REPLACEMENT FILING

To: Shonta Dunston, Chief Clerk

From: Kim Mitchell, Hearings and Court Reporting Manager

CC: All parties of record

Date: October 7, 2022

Re: Docket No. E-100, Sub 179, Volume 7

Official Exhibits filed in STAR on 9/20/2022

On September 20th, 2022, an official exhibit filing was made entitled "Official Exhibits for Hearing Held in Raleigh on Tuesday, September 13, 2022, Volume 7". The filing included a total of three (3) parts. It has been brought to my attention that there are many blank pages in the second part entitled "Verified Petition, et al. Part 2". Therefore, attached to this memo is a complete filing of "Verified Petition, et al. Part 2", which will replace the original filing.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans And Carbon Plan	))))))	VERIFIED PETITION FOR APPROVAL OF CARBON PLAN

Pursuant to Sections 1 and 2 of Session Law 2021-165 ("HB 951"), the North Carolina Utilities Commission's ("Commission") November 19, 2021 *Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines* (the "Initial Scheduling Order"), and November 29, 2021 *Order Granting Extension of Time*, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies" or "Duke Energy"), through counsel, hereby submit this Verified Petition for Approval of Carbon Plan ("Petition") to the Commission.

In support of this Petition, the Companies respectfully show as follows:

I. General Information

1. DEC and DEP are engaged in the generation, transmission, distribution, and sale of electricity to the public for compensation. The Companies also sell electricity at wholesale to municipal, cooperative, and investor-owned electric utilities, and such wholesale sales are subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). DEC and DEP are public utilities under the laws of North Carolina and are subject to the jurisdiction of the Commission with respect to their operations in this State. The Companies are also authorized to transact business in the State of South

Carolina, and each is a public utility under the laws of that State. Accordingly, their operations are also subject to the jurisdiction of the Public Service Commission of South Carolina ("PSCSC").

2. The attorneys for the Companies, to whom all notice and other communications with respect to this Petition should be sent, are:

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3. As required by HB 951, the Companies are filing this first-of-its-kind Carolinas Carbon Plan ("Carbon Plan" or the "Plan") to chart the next major steps of the continued energy transition of the DEC and DEP systems. Continuation of the energy transition is supported by a broad range of the Companies' customers and will play a crucial

role in retaining existing business and attracting new economic development to North Carolina and South Carolina. Executing the Carbon Plan for the benefit of Duke Energy's customers is prudent and necessary to mitigate the known long-term risks posed by continued reliance on emissions-intensive resources, provides for continued power system reliability, and ensures continued access to capital at reasonable rates.

4. The Plan is built on the foundation of decades of reasonable and prudent utility planning practices and decisions that have been jointly overseen by the Commission and the PSCSC. Utilizing these well-established planning practices, the Companies' proposed Carbon Plan assesses a range of portfolios that will facilitate continued modernization of the Companies' systems spanning the Carolinas and result in further carbon dioxide ("CO_2") emissions reductions through a prudent, orderly, and cost-effective energy system transition. Duke Energy's CO_2 emissions reductions trajectory represents reasonable and prudent planning for the benefit of customers and aligns with a fundamental energy transformation that is in progress across the United States and is changing how energy is produced, delivered, and used.

5. HB 951 was supported by overwhelming bipartisan majorities in the North Carolina General Assembly and then executed by Governor Roy Cooper. The strong bipartisan support of HB 951 affirms that the continuation of the energy transition that Duke Energy has been pursuing under the oversight of the Commission and PSCSC is sound and prudent energy policy. HB 951 was signed into law on October 13, 2021 and provides a crucial policy framework for the Companies regarding the continued orderly implementation of the energy transition towards achieving carbon neutrality in their operations by the year 2050.

6. The Carbon Plan is informed by diverse stakeholder engagement, occurring before and after HB 951 became law. In particular, the Plan is informed by the Carbon Plan-specific stakeholder process that has occurred in the months leading up to this filing as directed and overseen by the Commission. Through the Carbon Plan-specific stakeholder process, Duke Energy actively engaged stakeholders across the Carolinas through three primary virtual stakeholder meetings, coordinating with over 500 participants from stakeholder groups, such as customer and consumer advocacy groups, community leaders and advocates, renewable energy developers, environmental interests and academia. Stakeholder feedback directly influenced both the stakeholder process itself and the development of the Plan in a variety of ways, as described more fully in the Plan. Stakeholder feedback also influenced Plan assumptions and execution considerations, such as the importance of timely and adequate grid investments to achieve Plan targets, navigating future regulatory uncertainty and risk management. Finally, stakeholder feedback regarding community impacts of the energy transition in terms of environmental justice, local economies and employment will be used to inform execution decisions.

7. DEC and DEP are presenting their initial Carbon Plan to the Commission for review consistent with the requirements of Section 1 of HB 951 and seek the Commission's approval of, among other things, a defined set of near-term supply-side development and procurement activities as necessary to continue the energy transition mandated by HB 951 until the next biennial Carbon Plan proceeding in 2024.

II. <u>Planning Requirements for the Carbon Plan Under HB 951</u>

8. HB 951 directs the Commission to:

> [T]ake all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO_2) emitted in the State from electric generating facilities owned

> operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050.[1]

9. To achieve these carbon reduction goals, HB 951 further directs the Commission, considering stakeholder input, to "[d]evelop a plan, no later than December 31, 2022 . . . which may, at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs[.]"[2]

10. HB 951 establishes three primary requirements, all of which must be satisfied in the plan developed by the Commission with the utilities to achieve the targeted CO_2 reductions from the Companies' electric generating facilities in North Carolina. First, the Commission must comply with current law and practice with respect to least-cost planning for generation.[3] Second, any generation and resource changes must maintain or improve upon the adequacy and reliability of the existing grid.[4] Third, any new generation facilities or other resources selected by the Commission in order to achieve the authorized reduction goals for electric public utilities must be owned and recovered on a cost of service basis by the applicable electric public utility, except in the case of energy efficiency measures and demand-side management ("EE/DSM"), for which existing law applies, and in the case of solar generation, which is to be allocated according to the percentages specified in HB 951.[5]

11. HB 951 further instructs that in developing the plan, the Commission has the discretion to "determine optimal timing and generation and resource mix to achieve the

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[1] *Id.* Section 1.
[2] *Id.* Section 1(1).
[3] *Id.* Section 1(2).
[4] *Id.* Section 1(3).
[5] *Id.* Section 1(2).

least cost path to compliance."[6] In addition to this general discretion given to the Commission, HB 951 also specifies that the Commission has discretion with respect to the Plan "in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction."[7] HB 951 further specifies that the Commission "shall not exceed the dates specified to achieve the authorized carbon reduction goals by more than two years, except in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion" or to "maintain the adequacy and reliability of the existing grid."[8]

III. <u>Duke Energy's Proposed Carbon Plan for the Carolinas</u>

12. Duke Energy's proposed Carbon Plan is a system-wide plan for the Carolinas designed to aggressively pursue development of new EE/DSM to "shrink the challenge" of transitioning the Companies' supply-side resources to a less carbon-intensive but still highly reliable portfolio of new generating facilities and other resources to serve customers' future energy needs. Consistent with HB 951, the Carbon Plan evaluates and develops portfolios of resources that include "power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs[.]" Successfully executing on the continued energy transition in the Carolinas will require an all-of-the-above strategy through the aggressive pursuit of both Grid Edge and demand-side resources and a diverse portfolio of new supply-side resources.

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[6] *Id.* Section 1(4).
[7] *Id.*
[8] *Id.*

13. The Companies' proposed Plan presents for the Commission's consideration two pathways consisting of four discrete portfolios, all of which further the transition of the Companies' energy systems, achieve the CO_2 emissions reductions targets established under HB 951, and inform the Commission's assessment of optimal timing and resource mix. The Plan assesses each of the portfolios against four core Carbon Plan objectives (CO_2 reduction, affordability, reliability, and executability), all of which are grounded in prudent utility planning and operation and reflect the core requirements of HB 951.

14. More specifically, the Plan explores the risks and benefits of two pathways for achieving the interim 70% reduction target, with both pathways resulting in carbon neutrality of the systems by 2050. One pathway (which includes Portfolio 1) achieves the 70% target by 2030, and the second pathway (which includes Portfolios 2-4) achieves the 70% target by 2034 through reliance on offshore wind and/or nuclear small modular reactors ("SMR") generation technologies.

15. The Companies' Carbon Plan and underlying modeling presents a reasonable plan that complies with current law and practice with respect to the least cost planning for generation and appropriately achieves the objectives and CO_2 emissions reductions targets of HB 951.[9]

IV. Near-Term New Supply-Side Development and Procurement Activities

[9] This Carbon Plan represents a continuation of the carbon reduction, coal plant retirements and associated replacement resources that have been the subject of the Companies' integrated resource plans in North Carolina and South Carolina. While the Carbon Plan is being filed pursuant to HB 951, the Companies believe that the Plan represents the most reasonable and prudent resource planning to reduce risk, preserve reliability and operational flexibility, and accomplishes energy transition in an orderly manner. The Carbon Plan will be filed with the Public Service Commission of South Carolina for its independent consideration and decision in future resource planning dockets.

16. In directing the Commission and the utilities to "develop a plan" to meet the CO_2 emissions reductions targets identified, HB 951 contemplates that plan development must be an iterative process that allows the plan to be re-evaluated at least every two years and "adjusted as necessary in the determination of the Commission and the electric public utilities."[10] The Companies developed their Carbon Plan to reflect this critical flexibility, providing the Commission with a "snapshot in time" of four portfolio options for continuing the energy transition in the Carolinas, including further substantial progress in CO_2 emissions reductions that are consistent with the targets established under HB 951.

17. After describing the Companies' Carbon Plan modeling and key assumptions and introducing the four portfolios, the Carbon Plan presents a first-of-its-kind Execution Plan that builds on the short-term action plan framework of past IRPs. The Execution Plan provides a comprehensive summary of the activities the Companies will undertake in the "near-term" 2022-2024 timeframe to advance the Carbon Plan components across all portfolios. Specifically, the Companies are proposing, and requesting Commission approval of, the following supply-side development and procurement activities for the 2022-2024 period: (1) 3,100 MW of solar generations (a substantial portion of which is assumed to include paired storage), including 750 MW to be procured through the 2022 Solar Procurement Program; (2) 1,600 MW of battery storage (1,000 MW stand-alone storage, 600 MW storage paired with solar); (3) 600 MW of onshore wind; (4) 800 MW of combustion turbines units ("CTs"); and (5) 1,200 MW of combined cycle units ("CC").

[10] HB 951, Part I, Section 1(1).

18. The Companies are additionally requesting that the Commission approve as reasonable and prudent initial project development activities on three longer-lead time resources—offshore wind, SMRs, and new pumped storage hydro—all of which are likely to be needed either to achieve the interim 70% CO_2 emissions reductions target or carbon neutrality over the longer term. Such development work is needed both to gather information to provide a more refined cost estimate to the Commission in future regulatory processes (including the 2024 Carbon Plan update), as well as to be positioned to implement such resources for the benefit of customers on a timeline consistent with the portfolios. If the Companies do not undertake development activities in the near term to prepare for these zero-carbon emitting long lead time resources, such resources will not be available on the timelines required to reach the interim target set by HB 951.

19. Accordingly, to the extent not already authorized under applicable accounting rules and consistent with N.C. Gen. Stat. § 62-110.7 and as further explained in Chapter 4 (Execution Plan), the Companies request that the Commission authorize DEC and DEP to defer project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies' then authorized, net-of-tax weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of each specific cost involved.

20. Together, these supply-side procurement and development activities represent the reasonable and prudent near-term steps the Companies propose to undertake to continue their energy transition through 2024 when the Commission will have its next comprehensive opportunity in a biennial Carbon Plan proceeding to "check and adjust" the strategy with the benefit of substantial additional and more refined information.

21. The two-year period following the Commission's decision in this proceeding will offer substantially greater clarity and precision regarding a range of issues that will significantly impact the longer-term trajectory of the Carbon Plan. First, the PSCSC will review the Carbon Plan as part of the Companies' 2023 South Carolina IRP, providing important direction for further development of the Carbon Plan with respect to the Companies' combined Carolinas systems. In addition, the Companies will be able to gather and assess a wide a range of additional, crucial information as they begin to execute the near-term Carbon Plan steps, including, but not limited to, more refined cost estimates and timelines for new-to-the-Carolinas technologies, availability of gas supply from Appalachia, more clarity on supply chain challenges, more detailed market information gathered from procurement activities, *etc*. In addition, CPCN proceedings for resources selected by the Commission will provide opportunities for the Commission to assess more detailed market information to ensure alignment with the Carbon Plan trajectory presented in this initial Plan.

V. <u>Near-Term Existing Supply-Side Activities</u>

22. As coal units are retired and the integration of renewable resources increases, the flexibility of dispatchable gas-fired resources will become an increasingly important resource for maintaining system reliability in a least-cost manner. To increase the flexibility of the existing gas-fired fleet, the Companies will need to equip a number of its CC/CT stations to support more flexible operational capabilities, such as lower load operations, increased ramp rates, and the ability to cycle more often to respond to increased variability in the output of renewable resources. In the near and intermediate term, the Companies will plan and implement gas unit control upgrades and equipment changes and seek regulatory approvals for operational and air permit changes, where required.

23. Similarly, extending the life of the Companies' existing nuclear fleet is critical for ensuring a major source of reliable, zero-carbon, cost-competitive power through 2050 in every portfolio. Accomplishing this crucial Carbon Plan objective requires federal regulatory approval of 20-year subsequent license renewals ("SLRs") for the eleven existing nuclear generation units operating at six nuclear stations across the Carolinas and totaling 10,773 MW of generation. The current operating licenses will begin to expire in the 2030s, and the regulatory renewal process may take up to 4 years per SLR application. The Nuclear Regulatory Commission accepted the Companies' first SLR application for review in mid-2021 and is currently in the process of requesting additional information to support its review. The Companies plan to develop and submit an SLR application for each nuclear station approximately every three years, with the remaining submittals tentatively planned for 2024, 2027, 2030, 2033 and 2036.

24. Accordingly, the Companies are seeking Commission approval of their efforts to expand the flexibility of their natural gas fleet and the continued, disciplined pursuit of SLRs for their existing nuclear resource facilities.

VI. Grid Edge and Customer Programs

25. The Companies' Grid Edge and Customer Programs are another foundational component of the Carbon Plan. These programs are targeted to reduce or modify energy usage on the system at the customer level and implement technologies that enable Duke Energy to manage the electric system in ways that lower carbon emissions. Given the critical need for these programs to "shrink the challenge" of an energy transition, the Companies are asking the Commission to approve their plans to advance Grid Edge and Customer Programs and to revise inputs to the cost-effectiveness framework utilized

for energy efficiency and demand response programs to appropriately align values to supply-side alternative technologies.

VII. Transmission System Planning

26. HB 951 established public policy goals requiring new generation and other resources that will necessarily impact the manner in which the Companies plan and operate their transmission systems. Adding the significant new renewable and lower-carbon emitting resources required by the Carbon Plan will also require a transformation of the transmission grid to ensure these new resources can reliably serve customers' energy needs. Accordingly, in both the near- and long-term, the Companies will require timely and prudent transmission investments to enable the interconnection of an unprecedented amount of solar, storage, and wind resources. The Companies are already engaging through the North Carolina Transmission Planning Collaborative ("NCTPC") to advance consideration of transmission projects in the near-term that have been identified as needed to facilitate more solar interconnections and to achieve the targeted carbon reductions in the least cost manner while maintaining adequate grid reliability.

27. Accordingly, the Companies are asking the Commission to acknowledge that HB 951 establishes new public policy goals that necessarily informs the Companies' transmission system planning process and direct the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the NCTPC and other appropriate forums.

VIII. Methodologies for Carbon Baseline Calculation and Accounting

28. While HB 951 establishes CO_2 emissions reductions targets for certain electric generating facilities located in North Carolina, the Companies are committed to

system-wide CO_2 emissions reductions, targeting carbon neutrality for their entire system by 2050.

29. The Commission's Initial Scheduling Order directed the Companies to address, in their proposed Carbon Plan: (1) "the methodology used to determine the baseline 2005 level of carbon dioxide emitted in North Carolina by their electric generating facilities"; and (2) "the methodology used to quantify the reduction associated with any offset proposed and the methodology for verifying any such offset." Initial Scheduling Order, at 3 (Order Paragraph 3). The CO_2 emissions baseline and progression to achieve the interim 70% reduction target are explained in detail in Carbon Plan Appendix A (Carbon Baseline and Accounting). At this time, the Plan does not assume the Companies will utilize offsets in the near-term or intermediate-term towards meeting the interim 70% emissions reduction target, nor do the portfolios rely upon offsets to achieve carbon neutrality by 2050.

30. For modeling purposes in this proceeding, the Companies assumed that any new CO_2 emitting resources selected in the model would be sited in North Carolina. However, consistent with past practice in most cases, the selection and siting of new resources will occur after completion of the modeling process. This approach ensures that the most cost-effective resources are selected for the benefit of customers, taking into account a range of site-specific and other factors that are not practical for inclusion in the modeling process.

31. Therefore, the Companies request Commission confirmation with respect to two issues concerning CO_2 emissions accounting under HB 951. First, the Companies request Commission approval of the methodologies outlined in Appendix A (Carbon

Baseline and Accounting) for tracking achievement of HB 951's CO_2 emissions reductions targets. Second, the Companies request that the Commission determine whether CO_2 emissions from out-of-state generating resources ultimately selected to be part of the Plan should be accounted as if such emissions occurred in the State. Once again, for modeling purposes, the Companies assumed all new selected resources would be sited in North Carolina.

IX. <u>Future Proceedings</u>

32. The Commission's Initial Scheduling Order recognized the significant overlap between the analyses required to prepare a proposed Carbon Plan under HB 951 and development of the Companies' biennial IRP and indicated an intent to "sync, eventually, the Carbon Plan proceedings with the IRP proceedings."[11] In doing so, the Commission delayed DEC's and DEP's next biennial IRP filings required by Commission Rule R8-60(h)(1) to September 2023.

33. The Commission's Initial Scheduling Order also indicated that the Commission "will initiate, by separate order . . . a rulemaking proceeding to revise Commission Rule R8-60 to reflect the approach of syncing the Carbon Plan with the IRP proceedings."[12]

34. To achieve the Commission's goal of syncing the biennial IRP and Carbon Plan proceedings and in light of the fact that the Companies' initial Carbon Plan reflects a planning document that is at least as comprehensive as a biennial IRP filing, the Companies respectfully request that the Commission hold the Companies' next biennial IRPs in

[11] Initial Scheduling Order, at 1.
[12] *Id.* at 1-2.

abeyance to 2024 to align with the next Carbon Plan proceeding as contemplated under HB 951.

35. In addition, to ensure that the necessary revisions to R8-60 can be developed and implemented in advance of the proposed 2024 joint Carbon Plan / IRP proceeding, the Companies respectfully request that the Commission direct the Companies and Public Staff to, by January 31, 2023, develop and propose for comment revisions to Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan.

X. Conclusion and Request for Relief

The proposed Carbon Plan provides a comprehensive and detailed analysis and first-of-its-kind execution plan that supports the Companies continued energy transition designed to achieve the goals of HB 951 in a balanced and reasonable manner that will ensure reliable electric service for the Companies' customers at affordable rates over the short and long term. Accordingly, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC respectfully request that the Commission adopt their Carolinas Carbon Plan and take the following specific actions:

(1) Affirm that the Companies' Carbon Plan modeling is reasonable for planning purposes and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning;

(2) Approve the near-term supply-side development and procurement activities identified above in Table 3, including by:

(a) Deeming the following resources as being selected in this initial Carbon Plan for purposes of HB 951, Section 1.(2), in all cases subject to the obligation to obtain a CPCN (where applicable) and to keep the Commission apprised of material changes in assumed pricing or schedule:

(i) 3,100 MW of solar generation (including 750 MW requested to be procured through the 2022 Solar Procurement Program), of which a substantial portion is assumed to include paired storage;

(ii) 1,600 MW of battery storage (1,000 MW stand-alone storage, 600 MW storage paired with solar);

(iii) 600 MW of onshore wind;

(iv) 800 MW of CTs; and

(v) 1,200 MW of CC

(b) Approving the Companies' plans to pursue initial development activities to support the future availability of offshore wind, SMRs and new pumped storage hydro at Bad Creek to ensure that these resources are available options for the Companies' customers on the timelines identified the portfolios if selected in future Carbon Plan updates;

(c) Making the following additional determinations with respect to the project development activities summarized in Table 3:

(i) Engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;

(ii) To the extent not already authorized under applicable accounting rules, that the Companies are authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies then authorized, net-of-tax, weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and

(iii) That in the event the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time;

(3) Approve the Companies' proposed actions with respect to existing supply-side resources, including through expanding flexibility of the existing gas fleet and continued disciplined pursuit of SLRs for the Companies' existing nuclear fleet;

(4) Approve the Companies' plans to advance Grid Edge and Customer Programs and to update the underlying determination of the utility system benefits in the Companies' approved EE/DSM Cost Recovery Mechanism;

(5) Acknowledge that HB 951 establishes new public policy goals requiring new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the Open Access Transmission Tariff and direct the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the NCTPC and other appropriate forums;

(6) Approve the Companies' methodologies outlined in Appendix A (Carbon Baseline and Accounting) for tracking compliance with HB 951's CO_2 emissions reductions targets and confirm the Commissions' accounting requirements for emissions from new out-of-state resources selected by the Commission (if any) as described above;

(7) Affirm that the first biennial Carbon Plan update proceeding should be held in 2024 and that the Companies' next biennial IRPs will be held in abeyance to 2024 to align with the Carbon Plan update, as further discussed in Chapter 4 (Execution Plan);

(8) Direct the Companies and Public Staff to develop and propose for comment by January 31, 2023, revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan; and

(9) Grant such other and further relief as the Commission deems just and proper.

Respectfully submitted, this 16th day of May, 2022.

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and Duke Energy Progress, LLC

VERIFICATION

STATE OF NORTH CAROLINA)
) DOCKET NO. E-100, SUB 179
COUNTY OF WAKE)

The undersigned, Robert Mark Oliver, being first duly sworn, deposes and says that he is Vice President - Integrated System Planning; that he oversaw development of the foregoing Carbon Plan of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC and knows the contents thereof; that the same are true of his own knowledge, except as to those matters stated on information and belief, and as to those matters, he believes them to be true.

Robert Mark Oliver

Sworn to and subscribed before me this 13th day of May 2022.

Peggy Holton
Notary Public

PEGGY HOLTON
NOTARY PUBLIC
WAKE COUNTY, NC

My Commission Expires: 12/22/2026

ASTRAPÉ CONSULTING

innovation in electric system planning

Duke Energy Carolinas

2020 Resource Adequacy Study

9/1/2020

PREPARED FOR

Duke Energy

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Executive Summary

This study was performed by Astrapé Consulting at the request of Duke Energy Carolinas (DEC) as an update to the study performed in 2016. The primary purpose of this study is to provide Duke system planners with information on physical reliability and costs that could be expected with various reserve margin[1] planning targets. Physical reliability refers to the frequency of firm load shed events and is calculated using Loss of Load Expectation (LOLE). The one day in 10-year standard (LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed every 10 years due to a shortage of generating capacity and is used across the industry[2] to set minimum target reserve margin levels. Astrapé determined the reserve margin required to meet the one day in 10-year standard for the Base Case and multiple sensitivities included in the study. The study includes a Confidential Appendix containing confidential information such as fuel costs, outage rate data and transmission assumptions.

Customers expect to have electricity during all times of the year but especially during extreme weather conditions such as cold winter days when resource adequacy[3] is at risk for DEC[4]. In order

[1] Throughout this report, winter and summer reserve margins are defined by the formula: (installed capacity - peak load) / peak load. Installed capacity includes capacity value for intermittent resources such as solar and energy limited resources such as battery.

[2] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf; See Table 14 in A-1. PJM, MISO, NYISO ISO-NE, Quebec, IESO, FRCC, APS, NV Energy all use the 1 day in 10 year standard. As of this report, it is Astrapé's understanding that Southern Company has shifted to the greater of the economic reserve margin or the 1 day in 10 year standard.

[3] NERC RAPA Definition of "Adequacy" - The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf, at 9.

[4] Section (b)(4)(iv) of NCUC Rule R8-61 (Certificate of Public Convenience and Necessity for Construction of Electric Generation Facilities) requires the utility to provide "… a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located."

to ensure reliability during these peak periods, DEC maintains a minimum reserve margin level to manage unexpected conditions including extreme weather, load growth, and significant forced outages. To understand this risk, a wide distribution of possible scenarios must be simulated at a range of reserve margins. To calculate physical reliability and customer costs for the DEC system, Astrapé Consulting utilized a reliability model called SERVM (Strategic Energy and Risk Valuation Model) to perform thousands of hourly simulations for the 2024 study year at various reserve margin levels. Each of the yearly simulations was developed through a combination of deterministic and stochastic modeling of the uncertainty of weather, economic growth, unit availability, and neighbor assistance.

In the 2016 study, reliability risk was concentrated in the winter and the study determined that a 16.5% reserve margin was required to meet the one day in 10-year standard (LOLE of 0.1), for DEC. Because DEC's sister utility DEP required a 17.5% reserve margin to meet the same reliability standard, Duke Energy averaged the studies and used a 17% planning reserve margin target for both companies in its Integrated Resource Plan (IRP). This 2020 Study updates all input assumptions to reassess resource adequacy. As part of the update, several stakeholder meetings occurred to discuss inputs, methodology, and results. These stakeholder meetings included representatives from the North Carolina Public Staff, the South Carolina Office of Regulatory Staff (ORS), and the North Carolina Attorney General's Office. Following the initial meeting with stakeholders on February 21, 2020, the parties agreed to the key assumptions and sensitivities listed in Appendix A, Table A.1.

Preliminary results were presented to the stakeholders on May 8, 2020 and additional follow up was done throughout the month of May. Moving from the 2016 Study, the Study Year was shifted from 2019 to 2024 and assumed solar capacity was updated to the most recent projections. Because solar projections increased, LOLE has continued to shift from the summer to the winter. The high volatility in peak winter loads seen in the 2016 Study remained evident in recent historical data. In response to stakeholder feedback, the four year ahead economic load forecast error was dampened by providing a higher probability weighting on over-forecasting scenarios relative to under-forecasting scenarios. The net effect of the new distribution is to slightly reduce the target reserve margin compared to the previous distribution supplying slight upward pressure on the target reserve margin. This means that if the target reserve margin from this study is adopted, no reserves would be held for potential under-forecast of load growth. Generator outages remained in line with 2016 expectations, but additional cold weather outages of 260 MW for DEC were included for temperatures less than 10 degrees.

Physical Reliability Results-Island

Table ES1 shows the monthly contribution of LOLE at various reserve margin levels for the Island scenario. In this scenario, it is assumed that DEC is responsible for its own load and that there is no assistance from neighboring utilities. The summer and winter reserve margins differ for all scenarios due to seasonal demand forecast differences, weather-related thermal generation capacity differences, demand response seasonal availability, and seasonal solar capacity value. Using the one day in 10-year standard (LOLE of 0.1), which is used across the industry to set minimum target reserve margin levels, DEC would require a 22.5% winter reserve margin in the Island Case where no assistance from neighboring systems was assumed.

Given the significant level of solar on the system, the summer reserves are approximately 2% greater than winter reserves which results in essentially no reliability risk in the summer months when total LOLE is 0.1 days per year. This 22.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEC system. As discussed below, when compared to Base Case results which recognizes neighbor assistance, results of the Island Case illustrate both the benefits and risks of carrying lower reserve margins through reliance on neighboring systems.

Table ES1. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	12.4%	0.81	0.14	0.08	-	0.00	0.12	0.70	0.80	0.31	0.11	0.02	0.27	2.05	1.31	3.36
11.0%	13.3%	0.69	0.12	0.06	-	0.00	0.09	0.48	0.51	0.19	0.07	0.01	0.20	1.35	1.09	2.44
12.0%	14.2%	0.58	0.10	0.05	-	0.00	0.06	0.31	0.33	0.12	0.04	0.01	0.15	0.87	0.88	1.75
13.0%	15.0%	0.48	0.08	0.04	-	0.00	0.04	0.19	0.21	0.07	0.03	0.00	0.11	0.55	0.71	1.26
14.0%	15.9%	0.40	0.07	0.03	-	0.00	0.02	0.11	0.14	0.04	0.02	0.00	0.08	0.34	0.58	0.92
15.0%	16.8%	0.33	0.06	0.03	-	-	0.02	0.07	0.09	0.03	0.01	-	0.06	0.21	0.47	0.68
16.0%	17.6%	0.28	0.05	0.02	-	-	0.01	0.04	0.05	0.02	0.01	-	0.04	0.13	0.39	0.52
17.0%	18.5%	0.23	0.04	0.02	-	-	0.01	0.03	0.03	0.01	0.00	-	0.03	0.09	0.32	0.41
18.0%	19.4%	0.19	0.03	0.01	-	-	0.01	0.02	0.02	0.01	0.00	-	0.03	0.06	0.27	0.33
19.0%	20.2%	0.16	0.03	0.01	-	-	0.01	0.02	0.01	0.00	-	-	0.02	0.04	0.22	0.26
20.0%	21.1%	0.13	0.02	0.01	-	-	0.00	0.01	0.01	0.00	-	-	0.02	0.02	0.18	0.20
21.0%	22.0%	0.11	0.02	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.14	0.15
22.0%	22.8%	0.08	0.01	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.10	0.11
23.0%	23.7%	0.06	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.08	0.08
24.0%	24.6%	0.05	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.06	0.06

Physical Reliability Results-Base Case

Astrapé recognizes that DEC is part of the larger eastern interconnection and models neighbors one tie away to allow for market assistance during peak load periods. However, it is important to also understand that there is risk in relying on neighboring capacity that is less dependable than owned or contracted generation in which DEC would have first call rights. While there are certainly advantages of being interconnected due to weather diversity and generator outage diversity across regions, market assistance is not guaranteed and Astrapé believes Duke Energy has taken a moderate to aggressive approach (i.e. taking significant credit for neighboring regions) to modeling neighboring assistance compared to other surrounding entities such as PJM Interconnection L.L.C. (PJM)[5] and the Midcontinent Independent System Operator (MISO)[6]. A full description of the market assistance modeling and topology is available in the body of the report. Table ES2 shows the monthly LOLE at various reserve margin levels for the Base Case scenario which is the Island scenario with neighbor assistance included.[7]

[5] PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin compared to 6.5% assumed for DEC. https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx – page 11
[6]MISO limits external assistance to a Unforced Capacity (UCAP) of 2,331 MW which represents approximately 1.8% of its reserve margin compared to 6.5% assumed for DEC. https://www.misoenergy.org/api/documents/getbymediaid/80578 page 24 (copy and paste link in browser)
[7] Reference Appendix B, Table B.1 for percentage of loss of load by month and hour of day for the Base Case.

