	HVAC	2.30	3.21	4.33	5.66	7.18	8.82	10.50	12.10	13.52	14.70	15.62	16.30	16.79	17.12	17.34	17.49	17.64	17.65	17.69	17.72
	Large C&I	27.25	33.82	39.81	45.60	51.00	55.85	60.04	63.60	66.59	69.10	71.19	72.99	74.55	75.94	77.21	78.45	79.68	80.60	81.56	82.12
	LI_MF	4.81	6.74	9.12	11.95	15.18	18.68	22.27	25.71	28.83	31.49	33.65	35.37	36.71	37.74	38.56	39.20	39.85	40.14	40.49	40.80
	Recycling	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Res Behavior	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Retail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	School Kits	0.11	0.15	0.20	0.26	0.33	0.41	0.49	0.56	0.62	0.67	0.71	0.74	0.76	0.77	0.78	0.78	0.79	0.79	0.79	0.79
	Small C&I	12.67	16.08	19.44	23.07	26.57	29.86	32.75	35.20	37.20	38.83	40.12	41.18	42.06	42.81	43.47	44.10	44.73	45.18	45.65	45.83
	Subtotal Residential Energy Efficiency Programs	7.21	10.10	13.66	17.88	22.69	27.91	33.25	38.37	42.97	46.86	49.99	52.41	54.25	55.63	56.68	57.47	58.27	58.58	58.97	59.31
	Subtotal C&I Energy Efficiency Programs	54.73	68.14	80.55	92.47	103.28	112.75	120.74	127.32	132.68	137.05	140.58	143.51	146.01	148.18	150.13	152.01	153.89	155.25	156.68	157.43
	Subtotal Energy Efficiency Programs	61.94	78.24	94.20	110.35	125.97	140.66	153.99	165.69	175.65	183.91	190.56	195.93	200.26	203.81	206.81	209.48	212.16	213.82	215.65	216.73
Demand Response Program	BTMG - Battery Storage	0.26	0.34	0.45	0.58	0.75	0.96	1.22	1.55	1.77	1.88	2.00	2.12	2.25	2.58	2.97	3.40	3.88	4.39	4.94	5.39
	C&I Curtailment- Advanced Lighting Control	0.01	0.02	0.02	0.02	0.02	0.04	0.05	0.06	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
	C&I Curtailment- Auto-DR HVAC Control	4.63	6.04	7.64	9.98	12.65	15.06	17.39	19.11	20.62	21.88	23.01	24.06	24.95	25.76	26.40	26.96	27.40	27.80	28.19	28.67
	C&I Curtailment- Industrial	3.14	3.20	3.24	3.37	3.50	3.56	3.62	3.62	3.63	3.64	3.68	3.75	3.82	3.89	3.96	4.03	4.08	4.13	4.19	4.24
	C&I Curtailment- Other	0.63	0.66	0.68	0.73	0.79	0.82	0.84	0.84	0.84	0.84	0.85	0.87	0.88	0.90	0.92	0.93	0.94	0.96	0.97	0.98
	C&I Curtailment- Refrigeration Control	0.10	0.10	0.11	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16
	C&I Curtailment- Standard Lighting Control	1.30	1.35	1.39	1.50	1.60	1.64	1.68	1.67	1.67	1.68	1.70	1.73	1.76	1.79	1.82	1.85	1.88	1.90	1.93	1.95
	C&I Curtailment- Water Heating Control	0.09	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14
	DLC-Switch-Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DLC-Thermostat-Res	5.44	5.99	6.57	7.17	7.79	8.42	8.56	8.69	8.84	9.02	9.22	9.45	9.69	9.94	10.19	10.45	10.72	10.96	11.21	11.47
	Dynamic Pricing with enabling tech.	-	0.49	0.99	2.22	4.02	5.37	6.75	7.42	7.99	8.45	8.86	9.23	9.55	9.85	10.08	10.29	10.46	10.61	10.76	10.95
	Dynamic Pricing w/o enabling tech.	-	1.10	2.25	4.31	5.83	6.09	6.23	5.90	5.64	5.44	5.30	5.22	5.17	5.14	5.11	5.09	5.07	5.04	5.03	5.00
	EV Managed Charging	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Peak Time Rebate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal Demand Response Programs	15.61	19.38	23.42	30.11	37.19	42.22	46.60	49.13	51.33	53.18	54.96	56.76	58.43	60.20	61.82	63.38	64.80	66.19	67.59	69.06
	Total DSM Programs	77.55	97.63	117.62	140.46	163.16	182.88	200.59	214.82	226.98	237.09	245.52	252.69	258.70	264.01	268.63	272.86	276.96	280.01	283.24	285.79