Table ES2. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
5.00%	8.11%	0.21	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.05	0.33	0.38
6.00%	8.97%	0.20	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.04	0.30	0.35
7.00%	9.84%	0.18	0.05	0.02	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.04	0.28	0.31
8.00%	10.71%	0.17	0.04	0.01	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.03	0.25	0.28
9.00%	11.57%	0.15	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03	0.03	0.23	0.25
10.00%	12.44%	0.14	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.21	0.23
11.00%	13.31%	0.13	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.18	0.20
12.00%	14.18%	0.11	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.16	0.18
13.00%	15.04%	0.10	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.15	0.15
14.00%	15.91%	0.09	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.13	0.13
15.00%	16.78%	0.08	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.12
16.00%	17.64%	0.07	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
17.00%	18.51%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
18.00%	19.38%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.07
19.00%	20.24%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.06
20.00%	21.11%	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05
21.00%	21.98%	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04
22.00%	22.84%	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00-	0.03	0.03

As the table indicates, the required reserve margin to meet the one day in 10-year standard (LOLE of 0.1), is 16.00% which is 6.50% lower than the required reserve margin for 0.1 LOLE in the Island scenario. Approximately one third of the 22.5% required reserves is reduced due to interconnection ties. Astrapé also notes utilities around the country are continuing to retire and replace fossil-fuel resources with more intermittent or energy limited resources such as solar, wind, and battery capacity. For example, Dominion Energy Virginia has made substantial changes to its plans as this study was being conducted and plans to add substantial solar and other renewables to its system that could cause additional winter reliability stress than what is modeled. The below excerpt is from page 6 of Dominion Energy Virginia's 2020 IRP[8]:

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[9] While this is only one example, these potential changes to surrounding resource mixes may lead to less confidence in market assistance for the future during early morning winter peak loads. Changes in neighboring system resource portfolios and load profiles will be an important consideration in future resource adequacy studies. To the extent historic diversification between DEC and neighboring systems declines, the historic reliability benefits DEC has experienced from being an interconnected system will also decline. It is worth nothing that after this study was completed, California experienced rolling blackouts during extreme weather conditions as the ability to rely on imported power has declined and has shifted away from dispatchable fossil-fuel resources and put greater reliance on intermittent resources.[10] It is premature to fully ascertain the lessons learned from the California load shed events. However, it does highlight the fact that as DEC reduces dependence on

[8] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509
[9] Dominion Energy Virginia 2020 IRP, at 40.
[10] http://www.caiso.com/Documents/ISO-Stage-3-Emergency-Declaration-Lifted-Power-Restored-Statewide.pdf

dispatchable fossil fuels and increases dependence on intermittent resources, it is important to ensure it is done in a manner that does not impact reliability to customers.

Physical Reliability Results-DEC/DEP Combined Case

In addition to running the Island and Base Case scenarios, a DEC and DEP Combined Case scenario was simulated to see the reliability impact of DEC and DEP as a single balancing authority. In this scenario, DEC and DEP prioritize helping each other over their other external neighbors but also retain access to external market assistance. The various reserve margin levels are calculated as the total resources in both DEC and DEP using the combined coincident peak load, and reserve margins are increased together for the combined utilities. Table ES3 shows the results of the Combined Case which shows that a 16.75% combined reserve margin is needed to meet the 1 day in 10-year standard. An additional Combined Case sensitivity was simulated to assess the impact of a more constrained import limit. This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[11] resulting in an increase in the reserve margin from 16.75% to 18.0%.

Table ES3. Combined Case Physical Reliability Results

Sensitivity	1 in 10 LOLE Reserve Margin
Base Case	16.0%
Combined Target	16.75%
Combined Target 1,500 MW Import Limit	18.00%

[11] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

Results for the Combined Case and the individual Base Cases are outlined in the table below. The DEP results are documented in a separate report but show that a 19.25% reserve margin is required to meet the one day in 10-year standard (LOLE of 0.1).

Table ES4. Combined Case Differences

Region	1 in 10 LOLE Reserve Margin
DEC	16.00%
DEP	19.25%
Combined (Coincident)	16.75%

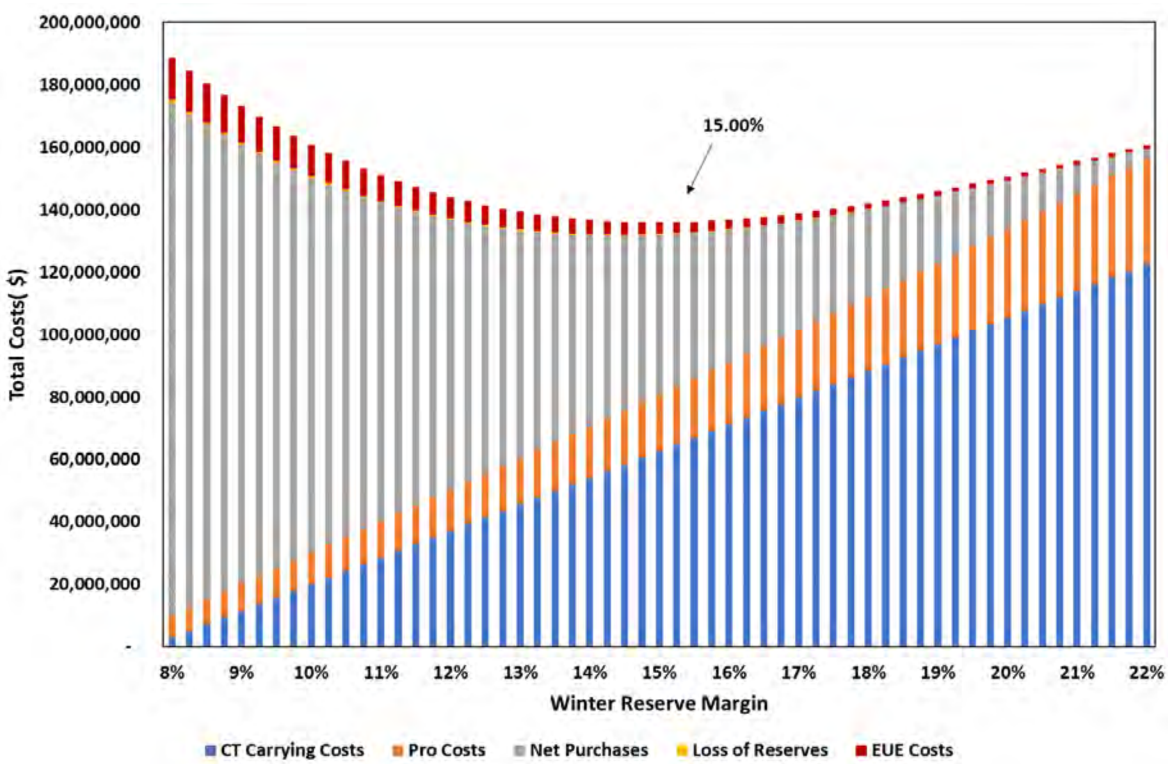
Economic Reliability Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs[12] were analyzed across reserve margin levels for the Base Case. Figure ES1 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and

[12] System costs = system energy costs plus capacity costs of incremental reserves. System energy costs include production costs + net purchases + loss of reserves costs + unserved energy costs while system capacity costs include the fixed capital and fixed operations & maintenance (FOM) costs for CT capacity. Unserved energy costs equal the value of lost load times the expected unserved energy

unit performance iterations at each reserve margin level and represents the yearly expected value on a year in and year out basis.

Figure ES1. Base Case Risk Neutral Economic Results[13]



As Figure ES1 shows, the lowest risk neutral cost falls at a 15.00% reserve margin very close to the one day in 10-year standard (LOLE of 0.1). These values are close because the summer reserve margins are only slightly higher than the winter reserve margins which increases the savings of adding additional CT capacity.[14] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there is always system energy cost savings from

[13] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEC has approximately 1.5 billion dollars in total costs.
[14] This is different than the results seen in DEP because DEP's summer reserves margins are much greater than its winter reserves margins causing CTs to provide less economic benefit in DEP than DEC.

either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure ES2, however, shows the distribution of system energy costs which includes production costs, purchase costs, loss of reserves costs, and expected unserved energy (EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margin levels to higher reserve margin levels, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

Figure ES2. System Energy Costs (Cumulative Probability Curves)

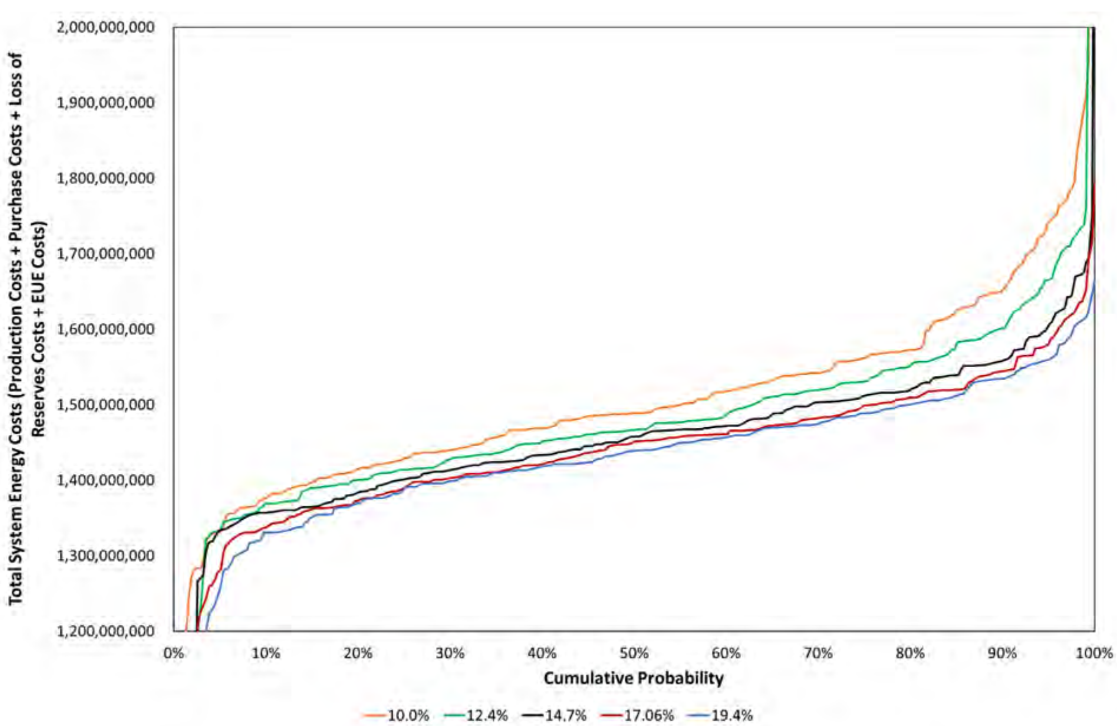


Table ES5 shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure ES1 as well as the energy savings at higher cumulative probability levels from Figure ES2. As shown in the table, going from the risk neutral reserve margin of 15.00% to 17% increases customer costs on average by $2.9 million a year[15] and reduces LOLE from 0.12 to 0.08 events per year. The LOLE for the island scenario decreases from 0.68 days per year to 0.41 days per year. However, 10% of the time energy savings are greater than or equal to $21 million if a 17% reserve margin is maintained versus the 15.00% reserve margin. While 5 % of the time, $34 million or more is saved.

Table ES5. Annual Customer Costs vs LOLE

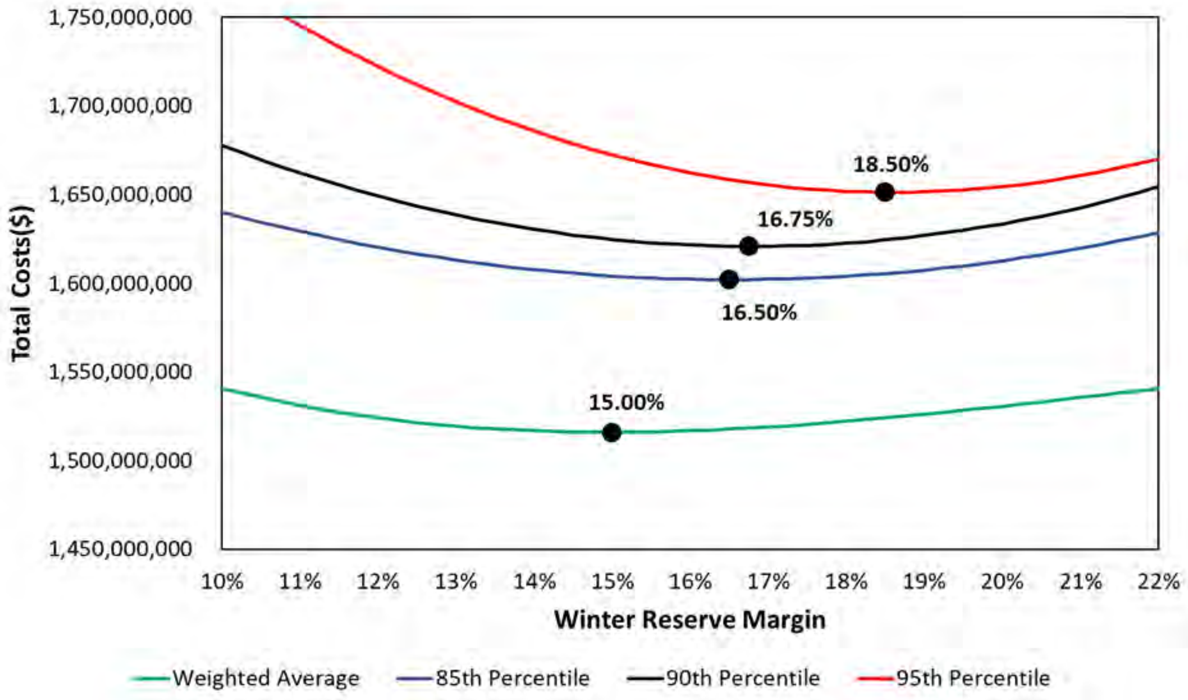
Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
15.00%	-	-	-	-	-	-	0.12	0.68
16.00%	8.5	-7.8	0.8	-10.4	-11.7	-18.6	0.1	0.52
17.00%	17.1	-14.2	2.9	-19.0	-21.0	-34.0	0.08	0.41
18.00%	25.6	-19.5	6.1	-25.8	-27.8	-46.1	0.07	0.33
19.00%	34.2	-24.0	10.1	-30.8	-32.1	-55.0	0.06	0.26
20.00%	42.7	-28.0	14.7	-34.1	-33.9	-60.6	0.05	0.20

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure ES2 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher

[15] This includes $17 million for additional CT costs less $14 million of system energy savings.

cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 15.00% reserve margin, the 85th to 95th percentile cost curves point to a 16-19% reserve margin.

Figure ES3. Total System Costs by Reserve Margin.



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEC is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

Sensitivity Results

Various sensitivities were run in addition to the Base Case to examine the reliability and cost impact of different assumptions and scenarios. Table ES6 lists the various sensitivities and the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as well as economic results of each. These include sensitivities around cold weather generator outages, load forecast error uncertainty, solar penetration, the cost of unserved energy, the cost of CT capacity, demand response, coal retirements, and climate change. Detailed explanations of each sensitivity are available in the body of the report. The target reserve margin to meet the one day in 10-year standard (LOLE of 0.1) ranged from 14.75% to 17.25% depending on the sensitivity simulated.

Table ES6. Sensitivity Results

Sensitivity	1 in 10 LOLE Reserve Margin	Economic Risk Neutral	Economic 90th Percentile
Base Case	16.00%	15.00%	16.75%
No Cold Weather Outages	14.75%	14.75%	16.75%
Cold Weather Outages based on 2014 - 2019	17.25%	15.00%	17.00%
Remove LFE	16.25%	15.00%	16.00%
Originally Proposed Normal Distribution	17.00%	16.00%	18.00%
Low Solar	16.00%	16.00%	18.25%
High Solar	15.75%	14.00%	14.50%
CT costs 40 $/kW-yr	16.00%	16.00%	17.25%
CT costs 60 $/kW-yr	16.00%	13.75%	16.00%
EUE 5,000 $/MWh	16.00%	14.50%	16.25%
EUE 25,000 $/MWh	16.00%	15.25%	16.75%
Demand Response Winter as High as Summer	16.75%	18.25%	19.50%
Retire all Coal	15.25%	17.00%	20.25%
Climate Change	15.75%	14.25%	16.75%

Recommendation

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEP Study, Astrapé recommends that DEC continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEC utility would require a 22.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and that with market assistance, DEC would need to maintain a 16.00% reserve margin. However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 19.25% reserve margin required by DEP to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target for both DEC and DEP is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increase the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEC will never be forced to shed firm load during extreme conditions as DEC and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEC has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. If not for non-firm external assistance which this study considers, firm load would have been shed. In addition, incorporation of tail end reliability risk in modeling should be from statistically and historically defendable methods; not from including subjective risks that cannot be assigned probability. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 15% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEC resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEC should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEC observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and in future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[16]

[16] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

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Table 25. Economic Sensitivities 60
Table 26. Combined Case Results 61

III. Input Assumptions

A. Study Year

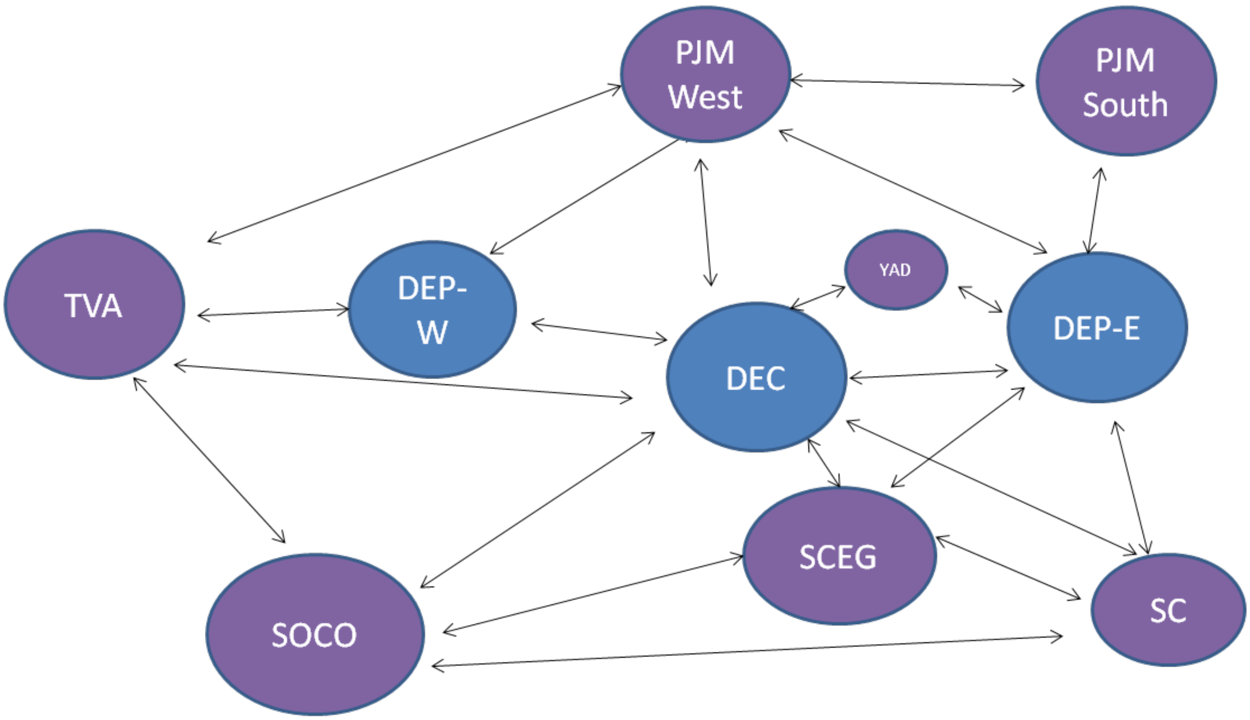
The selected study year is 2024[17]. The SERVM simulation results are broadly applicable to future years assuming that resource mixes and market structures do not change in a manner that shifts the reliability risk to a different season or different time of day.

B. Study Topology

Figure 1 shows the study topology that was used for the Resource Adequacy Study. While market assistance is not as dependable as resources that are utility owned or have firm contracts, Astrapé believes it is appropriate to capture the load diversity and generator outage diversity that DEC has with its neighbors. For this study, the DEC system was modeled with nine surrounding regions. The surrounding regions captured in the modeling included Duke Energy Progress (DEP) which was modeled in two interconnect zones: (1) DEP – E and (2) DEP – W, Tennessee Valley Authority (TVA), Southern Company (SOCO), PJM West &PJM South, Yadkin (YAD), Dominion Energy South Carolina (formally known as South Carolina Electric & Gas (SCEG)), and Santee Cooper (SC). SERVM uses a pipe and bubble representation in which energy can be shared based on economics but subject to transmission constraints.

[17] The year 2024 was chosen because it is four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility.

Figure 1. Study Topology



Confidential Appendix Table CA1 displays the DEC import capability from surrounding regions including the amount set aside for Transmission Reliability Margin (TRM).

C. Load Modeling

Table 1 displays SERVM's modeled seasonal peak forecast net of energy efficiency programs for 2024.

Table 1. 2024 Forecast: DEC Seasonal Peak (MW)

2024 Summer	18,456 MW
2024 Winter	17,976 MW

To model the effects of weather uncertainty, thirty-nine historical weather years (1980 - 2018) were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load[18], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from three weather stations across the DEC service territory. The weather stations included Charlotte, NC, Greensboro, NC, and Greenville, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last thirty-nine years of weather to develop thirty-nine synthetic load shapes for 2024. Equal probabilities were given to each of the thirty-nine load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Company's projected thirty-year weather normal load forecast for 2024.

Figures 2 and 3 show the results of the 2014-2019 weather load modeling by displaying the peak load variance for both the summer and winter seasons. The y-axis represents the percentage deviation from the average peak. For example, the 1985 synthetic load shape would result in a summer peak load approximately 2% below normal and a winter peak load approximately 18% above normal. Thus, the bars represent the variance in projected peak loads based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. As an example, extreme cold temperatures can cause load to spike from additional electric strip heating. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation.

[18] The historical load included years 2014 through September of 2019.

Figure 2. DEC Summer Peak Weather Variability

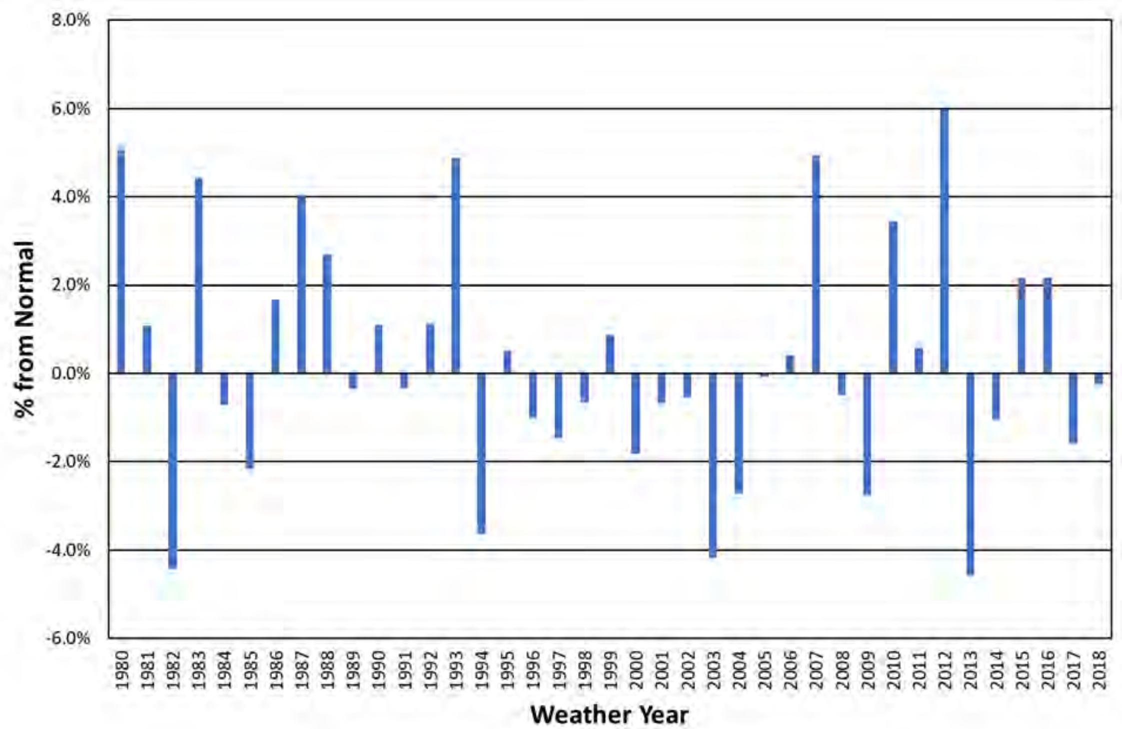


Figure 3. DEC Winter Peak Weather Variability

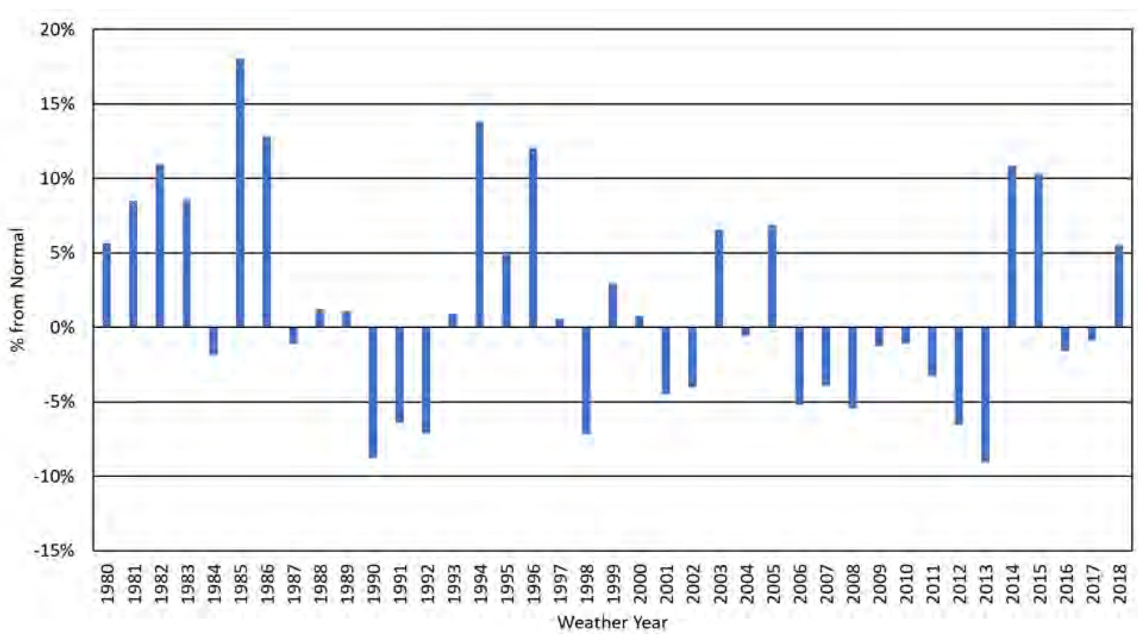
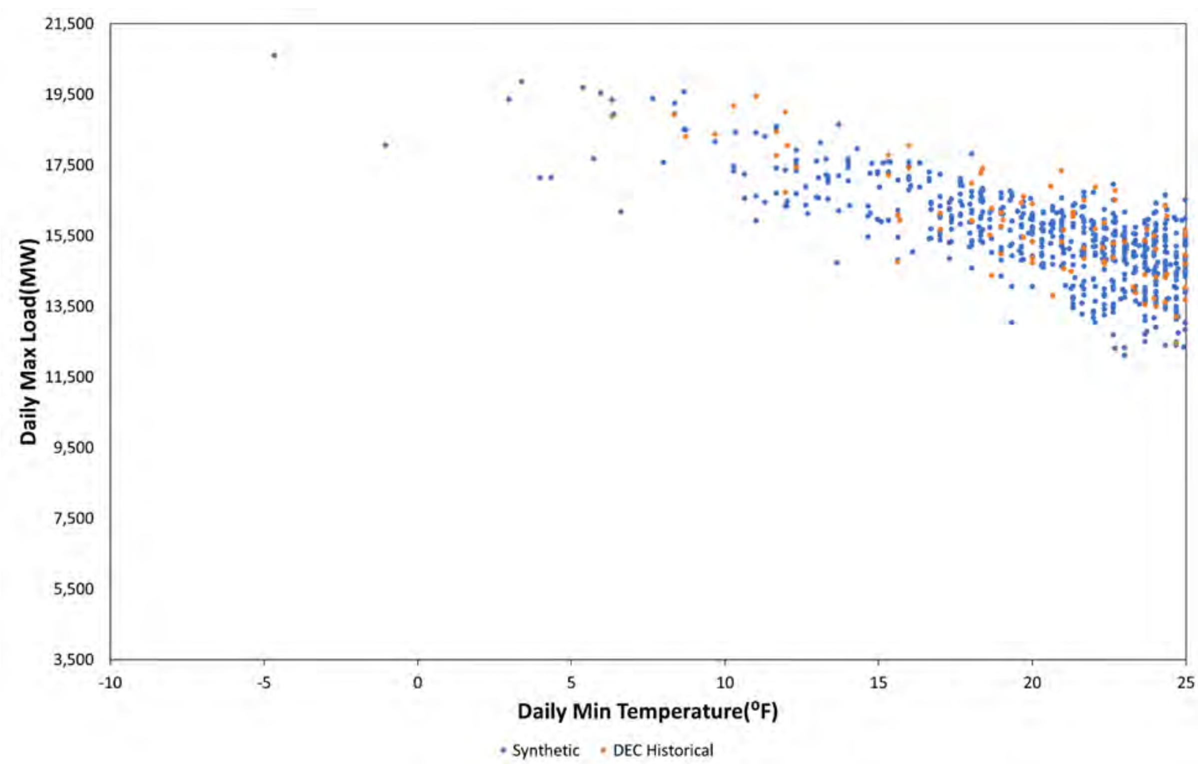


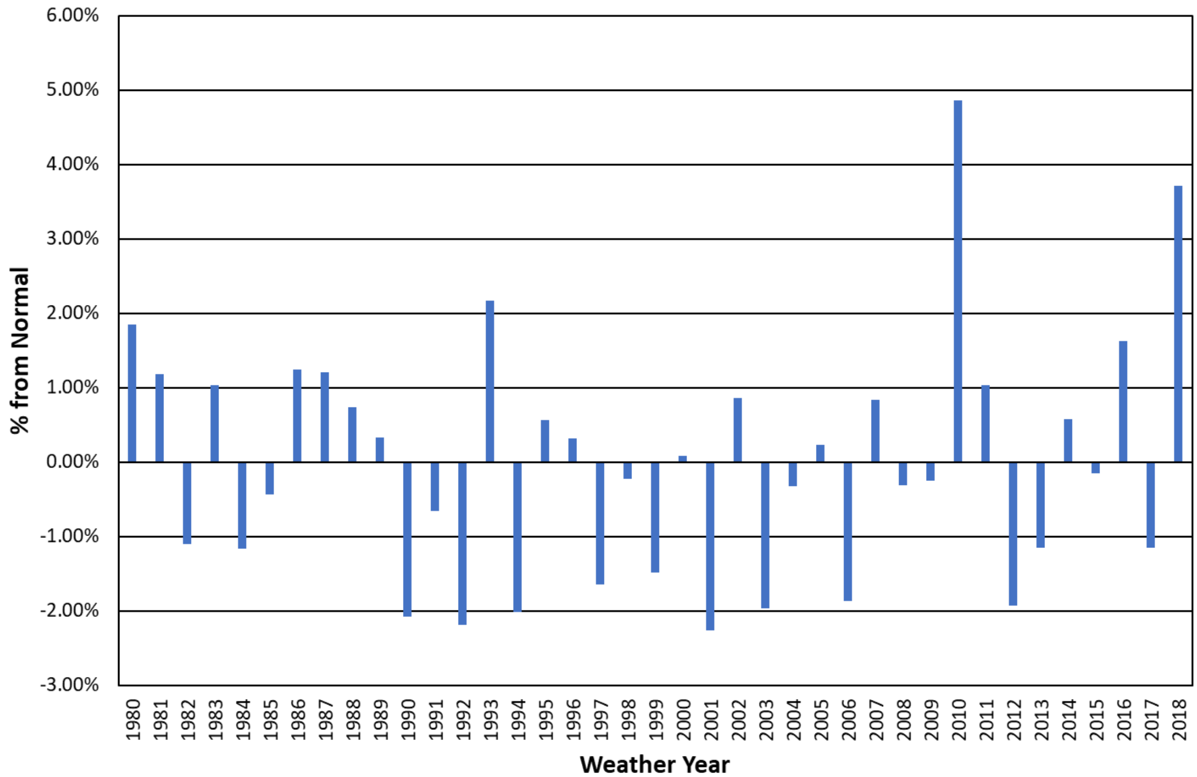
Figure 4 shows a daily peak load comparison of the synthetic load shapes and DEC history as a function of temperature. The predicted values align well with the history. Because recent historical observations only recorded a single minimum temperature of six degrees Fahrenheit, Astrapé estimated the extrapolation for extreme cold weather days using regression analysis on the historical data. This figure highlights that the frequency of cold weather events is captured as it has been seen in history.

Figure 4. DEC Winter Calibration



The energy variation is lower than peak variation across the weather years as expected. As shown in Figure 5, 2010 was an extreme year in total energy due to persistent severe temperatures across the summer and yet the deviation from average was only 5%.

Figure 5. DEC Annual Energy Variability



The synthetic shapes described above were then scaled to the forecasted seasonal energy and peaks within SERVM. Because DEC's load forecast is based on thirty years of weather, the shapes were scaled so that the average of the last thirty years equaled the forecast.

Synthetic loads for each external region were developed in a similar manner as the DEC loads. A relationship between hourly weather and publicly available hourly load[19] was developed based on

[19] Federal Energy Regulatory Commission (FERC) 714 Forms were accessed during January of 2020 to pull hourly historical load for all neighboring regions.

recent history, and then this relationship was applied to thirty-nine years of weather data to develop thirty-nine synthetic load shapes. Tables 2 and 3 show the resulting weather diversity between DEC and external regions for both summer and winter loads. When the system, which includes all regions in the study, is at its winter peak, the individual regions are approximately 2% - 9% below their non-coincidental peak load on average over the thirty-nine year period, resulting in an average system diversity of 4.7%. When DEC is at its winter peak load, DEP is 2.8% below its peak load on average while other regions are approximately 3% - 11% below their winter peak loads on average. Similar values are seen during the summer.

Table 2. External Region Summer Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	3.4%	3.8%	5.2%	4.2%	6.8%	7.0%	3.7%	1.4%	N/A
At DEC Peak	N/A	2.6%	7.0%	4.8%	5.7%	7.5%	4.5%	6.9%	2.3%

Table 3. External Region Winter Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	2.5%	2.8%	2.8%	5.8%	8.9%	4.8%	6.9%	3.2%	N/A
At DEC Peak	N/A	2.8%	3.0%	5.8%	9.2%	5.9%	7.0%	11.0%	2.8%

D. Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic uncertainty that Duke has in its four year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate the economic load forecast error, the difference between Congressional Budget Office (CBO) Gross Domestic Product (GDP) forecasts four years ahead and actual data was fit to a distribution which weighted over-forecasting more heavily than under-forecasting load[20]. This was a direct change accepted as part of the feedback in stakeholder meetings.[21] Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 4 shows the economic load forecast multipliers and associated probabilities. As an illustration, 25% of the time, it is expected that load will be over-forecasted by 2.7% four years out. Within the simulations, when DEC over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the thirty-nine weather years and applied each of these five load forecast error points to create 195 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 4. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.958	10.0%
0.973	25.0%
1.00	40.0%
1.02	15.0%
1.031	10.0%

[20] CBO's Economic Forecasting Record: 2017 Update. www.cbo.gov/publication/53090
www.cbo.gov/publication/53090

[21] Including the economic load forecast uncertainty actually results in a lower reserve margin compared to a scenario that excludes the load forecast uncertainty since over-forecasting load is weighted more heavily than under-forecasting load.

E. Conventional Thermal Resources

DEC resources are outlined in Tables 5 and 6 and represent summer ratings and winter ratings. All thermal resources are committed and dispatched to load economically. The capacities of the units are defined as a function of temperature in the simulations. Full winter rating is achieved at 35°F and below and summer rating is assumed for 95° and above. For temperatures in between 35°F and 95°F, a simple linear regression between the summer and winter rating was utilized for each unit.

Table 5. DEC Baseload and Intermediate Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Allen 1	Coal	162	167	Marshall 4	Coal	660	660
Allen 2	Coal	162	167	Catawba 1	Nuclear	260	294
Allen 3	Coal	258	270	Catawba 2	Nuclear	260	294
Allen 4	Coal	257	267	McGuire 1	Nuclear	1158	1199
Allen 5	Coal	259	259	McGuire 2	Nuclear	1158	1187
Belews Creek 1	Coal	1110	1110	Oconee 1	Nuclear	847	865
Belews Creek 2	Coal	1110	1110	Oconee 2	Nuclear	848	872
Cliffside 5	Coal	554	546	Oconee 3	Nuclear	859	881
Cliffside 6	Coal	844	849	Buck CC	Combined Cycle	668	716
Marshall 1	Coal	370	380	Dan River CC	Combined Cycle	662	718
Marshall 2	Coal	370	380	Lee CC	Combined Cycle	686	692
Marshall 3	Coal	658	658	Lee NG Conversion	Natural Gas	160	173

Table 6. DEC Peaking Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Lincoln CT_1	NG Peaker	76	98	Lee CT_1	Oil Peaker	42	48
Lincoln CT_2	NG Peaker	76	99	Lee CT_2	Oil Peaker	42	48
Lincoln CT_3	NG Peaker	75	99	Mill_Creek_CT_1	NG Peaker	71	95
Lincoln CT_4	NG Peaker	75	98	Mill_Creek_CT_2	NG Peaker	70	95
Lincoln CT_5	NG Peaker	74	97	Mill_Creek_CT_3	NG Peaker	71	95
Lincoln CT_6	NG Peaker	73	97	Mill_Creek_CT_4	NG Peaker	70	96
Lincoln CT_7	NG Peaker	75	98	Mill_Creek_CT_5	NG Peaker	69	96
Lincoln CT_8	NG Peaker	75	98	Mill_Creek_CT_6	NG Peaker	71	92
Lincoln CT_9	NG Peaker	75	97	Mill_Creek_CT_7	NG Peaker	70	95
Lincoln CT_10	NG Peaker	75	98	Mill_Creek_CT_8	NG Peaker	71	93
Lincoln CT_11	NG Peaker	74	98	Rockingham 1	NG Peaker	165	179
Lincoln CT_12	NG Peaker	75	98	Rockingham 2	NG Peaker	165	179
Lincoln CT_13	NG Peaker	74	98	Rockingham 3	NG Peaker	165	179
Lincoln CT_14	NG Peaker	74	97	Rockingham 4	NG Peaker	165	179
Lincoln CT_15	NG Peaker	73	98	Rockingham 5	NG Peaker	165	179
Lincoln CT_16	NG Peaker	73	97				

DEC purchase contracts were modeled as shown in Confidential Appendix Table CA2. These resources were treated as traditional thermal resources and counted towards reserve margin. Confidential Appendix Table CA3 shows the fuel prices used in the study for DEC and its neighboring power systems.

F. Unit Outage Data

Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events for the period 2014-2019 are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar technologies. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages
The actual schedule for 2024 was used.

To illustrate the outage logic, assume that from 2014 – 2019, a generator had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, shoulder, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw both a full outage and partial outage Time-to-Fail value from the distributions provided. Once the unit has been economically dispatched for that amount of time, it will fail. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture. Confidential Appendix Table CA4 shows system peak season Equivalent Forced Outage Rate (EFOR) for the system and by unit.

The most important aspect of unit performance modeling in resource adequacy studies is the cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Confidential Appendix Figure CA1 shows the distribution of modeled system outages as a percentage of time modeled and compared well with actual historical data.

Additional analysis was performed to understand the impact cold temperatures have on system outages. Confidential Appendix Figures CA2 and CA3 show the difference in cold weather outages during the 2014-2019 period and the 2016-2019 period. The 2014-2019 period showed more events than the 2016-2019 period which is logical because Duke Energy has put practices in place to enhance reliability during these periods, however the 2016 – 2019 data shows some events still occur. The average capacity offline below 10 degrees for DEC and DEP combined was 400 MW. Astrapé split this value by peak load ratio and included 260 MW in the DEC Study and 140 MW in the DEP Study at temperatures below 10 degrees. Sensitivities were performed with the cold weather outages removed and increased to match the 2014 – 2019 dataset which showed an average of 800 MW offline on days below 10 degrees. The MWs offline during the 10 coldest days can be seen in Confidential Appendix Table CA5. The outages shown are only events that included some type of freezing or cold weather problem as part of the description in the outage event.

G. Solar and Battery Modeling

Table 7 shows the solar and battery resources captured in the study.

Table 7. DEC Renewable Resources Excluding Existing Hydro

Unit Type	Summer Capacity (MW)	Winter Capacity (MW)	Modeling
Utility Owned-Fixed	85	85	Hourly Profiles
Transition-Fixed	660	660	Hourly Profiles
CPRE Tranche 1 Fixed 40%/Tracking 60%	465	465	Hourly Profiles
Future Solar Fixed 40%/Tracking 60%	1,368	1,368	Hourly Profiles
Total	2,578	2,578	
Total Battery	146	146	Modeled as energy arbitrage

The solar units were simulated with thirty-nine solar shapes representing thirty-nine years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. The solar capacity was given 37% credit in the summer and 1% in the winter for reserve margin calculations based on the 2018 Solar Capacity Value Study. The following figure shows the county locations that were used and Figure 7 shows the average August output for different fixed-tilt and single-axis-tracking inverter loading ratios.

Figure 6. Solar Map

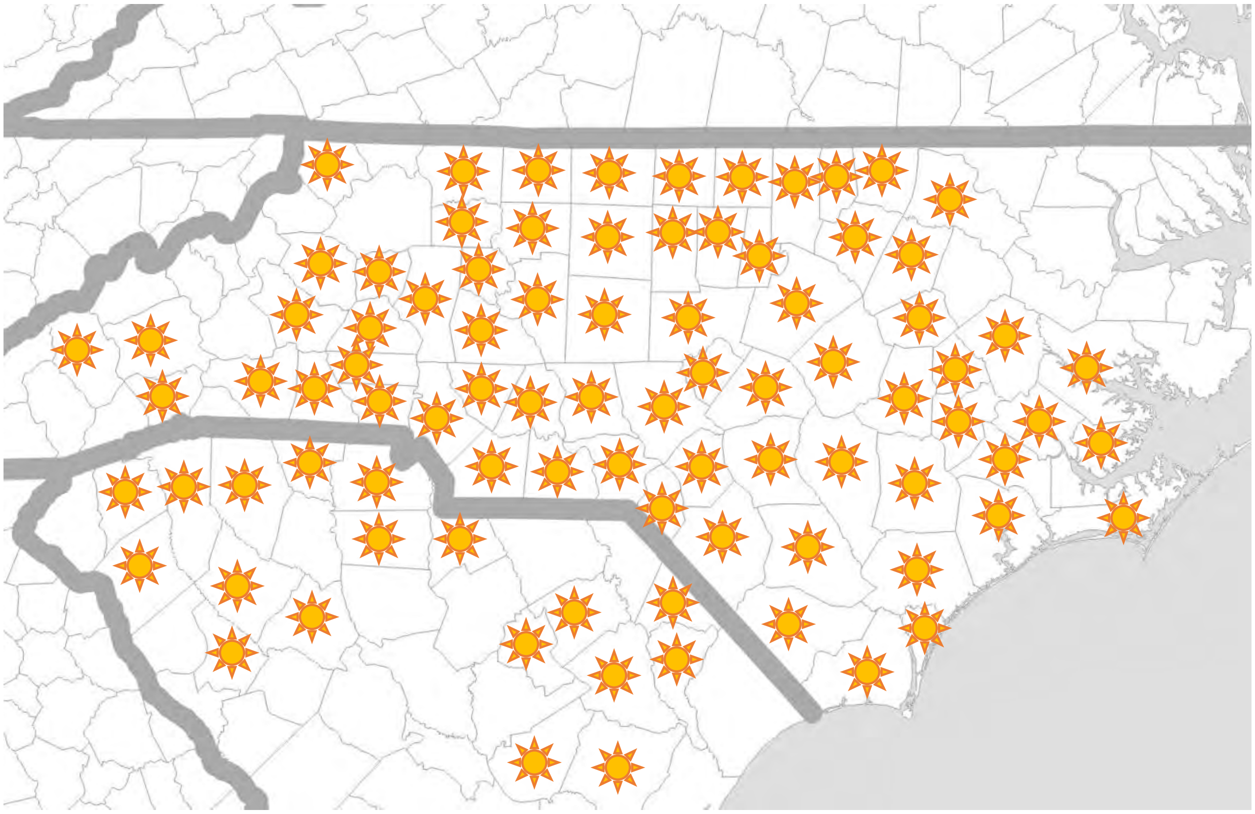
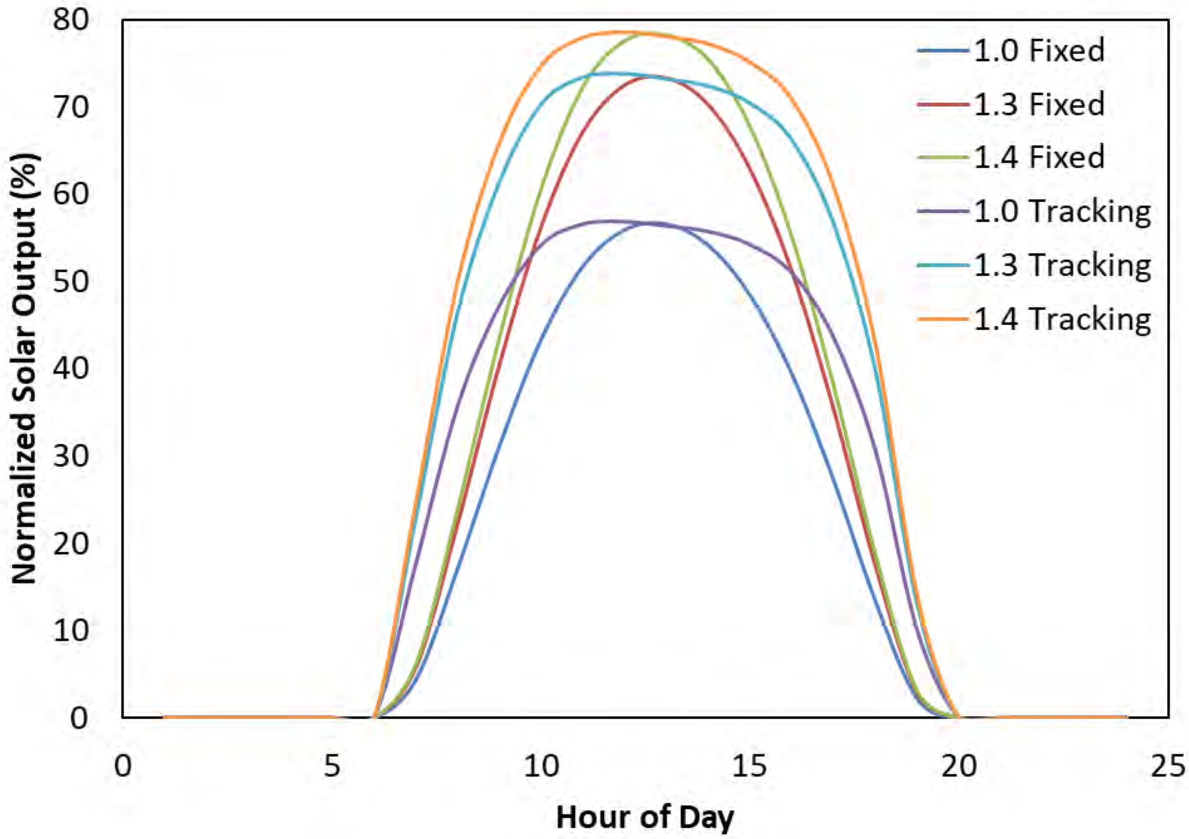


Figure 7. Average August Output for Different Inverter Loading Ratios



H. Hydro Modeling

The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. Figure 8 shows the total breakdown of scheduled hydro based on the last thirty-nine years of weather.

Figure 8. Scheduled Capacity

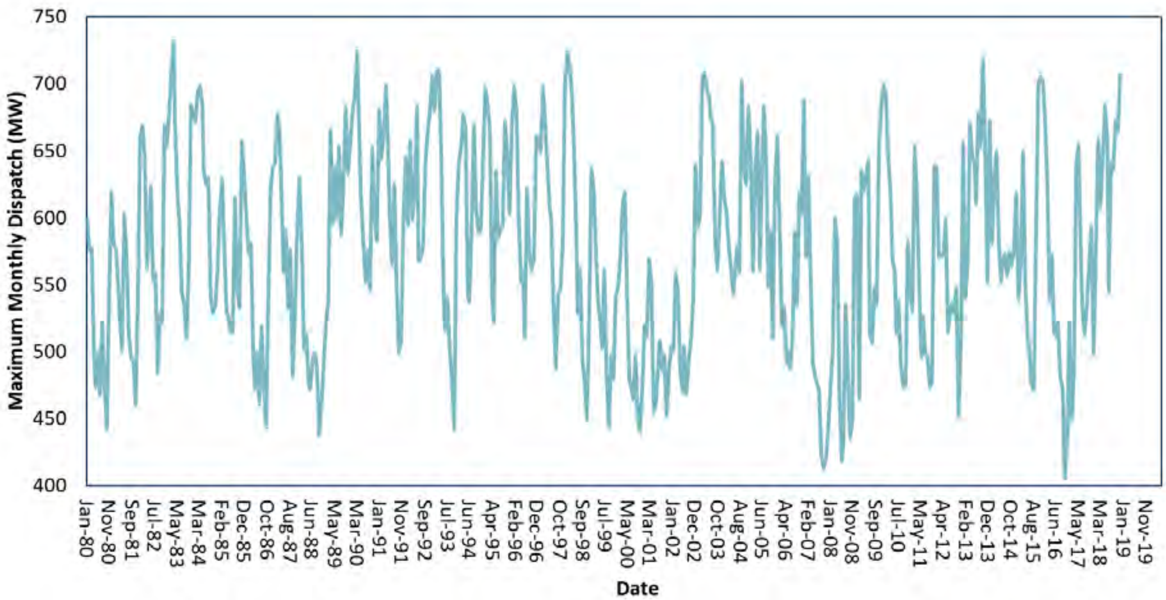
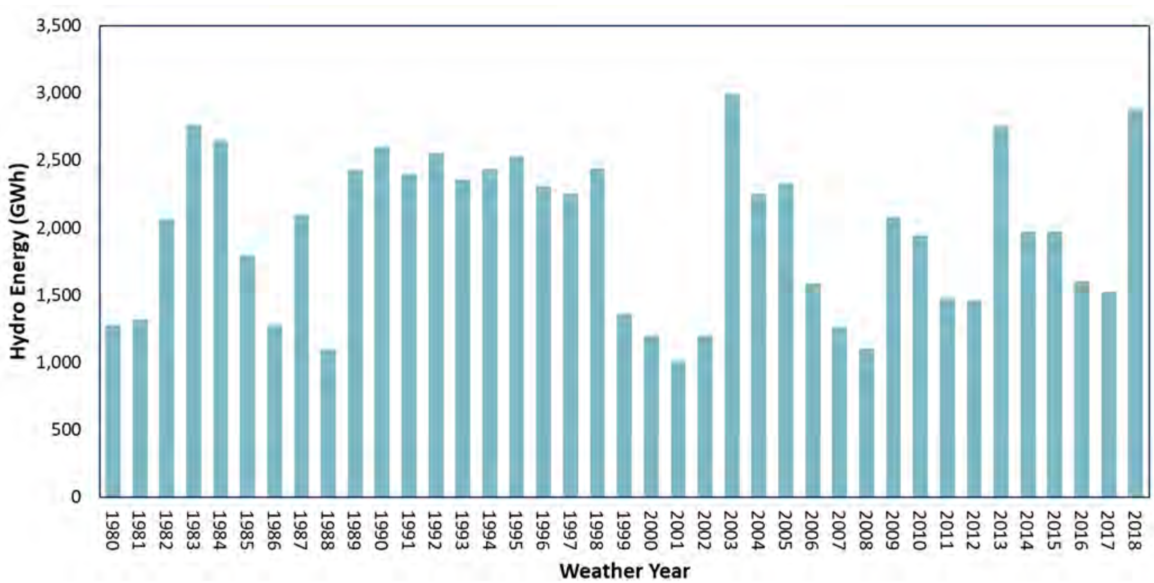


Figure 9 demonstrates the variation of hydro energy by weather year which is input into the model. The lower rainfall years such as 2001, 2007, and 2008 are captured in the reliability model with lower peak shaving as shown in Figure 9.

Figure 9. Hydro Energy by Weather Year



In addition to conventional hydro, DEC owns and operates a pump hydro fleet consisting of 2,400 MW. The fleet consists of two pump storage plants: (1) Bad Creek at a 1,620 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates[22]. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions.

I. Demand Response Modeling

Demand response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints. For this study, 1,122 MW of summer capacity and 442 MW of winter capacity were included as shown in Table 8. To ensure these resources were called after conventional generation, a $2,000/MWh strike price was included.

[22] See Confidential Appendix Table CA4

Table 8. DEC Demand Response Modeling

Region	Program	Summer Capacity (MW)	Winter Capacity (MW)	Hours Per Year	Days Per Week	Hours Per Day
DEC	PowerShare Mandatory	355	331	150	7	24
DEC	PowerShare Generator	11	10	100	7	10
DEC	Power Manager DLC	608	0	100	7	10
DEC	IS	94	89	150	7	10
DEC	Energy Wise Business	46	4	60	7	4
DEC	SG	8	8	150	7	24
	Total DEC	1,122	442			

J. Operating Reserve Requirements

The operating reserves assumed for DEC are shown below. SERVM commits to this level of operating reserves in all hours. However, all operating reserves except for the 218 MW of regulation are allowed to be depleted during a firm load shed event.

- Regulation Up/Down: 218 MW
- Spinning Requirement: 275 MW
- Non-Spin Requirement: 275 MW
- Additional Load Following Due to Intermittent Resources in 2024: Hourly values were used based on a 12x24 profile provided by Duke Energy from its internal modeling.

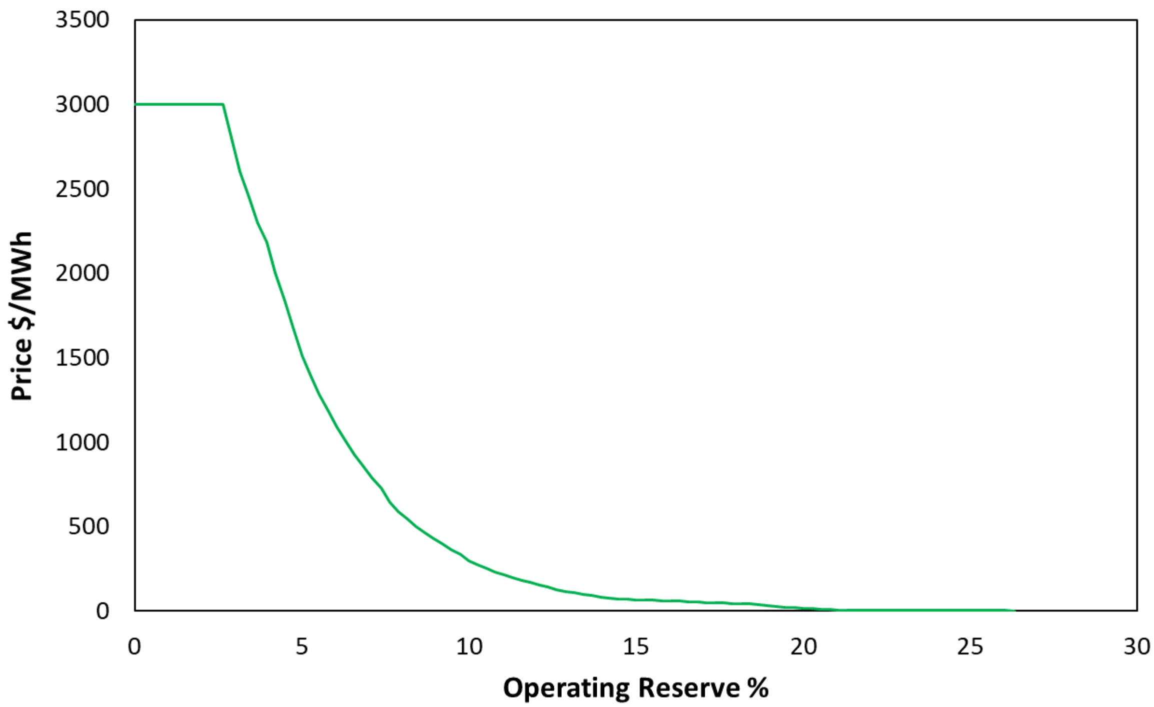
K. External Assistance Modeling

The external market plays a significant role in planning for resource adequacy. If several of the DEC resources were experiencing an outage at the same time, and DEC did not have access to surrounding markets, there is a high likelihood of unserved load. To capture a reasonable amount of assistance from surrounding neighbors, each neighbor was modeled at the one day in 10-year standard (LOLE of 0.1) level representing the target for many entities. By modeling in this manner, only weather diversity and generator outage diversity benefits are captured. The market representation used in SERVM is based on Astrapé's proprietary dataset which is developed based on FERC Forms, Energy Information Administration (EIA) Forms, and reviews of IRP information from neighboring regions. To ensure purchases in the model compared well in magnitude to historical data, the years 2015 and 2018 were simulated since they reflected cold weather years with high winter peaks. Figure CA4 in the confidential appendix shows that calibration with purchases on the y-axis and load on the x-axis for the 2015 and 2018 weather years. The actual purchases and modeled results show DEC purchases significant capacity during high load hours during these years.

The cost of transfers between regions is based on marginal costs. In cases where a region is short of resources, scarcity pricing is added to the marginal costs. As a region's hourly reserves approach zero, the scarcity pricing for that region increases. Figure 10 shows the scarcity pricing curve that was used in the simulations. It should be noted that the frequency of these scarcity prices is very low because in the majority of hours, there is plenty of capacity to meet load after the market has cleared[23].

[23]The market clearing algorithm within SERVM attempts to get all regions to the same price subject to transmission constraints. So, if a region's original price is $3,000/MWh based on the conditions and scarcity pricing in that region alone, it is highly probable that a surrounding region will provide enough capacity to that region to bring prices down to reasonable levels.

Figure 10. Operating Reserve Demand Curve (ORDC)



L. Cost of Unserved Energy

Unserved energy costs were derived from national studies completed for the Department of Energy (DOE) in 2003[24] and 2009[25], along with three other studies performed[26] previously by other consultants. The DOE studies were compilations of other surveys performed by utilities over the last two decades. All studies split the customer class categories into residential, commercial, and industrial. The values were then applied to the actual DEC customer class mix to develop a wide range of costs for unserved energy. Table 9 shows those results. Because expected unserved

[24] https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf
[25] https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf
[26] https://pdfs.semanticscholar.org/544b/d740304b64752b451d749221a00eede4c700.pdf Peter Cramton, Jeffrey Lien. Value of Lost Load. February 14, 2000.

energy costs are so low near the economic optimum reserve margin, this value, while high in magnitude, is not a significant driver in the economic analysis. Since the public estimates ranged significantly, DEC used $18,160/MWh for the Base Case in 2024, and sensitivities were performed around this value from $5,000 MWh to $25,000 MWh to understand the impact.

Table 9. Unserved Energy Costs / Value of Lost Load

	Weightings	2003 DOE Study 2024 $/kW-yr	2009 DOE Study 2024 $/kW-yr	Christiansen Associates 2024 $/kW-yr	Billinton and Wacker 2024 $/kW-yr	Karuiki and Allan 2024 $/kW-yr
Residential	36%	1.57	1.50	3.12	2.73	1.26
Commercial	37%	35.54	109.23	22.37	23.24	24.74
Industrial	26%	20.51	32.53	11.59	23.24	58.65
	Weighted Average $/kWh	19.25	49.96	12.54	15.78	25.08
	Average $/kWh	24.52				
	Average $/kWh excluding the 2009 DOE Study	18.16				

M. System Capacity Carrying Costs

The study assumes that the cheapest marginal resource is utilized to calculate the carrying cost of additional capacity. The cost of carrying incremental reserves was based on the capital and FOM of a new simple cycle natural gas Combustion Turbine (CT) consistent with the Company's IRP assumptions. For the study, the cost of each additional kW of reserves can be found in Confidential Appendix Table CA6. The additional CT units were forced to have a 5% EFOR in the simulations and used to vary reserve margin in the study.