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	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	14.81	18.24	21.30	23.80	25.70	27.04	27.94	28.53	28.89	29.12	29.26	29.34	29.40	29.43	29.45	29.46	29.47	29.47	29.47	29.48
	HPwES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	HVAC	2.40	3.36	4.53	5.93	7.51	9.22	10.94	12.55	13.96	15.10	15.97	16.59	17.02	17.31	17.49	17.62	17.74	17.75	17.78	17.80
	Large C&I	27.25	33.82	39.81	45.60	51.00	55.85	60.04	63.60	66.59	69.10	71.19	72.99	74.55	75.94	77.21	78.45	79.68	80.60	81.56	82.12
	LI_MF	4.81	6.74	9.12	11.95	15.18	18.68	22.27	25.71	28.83	31.49	33.65	35.37	36.71	37.74	38.56	39.20	39.85	40.14	40.49	40.80
	Recycling	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Res Behavior	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Retail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	School Kits	0.11	0.15	0.20	0.26	0.33	0.41	0.49	0.56	0.62	0.67	0.71	0.74	0.76	0.77	0.78	0.78	0.79	0.79	0.79	0.79
	Small C&I	12.67	16.08	19.44	23.07	26.57	29.86	32.75	35.20	37.20	38.83	40.12	41.18	42.06	42.81	43.47	44.10	44.73	45.18	45.65	45.83
	Subtotal Residential Energy Efficiency Programs	7.31	10.25	13.86	18.15	23.03	28.31	33.69	38.83	43.41	47.26	50.33	52.70	54.48	55.82	56.83	57.60	58.37	58.67	59.06	59.39
	Subtotal C&I Energy Efficiency Programs	54.73	68.14	80.55	92.47	103.28	112.75	120.74	127.32	132.68	137.05	140.58	143.51	146.01	148.18	150.13	152.01	153.89	155.25	156.68	157.43
	Subtotal Energy Efficiency Programs	62.04	78.39	94.41	110.62	126.31	141.06	154.43	166.14	176.09	184.31	190.91	196.22	200.50	204.00	206.96	209.61	212.26	213.92	215.74	216.82
Demand Response Program	BTMG - Battery Storage	0.22	0.29	0.38	0.49	0.64	0.81	1.04	1.32	1.50	1.60	1.70	1.80	1.92	2.19	2.52	2.89	3.30	3.73	4.20	4.58
	C&I Curtailment- Advanced Lighting Control	0.01	0.02	0.02	0.02	0.02	0.04	0.05	0.06	0.06	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08
	C&I Curtailment- Auto-DR HVAC Control	4.63	6.04	7.64	9.98	12.65	15.06	17.39	19.11	20.62	21.88	23.01	24.06	24.95	25.76	26.40	26.96	27.40	27.80	28.19	28.67
	C&I Curtailment- Industrial	2.84	2.91	2.95	3.08	3.21	3.27	3.33	3.33	3.34	3.36	3.40	3.46	3.53	3.60	3.66	3.71	3.76	3.81	3.86	3.91
	C&I Curtailment- Other	0.66	0.68	0.70	0.75	0.80	0.83	0.85	0.84	0.85	0.85	0.86	0.88	0.90	0.91	0.93	0.95	0.96	0.97	0.99	1.00
	C&I Curtailment- Refrigeration Control	0.09	0.09	0.10	0.11	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15
	C&I Curtailment- Standard Lighting Control	1.18	1.22	1.26	1.37	1.47	1.50	1.54	1.54	1.54	1.55	1.57	1.59	1.62	1.65	1.68	1.71	1.73	1.75	1.77	1.80
	C&I Curtailment- Water Heating Control	0.08	0.09	0.09	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13
	DLC-Switch-Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DLC-Thermostat-Res	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Dynamic Pricing with enabling tech.	-	0.49	0.99	2.22	4.02	5.37	6.75	7.42	7.99	8.45	8.86	9.23	9.55	9.85	10.08	10.29	10.46	10.61	10.76	10.95
	Dynamic Pricing w/o enabling tech.	-	1.10	2.25	4.31	5.83	6.09	6.23	5.90	5.64	5.44	5.30	5.22	5.17	5.14	5.11	5.09	5.07	5.04	5.03	5.00
	EV Managed Charging	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Peak Time Rebate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal Demand Response Programs	9.72	12.94	16.38	22.43	28.86	33.21	37.42	39.77	41.79	43.45	45.02	46.57	47.97	49.44	50.73	51.95	53.02	54.08	55.15	56.28
	Total DSM Programs	71.76	91.32	110.78	133.05	155.17	174.26	191.85	205.91	217.89	227.76	235.93	242.79	248.47	253.43	257.69	261.56	265.28	268.00	270.89	273.09