IV. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. For DEC, SERVM utilized thirty-nine years of historical weather and load shapes, five points of economic load growth forecast error, and fifteen iterations of unit outage draws for each scenario to represent a distribution of realistic scenarios. The number of yearly simulation cases equals 39 weather years * 5 load forecast errors * 15 unit outage iterations = 2,925 total iterations for the Base Case. This Base Case, comprised of 2,925 total iterations, was re-run at different reserve margin levels by varying the amount of CT capacity.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 10. Each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 10. Case Probability Example

Weather Year	Weather Year Probability (%)	Load multipliers Due to Load Economic Forecast Error (%)	Load Economic Forecast Error Probability (%)	Case Probability (%)
1980	2.56	95.8	10	0.256
1980	2.56	97.3	25	0.64
1980	2.56	100	40	1.024
1980	2.56	102	15	0.384
1980	2.56	103.1	10	0.256
1981	2.56	95.8	10	0.256
1981	2.56	97.3	25	0.64
1981	2.56	100	40	1.024
1981	2.56	102	15	0.384
1981	2.56	103.1	10	0.256
1982	2.56	95.8	10	0.256

1982	2.56	97.3	25	0.64
1982	2.56	100	40	1.024
1982	2.56	102	15	0.384
1982	2.56	103.1	10	0.256
...	...	...	...	...
...	...	...	...	...
2018	2.56	103.1	10	0.256
			Total	100

For this study, LOLE is defined in number of days per year and is calculated for each of the 195 load cases and weighted based on probability. When counting LOLE events, only one event is counted per day even if an event occurs early in the day and then again later in the day. Across the industry, the traditional 1 day in 10 year LOLE standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year, and Expected Unserved Energy (EUE) in MWh.

Total system energy costs are defined as the following for each region:

$$Production\ Costs\ (Fuel\ Burn + Variable\ O\&M) +\ Purchase\ Costs - Sales\ Revenue \\ + Loss\ of\ Reserves +\ Cost\ of\ Unserved\ Energy$$

These components are calculated for each case and weighted based on probability to calculate total system energy costs for each scenario simulated. Loss of Reserves costs recognize the additional risk of depleting operating reserves and are costed out at the ORDC curve when they occur. As shown in the results these costs are almost negligible. The cost of unserved energy is simply the MWh of load shed multiplied by the value of lost load. System capacity costs are calculated separately outside of the SERVM model using the economic carrying cost of a new CT.

B. Reserve Margin Definition

For this study, winter and summer reserve margins are defined as the following:

- (Resources – Demand) / Demand
    - Demand is 50/50 peak forecast
    - Demand response programs are included as resources and not subtracted from demand
    - Solar capacity is counted at 1% capacity credit for winter reserve margin calculations, 37% for summer reserve margin calculations, and the small amount of battery capacity was counted at 80%.

As previously noted, the Base Case was simulated at different reserve margin levels by varying the amount of CT capacity in order to evaluate the impact of reserves on LOLE. In order to achieve lower reserve margin levels, capacity needed to be removed. For DEC, the Allen coal units were removed since they are scheduled to retire shortly after 2024 along with other CT capacity to achieve lower reserve margin levels. Table 11 shows a comparison of winter and summer reserve margin levels for the Base Case. As an example, when the winter reserve margin is 16%, the resulting summer reserve margin is 17.6% due to the 2,578 MW of solar on the system which provides greater summer capacity contribution.

Table 11. Relationship Between Winter and Summer Reserve Margin Levels

Winter	10.0%	12.0%	14.0%	16.0%	18.0%	20.0%
Corresponding Summer	12.4%	14.2%	15.9%	17.6%	19.4%	21.1%

V. Physical Reliability Results

Table 12 shows LOLE by month across a range of reserve margin levels for the Island Case. The analysis shows all of the LOLE falls in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in the Island scenario, a 22.5% winter reserve margin is required. This 22.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEC system. Given the significant solar on the system, the summer reserves are approximately 2% greater than winter reserves which results in essentially no reliability risk in the summer months when total LOLE is 0.1 days per year.

Table 12. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	12.4%	0.81	0.14	0.08	-	0.00	0.12	0.70	0.80	0.31	0.11	0.02	0.27	2.05	1.31	3.36
11.0%	13.3%	0.69	0.12	0.06	-	0.00	0.09	0.48	0.51	0.19	0.07	0.01	0.20	1.35	1.09	2.44
12.0%	14.2%	0.58	0.10	0.05	-	0.00	0.06	0.31	0.33	0.12	0.04	0.01	0.15	0.87	0.88	1.75
13.0%	15.0%	0.48	0.08	0.04	-	0.00	0.04	0.19	0.21	0.07	0.03	0.00	0.11	0.55	0.71	1.26
14.0%	15.9%	0.40	0.07	0.03	-	0.00	0.02	0.11	0.14	0.04	0.02	0.00	0.08	0.34	0.58	0.92
15.0%	16.8%	0.33	0.06	0.03	-	-	0.02	0.07	0.09	0.03	0.01	-	0.06	0.21	0.47	0.68
16.0%	17.6%	0.28	0.05	0.02	-	-	0.01	0.04	0.05	0.02	0.01	-	0.04	0.13	0.39	0.52
17.0%	18.5%	0.23	0.04	0.02	-	-	0.01	0.03	0.03	0.01	0.00	-	0.03	0.09	0.32	0.41
18.0%	19.4%	0.19	0.03	0.01	-	-	0.01	0.02	0.02	0.01	0.00	-	0.03	0.06	0.27	0.33
19.0%	20.2%	0.16	0.03	0.01	-	-	0.01	0.02	0.01	0.00	-	-	0.02	0.04	0.22	0.26
20.0%	21.1%	0.13	0.02	0.01	-	-	0.00	0.01	0.01	0.00	-	-	0.02	0.02	0.18	0.20
21.0%	22.0%	0.11	0.02	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.14	0.15
22.0%	22.8%	0.08	0.01	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.10	0.11
23.0%	23.7%	0.06	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.08	0.08
24.0%	24.6%	0.05	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.06	0.06

Table 13 shows LOLE by month across a range of reserve margin levels for the Base Case which assumes neighbor assistance. As in the Island scenario, all of the LOLE occurs in the winter when total LOLE is at 0.1 days per year showing the same increased risk in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in this scenario that includes market assistance, a 16.00% winter reserve margin is required.

Table 13. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
5.00%	8.11%	0.21	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.05	0.33	0.38
6.00%	8.97%	0.20	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.04	0.30	0.35
7.00%	9.84%	0.18	0.05	0.02	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.04	0.28	0.31
8.00%	10.71%	0.17	0.04	0.01	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.03	0.25	0.28
9.00%	11.57%	0.15	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03	0.03	0.23	0.25
10.00%	12.44%	0.14	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.21	0.23
11.00%	13.31%	0.13	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.18	0.20
12.00%	14.18%	0.11	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.16	0.18
13.00%	15.04%	0.10	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.15	0.15
14.00%	15.91%	0.09	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.13	0.13
15.00%	16.78%	0.08	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.12
16.00%	17.64%	0.07	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
17.00%	18.51%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
18.00%	19.38%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.07
19.00%	20.24%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.06
20.00%	21.11%	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05
21.00%	21.98%	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04
22.00%	22.84%	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03

Table 14 shows LOLE and other physical reliability metrics by reserve margin for the Base Case simulations. Loss of Load Hours (LOLH) is expressed in hours per year and Expected Unserved Energy (EUE) is expressed in MWh. The table shows that an 8% reserve margin results in an LOLH of 0.69 hours per year. Thus, to achieve 2.4 hours per year, which is far less stringent than the 1 day in 10 year standard (1 event in 10 years), DEC would require a reserve margin less than 8%. Astrapé does not recommend targeting a standard that allows for 2.4 hours of firm load shed every year as essentially would expect a firm load shed during peak periods ever year. The hours per event can be calculated by dividing LOLH by LOLE. The firm load shed events last approximately 2-3 hours on average. As these reserve margins decrease and firm load shed events increase, it is expected that reliance on external assistance, depletion of contingency reserves, and more demand response calls will occur and increase the overall reliability risk on the system.

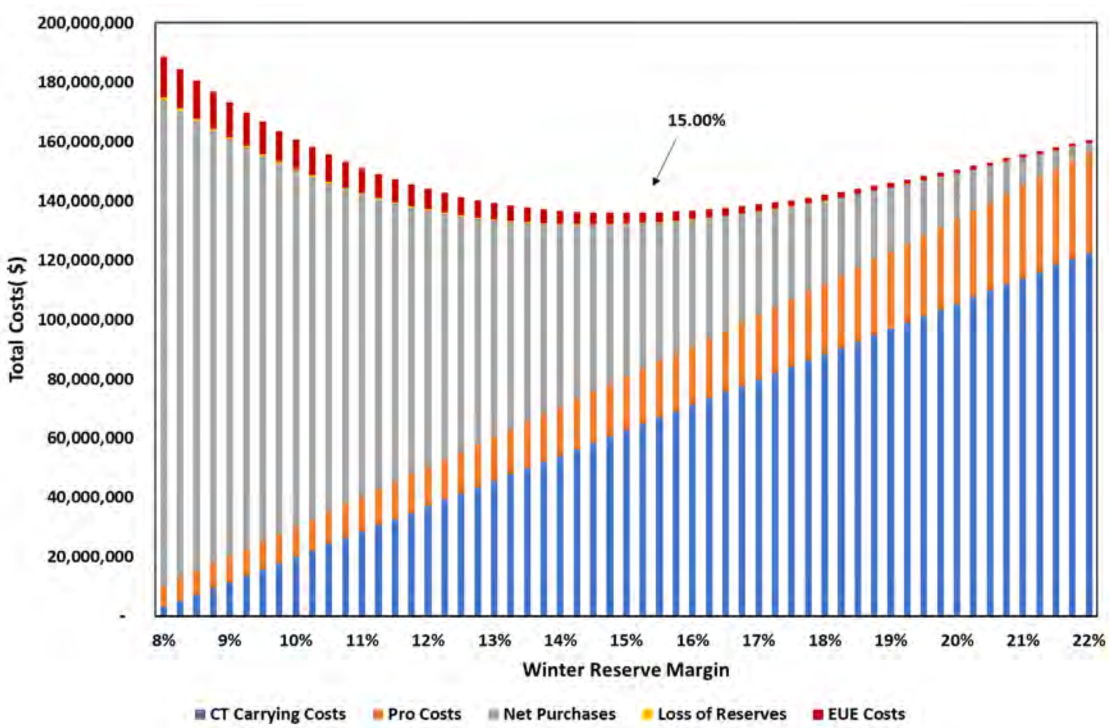
Table 14. Reliability Metrics: Base Case

Reserve Margin	LOLE	LOLH	EUE
%	Days Per Year	Hours Per Year	MWh
8.00%	0.28	0.69	748
8.50%	0.27	0.65	698
9.00%	0.25	0.61	650
9.50%	0.24	0.57	603
10.00%	0.23	0.54	559
10.50%	0.21	0.50	516
11.00%	0.20	0.47	475
11.50%	0.19	0.44	436
12.00%	0.18	0.41	399
12.50%	0.17	0.38	364
13.00%	0.16	0.35	330
13.50%	0.15	0.32	298
14.00%	0.14	0.29	268
14.50%	0.13	0.27	240
15.00%	0.12	0.25	214
15.50%	0.11	0.22	189
16.00%	0.10	0.20	167
16.50%	0.09	0.18	146
17.00%	0.08	0.17	127
17.50%	0.08	0.15	110
18.00%	0.07	0.13	94
18.50%	0.06	0.12	81
19.00%	0.06	0.11	69
19.50%	0.05	0.10	59
20.00%	0.05	0.09	51
20.50%	0.04	0.08	45
21.00%	0.04	0.07	40
21.50%	0.04	0.06	38
22.00%	0.03	0.06	37
22.50%	0.03	0.06	38
23.00%	0.03	0.05	41
23.50%	0.03	0.05	46
24.00%	0.02	0.05	52

VI. Base Case Economic Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs were analyzed across reserve margin levels for the Base Case. Figure 11 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and unit performance iterations at each reserve margin level and represents the expected value on a year in and year out basis.

Figure 11. Base Case Risk Neutral Economic Results[27]

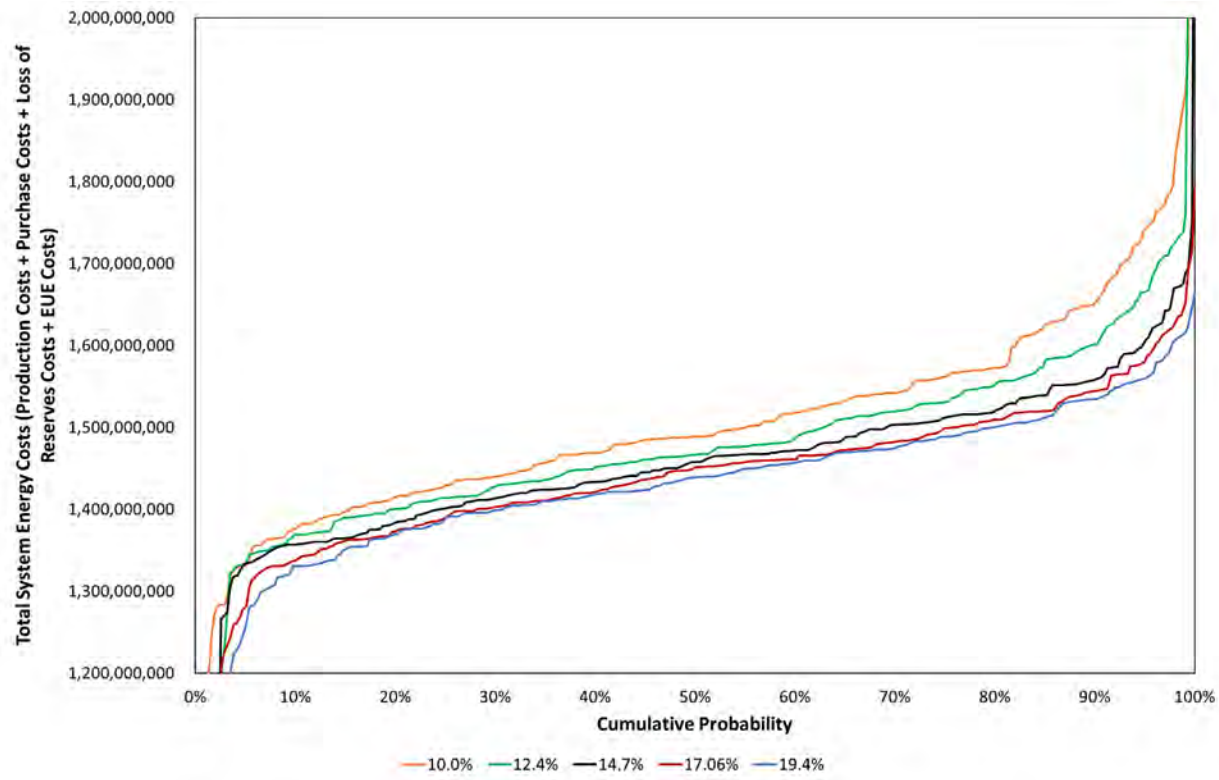


[27] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEC has approximately 1.5 billion dollars in total costs.

As Figure 11 shows, the lowest risk neutral cost falls at a 15.00% reserve margin very close to the one day in 10-year standard (LOLE of 0.1). These values are close because the summer reserve margins are only slightly higher than the winter reserve margins which increases the savings of adding additional CT capacity. The majority of the savings seen in adding additional capacity is recognized in the winter.[28] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there is always system energy cost savings from either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure 12, however, shows the distribution of system energy costs (production costs, purchase costs, loss of reserves costs, and the costs of EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margins to higher reserve margins, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

[28] As the DEC study shows, the lower DEC summer reserve margins increase the risk neutral economic reserve margin level compared to the DEP Study.

Figure 12. Cumulative Probability Curves



The next table shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure 11 as well as the energy savings at higher cumulative probability levels. As shown in the table, going from the risk neutral reserve margin of 15% to 17% increases customer costs on average by $2.9 million a year[29] and reduces LOLE from 0.12 to 0.08 events per year. The LOLE for the island scenario decreases from 0.68 days per year to 0.41 days per year. However, 10% of the time energy savings are greater than or equal to $21 million if a 17% reserve margin is maintained versus the 15% reserve margin. And 5 % of the time, $34 million or more is saved.

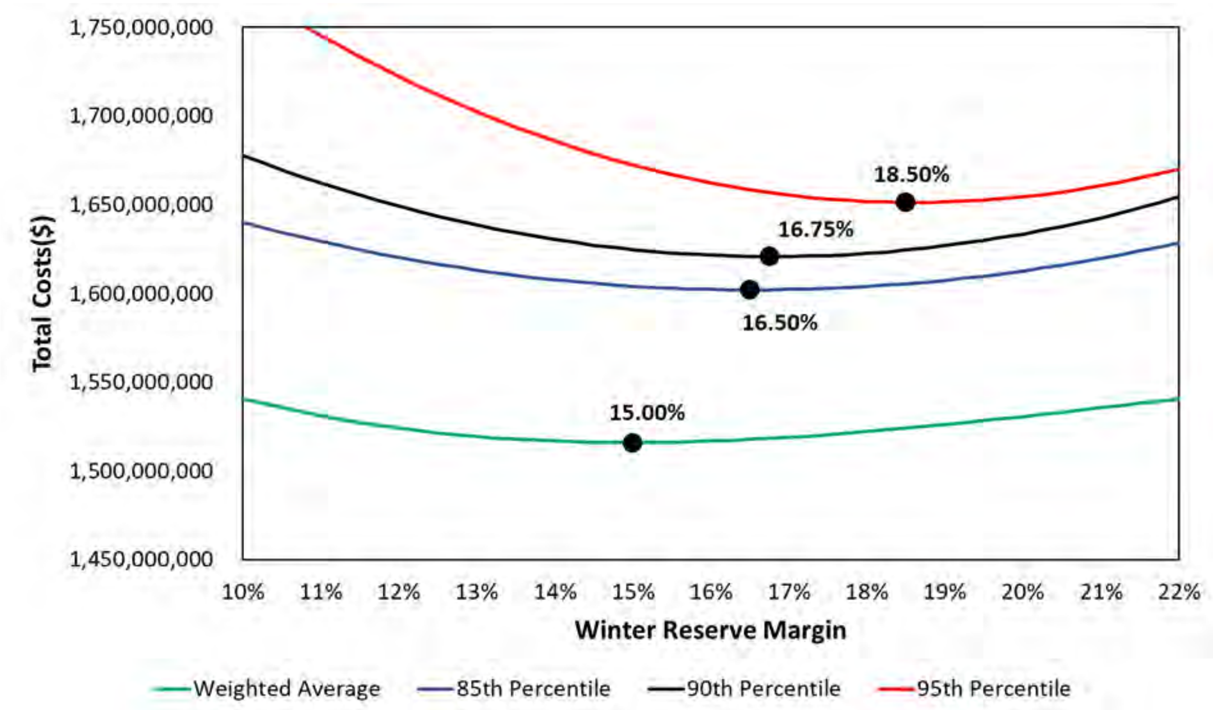
[29] This includes $17 million for CT costs and $14 million of system energy savings.

Table 15. Annual Customer Costs vs LOLE

Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
15.00%	-	-	-	-	-	-	0.12	0.68
16.00%	8.5	-7.8	0.8	-10.0	-11.7	-18.6	0.1	0.52
17.00%	17.1	-14.2	2.9	-19.0	-21.0	-34.0	0.08	0.41
18.00%	25.6	-19.5	6.1	-25.8	-27.8	-46.1	0.07	0.33
19.00%	34.2	-24.0	10.1	-30.8	-32.1	-55.0	0.06	0.26
20.00%	42.7	-28.0	14.7	-34.1	-33.9	-60.6	0.05	0.20

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure 12 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 15% reserve margin, the 85th to 95th percentile cost curves point to a 16-19% reserve margin.

Figure 13. Total System Costs by Reserve Margin



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEC is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

VII. Sensitivities

Several sensitivities were simulated in order to understand the effects of different assumptions on the 0.1 LOLE minimum winter reserve margin and to address questions and requests from stakeholders.

Outage Sensitivities

As previously noted, the Base Case included a total of 400 MW of cold weather outages between DEC and DEP below ten degrees Fahrenheit based on outage data for the period 2016-2019. Sensitivities were run to see the effect of two cold weather outage assumptions. The first assumed that the 400 MW of total outages between DEC and DEP below ten degrees Fahrenheit were removed. As Table 16 indicates, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is lowered by 1.25% from the Base Case to 14.75%. This shows that if the Company was able to eliminate all cold weather outage risk, it could carry up to a 1.25% lower reserve margin. However, Astrapé recognizes based on North American Electric Reliability Corporation (NERC) documentation across the industry[30] that outages during cold temperatures could be substantially more than the 400 MW being applied at less than 10 degrees in this modeling.

30 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdfvv (page 5)

https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

(beginning page 43)

Table 16. No Cold Weather Outage Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
No Cold Weather Outages	14.75%	14.75%	16.75%

The second outage sensitivity showed what the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) would need to be if cold weather outages were based solely on 2014-2019 historical data which increased the total MW of outages from 400 MW to 800 MW. Table 17 shows that the minimum reserve margin for 0.1 LOLE is 17.25 %.

Table 17. Cold Weather Outages Based on 2014-2019 Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Cold Weather Outages Based on 2014 - 2019	17.25%	15.00%	17.00%

Load Forecast Error Sensitivities

These sensitivities were run to see the effects of the Load Forecast Error (LFE) assumptions. In response to stakeholder feedback, an asymmetric LFE distribution was adopted in the Base Case which reflected a higher probability weighting on over-forecasting scenarios. In the first sensitivity, the LFE uncertainty was completely removed. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 0.25% to 16.25%. This demonstrates that the load forecast error assumed in the Base Case was reducing the target reserve margin levels since over-forecasting was more heavily weighted in the LFE distribution. Because of this result, Astrapé did not simulate additional sensitivities such as 2-year, 3-year, or 5-year LFE distributions.

Table 18. Remove LFE Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Remove LFE	16.25%	15.00%	16.00%

The second sensitivity removed the asymmetric Base Case distribution and replaced it with the originally proposed normal distribution. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 1.0% to 17.0%.

Table 19. Originally Proposed LFE Distribution Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Originally Proposed Normal Distribution	17.00%	16.00%	18.00%

Solar Sensitivities

The Base Case for DEC assumed that there was 2,578 MW of solar on the system. The first solar sensitivity decreased this number to 1,626 MW. This change in solar had no impact on the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as the results in Table 20 show because the capacity contribution of solar in the winter reserve margin calculation is 1%.

Table 20. Low Solar Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Low Solar	16.00%	16.00%	18.25%

The second solar sensitivity increased the amount of solar on the DEC system to 3,752 MW. This increase also had very little impact on the minimum reserve margins as Table 21 indicates. Both of these results are expected as solar provides almost no capacity value in the winter.

Table 21. High Solar Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
High Solar	15.75%	14.00%	14.50%

Demand Response (DR) Sensitivity

In this scenario, the winter demand response is increased to 1,122 MW to match the summer capacity. It is important to note that DR is counted as a resource in the reserve margin calculation similar to a conventional generator. Simply increasing DR to 1,122 MW results in a higher reserve margin and lower LOLE compared to the Base Case. Thus, CT capacity was adjusted (lowered) in the high DR sensitivity to maintain the same reserve margin level. Results showed that the 0.1 LOLE minimum reserve margin actually increased from 16.00% to 16.75% due to demand response's dispatch limits compared to a fully dispatchable traditional resource. DR may be an economic alternative to installing CT capacity, depending on market potential and cost. However, it should be noted that while Duke counts DR and conventional capacity as equivalent in load carrying capability in its IRP planning, the sensitivity results show that DR may have a slightly lower equivalent load carrying capability especially for programs with strict operational limits. The results are listed in Table 22 below.

Table 22. Demand Response Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Demand Response Winter as High as Summer	16.75%	18.25%	19.50%

No Coal Sensitivity

In this scenario, all coal units were replaced with CC/CT units. The CC units were modeled with a 4% EFOR and the CT units were modeled with a 5% EFOR. Due to the high EFOR's of the DEC coal units, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) decreased slightly as shown in Table 23 below.

Table 23. No Coal Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Retire all Coal	15.25%	17.00%	20.25%

Climate Change Sensitivity

In this scenario, the loads were adjusted to reflect the temperature increase outlined in the National Oceanic and Atmospheric Administration (NOAA) Climate Change Analysis[31]. Based on NOAA's research, temperatures since 1981 have increased at an average rate of 0.32 degrees Fahrenheit per decade. Each synthetic load shape was increased to reflect the increase in temperature it would see to meet the 2024 Study Year. For example, 1980 has a 1.4 degree increase ($0.32 \frac{°\mathrm{F}}{Decade} * \frac{1\,Decade}{10\,Year} * 44\,Years$). After the loads were adjusted, the analysis was rerun. The summer peaks saw an increase and the winter peaks especially in earlier weather years saw a decrease. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is reduced to 16.00% from 15.75% in the Base Case under these assumptions. The results are listed in the table below.

Table 24. Climate Change Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Climate Change	15.75%	14.25%	16.75%

[31] https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature

VIII. Economic Sensitivities

Table 25 shows the economic results if the cost of unserved energy is varied from $5,000/MWh to $25,000/MWh and the cost of incremental capacity is varied from $40/kW-yr to $60/kW-yr. As CT costs decrease, the economic reserve margin increases and as CT costs increase, the economic reserve margin decreases. The opposite occurs with the cost of EUE. The higher the cost of EUE, the higher the economic target.

Table 25. Economic Sensitivities

	Economics	
Sensitivity	**Weighted Average (risk neutral)**	**90th %**
Base Case	15.00%	16.75%
CT costs $40kW-yr	16.00%	17.25%
CT costs $60/kW-yr	13.75%	16.00%
EUE 5,000 $/MWh	14.50%	16.25%
EUE 25,000 $/MWh	15.25%	16.75%

IX. DEC/DEP Combined Sensitivity

A set of sensitivities was performed which assumed DEC, DEP-E, and DEP-W were dispatched together and all reserves were calculated as a single company across the three regions. In these scenarios, all resources down to the firm load shed point can be utilized to assist each other and there is a priority in assisting each other before assisting an outside neighbor. The following three scenarios were simulated for the Combined Case and their results are listed in the table below:

1) Combined-Base

2) Combined Target 1,500 MW Import Limit- This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[32].

3) Combined-Remove LFE

As shown in the table below, the combined target scenario yielded a 0.1 LOLE reserve margin of 16.75% (based on DEC and DEP coincident peak).

Table 26. Combined Case Results

	LOLE	Economics	
Sensitivity	1 in 10	weighted avg (risk neutral)	90th %
Base Case	19.25%	10.25%	17.50%
Combined Target	16.75%	17.00%	17.75%
Combined Target 1,500 MW Import Limit	18.00%	17.25%	18.25%
Combined Target - Remove LFE	17.25%	17.00%	18.25%

[32] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

X. Conclusions

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEP Study, Astrapé recommends that DEC continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEC utility would require a 22.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and even with market assistance, DEC would need to maintain a 16.00% reserve margin. However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 19.25% reserve margin required by DEP to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increases the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEC will never be forced to shed firm load during extreme conditions as DEC and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEC has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. If not for non-firm external assistance which this study considers, firm load would have been shed. In addition, it is not possible to capture all tail end risk that could occur from a reliability perspective. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 15% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEC resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEC should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEC observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[33]

[33] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

XI. Appendix A

Table A.1 Base Case Assumptions and Sensitivities

Assumption	Base Case Value	Sensitivity	Comments
Weather Years	1980-2018		Based on the historical data, the 1980 - 2018 period aligns well with the last 100 years. Shorter time periods do not capture the distribution of extreme days seen in history.
Synthetic Loads and Load Shapes	As Documented in 2-21-20 Presentation	Impact of Climate Change on synthetic load shapes and peak load forecast	Note: This is a rather complex sensitivity and the ability to capture the impact of climate change may be difficult. We would appreciate input and suggestions from other parties on developing an approach to capture the potential impacts of climate change on resource adequacy planning.
LFE	Use an asymmetrical distribution. Use full LFE impact in years 4 and beyond. Recognize reduced LFE impacts in years 1-3.	1,2,3,5 year ahead forecast error	
Unit Outages	As Documented in 2-21-20 Presentation		
Cold Weather Outages	Moderate Cold Weather Outages: Capture Incremental Outages at temps less than 10 degrees based on the 2016 - 2018 dataset (~400 MW total across the DEC and DEP for all temperature below 10 degree. This will be applied on a peak load ratio basis) For Neighboring regions, the same ratio of cold weather outages to peak load will be applied.	2 Sensitivities: (1) Remove cold weather outages (2) Include cold weather outages based on 2014 -2018 dataset	The DEC and DEP historical data shows that during extreme cold temperatures it is likely to experience an increase in generator forced outages; this is consistent with NERC's research across the industry. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf - page 5 https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf - beginning on pg 43
Hydro/Pumped Storage	As Documented in 2-21-20 Presentation		
Solar	As Documented in 2-21-20 Presentation		
Demand Response	As Documented in 2-21-20 Presentation	Sensitivity increasing winter DR	
Neighbor Assistance	As Documented in 2-21-20 Presentation	Island Sensitivity	Provide summary of market assistance during EUE hours; transmission versus capacity limited.
Operating Reserves	As Documented in 2-21-20 Presentation		
CT costs/ORDC/VOLL	As Documented in 2-21-20 Presentation	Low and High Sensitivities for each	
Study Topology	Determine separate DEC and DEP reserve margin targets	Combined DEC/DEP target	A simulation will be performed which assumes DEC, DEP-E and DEP-W are dispatched together and reserves are calculated as a single company across the three regions.

XII. Appendix B

Table B.1 Percentage of Loss of Load by Month and Hour of Day for the Base Case

	Month											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	0.16%	0.16%	-	-	-	-	-	-	-	-	-	-
5	0.98%	0.49%	-	-	-	-	-	-	-	-	-	-
6	4.43%	1.48%	-	-	-	-	-	-	-	-	-	-
7	16.56%	5.74%	-	-	-	-	-	-	-	-	-	0.33%
8	32.79%	7.87%	-	-	-	-	-	-	-	-	-	2.62%
9	15.57%	0.82%	-	-	-	-	-	-	-	-	-	0.16%
10	4.43%	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	0.16%	-	-	-	-
18	-	-	-	-	-	-	0.33%	0.98%	-	-	-	-
19	-	-	-	-	-	-	0.49%	1.15%	-	-	-	-
20	-	-	-	-	-	-	0.16%	0.33%	-	-	-	-
21	-	-	-	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-
Sum	74.92%	16.56%	1.80%	-	-	-	0.98%	2.62%	-	-	-	3.11%

Duke Energy Progress

2020 Resource Adequacy Study

9/1/2020

PREPARED FOR

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Executive Summary

This study was performed by Astrapé Consulting at the request of Duke Energy Progress (DEP) as an update to the study performed in 2016. The primary purpose of this study is to provide Duke system planners with information on physical reliability and costs that could be expected with various reserve margin[1] planning targets. Physical reliability refers to the frequency of firm load shed events and is calculated using Loss of Load Expectation (LOLE). The one day in 10-year standard (LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed every 10 years due to a shortage of generating capacity and is used across the industry[2] to set minimum target reserve margin levels. Astrapé determined the reserve margin required to meet the one day in 10-year standard for the Base Case and multiple sensitivities included in the study. The study includes a Confidential Appendix containing confidential information such as fuel costs, outage rate data and transmission assumptions.