Scenario 1 / Strategy 2

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	10.76	14.19	17.32	19.95	21.98	23.45	24.45	25.10	25.51	25.77	25.92	26.02	26.08	26.11	26.14	26.15	26.16	26.16	26.17	26.17
	HPwES	4.47	6.35	8.69	11.48	14.70	18.21	21.85	25.37	28.58	31.32	33.55	35.29	36.61	37.60	38.35	38.92	39.50	39.74	40.05	40.34
	HVAC	2.40	3.36	4.53	5.93	7.51	9.22	10.94	12.55	13.96	15.10	15.97	16.59	17.02	17.31	17.49	17.62	17.74	17.75	17.78	17.80
	Large C&I	27.25	33.82	39.81	45.60	51.00	55.85	60.04	63.60	66.59	69.10	71.19	72.99	74.55	75.94	77.21	78.45	79.68	80.60	81.56	82.12
	LI_MF	5.58	7.92	10.81	14.28	18.25	22.59	27.07	31.40	35.31	38.65	41.32	43.38	44.91	46.03	46.84	47.45	48.06	48.26	48.55	48.81
	Recycling	0.07	0.10	0.13	0.16	0.19	0.23	0.27	0.32	0.36	0.41	0.46	0.52	0.57	0.63	0.70	0.76	0.83	0.89	0.96	1.03
	Res Behavior	2.37	2.39	2.40	2.42	2.44	2.45	2.47	2.49	2.50	2.53	2.55	2.58	2.61	2.63	2.66	2.69	2.72	2.74	2.76	2.78
	Retail	0.93	1.23	1.57	1.93	2.29	2.66	3.03	3.42	3.80	4.20	4.59	4.99	5.39	5.78	6.15	6.53	6.93	7.25	7.58	7.94
	School Kits	0.11	0.15	0.20	0.26	0.33	0.41	0.49	0.56	0.62	0.67	0.71	0.74	0.76	0.77	0.78	0.78	0.79	0.79	0.79	0.79
	Small C&I	12.67	16.08	19.44	23.07	26.57	29.86	32.75	35.20	37.20	38.83	40.12	41.18	42.06	42.81	43.47	44.10	44.73	45.18	45.65	45.83
	Subtotal Residential Energy Efficiency Programs	15.93	21.49	28.33	36.46	45.72	55.78	66.11	76.10	85.14	92.87	99.15	104.08	107.87	110.75	112.97	114.75	116.55	117.42	118.48	119.49
	Subtotal C&I Energy Efficiency Programs	50.67	64.09	76.57	88.62	99.56	109.15	117.24	123.89	129.30	133.70	137.24	140.19	142.70	144.86	146.82	148.70	150.58	151.94	153.37	154.12

	Subtotal Energy Efficiency Programs	66.60	85.58	104.90	125.08	145.28	164.93	183.35	199.99	214.44	226.57	236.39	244.28	250.56	255.61	259.79	263.45	267.13	269.36	271.86	273.61
Demand Response Program	BTMG - Battery Storage	0.26	0.34	0.45	0.58	0.75	0.96	1.22	1.55	1.77	1.88	2.00	2.12	2.25	2.58	2.97	3.40	3.88	4.39	4.94	5.39
	C&I Curtailment- Advanced Lighting Control	0.01	0.02	0.02	0.02	0.02	0.04	0.05	0.06	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
	C&I Curtailment- Auto-DR HVAC Control	5.31	6.93	8.77	11.46	14.50	17.20	19.76	21.57	23.10	24.34	25.44	26.47	27.37	28.19	28.86	29.45	29.92	30.36	30.78	31.30
	C&I Curtailment- Industrial	3.14	3.20	3.24	3.37	3.50	3.56	3.62	3.62	3.63	3.64	3.68	3.75	3.82	3.89	3.96	4.03	4.08	4.13	4.19	4.24
	C&I Curtailment- Other	0.63	0.66	0.68	0.73	0.79	0.82	0.84	0.84	0.84	0.84	0.85	0.87	0.88	0.90	0.92	0.93	0.94	0.96	0.97	0.98
	C&I Curtailment- Refrigeration Control	0.10	0.10	0.11	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16
	C&I Curtailment- Standard Lighting Control	1.30	1.35	1.39	1.50	1.60	1.64	1.68	1.67	1.67	1.68	1.70	1.73	1.76	1.79	1.82	1.85	1.88	1.90	1.93	1.95
	C&I Curtailment- Water Heating Control	0.09	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14
	DLC-Switch-Water Heating	-	1.54	3.46	7.70	11.93	13.85	15.39	15.38	15.37	15.37	15.38	15.41	15.43	15.45	15.47	15.48	15.48	15.47	15.45	15.45
	DLC-Thermostat-Res	6.73	7.58	8.54	9.62	10.84	12.18	12.85	13.51	14.14	14.70	15.18	15.57	15.87	16.11	16.28	16.41	16.51	16.57	16.63	16.74
	Dynamic Pricing with enabling tech.	-	0.49	0.99	2.22	4.02	5.37	6.75	7.42	7.99	8.45	8.86	9.23	9.55	9.85	10.08	10.29	10.46	10.61	10.76	10.95
	Dynamic Pricing w/o enabling tech.	-	1.11	2.24	4.16	5.44	5.50	5.44	5.01	4.67	4.42	4.24	4.14	4.09	4.06	4.04	4.04	4.04	4.05	4.06	4.06
	EV Managed Charging	1.57	2.38	3.19	4.00	4.81	5.62	7.55	9.79	12.66	15.82	19.19	22.70	26.28	29.86	33.40	36.89	40.29	43.61	46.85	50.29
	Peak Time Rebate	1.40	3.16	6.92	9.92	10.58	11.28	10.90	10.90	10.90	10.90	10.91	10.93	10.95	10.96	10.98	10.99	10.99	10.98	10.97	10.98
	Subtotal Demand Response Programs	20.55	28.95	40.09	55.53	69.03	78.28	86.30	91.59	97.06	102.38	107.77	113.26	118.60	124.01	129.16	134.14	138.86	143.42	147.90	152.72
	Total DSM Programs	87.16	114.53	144.99	180.60	214.31	243.21	269.66	291.58	311.50	328.95	344.17	357.54	369.17	379.62	388.95	397.60	405.99	412.79	419.76	426.34