Customers expect to have electricity during all times of the year but especially during extreme weather conditions such as cold winter days when resource adequacy[3] is at risk for DEP[4] . In

[1] Throughout this report, winter and summer reserve margins are defined by the formula: (installed capacity - peak load) / peak load. Installed capacity includes capacity value for intermittent resources such as solar and energy limited resources such as battery.

[2] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf; See Table 14 in A-1. PJM, MISO, NYISO ISO-NE, Quebec, IESO, FRCC, APS, NV Energy all use the 1 day in 10 year standard. As of this report, it is Astrapé's understanding that Southern Company has shifted to the greater of the economic reserve margin or the 1 day in 10 year standard.

[3] NERC RAPA Definition of "Adequacy" - The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components.

[4] Section (b)(4)(iv) of NCUC Rule R8-61 (Certificate of Public Convenience and Necessity for Construction of Electric Generation Facilities) requires the utility to provide "… a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located."

order to ensure reliability during these peak periods, DEP maintains a minimum reserve margin level to manage unexpected conditions including extreme weather, load growth, and significant forced outages. To understand this risk, a wide distribution of possible scenarios must be simulated at a range of reserve margins. To calculate physical reliability and customer costs for the DEP system, Astrapé Consulting utilized a reliability model called SERVM (Strategic Energy and Risk Valuation Model) to perform thousands of hourly simulations for the 2024 study year at various reserve margin levels. Each of the yearly simulations was developed through a combination of deterministic and stochastic modeling of the uncertainty of weather, economic growth, unit availability, and neighbor assistance.

In the 2016 study, reliability risk was concentrated in the winter and the study determined that a 17.5% reserve margin was required to meet the one day in 10-year standard (LOLE of 0.1), for DEP. Because DEP's sister utility DEC required a 16.5% reserve margin to meet the same reliability standard, Duke Energy averaged the studies and used a 17% planning reserve margin target for both companies in its Integrated Resource Plan (IRP). This 2020 Study updates all input assumptions to reassess resource adequacy. As part of the update, several stakeholder meetings occurred to discuss inputs, methodology, and results. These stakeholder meetings included representatives from the North Carolina Public Staff, the South Carolina Office of Regulatory Staff (ORS), and the North Carolina Attorney General's Office. Following the initial meeting with stakeholders on February 21, 2020, the parties agreed to the key assumptions and sensitivities listed in Appendix A, Table A.1.

Preliminary results were presented to the stakeholders on May 8, 2020 and additional follow up was done throughout the month of May. Moving from the 2016 Study, the Study Year was shifted from 2019 to 2024 and assumed solar capacity was updated to the most recent projections. Because solar projections increased, LOLE has continued to shift from the summer to the winter. The high volatility in peak winter loads seen in the 2016 Study remained evident in recent historical data. In response to stakeholder feedback, the four year ahead economic load forecast error was dampened by providing a higher probability weighting on over-forecasting scenarios relative to under-forecasting scenarios. The net effect of the new distribution is to slightly reduce the target reserve margin compared to the previous distribution supplying slight upward pressure on the target reserve margin. This means that if the target reserve margin from this study is adopted, no reserves would be held for potential under-forecast of load growth. Generator outages remained in line with 2016 expectations, but additional cold weather outages of 140 MW for DEP were included for temperatures less than 10 degrees.

Physical Reliability Results-Island

Table ES1 shows the monthly contribution of LOLE at various reserve margin levels for the Island scenario. In this scenario, it is assumed that DEP is responsible for its own load and that there is no assistance from neighboring utilities. The summer and winter reserve margins differ for all scenarios due to seasonal demand forecast differences, weather-related thermal generation capacity differences, demand response seasonal availability, and seasonal solar capacity value. Using the one day in 10-year standard (LOLE of 0.1), which is used across the industry to set minimum target reserve margin levels, DEP would require a 25.5% winter reserve margin in the Island Case where no assistance from neighboring systems was assumed.

Given the significant level of solar on the system, the summer reserves are approximately 12% greater than winter reserves which results in no reliability risk in the summer months. This 25.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEP system. As discussed below, when compared to Base Case results which recognizes neighbor assistance, results of the Island Case illustrate both the benefits and risks of carrying lower reserve margins through reliance on neighboring systems.

Table ES1. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	22.3%	0.43	0.09	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.70	0.71
11.0%	23.2%	0.37	0.08	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.61	0.62
12.0%	24.2%	0.32	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.53	0.54
13.0%	25.2%	0.28	0.06	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.47	0.47
14.0%	26.2%	0.25	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.41	0.41
15.0%	27.2%	0.21	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.35	0.36
16.0%	28.2%	0.19	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.31	0.31
17.0%	29.1%	0.17	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.28	0.28
18.0%	30.1%	0.15	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.25	0.25
19.0%	31.1%	0.13	0.04	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.22	0.22
20.0%	32.1%	0.12	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.20	0.20
21.0%	33.1%	0.11	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.18	0.18
22.0%	34.1%	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.16	0.16
23.0%	35.1%	0.09	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.14	0.14
24.0%	36.0%	0.08	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.12	0.12
25.0%	37.0%	0.07	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.11
26.0%	38.0%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.10	0.10

Physical Reliability Results-Base Case

Astrapé recognizes that DEP is part of the larger eastern interconnection and models neighbors one tie away to allow for market assistance during peak load periods. However, it is important to also understand that there is risk in relying on neighboring capacity that is less dependable than owned or contracted generation in which DEP would have first call rights. While there are certainly advantages of being interconnected due to weather diversity and generator outage diversity across regions, market assistance is not guaranteed and Astrapé believes Duke Energy has taken a moderate to aggressive approach (i.e. taking significant credit for neighboring regions) to modeling neighboring assistance compared to other surrounding entities such as PJM Interconnection L.L.C. (PJM)[5] and the Midcontinent Independent System Operator (MISO)[6]. A full description of the market assistance modeling and topology is available in the body of the report. Table ES2 shows the monthly LOLE at various reserve margin levels for the Base Case scenario which is the Island scenario with neighbor assistance included[7].

[5] PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin compared to 6.25% assumed for DEP. https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx – page 11

[6] MISO limits external assistance to a Unforced Capacity (UCAP) of 2,331 MW which represents approximately 1.8% of its reserve margin compared to 6.25% assumed for DEP. https://www.misoenergy.org/api/documents/getbymediaid/80578 page 24 (copy and paste link in browser)

[7] Reference Appendix B, Table B.1 for percentage of loss of load by month and hour of day for the Base Case.

Table ES2. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	22.3%	0.14	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.23	0.23
11.0%	23.2%	0.13	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.21	0.21
12.0%	24.2%	0.12	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.19	0.19
13.0%	25.2%	0.11	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.18	0.18
14.0%	26.2%	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.16	0.16
15.0%	27.2%	0.09	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.15	0.15
16.0%	28.2%	0.08	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.13	0.13
17.0%	29.1%	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.12	0.12
18.0%	30.1%	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.11
19.0%	31.1%	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
20.0%	32.1%	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
21.0%	33.1%	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
22.0%	34.1%	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08

As the table indicates, the required reserve margin to meet the one day in 10-year standard (LOLE of 0.1), is 19.25% which is 6.25% lower than the required reserve margin for 0.1 LOLE in the Island scenario. Approximately one fourth of the 25.5% required reserves is reduced due to interconnection ties. Astrapé also notes utilities around the country are continuing to retire and replace fossil-fuel resources with more intermittent or energy limited resources such as solar, wind, and battery capacity. For example, Dominion Energy Virginia has made substantial changes to its plans as this study was being conducted and plans to add substantial solar and other renewables to its system that could cause additional winter reliability stress than what is modeled. The below excerpt is from page 6 of Dominion Energy Virginia's 2020 IRP[8]:

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[9] While this is only one example, these potential changes to surrounding resource mixes may lead to less confidence in market assistance for the future during early morning winter peak loads. Changes in neighboring system resource portfolios and load profiles will be an important consideration in future resource adequacy studies. To the extent historic diversification between DEP and neighboring systems declines, the historic reliability benefits DEP has experienced from being an interconnected system will also decline. It is worth nothing that after this study was completed, California experienced rolling blackouts during extreme weather conditions as the ability to rely on imported power has declined and has shifted away from dispatchable fossil-fuel resources and put greater reliance on intermittent resources.[10] It is premature to fully ascertain the lessons learned from the California load shed events. However, it does highlight the fact that as DEP reduces dependence on

[8] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509

[9] Dominion Energy Virginia 2020 IRP, at 40.

[10] http://www.caiso.com/Documents/ISO-Stage-3-Emergency-Declaration-Lifted-Power-Restored-Statewide.pdf

dispatchable fossil fuels and increases dependence on intermittent resources, it is important to ensure it is done in a manner that does not impact reliability to customers.

Physical Reliability Results-DEP/DEC Combined Case

In addition to running the Island and Base Case scenarios, a DEP and DEC Combined Case scenario was simulated to see the reliability impact of DEP and DEC as a single balancing authority. In this scenario, DEC and DEP prioritize helping each other over their other external neighbors but also retain access to external market assistance. The various reserve margin levels are calculated as the total resources in both DEC and DEP using the combined coincident peak load, and reserve margins are increased together for the combined utilities. Table ES3 shows the results of the Combined Case which shows that a 16.75% combined reserve margin is needed to meet the 1 day in 10-year standard. An additional Combined Case sensitivity was simulated to assess the impact of a more constrained import limit. This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[11] resulting in an increase in the reserve margin from 16.75% to 18.0%.

Table ES3. Combined Case Physical Reliability Results

Sensitivity	1 in 10 LOLE Reserve Margin
Base Case	19.25%
Combined Target	16.75%
Combined Target 1,500 MW Import Limit	18.00%

[11] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

Results for the Combined Case and the individual Base Cases are outlined in the table below. The DEC results are documented in a separate report but show that a 16.0% reserve margin is required to meet the one day in 10-year standard (LOLE of 0.1).

Table ES4. Combined Case Differences

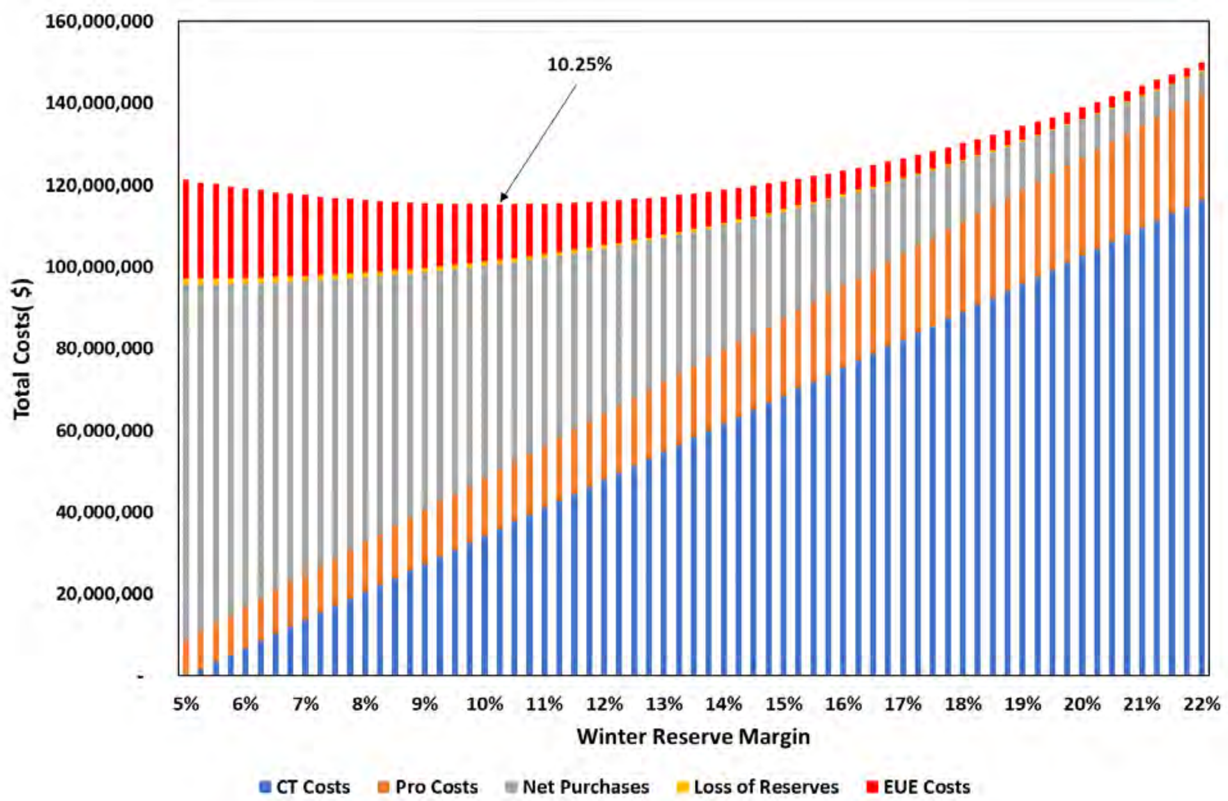
Region	1 in 10 LOLE Reserve Margin
DEC	16.00%
DEP	19.25%
Combined (Coincident)	16.75%

Economic Reliability Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs[12] were analyzed across reserve margin levels for the Base Case. Figure ES1 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and unit performance iterations at each reserve margin level and represents the yearly expected value on a year in and year out basis.

[12] System costs = system energy costs plus capacity costs of incremental reserves. System energy costs include production costs + net purchases + loss of reserves costs + unserved energy costs while system capacity costs include the fixed capital and fixed Operations and Maintenance (FOM) for CT capacity. Unserved energy costs equal the value of lost load times the expected unserved energy.

Figure ES1. Base Case Risk Neutral Economic Results[13]



As Figure ES1 shows, the lowest risk neutral cost falls at a 10.25% reserve margin. The reason this risk neutral reserve margin is significantly lower than 19.25% reserve margin required to meet the one day in 10-year standard (LOLE of 0.1) is due to high reserve margins in the summer. The majority of the economic benefit of additional capacity is recognized in the winter which generally has shorter duration high load periods.[14] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there are system energy cost savings from either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate

[13] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEP has approximately 1 billion dollars in total costs.
[14] As the DEC study shows, the lower DEC summer reserve margins increase the risk neutral economic reserve margin level compared to the DEP Study.

the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure ES2, however, shows the distribution of system energy costs which includes production costs, purchase costs, loss of reserves costs, and the costs of expected unserved energy (EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margins to higher reserve margins, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

Figure ES2. System Energy Costs (Cumulative Probability Curves)

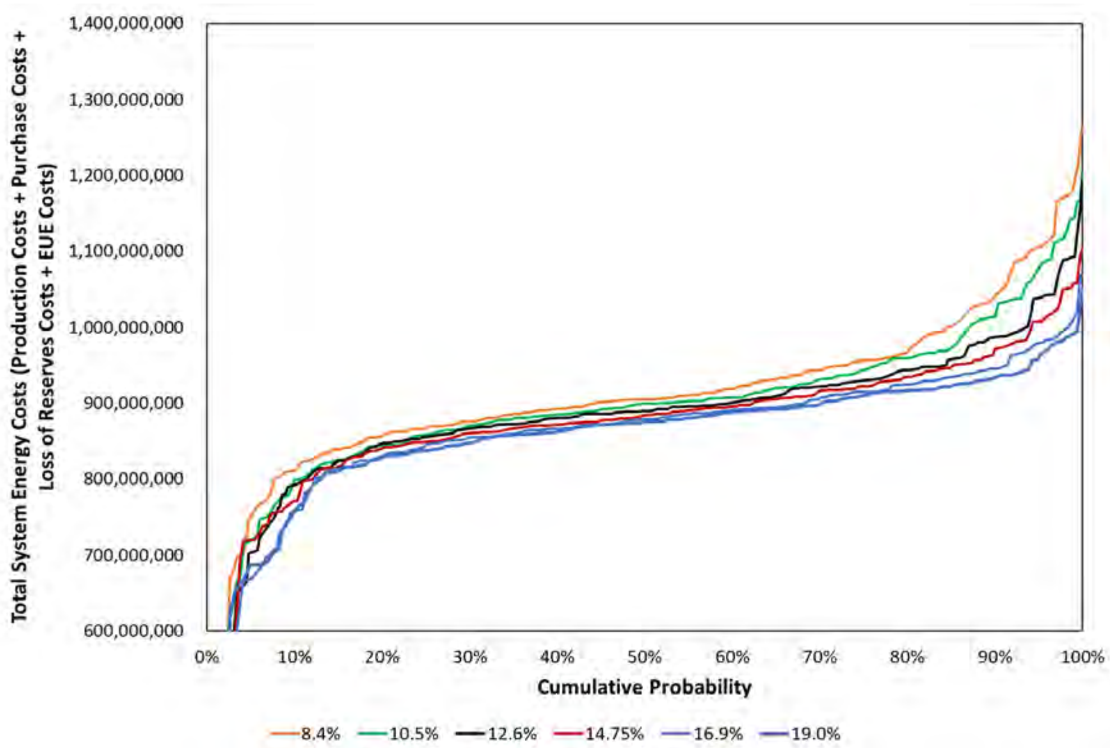


Table ES5 shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure ES1 as well as the energy savings at higher cumulative probability levels from

Figure ES2. As shown in the table, going from the risk neutral reserve margin of 10.25% to 17%, customer costs on average increase by $11 million a year[15] and LOLE is reduced from 0.23 to 0.12 events per year. The LOLE for the island scenario decreases from 0.71 days per year to 0.28 days per year. However, 10% of the time energy savings are greater than or equal to $67 million if a 17% reserve margin is maintained versus the 10.25% reserve margin. While 5% of the time, $101 million or more is saved.

Table ES5. Annual Customer Costs vs LOLE

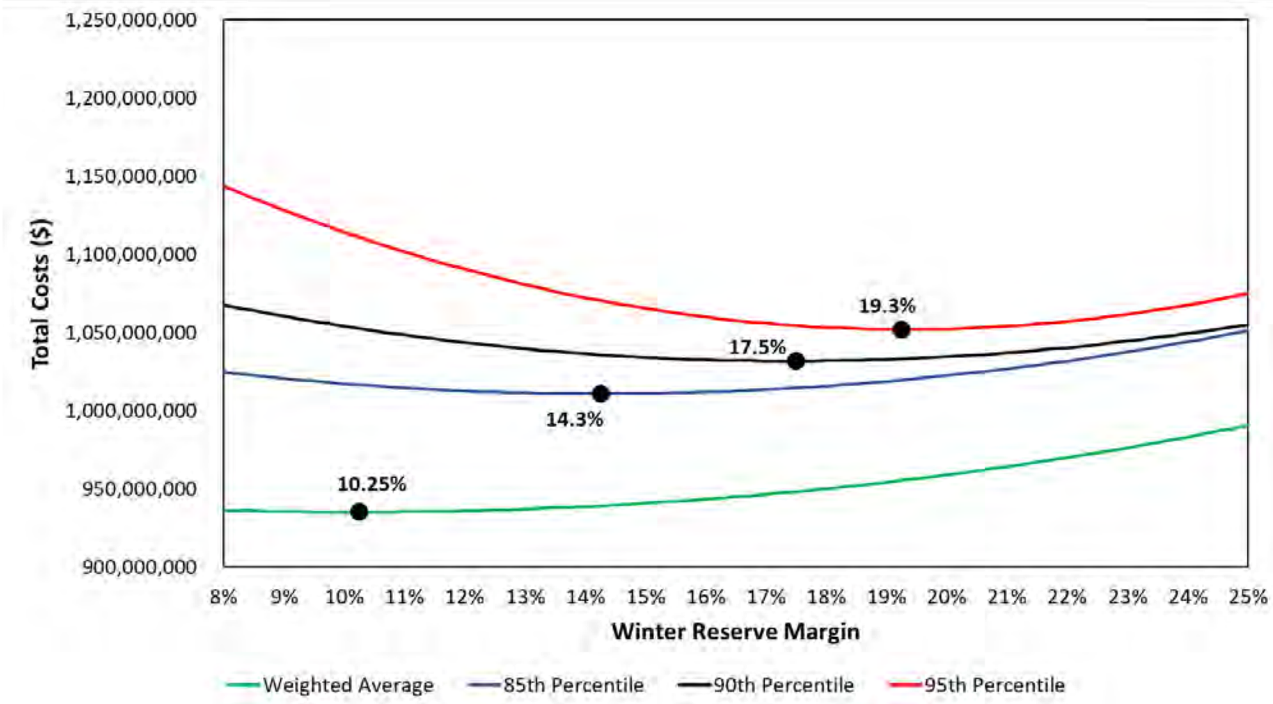
Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
10.25%	-	-	-	-	-	-	0.23	0.71
11.00%	5.1	-5.0	0.2	-7.1	-9.3	-14.5	0.21	0.62
12.00%	12.0	-11.2	0.8	-15.9	-20.9	-32.5	0.19	0.54
13.00%	18.8	-16.9	1.9	-24.0	-31.8	-49.1	0.18	0.47
14.00%	25.7	-22.2	3.5	-31.4	-41.8	-64.3	0.16	0.41
15.00%	32.5	-26.9	5.6	-38.0	-51.0	-78.0	0.15	0.36
16.00%	39.4	-31.2	8.2	-44.0	-59.4	-90.3	0.13	0.31
17.00%	46.2	-34.9	11.3	-49.3	-67.0	-101.2	0.12	0.28
18.00%	53.1	-38.1	14.9	-53.9	-73.7	-110.7	0.11	0.25
19.00%	59.9	-40.8	19.1	-57.8	-79.7	-118.7	0.1	0.22
20.00%	66.7	-43.0	23.8	-61.0	-84.8	-125.3	0.09	0.2

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure ES2 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher

[15] This includes $46 million for additional CT costs less $35 million of system energy savings.

cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 10.25% reserve margin, the 85th to 95th percentile cost curves point to a 14-19% reserve margin.

Figure ES3. Total System Costs by Reserve Margin



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEP is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

Sensitivity Results

Various sensitivities were run in addition to the Base Case to examine the reliability and cost impact of different assumptions and scenarios. Table ES6 lists the various sensitivities and the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as well as economic results of each. These include sensitivities around cold weather generator outages, load forecast error uncertainty, solar penetration, the cost of unserved energy, the cost of CT capacity, demand response, coal retirements, and climate change. Detailed explanations of each sensitivity are available in the body of the report. The target reserve margin to meet the one day in 10-year standard (LOLE of 0.1) ranged from 18.50% to 20.50% depending on the sensitivity simulated.

Table ES6. Sensitivity Results

Sensitivity	1 in 10 LOLE Reserve Margin	Economic Risk Neutral	Economic 90th Percentile
Base Case	19.25%	10.25%	17.50%
No Cold Weather Outages	18.50%	9.50%	16.25%
Cold Weather Outages based on 2014 - 2019	20.50%	10.50%	17.75%
Remove LFE	20.00%	10.50%	17.50%
Originally Proposed Normal Distribution	20.25%	11.25%	17.50%
Low Solar	19.25%	11.75%	17.50%
High Solar	19.00%	9.50%	16.75%
CT costs 40 $/kW-yr	19.25%	12.50%	18.75%
CT costs 60 $/kW-yr	19.25%	6.00%	15.25%
EUE 5,000 $/MWh	19.25%	7.00%	13.75%
EUE 25,000 $/MWh	19.25%	11.75%	19.25%
Demand Response Winter as High as Summer	20.00%	12.50%	18.50%
Retire all Coal	19.50%	11.25%	17.50%
Climate Change	18.50%	9.75%	16.25%

Recommendation

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEC Study, Astrapé recommends that DEP continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEP utility would require a 25.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and even with market assistance, DEP would need to maintain a 19.25% reserve margin. Customers expect electricity during extreme hot and cold weather conditions and maintaining a 17% reserve margin is estimated to provide an LOLE of 0.12 events per year which is slightly less reliable than the one day in 10-year standard (LOLE of 0.1). However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 16% reserve margin required by DEC to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increase the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEP will never be forced to shed firm load during extreme conditions as DEP and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEP has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. If not for non-firm external assistance, which this study considers, firm load would have been shed. In addition, incorporation of tail end reliability risk in modeling should be from statistically and historically defendable methods; not from including subjective risks that cannot be assigned probability. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 10.25% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEP resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEP should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEP observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and in future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[16]

[16] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

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III. Input Assumptions

A. Study Year

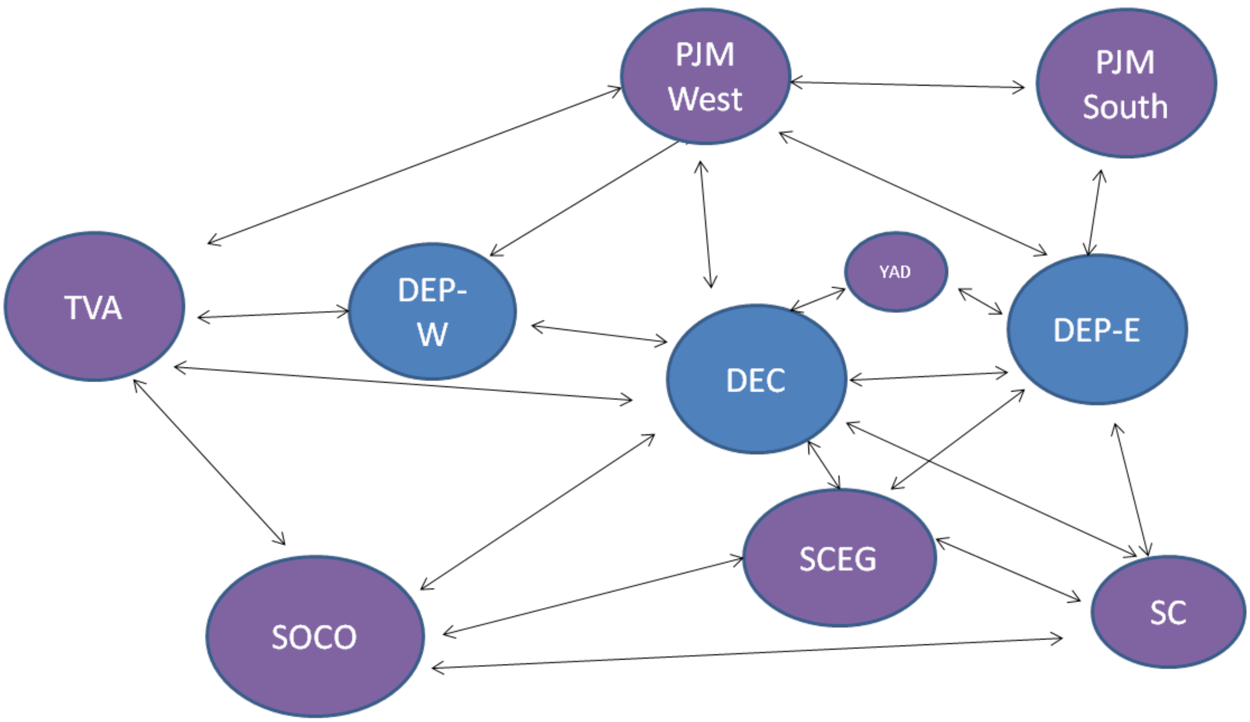
The selected study year is 2024[17]. The SERVM simulation results are broadly applicable to future years assuming that resource mixes and market structures do not change in a manner that shifts the reliability risk to a different season or different time of day.

B. Study Topology

Figure 1 shows the study topology that was used for the Resource Adequacy Study. DEP was modeled in two interconnect zones: (1) DEP – E and (2) DEP – W. While market assistance is not as dependable as resources that are utility owned or have firm contracts, Astrapé believes it is appropriate to capture the load diversity and generator outage diversity that DEP has with its neighbors. For this study, the DEP system was modeled with eight surrounding regions. The surrounding regions captured in the modeling included Duke Energy Carolinas (DEC), Tennessee Valley Authority (TVA), Southern Company (SOCO), PJM West & PJM South, Yadkin (YAD), Dominion Energy South Carolina (formally known as South Carolina Electric & Gas (SCEG)), and Santee Cooper (SC). SERVM uses a pipe and bubble representation in which energy can be shared based on economics but subject to transmission constraints.

[17] The year 2024 was chosen because it is four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility.

Figure 1. Study Topology



Confidential Appendix Table CA1 displays the DEP import capability from surrounding regions including the amount set aside for Transmission Reliability Margin (TRM).

C. Load Modeling

Table 1 displays SERVM's modeled seasonal peak forecast net of energy efficiency programs for 2024.

Table 1. 2024 Forecast: DEP Seasonal Peak (MW)

	DEP-E Non-Coincident	DEP-W Non-Coincident	Combined Coincident
2024 Summer	12,227	879	13,042
2024 Winter	13,390	1,175	14,431

To model the effects of weather uncertainty, thirty-nine historical weather years (1980 - 2018) were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load[18], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from five weather stations across the DEP service territory. The weather stations included Raleigh, NC, Wilmington, NC, Fayetteville, NC, Asheville, NC, and Columbia, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last thirty-nine years of weather to develop thirty-nine synthetic load shapes for 2024. Equal probabilities were given to each of the thirty-nine load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Company's projected thirty-year weather normal load forecast for 2024.

Figures 2 and 3 show the results of the 2014-2019 weather load modeling by displaying the peak load variance for both the summer and winter seasons. The y-axis represents the percentage

[18] The historical load included years 2014 through September of 2019.

deviation from the average peak. For example, the 1985 synthetic load shape would result in a summer peak load approximately 4.7% below normal and a winter peak load approximately 21.1% above normal. Thus, the bars represent the variance in projected peak loads based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. As an example, extreme cold temperatures can cause load to spike from additional electric strip heating. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation.