Scenario 2 / Strategy 4

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	14.81	18.24	21.30	23.80	25.70	27.04	27.94	28.53	28.89	29.12	29.26	29.34	29.40	29.43	29.45	29.46	29.47	29.47	29.47	29.48
	HPwES	5.31	7.47	10.12	13.27	16.85	20.71	24.62	28.34	31.62	34.35	36.51	38.16	39.38	40.30	41.00	41.54	42.08	42.33	42.64	42.92
	HVAC	4.21	6.02	8.26	10.90	13.86	17.06	20.34	23.54	26.51	29.21	31.60	33.71	35.56	37.19	38.65	39.96	41.28	42.22	43.20	44.18
	Large C&I	38.88	47.30	54.94	62.51	69.29	75.47	80.85	85.40	89.23	92.47	95.19	97.54	99.58	101.41	103.09	104.75	106.40	107.66	108.97	109.63
	LI_MF	6.54	9.18	12.44	16.31	20.71	25.45	30.25	34.79	38.78	42.08	44.65	46.57	47.97	48.98	49.72	50.27	50.82	51.03	51.30	51.54
	Recycling	0.11	0.14	0.17	0.20	0.23	0.27	0.31	0.35	0.40	0.45	0.50	0.55	0.61	0.67	0.73	0.80	0.86	0.93	1.00	1.07
	Res Behavior	2.37	2.39	2.40	2.42	2.44	2.45	2.47	2.49	2.50	2.53	2.55	2.58	2.61	2.63	2.66	2.69	2.72	2.74	2.76	2.78
	Retail	1.31	1.71	2.14	2.59	3.04	3.48	3.90	4.33	4.75	5.16	5.57	5.99	6.40	6.80	7.19	7.55	7.92	8.22	8.52	8.84
	School Kits	0.11	0.15	0.20	0.26	0.33	0.41	0.49	0.56	0.62	0.67	0.71	0.74	0.76	0.77	0.78	0.78	0.79	0.79	0.79	0.79
	Small C&I	17.91	22.40	26.78	31.47	36.12	40.51	44.37	47.61	50.25	52.37	54.04	55.40	56.50	57.43	58.26	59.04	59.82	60.37	60.95	61.18
	Subtotal Residential Energy Efficiency Programs	19.95	27.05	35.74	45.96	57.47	69.83	82.38	94.39	105.19	114.46	122.09	128.30	133.29	137.35	140.72	143.60	146.48	148.25	150.21	152.13
	Subtotal C&I Energy Efficiency Programs	71.61	87.94	103.03	117.78	131.11	143.02	153.16	161.54	168.37	173.95	178.49	182.28	185.48	188.27	190.79	193.24	195.69	197.50	199.40	200.28
	Subtotal Energy Efficiency Programs	91.56	115.00	138.76	163.73	188.58	212.85	235.54	255.93	273.56	288.41	300.58	310.58	318.77	325.62	331.52	336.84	342.17	345.75	349.61	352.41
Demand Response Program	BTMG - Battery Storage	0.29	0.37	0.49	0.64	0.82	1.05	1.34	1.71	1.95	2.07	2.20	2.34	2.48	2.84	3.27	3.74	4.27	4.83	5.43	5.93
	C&I Curtailment- Advanced Lighting Control	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07
	C&I Curtailment- Auto-DR HVAC Control	5.62	7.29	9.15	11.88	14.94	17.64	20.19	21.97	23.49	24.72	25.83	26.89	27.83	28.70	29.41	30.03	30.53	31.00	31.45	31.99
	C&I Curtailment- Industrial	3.29	3.33	3.34	3.45	3.57	3.62	3.66	3.65	3.66	3.68	3.72	3.79	3.87	3.96	4.03	4.10	4.16	4.21	4.27	4.33
	C&I Curtailment- Other	0.66	0.68	0.70	0.75	0.80	0.83	0.85	0.84	0.85	0.85	0.86	0.88	0.90	0.91	0.93	0.95	0.96	0.97	0.99	1.00
	C&I Curtailment- Refrigeration Control	0.10	0.11	0.11	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17
	C&I Curtailment- Standard Lighting Control	1.36	1.40	1.43	1.53	1.63	1.66	1.70	1.69	1.69	1.70	1.72	1.75	1.79	1.83	1.86	1.89	1.92	1.95	1.97	2.00
	C&I Curtailment- Water Heating Control	0.10	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.15
	DLC-Switch-Water Heating	-	1.69	3.81	8.47	13.13	15.24	16.93	16.92	16.90	16.91	16.92	16.95	16.97	17.00	17.02	17.03	17.03	17.01	16.99	17.00
	DLC-Thermostat-Res	7.93	9.14	10.60	12.33	14.34	16.65	18.11	19.55	20.91	22.11	23.09	23.86	24.42	24.82	25.08	25.26	25.36	25.39	25.40	25.53
	Dynamic Pricing with enabling tech.	-	0.46	0.95	2.10	3.87	5.21	6.53	7.17	7.70	8.14	8.53	8.89	9.21	9.51	9.74	9.95	10.12	10.28	10.43	10.61
	Dynamic Pricing w/o enabling tech.	-	1.10	2.19	3.94	4.93	4.77	4.51	3.99	3.57	3.25	3.02	2.87	2.79	2.74	2.72	2.71	2.71	2.72	2.73	2.73
	EV Managed Charging	1.57	2.38	3.19	4.00	4.81	5.62	7.55	9.79	12.66	15.82	19.19	22.70	26.28	29.86	33.40	36.89	40.29	43.61	46.85	50.29
	Peak Time Rebate	2.11	4.22	8.14	11.01	11.47	12.03	11.58	11.57	11.57	11.57	11.58	11.60	11.62	11.64	11.66	11.67	11.67	11.66	11.65	11.66
	Subtotal Demand Response Programs	23.04	32.30	44.23	60.36	74.58	84.63	93.25	99.17	105.27	111.14	117.00	122.87	128.51	134.15	139.47	144.59	149.39	154.01	158.53	163.46
	Total DSM Programs	114.60	147.29	182.99	224.10	263.16	297.48	328.79	355.10	378.82	399.55	417.57	433.45	447.28	459.77	470.99	481.43	491.56	499.76	508.14	515.87

Scenario 3 / Strategy 3

	Programs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Energy Efficiency Program	Com Behavior	10.76	14.19	17.32	19.95	21.98	23.45	24.45	25.10	25.51	25.77	25.92	26.02	26.08	26.11	26.14	26.15	26.16	26.16	26.17	26.17
	HPwES	4.47	6.35	8.69	11.48	14.70	18.21	21.85	25.37	28.58	31.32	33.55	35.29	36.61	37.60	38.35	38.92	39.50	39.74	40.05	40.34
	HVAC	2.40	3.36	4.53	5.93	7.51	9.22	10.94	12.55	13.96	15.10	15.97	16.59	17.02	17.31	17.49	17.62	17.74	17.75	17.78	17.80
	Large C&I	27.25	33.82	39.81	45.60	51.00	55.85	60.04	63.60	66.59	69.10	71.19	72.99	74.55	75.94	77.21	78.45	79.68	80.60	81.56	82.12
	LI_MF	5.58	7.92	10.81	14.28	18.25	22.59	27.07	31.40	35.31	38.65	41.32	43.38	44.91	46.03	46.84	47.45	48.06	48.26	48.55	48.81
	Recycling	0.07	0.10	0.13	0.16	0.19	0.23	0.27	0.32	0.36	0.41	0.46	0.52	0.57	0.63	0.70	0.76	0.83	0.89	0.96	1.03
	Res Behavior	2.37	2.39	2.40	2.42	2.44	2.45	2.47	2.49	2.50	2.53	2.55	2.58	2.61	2.63	2.66	2.69	2.72	2.74	2.76	2.78
	Retail	0.93	1.23	1.57	1.93	2.29	2.66	3.03	3.42	3.80	4.20	4.59	4.99	5.39	5.78	6.15	6.53	6.93	7.25	7.58	7.94
	School Kits	0.11	0.15	0.20	0.26	0.33	0.41	0.49	0.56	0.62	0.67	0.71	0.74	0.76	0.77	0.78	0.78	0.79	0.79	0.79	0.79
	Small C&I	12.67	16.08	19.44	23.07	26.57	29.86	32.75	35.20	37.20	38.83	40.12	41.18	42.06	42.81	43.47	44.10	44.73	45.18	45.65	45.83
	Subtotal Residential Energy Efficiency Programs	15.93	21.49	28.33	36.46	45.72	55.78	66.11	76.10	85.14	92.87	99.15	104.08	107.87	110.75	112.97	114.75	116.55	117.42	118.48	119.49
	Subtotal C&I Energy Efficiency Programs	50.67	64.09	76.57	88.62	99.56	109.15	117.24	123.89	129.30	133.70	137.24	140.19	142.70	144.86	146.82	148.70	150.58	151.94	153.37	154.12
	Subtotal Energy Efficiency Programs	66.60	85.58	104.90	125.08	145.28	164.93	183.35	199.99	214.44	226.57	236.39	244.28	250.56	255.61	259.79	263.45	267.13	269.36	271.86	273.61
Demand Response Program	BTMG - Battery Storage	0.26	0.34	0.45	0.58	0.75	0.96	1.22	1.55	1.77	1.88	2.00	2.12	2.25	2.58	2.97	3.40	3.88	4.39	4.94	5.39
	C&I Curtailment- Advanced Lighting Control	0.01	0.02	0.02	0.02	0.02	0.04	0.05	0.06	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