Figure 2. DEP Summer Peak Weather Variability

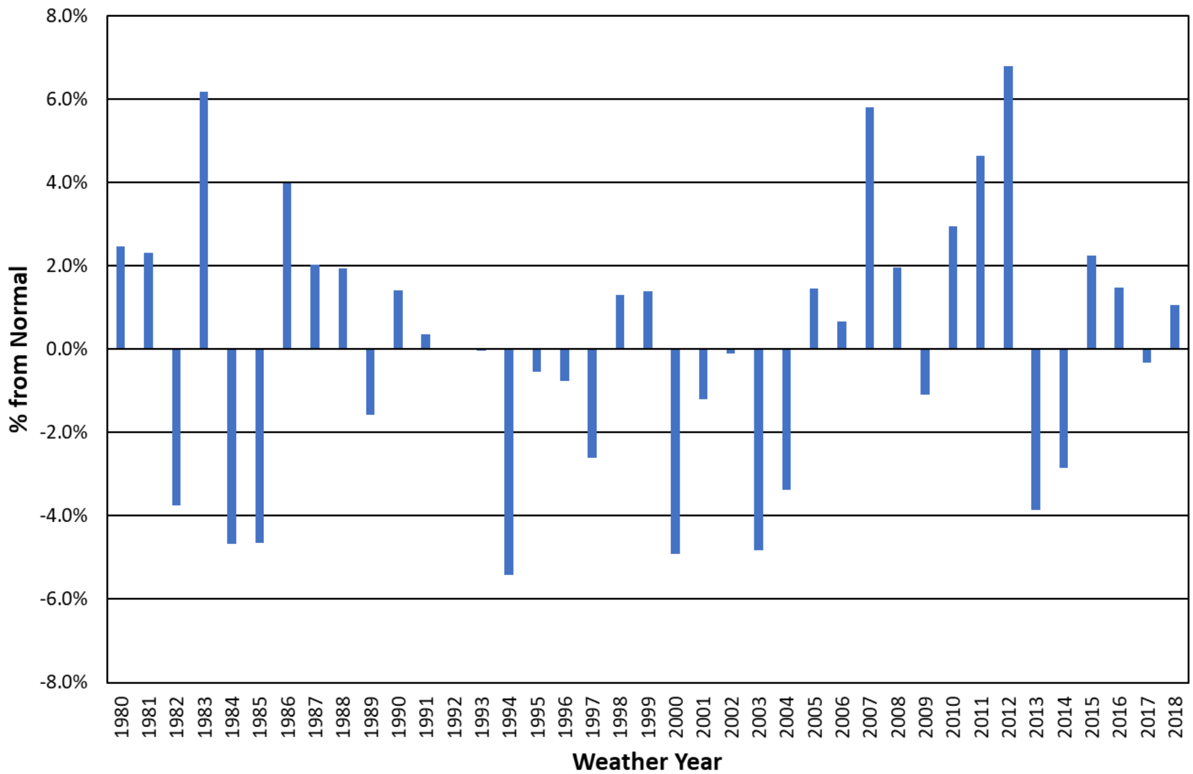


Figure 3. DEP Winter Peak Weather Variability

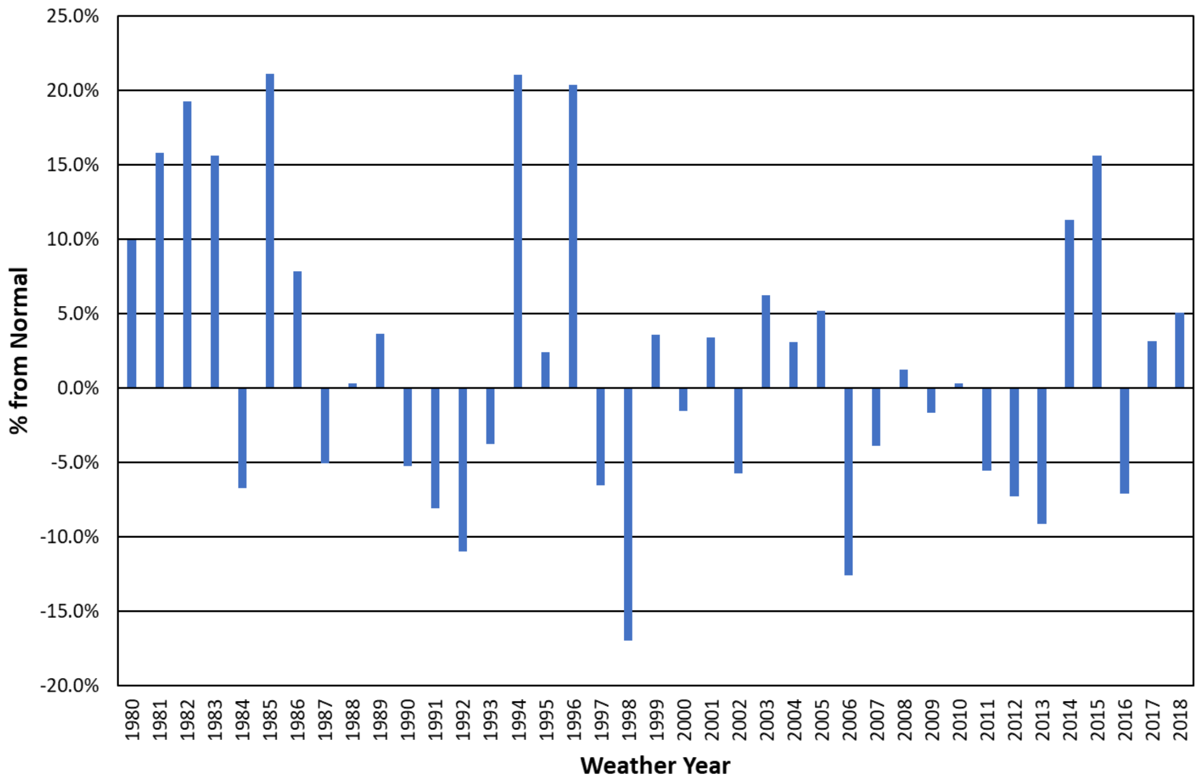
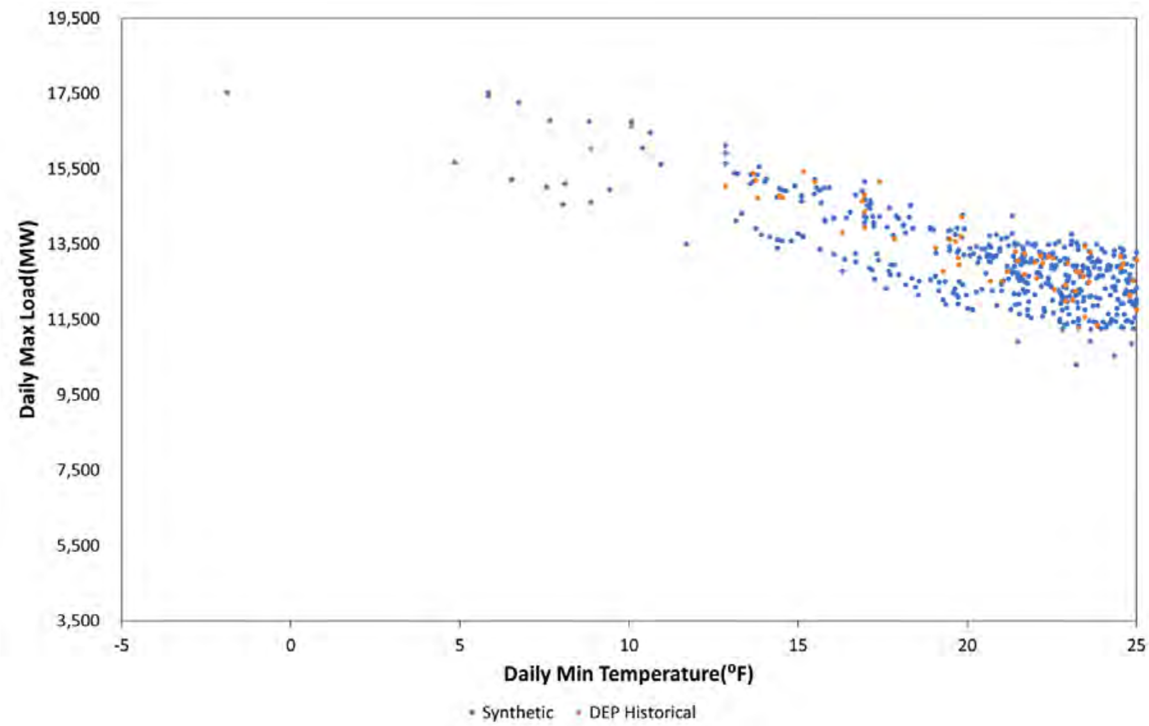


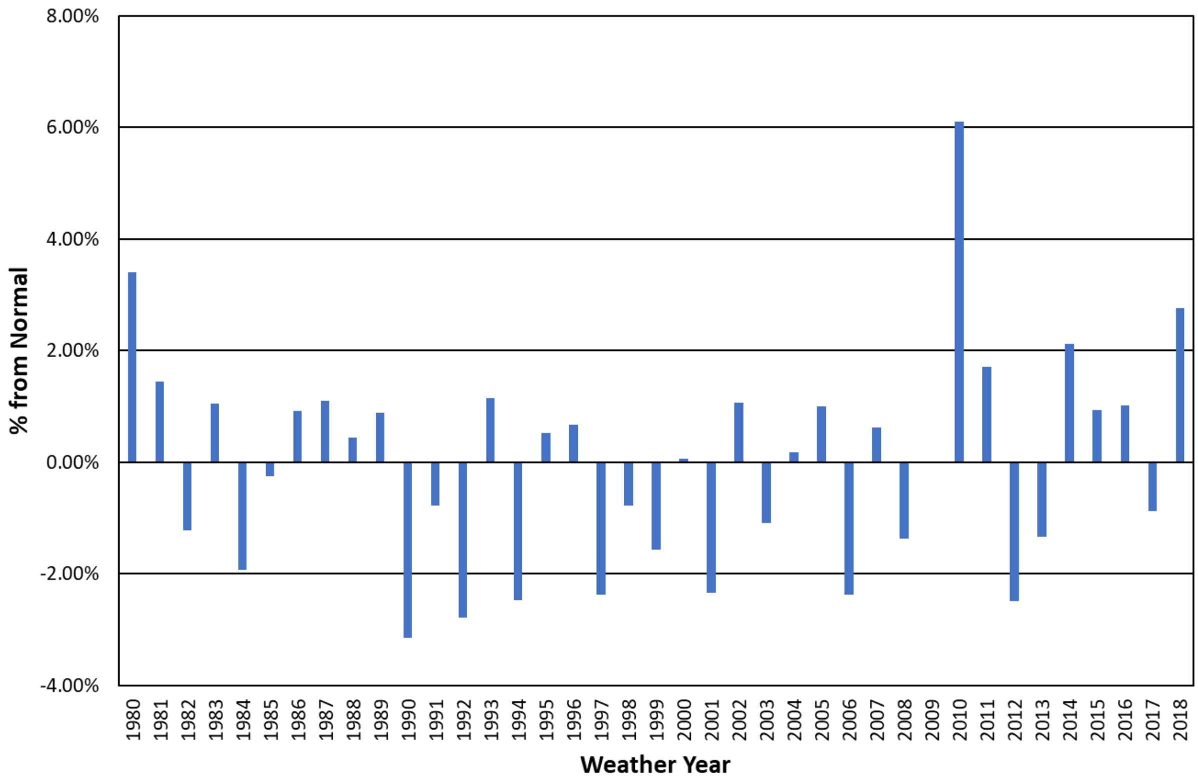
Figure 4 shows a daily peak load comparison of the synthetic load shapes and DEP history as a function of temperature. The predicted values align well with the history. Because recent historical observations only recorded a single minimum temperature of seven degrees Fahrenheit, Astrapé estimated the extrapolation for extreme cold weather days using regression analysis on the historical data. This figure highlights that the frequency of cold weather events is captured as it has been seen in history. The worst day seen in the thirty-nine year history was negative three degrees Fahrenheit. As shown in the following figure, the load associated with this day was capped very close to the six degree Fahrenheit day to assume saturation, however, the Company is skeptical that there would be much saturation on cold winter days because customers have continued to turn on additional heating options such as space heaters, ovens, etc.

Figure 4. DEP Winter Calibration



The energy variation is lower than peak variation across the weather years as expected. As shown in Figure 5, 2010 was an extreme year in total energy due to persistent severe temperatures across the summer and yet the deviation from average was only 6%.

Figure 5. DEP Annual Energy Variability



The synthetic shapes described above were then scaled to the forecasted seasonal energy and peaks within SERVM. Because DEP's load forecast is based on thirty years of weather, the shapes were scaled so that the average of the last thirty years equaled the forecast.

Synthetic loads for each external region were developed in a similar manner as the DEP loads. A relationship between hourly weather and publicly available hourly load[19] was developed based on recent history, and then this relationship was applied to thirty-nine years of weather data to develop thirty-nine synthetic load shapes. Tables 2 and 3 show the resulting weather diversity between DEP and external regions for both summer and winter loads. When the system, which includes all

[19] Federal Energy Regulatory Commission (FERC) 714 Forms were accessed during January of 2020 to pull hourly historical load for all neighboring regions.

regions in the study, is at its winter peak, the individual regions are approximately 2% - 9% below their non-coincidental peak load on average over the thirty-nine year period, resulting in an average system diversity of 4.7%. When DEP is at its winter peak load, DEC is 2.7% below its peak load on average while other regions are approximately 3 - 9% below their winter peak loads on average. Similar values are seen during the summer.

Table 2. External Region Summer Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	3.4%	3.8%	5.2%	4.2%	6.8%	7.0%	3.7%	1.4%	N/A
At DEP Peak	2.0%	N/A	8.0%	6.8%	7.3%	7.1%	5.7%	9.6%	3.6%

Table 3. External Region Winter Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	2.5%	2.8%	2.8%	5.8%	8.9%	4.8%	6.9%	3.2%	N/A
At DEP Peak	2.7%	N/A	4.7%	8.4%	6.7%	3.0%	5.2%	8.9%	2.4%

D. Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic uncertainty that Duke has in its four year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate the economic load forecast error, the difference between Congressional Budget Office (CBO) Gross Domestic Product (GDP) forecasts four years ahead and actual data was fit to a distribution which weighted over-forecasting more heavily than under-forecasting load[20]. This was a direct

[20] CBO's Economic Forecasting Record: 2017 Update. www.cbo.gov/publication/53090
www.cbo.gov/publication/53090

change accepted as part of the feedback in stakeholder meetings.[21] Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 4 shows the economic load forecast multipliers and associated probabilities. As an illustration, 25% of the time, it is expected that load will be over-forecasted by 2.7% four years out. Within the simulations, when DEP over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the thirty-nine weather years and applied each of these five load forecast error points to create 195 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 4. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.958	10.0%
0.973	25.0%
1.00	40.0%
1.02	15.0%
1.031	10.0%

E. Conventional Thermal Resources

DEP resources are outlined in Tables 5 and 6 and represent summer ratings and winter ratings. All thermal resources are committed and dispatched to load economically. The capacities of the units are defined as a function of temperature in the simulations. Full winter rating is achieved at 35°F and below and summer rating is assumed for 95° and above. For temperatures in between 35°F and 95°F, a simple linear regression between the summer and winter rating was utilized for each unit.

[21] Including the economic load forecast uncertainty actually results in a lower reserve margin compared to a scenario that excludes the load forecast uncertainty since over-forecasting load is weighted more heavily than under-forecasting load.

Table 5. DEP Baseload and Intermediate Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Mayo 1	Coal	727	746	Smith CC 4	NG - Combined Cycle	476	570
Roxboro 1	Coal	379	380	Smith CC 5	NG - Combined Cycle	489	589
Roxboro 2	Coal	671	673	Smith CC 5_DF/PAG	NG – Duct Firing/Power Aug	65/43	61/30
Roxboro 3	Coal	694	698	Lee/Wayne CC 1	NG - Combined Cycle	794	990
Roxboro 4	Coal	698	711	Lee/Wayne CC 1_DF	NG – Duct Firing	94	69
Brunswick 1	Nuclear	938	975	Sutton CC 1	NG - Combined Cycle	536	658
Brunswick 2	Nuclear	932	953	Sutton CC 1_DF	NG - Duct Firing	71	61
Harris 1	Nuclear	964	1009	Asheville CC	NG - Combined Cycle	496	560
Robinson 2	Nuclear	741	797				

Table 6. DEP Peaking Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Blewett CT 1	Oil Peaker	13	17	Smith CT 3	NG Peaker	155	185
Blewett CT 2	Oil Peaker	13	17	Smith CT 4	NG Peaker	159	186
Blewett CT 3	Oil Peaker	13	17	Smith CT 6	NG Peaker	155	187
Blewett CT 4	Oil Peaker	13	17	Wayne CT 1	Oil Peaker	177	192
Asheville CT 3	NG Peaker	160	185	Wayne CT 2	Oil Peaker	174	192
Asheville CT 4	Natural Gas Peaker	160	185	Wayne CT 3	Oil/NG Peaker	173	193
Darl CT 12	NG Peaker	118	133	Wayne CT 4	Oil/NG Peaker	170	191
Darl CT 13	NG Peaker	116	133	Wayne CT 5	Oil/NG Peaker	163	195
LM6000 (Sutton)	NG Peaker	39	49	Weatherspoon CT 1	Oil Peaker	31	41
LM6000 (Sutton)	NG Peaker	39	49	Weatherspoon CT 2	Oil Peaker	31	41
Smith CT 1	NG Peaker	157	189	Weatherspoon CT 3	Oil Peaker	32	41
Smith CT 2	NG Peaker	156	187	Weatherspoon CT 4	Oil Peaker	30	41

DEP purchase contracts were modeled as shown in Confidential Appendix Table CA2. These resources were treated as traditional thermal resources and counted towards reserve margin. Confidential Appendix Table CA3 shows the fuel prices used in the study for DEP and its neighboring power systems.

F. Unit Outage Data

Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events for the period 2014-2019 are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar technologies. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages
The actual schedule for 2024 was used.

To illustrate the outage logic, assume that from 2014 – 2019, a generator had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, shoulder, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw both a full outage and partial outage Time-to-Fail value from the distributions provided. Once the unit has been economically dispatched for that amount of time, it will fail. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture. Confidential Appendix Table CA4 shows system peak season Equivalent Forced Outage Rate (EFOR) for the system and by unit.

The most important aspect of unit performance modeling in resource adequacy studies is the cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Confidential Appendix Figure CA1 shows the distribution of modeled system outages as a percentage of time modeled and compared well with actual historical data.

Additional analysis was performed to understand the impact cold temperatures have on system outages. Confidential Appendix Figures CA2 and CA3 show the difference in cold weather outages during the 2014-2019 period and the 2016-2019 period. The 2014-2019 period showed more events than the 2016-2019 period which is logical because Duke Energy has put practices in place to enhance reliability during these periods, however the 2016 – 2019 data shows some events still occur. The average capacity offline below 10 degrees for DEC and DEP combined was 400 MW. Astrapé split this value by peak load ratio and included 140 MW in the DEP Study and 260 MW in the DEC Study at temperatures below 10 degrees. Sensitivities were performed with the cold weather outages removed and increased to match the 2014 – 2019 dataset which showed an average of 800 MW offline on days below 10 degrees. The MWs offline during the 10 coldest days can be seen in Confidential Appendix Table CA5. The outages shown are only events that included some type of freezing or cold weather problem as part of the description in the outage event.

G. Solar and Battery Modeling

Table 7 shows the solar and battery resources captured in the study.

Table 7. DEP Renewable Resources Excluding Existing Hydro

Unit Type	Summer Capacity (MW)	Winter Capacity (MW)	Modeling
Utility Owned-Fixed	141	141	Hourly Profiles
Transition-Fixed	2,432	2,432	Hourly Profiles
Competitive Procurement of Renewable Energy (CPRE) Tranche 1 Fixed 40%/Tracking 60%	86	86	Hourly Profiles
Future Solar Fixed 40%/Tracking 60%	1,448	1,448	Hourly Profiles
Total Solar	4,107	4,107	
Total Battery	83	83	Modeled as energy arbitrage

The solar units were simulated with thirty-nine solar shapes representing thirty-nine years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. The solar capacity was given 20% credit in the summer and 1% in the winter for reserve margin calculations based on the 2018 Solar Capacity Value Study. Figure 6 shows the county locations that were used and Figure 7 shows the average August output for different fixed-tilt and single-axis-tracking inverter loading ratios.

Figure 6. Solar Map

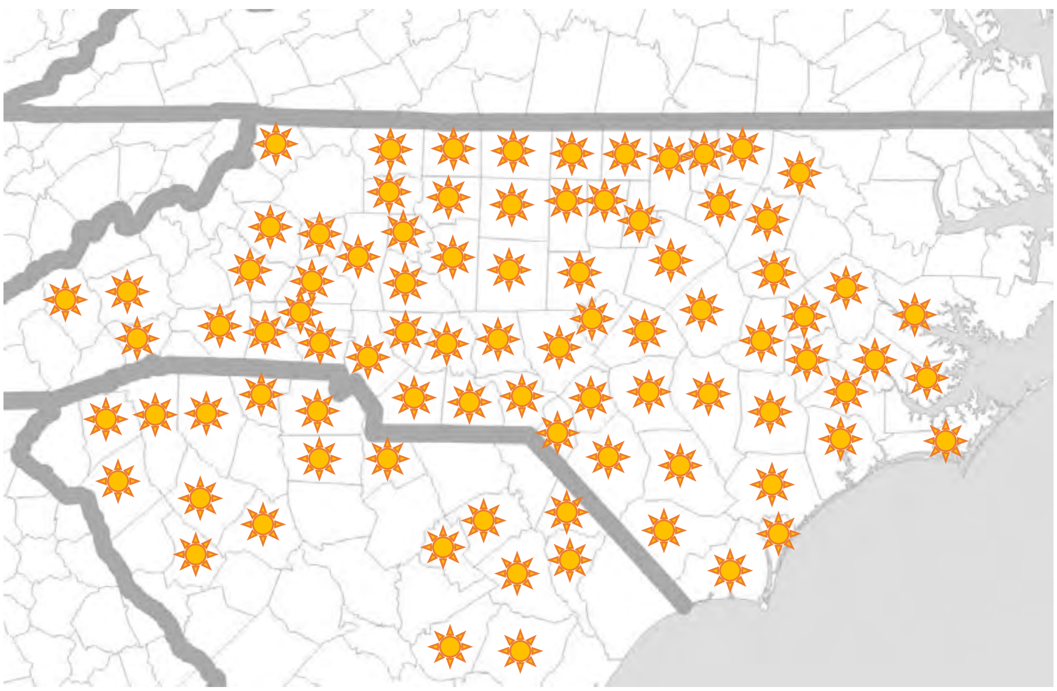
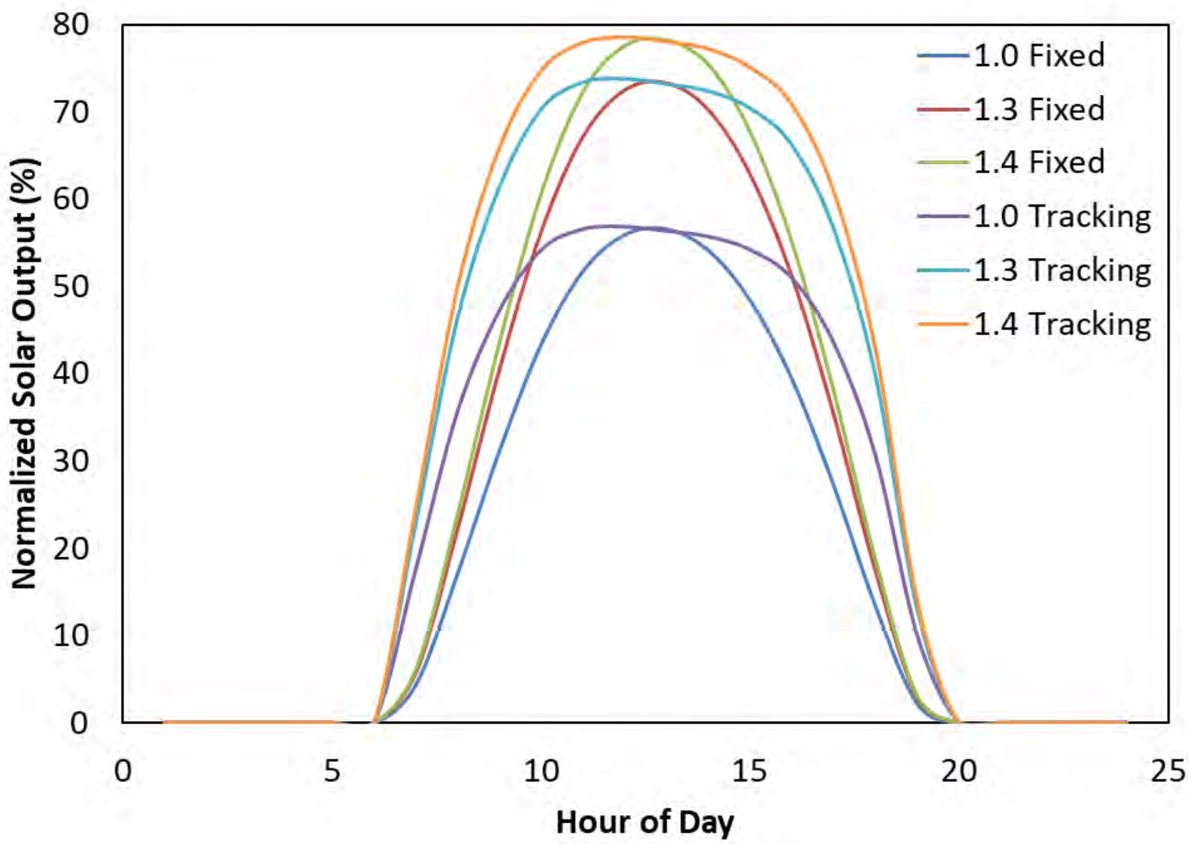


Figure 7. Average August Output for Different Inverter Loading Ratios



H. Hydro Modeling

The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. Figure 8 shows the total breakdown of scheduled hydro based on the last thirty-nine years of weather.

Figure 8. Scheduled Capacity

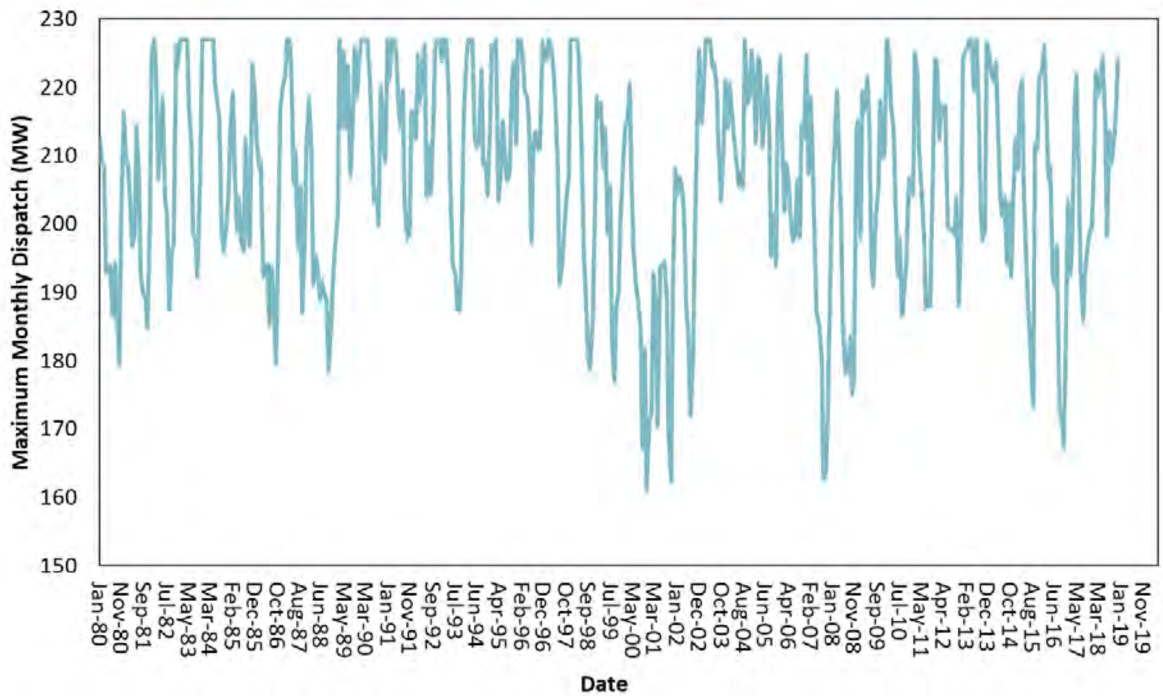
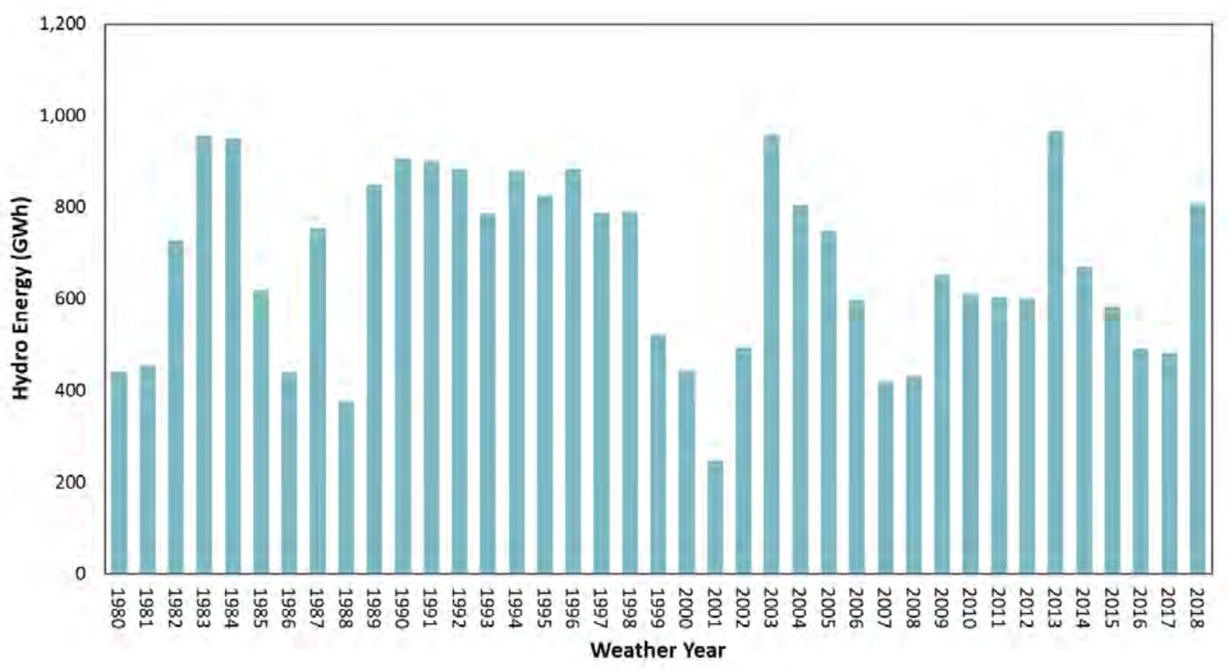


Figure 9 demonstrates the variation of hydro energy by weather year which is input into the model. The lower rainfall years such as 2001, 2007, and 2008 are captured in the reliability model with lower peak shaving as shown in Figure 9.

Figure 9. Hydro Energy by Weather Year



I. Demand Response Modeling

Demand response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints. For this study, 1,001 MW of summer capacity and 461 MW of winter capacity were included as shown in Table 8. To ensure these resources were called after conventional generation, a $2,000/MWh strike price was included.

Table 8. DEP Demand Response Modeling

Region	Program	Summer Capacity (MW)	Winter Capacity (MW)	Hours Per Year	Days Per Week	Hours Per Day
DEP	EnergyWise Home	430	22	60	7	4
DEP	EnergyWise Business	22	2	60	7	4
DEP	Demand Response Automation	44	24	80	7	8
DEP	Large Load Curtailable	265	245	100	7	8
DEP	Distribution System Demand Response	240	168	100	7	8
	Total DEP	1,001	461			

J. Operating Reserve Requirements

The operating reserves assumed for DEP are shown below. SERVM commits to this level of operating reserves in all hours. However, all operating reserves except for the 150 MW of regulation are allowed to be depleted during a firm load shed event.

- Regulation Up/Down: 150 MW
- Spinning Requirement: 200 MW
- Non-Spin Requirement: 200 MW
- Additional Load Following Due to Intermittent Resources in 2024: Hourly values were used based on a 12x24 profile provided by Duke Energy from its internal modeling.

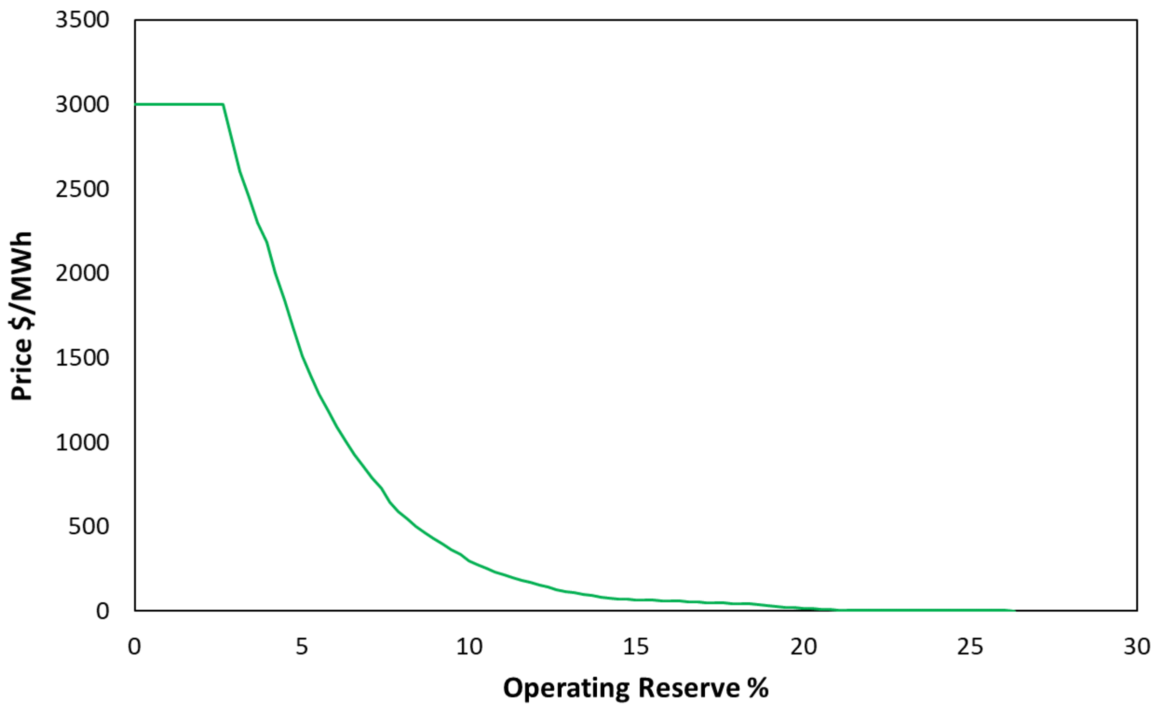
K. External Assistance Modeling

The external market plays a significant role in planning for resource adequacy. If several of the DEP resources were experiencing an outage at the same time, and DEP did not have access to surrounding markets, there is a high likelihood of unserved load. To capture a reasonable amount of assistance from surrounding neighbors, each neighbor was modeled at the one day in 10-year standard (LOLE of 0.1) level representing the target for many entities. By modeling in this manner, only weather diversity and generator outage diversity benefits are captured. The market representation used in SERVM is based on Astrapé's proprietary dataset which is developed based on FERC Forms, Energy Information Administration (EIA) Forms, and reviews of IRP information from neighboring regions. To ensure purchases in the model compared well in magnitude to historical data, the years 2015 and 2018 were simulated since they reflected cold weather years with high winter peaks. Figure CA4 in the confidential appendix shows that calibration with purchases on the y-axis and load on the x-axis for the 2015 and 2018 weather years. The actual purchases and modeled results show DEP purchases significant capacity during high load hours during these years.

The cost of transfers between regions is based on marginal costs. In cases where a region is short of resources, scarcity pricing is added to the marginal costs. As a region's hourly reserves approach zero, the scarcity pricing for that region increases. Figure 10 shows the scarcity pricing curve that was used in the simulations. It should be noted that the frequency of these scarcity prices is very low because in the majority of hours, there is plenty of capacity to meet load after the market has cleared[22].

[22]The market clearing algorithm within SERVM attempts to get all regions to the same price subject to transmission constraints. So, if a region's original price is $3,000/MWh based on the conditions and scarcity pricing in that region alone, it is highly probable that a surrounding region will provide enough capacity to that region to bring prices down to reasonable levels.

Figure 10. Operating Reserve Demand Curve (ORDC)



L. Cost of Unserved Energy

Unserved energy costs were derived from national studies completed for the Department of Energy (DOE) in 2003[23] and 2009[24], along with three other studies performed[25] previously by other consultants. The DOE studies were compilations of other surveys performed by utilities over the last two decades. All studies split the customer class categories into residential, commercial, and industrial. The values were then applied to the actual DEP customer class mix to develop a wide

[23] https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf
[24] https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf
[25] https://pdfs.semanticscholar.org/544b/d740304b64752b451d749221a00eede4c700.pdf
Peter Cramton, Jeffrey Lien. Value of Lost Load. February 14, 2000.

range of costs for unserved energy. Table 9 shows those results. Because expected unserved energy costs are so low near the economic optimum reserve margin, this value, while high in magnitude, is not a significant driver in the economic analysis. Since the public estimates ranged significantly, DEP used $16,450/MWh for the Base Case in 2024, and sensitivities were performed around this value from $5,000 MWh to $25,000 MWh to understand the impact.

Table 9. Unserved Energy Costs / Value of Lost Load

	Weightings	2003 DOE Study 2024 $/kWh	2009 DOE Study 2024 $/kWh	Christiansen Associates 2024 $/kWh	Billinton and Wacker 2024 $/kWh	Karuiki and Allan 2024 $/kWh
Residential	43%	1.57	1.50	3.12	2.73	1.26
Commercial	33%	35.54	109.23	22.37	23.24	24.74
Industrial	24%	20.51	32.53	11.59	23.24	58.65
	Weighted Average $/kWh	17.31	44.55	11.50	14.38	22.60
	Average $/kWh	22.07				
	Average $/kWh excluding the 2009 DOE Study	16.45				

M. System Capacity Carrying Costs

The study assumes that the cheapest marginal resource is utilized to calculate the carrying cost of additional capacity. The cost of carrying incremental reserves was based on the capital and FOM of a new simple cycle natural gas Combustion Turbine (CT) consistent with the Company's IRP assumptions. For the study, the cost of each additional kW of reserves can be found in Confidential Appendix Table CA6. The additional CT units were forced to have a 5% EFOR in the simulations and used to vary reserve margin in the study.

IV. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. For DEP, SERVM utilized thirty-nine years of historical weather and load shapes, five points of economic load growth forecast error, and fifteen iterations of unit outage draws for each scenario to represent a distribution of realistic scenarios. The number of yearly simulation cases equals 39 weather years * 5 load forecast errors * 15 unit outage iterations = 2,925 total iterations for the Base Case. This Base Case, comprised of 2,925 total iterations, was re-run at different reserve margin levels by varying the amount of CT capacity.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 10. Each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 10. Case Probability Example

Weather Year	Weather Year Probability (%)	Load multipliers Due to Load Economic Forecast Error (%)	Load Economic Forecast Error Probability (%)	Case Probability (%)
1980	2.56	95.8	10	0.256
1980	2.56	97.3	25	0.64
1980	2.56	100	40	1.024
1980	2.56	102	15	0.384
1980	2.56	103.1	10	0.256
1981	2.56	95.8	10	0.256
1981	2.56	97.3	25	0.64
1981	2.56	100	40	1.024
1981	2.56	102	15	0.384
1981	2.56	103.1	10	0.256
1982	2.56	95.8	10	0.256
1982	2.56	97.3	25	0.64
1982	2.56	100	40	1.024
1982	2.56	102	15	0.384

1982	2.56	103.1	10	0.256
...	...	...	...	...
...	...	...	...	...
2018	2.56	103.1	10	0.256
			Total	100

For this study, LOLE is defined in number of days per year and is calculated for each of the 195 load cases and weighted based on probability. When counting LOLE events, only one event is counted per day even if an event occurs early in the day and then again later in the day. Across the industry, the traditional 1 day in 10 year LOLE standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year and Expected Unserved Energy (EUE) in MWh.

Total system energy costs are defined as the following for each region:

$$Production\ Costs\ (Fuel\ Burn + Variable\ O\&M) + \ Purchase\ Costs - Sales\ Revenue \\ + Loss\ of\ Reserves + \ Cost\ of\ Unserved\ Energy$$

These components are calculated for each case and weighted based on probability to calculate total system energy costs for each scenario simulated. Loss of Reserves costs recognize the additional risk of depleting operating reserves and are costed out at the ORDC curve when they occur. As shown in the results these costs are almost negligible. The cost of unserved energy is simply the MWh of load shed multiplied by the value of lost load. System capacity costs are calculated separately outside of the SERVM model using the economic carrying cost of a new CT.

B. Reserve Margin Definition

For this study, winter and summer reserve margins are defined as the following:

- (Resources – Demand) / Demand
  - Demand is 50/50 peak forecast
  - Demand response programs are included as resources and not subtracted from demand
  - Solar capacity is counted at 1% capacity credit for winter reserve margin calculations, 20% for summer reserve margin calculations, and the small amount of battery capacity was counted at 80%.

As previously noted, the Base Case was simulated at different reserve margin levels by varying the amount of CT capacity in order to evaluate the impact of reserves on LOLE. In order to achieve lower reserve margin levels, capacity needed to be removed. For DEP, purchase capacity was removed to achieve lower reserve margin levels. Table 11 shows a comparison of winter and summer reserve margin levels for the Base Case. As an example, when the winter reserve margin is 16%, the resulting summer reserve margin is 28.2% due to the lower summer peak demand and 4,107 MW of solar on the system which provides greater summer capacity contribution.

Table 11. Relationship Between Winter and Summer Reserve Margin Levels

Winter	10.0%	12.0%	14.0%	16.0%	18.0%	20.0%
Corresponding Summer	22.3%	24.2%	26.2%	28.2%	30.2%	32.1%

V. Physical Reliability Results

Table 12 shows LOLE by month across a range of reserve margin levels for the Island Case. The analysis shows all of the LOLE falls in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in the Island scenario, a 25.5% winter reserve margin is required. Given the significant solar on the system, the summer reserves are approximately 12% greater than winter reserves which results in no reliability risk in the summer months. This 25.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEP system.

Table 12. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	22.3%	0.43	0.09	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.70	0.71
11.0%	23.2%	0.37	0.08	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.61	0.62
12.0%	24.2%	0.32	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.53	0.54
13.0%	25.2%	0.28	0.06	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.47	0.47
14.0%	26.2%	0.25	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.41	0.41
15.0%	27.2%	0.21	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.35	0.36
16.0%	28.2%	0.19	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.31	0.31
17.0%	29.1%	0.17	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.28	0.28
18.0%	30.1%	0.15	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.25	0.25
19.0%	31.1%	0.13	0.04	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.22	0.22
20.0%	32.1%	0.12	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.20	0.20
21.0%	33.1%	0.11	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.18	0.18
22.0%	34.1%	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.16	0.16
23.0%	35.1%	0.09	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.14	0.14
24.0%	36.0%	0.08	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.12	0.12
25.0%	37.0%	0.07	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.11
26.0%	38.0%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.10	0.10

Table 13 shows LOLE by month across a range of reserve margin levels for the Base Case which assumes neighbor assistance. As in the Island scenario, all of the LOLE occurs in the winter showing the same increased risk in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in this scenario that includes market assistance, a 19.25% winter reserve margin is required.

Table 13. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	22.3%	0.14	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.23	0.23
11.0%	23.2%	0.13	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.21	0.21
12.0%	24.2%	0.12	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.19	0.19
13.0%	25.2%	0.11	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.18	0.18
14.0%	26.2%	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.16	0.16
15.0%	27.2%	0.09	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.15	0.15
16.0%	28.2%	0.08	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.13	0.13
17.0%	29.1%	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.12	0.12
18.0%	30.1%	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.11
19.0%	31.1%	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
20.0%	32.1%	0.06	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
21.0%	33.1%	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
22.0%	34.1%	0.05	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08

Table 14 shows LOLE and other physical reliability metrics by reserve margin for the Base Case simulations. Loss of Load Hours (LOLH) is expressed in hours per year and Expected Unserved Energy (EUE) is expressed in MWh. The table shows that an 8% reserve margin results in an LOLH of 0.92 hours per year. Thus, to achieve 2.4 hours per year, which is far less stringent than the 1 day in 10 year standard (1 event in 10 years), DEP would require a reserve margin less than 8%. Astrapé does not recommend targeting a standard that allows for 2.4 hours of firm load shed every year as essentially would expect a firm load shed during peak periods ever year. The hours per event can be calculated by dividing LOLH by LOLE. The firm load shed events last approximately 2-3 hours on average. As these reserve margins decrease and firm load shed events increase, it is expected that reliance on external assistance, depletion of contingency reserves, and more demand response calls will occur and increase the overall reliability risk on the system.

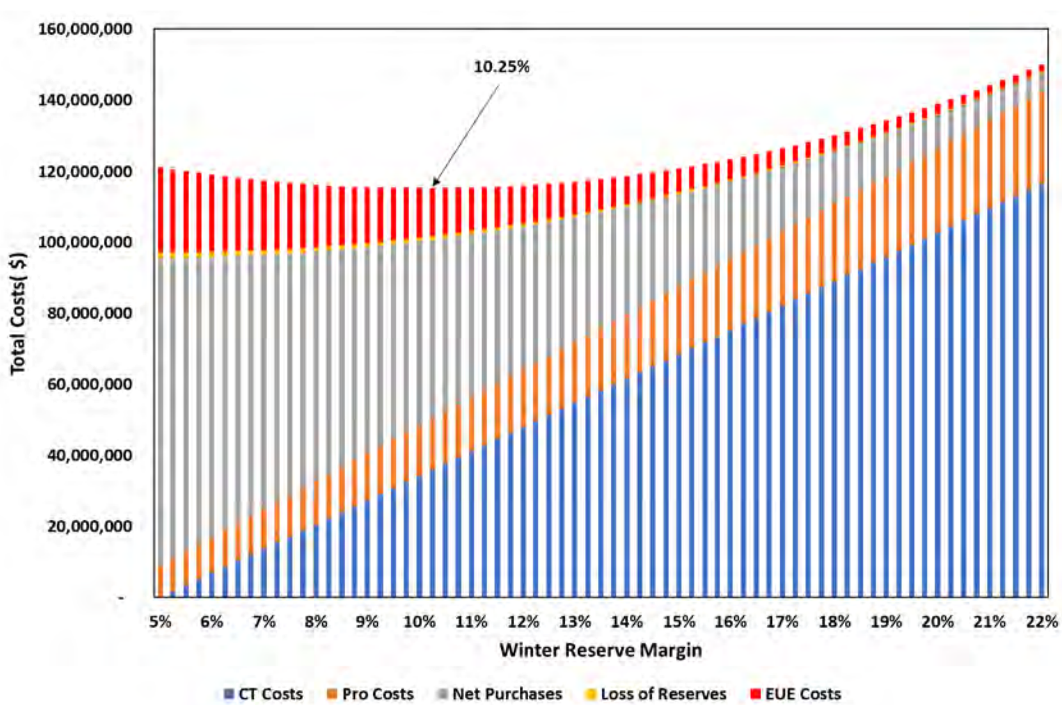
Table 14. Reliability Metrics: Base Case

Reserve Margin	LOLE	LOLH	EUE
%	Days Per Year	Hours Per Year	MWh
8.0%	0.272	0.92	1,075
8.5%	0.261	0.88	1,016
9.0%	0.251	0.84	959
9.5%	0.241	0.80	904
10.0%	0.231	0.77	850
10.5%	0.222	0.73	799
11.0%	0.212	0.70	749
11.5%	0.203	0.66	701
12.0%	0.195	0.63	655
12.5%	0.186	0.60	611
13.0%	0.178	0.56	568
13.5%	0.170	0.53	528
14.0%	0.163	0.51	489
14.5%	0.155	0.48	452
15.0%	0.148	0.45	417
15.5%	0.141	0.42	384
16.0%	0.135	0.40	352
16.5%	0.129	0.38	322
17.0%	0.123	0.35	294
17.5%	0.117	0.33	268
18.0%	0.112	0.31	244
18.5%	0.106	0.29	222
19.0%	0.102	0.27	201
19.5%	0.097	0.26	182
20.0%	0.093	0.24	165
20.5%	0.089	0.22	150
21.0%	0.085	0.21	137
21.5%	0.082	0.20	125
22.0%	0.078	0.18	115
22.5%	0.076	0.17	107
23.0%	0.073	0.16	101
23.5%	0.071	0.15	97
24.0%	0.068	0.15	95
24.5%	0.067	0.14	94
25.0%	0.065	0.13	95

VI. Base Case Economic Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs were analyzed across reserve margin levels for the Base Case. Figure 11 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and unit performance iterations at each reserve margin level and represents the expected value on a year in and year out basis.

Figure 11. Base Case Risk Neutral Economic Results[26]

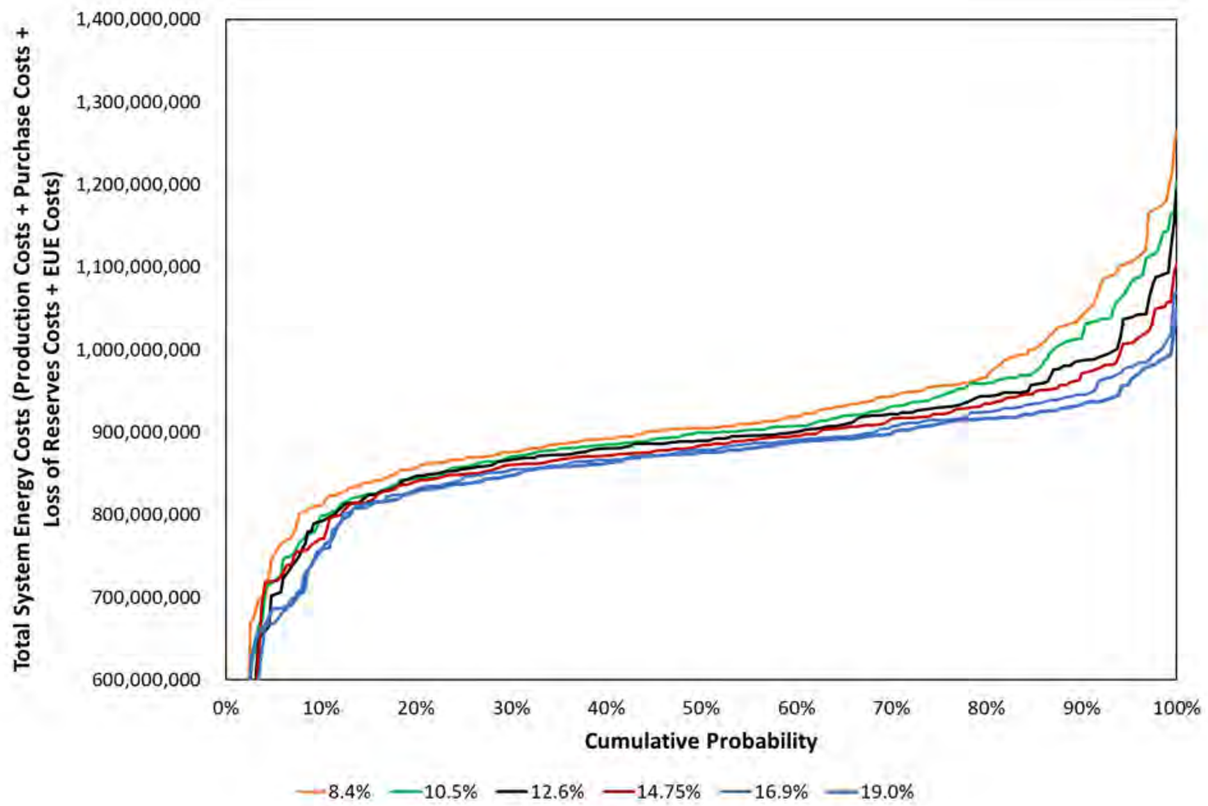


[26] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEP has approximately 1 billion dollars in total costs.

As Figure 11 shows, the lowest risk neutral cost falls at a 10.25% reserve margin. The reason this risk neutral reserve margin is significantly lower than 19.25% reserve margin required to meet the 0.1 LOLE is due to high reserve margins in the summer. The majority of the savings seen in adding additional capacity is recognized in the winter.[27] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there is always system energy cost savings from either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure 12, however, shows the distribution of system energy costs (production costs, purchase costs, loss of reserves costs, and the costs of EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margins to higher reserve margins, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

[27] As the DEC study shows, the lower DEC summer reserve margins increase the risk neutral economic reserve margin level compared to the DEP Study.

Figure 12. Cumulative Probability Curves



The next table shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure 11 as well as the energy savings at higher cumulative probability levels. As shown in the table, going from the risk neutral reserve margin of 10.25% to 17%, customer costs on average increase by 11 million dollars a year[28] and LOLE is reduced from 0.23 to 0.12 events per year. The LOLE for the island scenario decreases from 0.71 days per year to 0.28 days per year. However, 10% of the time energy savings are greater than or equal to $67 million if a 17% reserve margin is maintained versus the 10.25% reserve margin. And 5% of the time, $101 million or more is saved.

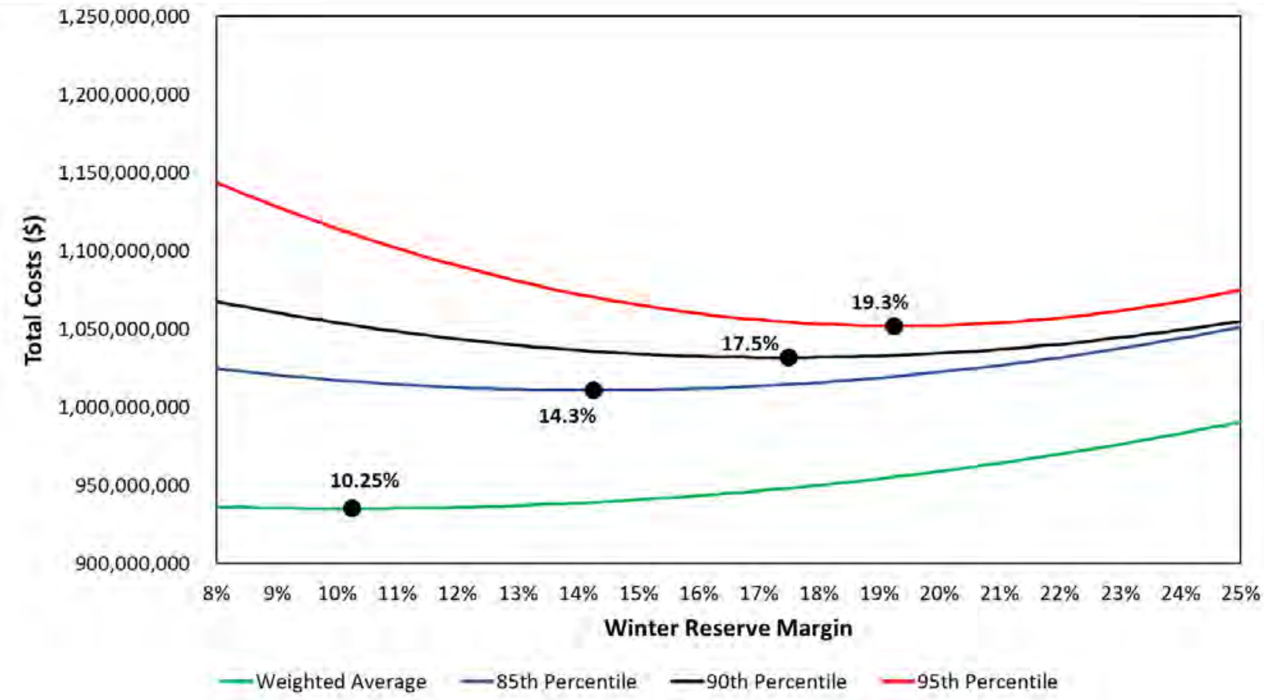
[28] This includes $46 million for CT costs and $35 million of system energy savings.

Table 15. Annual Customer Costs vs LOLE

Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
10.25%	-	-	-	-	-	-	0.23	0.71
11.00%	5.1	-5.0	0.2	-7.1	-9.3	-14.5	0.21	0.62
12.00%	12.0	-11.2	0.8	-15.9	-20.9	-32.5	0.19	0.54
13.00%	18.8	-16.9	1.9	-24.0	-31.8	-49.1	0.18	0.47
14.00%	25.7	-22.2	3.5	-31.4	-41.8	-64.3	0.16	0.41
15.00%	32.5	-26.9	5.6	-38.0	-51.0	-78.0	0.15	0.36
16.00%	39.4	-31.2	8.2	-44.0	-59.4	-90.3	0.13	0.31
17.00%	46.2	-34.9	11.3	-49.3	-67.0	-101.2	0.12	0.28
18.00%	53.1	-38.1	14.9	-53.9	-73.7	-110.7	0.11	0.25
19.00%	59.9	-40.8	19.1	-57.8	-79.7	-118.7	0.1	0.22
20.00%	66.7	-43.0	23.8	-61.0	-84.8	-125.3	0.09	0.2

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure 12 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 10.25% reserve margin, the 85th to 95th percentile cost curves point to a 14-19% reserve margin.

Figure 13. Total System Costs by Reserve Margin



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEP is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

VII. Sensitivities

Several sensitivities were simulated in order to understand the effects of different assumptions on the 0.1 LOLE minimum winter reserve margin and to address questions and requests from stakeholders.

Outage Sensitivities

As previously noted, the Base Case included a total of 400 MW of cold weather outages between DEC and DEP below ten degrees Fahrenheit based on outage data for the period 2016-2019. Sensitivities were run to see the effect of two cold weather outage assumptions. The first assumed that the 400 MW of total outages between DEC and DEP below ten degrees Fahrenheit were removed. As Table 16 indicates, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is lowered by 0.75% from the Base Case to 18.50%. This shows that if the Company was able to eliminate all cold weather outage risk, it could carry up to a 0.75% lower reserve margin. However, Astrapé recognizes based on North American Electric Reliability Corporation (NERC) documentation across the industry[29] that outages during cold temperatures could be substantially more than the 400 MW being applied at less than 10 degrees in this modeling.

[29] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdfvv (page 5)

https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

(beginning page 43)

Table 16. No Cold Weather Outage Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
No Cold Weather Outages	18.50%	9.50%	16.25%

The second outage sensitivity showed what the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) would need to be if cold weather outages were based solely on 2014-2019 historical data which increased the total MW of outages from 400 MW to 800 MW. Table 17 shows that the minimum reserve margin for 0.1 LOLE is 20.50 %.

Table 17. Cold Weather Outages Based on 2014-2019 Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Cold Weather Outages Based on 2014 - 2019	20.50%	10.50%	17.75%

Load Forecast Error Sensitivities

These sensitivities were run to see the effects of the Load Forecast Error (LFE) assumptions. In response to stakeholder feedback, an asymmetric LFE distribution was adopted in the Base Case which reflected a higher probability weighting on over-forecasting scenarios. In the first sensitivity, the LFE uncertainty was completely removed. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 0.75% to 20.00%. This demonstrates that the load forecast error assumed in the Base Case was reducing the target reserve margin levels since over-forecasting was more heavily weighted in the LFE distribution. Because of this result, Astrapé did not simulate additional sensitivities such as 2-year, 3-year, or 5-year LFE distributions.

Table 18. Remove LFE Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Remove LFE	20.00%	10.50%	17.50%

The second sensitivity removed the asymmetric Base Case distribution and replaced it with the originally proposed normal distribution. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 1.0% to 20.25%.

Table 19. Originally Proposed LFE Distribution Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Originally Proposed Normal Distribution	20.25%	11.25%	17.50%

Solar Sensitivities

The Base Case for DEP assumed that there was 4,107 MW of solar on the system. The first solar sensitivity decreased this number to 3,404 MW. This change in solar had no impact on the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as the results in Table 20 show because the capacity contribution of solar in the winter reserve margin calculation is 1%.

Table 20. Low Solar Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Low Solar	19.25%	11.75%	17.50%

The second solar sensitivity increased the amount of solar on the DEP system to 4,629 MW. This increase also had very little impact on the minimum reserve margins as Table 21 indicates. Both of these results are expected as solar provides almost no capacity value in the winter.

Table 21. High Solar Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
High Solar	19.00%	9.50%	16.75%

Demand Response (DR) Sensitivity

In this scenario, the winter demand response is increased to 1,001 MW to match the summer capacity. It is important to note that DR is counted as a resource in the reserve margin calculation similar to a conventional generator. Simply increasing DR to 1,001 MW results in a higher reserve margin and lower LOLE compared to the Base Case. Thus, CT capacity was adjusted (lowered) in the high DR sensitivity to maintain the same reserve margin level. Results showed that the 0.1 LOLE minimum reserve margin actually increased from 19.25% to 20.00% due to demand response's dispatch limits compared to a fully dispatchable traditional resource. DR may be an economic alternative to installing CT capacity, depending on market potential and cost. However, it should be noted that while Duke counts DR and conventional capacity as equivalent in load carrying capability in its IRP planning, the sensitivity results show that DR may have a slightly lower equivalent load carrying capability especially for programs with strict operational limits. The results are listed in Table 22 below.