	C&I Curtailment- Auto-DR HVAC Control	5.31	6.93	8.77	11.46	14.50	17.20	19.76	21.57	23.10	24.34	25.44	26.47	27.37	28.19	28.86	29.45	29.92	30.36	30.78	31.30
	C&I Curtailment- Industrial	3.14	3.20	3.24	3.37	3.50	3.56	3.62	3.62	3.63	3.64	3.68	3.75	3.82	3.89	3.96	4.03	4.08	4.13	4.19	4.24
	C&I Curtailment- Other	0.63	0.66	0.68	0.73	0.79	0.82	0.84	0.84	0.84	0.84	0.85	0.87	0.88	0.90	0.92	0.93	0.94	0.96	0.97	0.98
	C&I Curtailment- Refrigeration Control	0.10	0.10	0.11	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16
	C&I Curtailment- Standard Lighting Control	1.30	1.35	1.39	1.50	1.60	1.64	1.68	1.67	1.67	1.68	1.70	1.73	1.76	1.79	1.82	1.85	1.88	1.90	1.93	1.95
	C&I Curtailment- Water Heating Control	0.09	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14
	DLC-Switch-Water Heating	-	1.54	3.46	7.70	11.93	13.85	15.39	15.38	15.37	15.37	15.38	15.41	15.43	15.45	15.47	15.48	15.48	15.47	15.45	15.45
	DLC-Thermostat-Res	6.73	7.58	8.54	9.62	10.84	12.18	12.85	13.51	14.14	14.70	15.18	15.57	15.87	16.11	16.28	16.41	16.51	16.57	16.63	16.74
	Dynamic Pricing with enabling tech.	-	0.49	0.99	2.22	4.02	5.37	6.75	7.42	7.99	8.45	8.86	9.23	9.55	9.85	10.08	10.29	10.46	10.61	10.76	10.95
	Dynamic Pricing w/o enabling tech.	-	1.11	2.24	4.16	5.44	5.50	5.44	5.01	4.67	4.42	4.24	4.14	4.09	4.06	4.04	4.04	4.04	4.05	4.06	4.06
	EV Managed Charging	1.57	2.38	3.19	4.00	4.81	5.62	7.55	9.79	12.66	15.82	19.19	22.70	26.28	29.86	33.40	36.89	40.29	43.61	46.85	50.29
	Peak Time Rebate	1.40	3.16	6.92	9.92	10.58	11.28	10.90	10.90	10.90	10.90	10.91	10.93	10.95	10.96	10.98	10.99	10.99	10.98	10.97	10.98
	Subtotal Demand Response Programs	20.55	28.95	40.09	55.53	69.03	78.28	86.30	91.59	97.06	102.38	107.77	113.26	118.60	124.01	129.16	134.14	138.86	143.42	147.90	152.72
	Total DSM Programs	87.16	114.53	144.99	180.60	214.31	243.21	269.66	291.58	311.50	328.95	344.17	357.54	369.17	379.62	388.95	397.60	405.99	412.79	419.76	426.34

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***EX PARTE: IN RE*: 2024 TRIENNIAL INTEGRATED RESOURCE PLAN OF ENTERGY NEW ORLEANS, LLC**	**))))**	**DOCKET NO. UD-23-01**

APPENDIX H

LOAD & CAPABILITY TABLES

HIGHLY SENSITIVE
PROTECTED MATERIALS

INTENTIONALLY OMITTED

DECEMBER 2024