Table 22. Demand Response Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Demand Response Winter as High as Summer	20.00%	12.50%	18.50%

No Coal Sensitivity

In this scenario, all coal units were replaced with CC/CT units. The CC units were modeled with a 4% EFOR and the CT units were modeled with a 5% EFOR. Due to the low EFOR's of the DEP coal units, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased slightly as shown in Table 23 below. Essentially these thermal resources were interchangeable and had a minimal impact on the reserve margin.

Table 23. No Coal Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Retire all Coal	19.50%	11.25%	17.50%

Climate Change Sensitivity

In this scenario, the loads were adjusted to reflect the temperature increase outlined in the National Oceanic and Atmospheric Administration (NOAA) Climate Change Analysis[30]. Based on NOAA's research, temperatures since 1981 have increased at an average rate of 0.32 degrees Fahrenheit per decade. Each synthetic load shape was increased to reflect the increase in temperature it would see to meet the 2024 Study Year. For example, 1980 has a 1.4 degree increase $(0.32 \frac{°\mathrm{F}}{Decade} * \frac{1\, Decade}{10\, Year} * 44\, Years)$. After the loads were adjusted, the analysis was rerun. The summer peaks saw an increase and the winter peaks especially in earlier weather years saw a decrease. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is reduced to 18.50% from 19.25% in the Base Case under these assumptions. The results are listed in the table below.

Table 24. Climate Change Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Climate Change	18.50%	9.75%	16.25%

[30] https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature

VIII. Economic Sensitivities

Table 25 shows the economic results if the cost of unserved energy is varied from $5,000/MWh to $25,000/MWh and the cost of incremental capacity is varied from $40/kW-yr to $60/kW-yr. As CT costs decrease, the economic reserve margin increases and as CT costs increase, the economic reserve margin decreases. The opposite occurs with the cost of EUE. The higher the cost of EUE, the higher the economic target.

Table 25. Economic Sensitivities

	Economics	
Sensitivity	**Weighted Average (risk neutral)**	**90th %**
Base Case	10.25%	17.50%
CT costs $40kW-yr	12.50%	18.75%
CT costs $60/kW-yr	6.00%	15.25%
EUE 5,000 $/MWh	7.00%	13.75%
EUE 25,000 $/MWh	11.75%	19.25%

IX. DEC/DEP Combined Sensitivity

A set of sensitivities was performed which assumed DEC, DEP-E, and DEP-W were dispatched together and all reserves were calculated as a single company across the three regions. In these scenarios, all resources down to the firm load shed point can be utilized to assist each other and there is a priority in assisting each other before assisting an outside neighbor. The following three scenarios were simulated for the Combined Case and their results are listed in the table below:

1) Combined-Base

2) Combined Target 1,500 MW Import Limit - This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[31].

3) Combined-Remove LFE

As shown in the table below, the combined target scenario yielded a 0.1 LOLE reserve margin of 16.75% (based on DEP and DEC coincident peak).

Table 26. Combined Case Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**weighted avg (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Combined Target	16.75%	17.00%	17.75%
Combined Target 1,500 MW Import Limit	18.00%	17.25%	18.25%
Combined Target - Remove LFE	17.25%	17.00%	18.25%

[31] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

X. Conclusions

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEC Study, Astrapé recommends that DEP continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEP utility would require a 25.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and even with market assistance, DEP would need to maintain a 19.25% reserve margin. Customers expect electricity during extreme hot and cold weather conditions and maintaining a 17% reserve margin is estimated to provide an LOLE of 0.12 events per year which is slightly less reliable than the one day in 10-year standard (LOLE of 0.1). However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 16% reserve margin required by DEC to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increases the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEP will never be forced to shed firm load during extreme conditions as DEP and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEP has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. But if not for non-firm external assistance which this study considers, firm load would have been shed. In addition, incorporation of tail end reliability risk in modeling should be from statistically and historically defendable methods; not from including subjective risks that cannot be assigned probability. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 10.25% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEP resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEP should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEP observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[32]

[32] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

XI. Appendix A

Table A.1 Base Case Assumptions and Sensitivities

Assumption	Base Case Value	Sensitivity	Comments
Weather Years	1980-2018		Based on the historical data, the 1980 - 2018 period aligns well with the last 100 years. Shorter time periods do not capture the distribution of extreme days seen in history.
Synthetic Loads and Load Shapes	As Documented in 2-21-20 Presentation	Impact of Climate Change on synthetic load shapes and peak load forecast	Note: This is a rather complex sensitivity and the ability to capture the impact of climate change may be difficult. We would appreciate input and suggestions from other parties on developing an approach to capture the potential impacts of climate change on resource adequacy planning.
LFE	Use an asymmetrical distribution. Use full LFE impact in years 4 and beyond. Recognize reduced LFE impacts in years 1-3.	1,2,3,5 year ahead forecast error	
Unit Outages	As Documented in 2-21-20 Presentation		
Cold Weather Outages	Moderate Cold Weather Outages: Capture Incremental Outages at temps less than 10 degrees based on the 2016 - 2018 dataset (~400 MW total across the DEC and DEP for all temperature below 10 degree. This will be applied on a peak load ratio basis) For Neighboring regions, the same ratio of cold weather outages to peak load will be applied.	2 Sensitivities: (1) Remove cold weather outages (2) Include cold weather outages based on 2014 -2018 dataset	The DEC and DEP historical data shows that during extreme cold temperatures it is likely to experience an increase in generator forced outages; this is consistent with NERC's research across the industry. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf - page 5 https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf - beginning on pg 43
Hydro/Pumped Storage	As Documented in 2-21-20 Presentation		
Solar	As Documented in 2-21-20 Presentation		
Demand Response	As Documented in 2-21-20 Presentation	Sensitivity increasing winter DR	
Neighbor Assistance	As Documented in 2-21-20 Presentation	Island Sensitivity	Provide summary of market assistance during EUE hours; transmission versus capacity limited.
Operating Reserves	As Documented in 2-21-20 Presentation		
CT costs/ORDC/VOLL	As Documented in 2-21-20 Presentation	Low and High Sensitivities for each	
Study Topology	Determine separate DEC and DEP reserve margin targets	Combined DEC/DEP target	A simulation will be performed which assumes DEC, DEP-E and DEP-W are dispatched together and reserves are calculated as a single company across the three regions.

XII. Appendix B

Table B.1 Percentage of Loss of Load by Month and Hour of Day for the Base Case

	Month											
Hour of Day	1	2	3	4	5	6	7	8	9	10	11	12
1	-	-	-	-	-	-	-	-	-	-	-	-
2	0.12%	-	-	-	-	-	-	-	-	-	-	-
3	0.58%	0.12%	0.12%	-	-	-	-	-	-	-	-	-
4	1.84%	0.46%	0.12%	-	-	-	-	-	-	-	-	0.12%
5	5.30%	3.80%	0.12%	-	-	-	-	-	-	-	-	0.35%
6	10.71%	6.45%	-	-	-	-	-	-	-	-	-	0.92%
7	16.82%	10.71%	-	-	-	-	-	-	-	-	-	1.84%
8	21.89%	9.22%	-	-	-	-	-	-	-	-	-	1.61%
9	4.03%	0.46%	-	-	-	-	-	-	-	-	-	-
10	0.35%	-	-	-	-	-	-	-	-	-	-	-
11	0.46%	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	0.12%	-	-	-	-	-	-	-	-	-	-	-
14	0.12%	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	0.12%	-	-	-	-	-	0.12%	-	-	-	-	-
18	0.12%	-	-	-	-	-	-	-	-	-	-	-
19	0.12%	-	-	-	-	-	-	-	-	-	-	-
20	0.12%	0.12%	-	-	-	-	-	-	-	-	-	-
21	-	0.12%	-	-	-	-	-	-	-	-	-	-
22	0.12%	0.12%	-	-	-	-	-	-	-	-	-	-
23	0.23%	-	-	-	-	-	-	-	-	-	-	-
24	0.00%	-	-	-	-	-	-	-	-	-	-	-
Sum	63.13%	31.57%	0.35%	-	-	-	0.12%	-	-	-	-	4.84%

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study

4/25/2022

PREPARED FOR

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I. Summary of Methodology and Results

This study was requested by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) to analyze the capacity value of solar, storage, and wind within each system. Capacity value is the reliability contribution of a generating resource and is the fraction of the rated capacity considered to be firm. Average seasonal capacity values are used for reserve margin calculation purposes and seasonal marginal values can be used for expansion planning. Both Companies are winter planning due to winter peak loads and the amount of solar on the systems. As more solar is added, Loss of Load Expectation (LOLE) is shifted to the winter when solar provides less reliability contribution. Because of this winter planning, the winter capacity values were the focus of the study which can then be used for reserve margin accounting and expansion planning purposes.[1]

Because solar and wind are intermittent resources, a solar or wind facility's ability to provide reliable capacity when it is needed is different from that of a fully dispatchable resource such as a gas-fired turbine, which can be called upon in any hour to produce energy, notwithstanding unit outages. Similarly, battery systems have limited energy storage capability and must be recharged, either from the grid or a dedicated generation resource. A battery's ability to reliably provide capacity when it is needed will also differ from that of a fully dispatchable resource. The study results provide the winter capacity value for solar, storage, and wind which are used in the Companies' Carbon Plan and Integrated Resource Plans.

[1] The Appendix includes one set of summer ELCC values for solar and wind for purposes of calculating DEC and DEP summer reserve margins. For determining marginal resources, the summer capacity values have no impact on plans because capacity needs are driven by the winter and resource adequacy risk is in the winter season given the level of solar being included in the plans.

A. Methodology

Astrapé performed this Effective Load Carrying Capacity (ELCC) study using the Strategic Energy Risk Valuation Model (SERVM) which is the same model used for DEC and DEP's past Resource Adequacy and ELCC Studies. The terms capacity value and ELCC are often used interchangeably for the purposes of this report. Additional details of the model setup and assumptions are included in the Technical Modeling Appendix of this report.

The Effective Load Carrying Capacity (ELCC) methodology was used to calculate the capacity value of the resource being studied. A "base" case of the system with no solar or storage was developed that resulted in the DEC and DEP systems achieving the 1 day in 10-year industry standard of 0.1 Loss of Load Expectation (LOLE). This is a common industry standard and ensures that these resources are being evaluated within a reliable system. Once the "base" case is established, battery, solar, and/or wind resources are added to the system. The additional resources improve LOLE to less than 0.1. Next, load is increased by adding a negative resource until the LOLE is returned to the same seasonal reliability as seen in the Base Case.[2] The ratio of the additional load to the additional resource being added is the reliability contribution or ELCC of the battery or renewable resource. For example, if 100 MW of battery is added and achieves the same Base Case seasonal LOLE after adding 90 MW of load, the ELCC is 90% (90 MW divided by 100 MW).

[2] Because it is difficult to return cases back to the exact seasonal reliability, several load levels were analyzed for each setup and interpolation was performed to determine the amount of load added to return to the Base Case seasonal LOLE.

As part of the 2020 IRP filed by the Companies, the Public Service Commission of South Carolina required the Companies to make several adjustments to its solar and storage ELCC studies. [3] For the Companies' Carbon Plan the following items have been taken into account in this study.

1. Perform Surface ELCCs for Solar and Storage –

   To accommodate the surface ELCC, Astrapé performed solar only ELCC analyses, storage only ELCC analyses, and storage and solar aggregated ELCC analysis to ensure any synergistic benefits were included. As laid out in the report, this analysis was performed over a broad range of capacity and storage durations. Previously, in the 2020 Storage ELCC Study, the storage ELCC analysis was performed with significant solar on the system, so all synergistic value was given to storage. Similar surface analysis was performed for wind and solar.

2. Use of 2035 Load Forecasts in the Analysis-

   Utilizing the 2035 load forecast captures a larger system and provides these resources more capacity value as the penetration increases.[4]

3. Use higher capacity factor solar resources –

   All future solar additions were modeled as bifacial, single-axis tracking resources.

4. Incorporate the Company's Winter Peak Demand Reduction Potential Assessment-

   The Winter Peak Study, which included additional demand response programs, adds demand response capacity in both winter and summer. [5]

[3] South Carolina Docket Nos. 2019-224-E and 2019-225-E, Order No. 2021-447, June 28, 2021, at 87.
[4] Given this assumption, ELCCs could potentially be overstated prior to 2035.
[5] The 2020 Winter Peak Demand Reduction Potential Assessment (also referred to as the Winter Peak Study) was prepared for Duke Energy by Dunsky Energy Consulting in partnership with Tierra Resource Consultants. The objective of the study was to identify the potential for new demand response programs and measures to reduce the

B. Solar and Storage Scope

Astrapé calculated the average ELCC of solar and battery energy storage systems as shown in Tables 1 and 2 for both Companies. These tables show the surface that was analyzed across solar and storage resources for each Company. The highlighted blue cells were simulated representing only solar, only storage, and aggregated solar and storage scenarios. Each of the matrices were duplicated for 2-hour, 4-hour, 6-hour, 8-hour, and 12-hour storage systems. The surface methodology allows modelers to understand the benefit of each resource alone and together to determine any synergistic values the resources may have with one another. There is synergistic benefit between solar and storage resources because the resources work together to increase their value from a resource adequacy perspective. After adding a fixed solar profile, the net peak load (gross load minus solar) is typically narrower allowing for short duration storage to better serve the new net load peak.

winter peak demand in each of the DEC and DEP systems. The Winter Peak Study reports were filed with the NCUC in Docket No. E-100, Sub 165.

Table 1. DEC Solar Storage Surface Matrix[6]

		Solar MW						
	DEC	-	2,000	3,000	4,000	6,000	8,000	8,000
Battery MW	-							
	300							
	600							
	1,200							
	2,400							
	3,200							

Table 2. DEP Solar Storage Surface Matrix

		Solar MW						
	DEP	-	3,000	4,500	6,000	7,500	9,000	12,000
Battery MW	-							
	450							
	900							
	1,800							
	3,600							
	4,800							

C. Battery and Solar Modeling

For this study, battery resources were modeled in economic arbitrage mode. The objective of economic arbitrage mode is to maximize the economic value of the battery. In this mode, SERVM schedules the battery to charge at times when system energy costs are low, and to discharge when system energy costs are high. This type of dispatch aligns well with resource adequacy risks, meaning the battery will be available to discharge during peak net load conditions when loss of load events are most likely to occur. In this mode, SERVM offers recourse options during a

[6] The black highlighted areas were not simulated. If it became necessary, these values could be interpolated based on the simulated values.

reliability event. In other words, SERVM allows the schedule of the battery to be adjusted in real time, and discharge if its state of charge is greater than zero to avoid firm load shed. This method also assumes the utility has full control of the battery and best represents how batteries are expected to be operated on the DEC and DEP systems. Batteries were assumed to have no limits on ramping capability or constraints on number of cycles per day outside of the ability to charge the battery. Batteries were given an equivalent forced outage rate ("EFOR") of 2.4% compared to the negative resource (modeled as load) that was given a 4% outage rate.[7] By modeling resources with their unit specific EFOR values, all resources are captured on a level playing field. Solar was modeled with hourly profiles as described in the Technical Appendix, and a 2.7% outage rate. All new solar was based on bifacial single-axis tracking profiles.

D. Storage/Solar Surface Winter Results

Tables 3 and 4 show the average winter ELCC for battery without any solar included in the setup, solar without any battery included in the setup, and the synergistic ELCC's when both are included. For DEC, battery levels were modeled from 0 to 3,200 MW and solar resources from 0 to 8,000 MW. The synergistic values are higher than the single resource values especially as penetrations increase.

[7] The 4% outage rate represents the high end of new thermal resources such as new combined cycle or combustion turbine resources.

Table 3. DEC Winter Solar and Storage Results[8]

Solar MW	Battery MW	Duration Hours	Average Battery Capacity Value (no solar included)	Average Solar Capacity Value (no battery included)	Average Battery Capacity Value including any synergistic value	Average Solar Capacity Value including any synergistic value
2,000	200	2	99.2%	6.1%	100.0%	6.5%
3,000	400	2	97.8%	5.0%	100.0%	5.0%
4,000	600	2	96.4%	4.1%	98.7%	4.1%
5,000	800	2	95.1%	3.4%	95.7%	3.8%
2,000	300	4	99.5%	6.1%	99.9%	6.1%
3,000	600	4	99.8%	5.0%	99.8%	5.1%
4,000	1,200	4	98.5%	4.1%	98.8%	4.3%
5,000	2,400	4	87.3%	3.4%	94.0%	3.7%
6,000	3,200	4	73.5%	2.9%	88.4%	3.3%
8,000	3,200	4	73.5%	2.4%	88.6%	3.0%
2,000	300	6	99.8%	6.1%	100.0%	6.1%
3,000	600	6	99.4%	5.0%	100.0%	5.0%
4,000	1,200	6	97.4%	4.1%	99.3%	4.3%
5,000	2,400	6	88.7%	3.4%	95.6%	3.7%
6,000	3,200	6	79.2%	2.9%	91.7%	3.3%
8,000	3,200	6	79.2%	2.4%	91.8%	2.8%
2,000	300	8	99.6%	6.1%	99.6%	6.1%
3,000	600	8	99.6%	5.0%	99.6%	5.1%
4,000	1,200	8	98.1%	4.1%	98.3%	4.3%
5,000	2,400	8	89.6%	3.4%	94.7%	3.6%
6,000	3,200	8	79.8%	2.9%	91.0%	3.2%
8,000	3,200	8	79.8%	2.4%	92.6%	2.8%
2,000	300	12	99.8%	6.1%	100.0%	6.1%
3,000	600	12	99.5%	5.0%	99.8%	5.1%
4,000	1,200	12	97.7%	4.1%	98.3%	4.2%
5,000	2,400	12	90.2%	3.4%	94.8%	3.6%
6,000	3,200	12	82.1%	2.9%	92.1%	3.1%
8,000	3,200	12	82.1%	2.4%	92.7%	2.8%

[8] All values have been curve fitted to reflect smooth curves across the solar and storage penetrations resulting in minor adjustments for reporting purposes.

The same results are shown for DEP. The solar was simulated up to 12,000 MW and battery was simulated up to 4,800 MW.

Table 4. DEP Winter Solar and Storage Results[9]

Solar MW	Battery MW	Duration Hours	Average Battery Capacity Value (no solar included)	Average Stand-Alone Solar Capacity Value (no battery included)	Average Battery Capacity Value including any synergistic value	Average Solar Capacity Value including any synergistic value
3,000	300	2	97.7%	7.7%	100.0%	8.2%
4,500	600	2	91.2%	6.3%	96.2%	6.4%
6,000	900	2	84.8%	5.2%	90.4%	5.3%
7,500	1,200	2	78.4%	4.4%	83.3%	4.8%
3,000	450	4	100.0%	7.7%	100.0%	7.8%
4,500	900	4	95.8%	6.3%	96.6%	6.5%
6,000	1,800	4	86.9%	5.2%	88.4%	5.5%
7,500	3,600	4	68.3%	4.4%	73.4%	4.7%
9,000	4,800	4	55.3%	3.8%	64.5%	4.2%
12,000	4,800	4	55.3%	3.3%	64.5%	3.9%
3,000	450	6	100.0%	7.7%	100.0%	7.7%
4,500	900	6	97.5%	6.3%	98.3%	6.5%
6,000	1,800	6	93.5%	5.2%	94.5%	5.5%
7,500	3,600	6	78.2%	4.4%	84.1%	4.8%
9,000	4,800	6	62.5%	3.8%	75.1%	4.3%
12,000	4,800	6	62.5%	3.3%	75.1%	4.0%
3,000	450	8	100.0%	7.7%	100.0%	7.7%
4,500	900	8	97.8%	6.3%	98.8%	6.4%
6,000	1,800	8	95.0%	5.2%	96.4%	5.5%
7,500	3,600	8	81.6%	4.4%	87.3%	4.7%
9,000	4,800	8	66.9%	3.8%	78.0%	4.2%
12,000	4,800	8	66.9%	3.3%	78.0%	3.9%
3,000	450	12	100.0%	7.7%	100.0%	7.8%

[9] At the low battery capacity levels (450-900 MW), additional Monte Carlo outage iterations are likely required to understand any clear differences between battery durations which are showing capacity values all near 100%. For reporting purposes, minor adjustments were made. For example, if the 450 MW 8 hour was interpolated at 99% it was adjusted to 100% since the 6-hour showed 100% for 450 MW. All values have been curve fitted to reflect smooth curves across the solar and storage penetrations resulting in minor adjustments for reporting purposes.

4,500	900	12	97.8%	6.3%	98.8%	6.4%
6,000	1,800	12	95.6%	5.2%	96.5%	5.4%
7,500	3,600	12	85.2%	4.4%	88.8%	4.6%
9,000	4,800	12	71.1%	3.8%	79.3%	4.1%
12,000	4,800	12	71.1%	3.3%	79.3%	4.0%

Tables 5 and 6 show the same ELCC results but calculated as the marginal ELCC. These include any synergistic value between the solar and storage. The marginal values were developed by curve fitting the average results to a polynomial and taking the first derivative. A single set of solar winter values were reported since all the values were similar across all the battery durations. The marginal ELCC represents the next MW at each point in the penetration. For example, the 2401st MW of 4-hour storage is worth 79.4%.

Table 5. DEC Winter Marginal Values

Solar	Battery	Duration	Marginal Battery including any synergistic values	Marginal Solar including any synergistic values
2,000	200	2	100.0%	
3,000	400	2	98.0%	
4,000	600	2	93.9%	
5,000	800	2	89.8%	
2,000	300	4	100.0%	3.1%
3,000	600	4	100.0%	2.4%
4,000	1,200	4	94.9%	1.8%
5,000	2,400	4	79.4%	1.2%
6,000	3,200	4	69.0%	1.1%
2,000	300	6	100.0%	
3,000	600	6	100.0%	
4,000	1,200	6	96.2%	
5,000	2,400	6	85.2%	
6,000	3,200	6	77.9%	
2,000	300	8	100.0%	
3,000	600	8	99.3%	
4,000	1,200	8	95.0%	
5,000	2,400	8	86.5%	
6,000	3,200	8	80.8%	

2,000	300	12	100.0%	[redacted]
3,000	600	12	98.7%	
4,000	1,200	12	95.0%	
5,000	2,400	12	87.6%	
6,000	3,200	12	82.7%	

Table 6 shows the same information for DEP. At some point, batteries will flatten the net load shape, removing the arbitrage opportunity, making the value of the next MW of short duration storage much less valuable.

Table 6. DEP Winter Marginal Values

Solar	Battery	Duration	Marginal Battery including any synergistic values	Marginal Solar including any synergistic values
3,000	300	2	100.0%	[redacted]
4,500	600	2	85.1%	
6,000	900	2	70.2%	
7,500	1,200	2	55.4%	
3,000	450	4	93.7%	4.7%
4,500	900	4	86.8%	3.2%
6,000	1,800	4	73.1%	1.7%
7,500	3,600	4	45.8%	1.7%
9,000	4,800	4	27.5%	1.6%
3,000	450	6	100.0%	[redacted]
4,500	900	6	97.9%	
6,000	1,800	6	84.9%	
7,500	3,600	6	59.0%	
9,000	4,800	6	41.6%	
3,000	450	8	100.0%	
4,500	900	8	100.0%	
6,000	1,800	8	88.5%	
7,500	3,600	8	62.2%	
9,000	4,800	8	44.7%	
3,000	450	12	100.0%	
4,500	900	12	100.0%	
6,000	1,800	12	90.4%	
7,500	3,600	12	64.2%	
9,000	4,800	12	46.7%	

In addition to standalone solar and standalone storage resources, the Companies also include storage that is "DC coupled" with solar in their capacity expansion model. While not explicitly analyzed in this study, it is reasonable to assume that the ELCC of the solar resource and the ELCC of the storage resource are additive. As an example, a 100 MW solar facility that is DC-coupled with a 50 MW, 4-hour storage facility in DEP should have a firm capacity rating of approximately 52 MW (100 MW solar * 4.7% + 50 MW, 4-hour storage * 93.7%).

E. Sensitivity – 6-Hour Standalone Winter Battery Capacity Values Beyond 4-Hour Values

Additional surface analysis was performed to understand how 6-hour storage performed after significant 4-hour storage had already been added to the system. For these runs, storage and solar were added together as in the previous analysis to capture the synergistic value. The results are listed in Tables 7 and 8.

Table 7. DEC Winter 6-Hour after 4-Hour Battery

Solar	Battery	Duration	Average Battery Capacity Value (including any synergistic value)	Marginal Battery Capacity Value (including any synergistic value)
2,000	300	4	100%	100%
3,000	600	4	100%	100%
4,000	1,200	4	99%	95%
5,000	2,400	4	94%	79%
6,000	3,200	4	88%	69%
8,000	4,000	6	81%	51%
8,000	5,000	6	74%	38%

Table 8. DEP Winter 6-Hour after 4-Hour Battery

Solar	Battery	Duration	Average Battery Capacity Value (including any synergistic value)	Marginal Battery Capacity Value (including any synergistic value)
3,000	450	4	100%	94%
4,500	900	4	97%	87%
6,000	1,800	4	88%	73%
7,500	2,300	6	90%	85%
7,500	2,800	6	87%	68%

One last sensitivity was performed for DEC evaluating the existing Bad Creek Pump Hydro Facility. DEC's existing Bad Creek (BC1) is modeled with 19 hours of storage and 1,640 MW of capacity. Because of its long duration, existing pump storage on the system was assumed to provide nearly 100% capacity value. DEC is evaluating adding a second powerhouse (Bad Creek 2 or BC2) at the existing Bad Creek 1 facility. In that case, Bad Creek 1 is reduced to 12 hours and an incremental 1,680 MW of 12-hour duration storage capacity is added. To assess the impact of reduced duration of Bad Creek 1 on the incremental 12-hour storage created by the addition of Bad Creek 2, the 12-hour surface analysis was rerun assuming a lower duration BC1. This analysis, depicted in Table 9, determined that the capacity value of incremental 12-hour storage decreases slightly with a reduction in BC1 storage duration.

Table 9. DEC Winter 12-Hour Bad Creek 2 Sensitivity

Solar	Battery	Duration	Average Battery Capacity Value BC1 @ 19 hours including any synergistic value	Marginal Battery Capacity Value BC1 @ 19 storage including any synergistic value	Average Battery Capacity Value BC1@ 12 hours including any synergistic value	Marginal Battery Capacity Value BC1@ 12 hours including any synergistic value
2,000	300	12	100.0%	100.0%	100.5%	100.0%
3,000	600	12	99.8%	98.7%	99.6%	98.3%
4,000	1,200	12	98.3%	95.0%	97.7%	93.6%
5,000	2,400	12	94.8%	87.6%	93.5%	84.1%
6,000	3,200	12	92.1%	82.7%	90.2%	77.8%

F. Wind Resources

Wind resources were modeled as hourly profiles provided by the Companies. The Technical Appendix provides more information surrounding these shapes. Wind profiles were provided assuming a 2.6% outage rate compared to the negative resource that was assumed to have a 4% outage rate.

G. Wind/Solar Surface Scope

Astrapé calculated the average ELCC of wind and solar as laid out in Tables 10 and 11 for both Companies. The highlighted blue cells were simulated representing only wind, only solar, and aggregated solar and wind scenarios. Each of the matrices were duplicated for offshore and onshore wind for both Companies.

Table 10. DEC Solar/Wind Surface Matrix

		Solar MW			
	DEC	-	2,000	4,000	6,000
Wind MW	-				
	1,000				
	2,000				
	3,000				

Table 11. DEP Solar/Wind Surface Matrix

		Solar MW			
	DEP	-	3,000	6,000	9,000
Wind MW	-				
	1,000				
	2,000				
	3,000				

H. Winter Wind/Solar Surface Results

Tables 12 and 13 show the average winter ELCC for wind without any solar included in the setup, solar without any wind included in the setup, and the ELCC's when both are included to capture any synergistic value the resources have. There was very little synergistic value seen in the onshore wind and solar analysis but a higher amount in the offshore wind and solar analysis. DEC was modeled with solar from 0 to 6,000 MW and wind from 0 to 3,000 MW. DEP was modeled with solar from 0 to 9,000 MW and wind from 0 to 3,000 MW. The profiles provided by the Company showed substantial output during cold winter mornings in the offshore wind profiles.[10] Even for winter values, to see ELCC's of this magnitude for offshore wind, particularly in DEC, is not intuitive and it is recommended that the Companies continue to understand offshore wind profiles especially during extreme cold periods.

Table 12. DEC Winter Wind Results

Solar MW	Wind MW	Offshore/ Onshore	Average Wind Capacity Value (no solar included)	Average Solar Capacity Value (no wind included)	Average Wind Capacity Value (including any synergistic value)	Average Solar Capacity Value (including any synergistic value)	Marginal Wind Capacity Value (including any synergistic value)
2,000	1,000	Onshore	39.9%	6.1%	40.7%	6.6%	29.1%
4,000	2,000	Onshore	36.9%	4.1%	36.9%	3.9%	32.0%
6,000	3,000	Onshore	35.8%	2.9%	34.9%	3.0%	35.0%
2,000	1,000	Offshore	89.5%	6.1%	94.9%	6.9%	86.6%
4,000	2,000	Offshore	84.2%	4.2%	89.3%	4.3%	80.7%
6,000	3,000	Offshore	76.4%	2.9%	85.5%	3.4%	74.8%

[10] Profiles are based on "ERA5" climate and weather data from the European Centre for Medium-Range Weather Forecasts. More information can be found at: https://cds.climate.copernicus.eu/cdsapp#!/dataset/reanalysis-era5-single-levels?tab=overview

Table 13. DEP Winter Wind Results

Solar MW	Wind MW	Offshore/ Onshore	Average Wind Capacity Value (no solar included)	Average Solar Capacity Value (no wind included)	Average Wind Capacity Value (including any synergistic value)	Average Solar Capacity Value (including any synergistic value)	Marginal Wind Capacity Value (including any synergistic value)
3000	1000	Onshore	44.3%	7.7%	43.2%	7.8%	42.1%
6000	2000	Onshore	40.9%	5.2%	41.9%	5.4%	39.2%
9000	3000	Onshore	39.1%	3.8%	40.5%	4.1%	36.3%
3000	1000	Offshore	72.8%	7.7%	81.8%	6.9%	69.7%
6000	2000	Offshore	71.4%	5.2%	74.4%	5.5%	64.3%
9000	3000	Offshore	67.6%	3.8%	70.1%	4.1%	58.9%

I. Winter ELCC Conclusions

Winter ELCC's are a driver in resource plans for the Companies. Astrapé has taken an approach to recognize the synergistic value of combinations of resources. The winter storage ELCC's are at or near 100% for the first couple of battery tranches, but eventually these values will drop dramatically given winter load shapes can remain high across the day. Once enough storage is on the system, the net loads flatten to the point storage is needed in both the evening and morning peaks with limited reserve capacity available throughout the night to recharge the batteries. Solar values remain low during the winter as the risk of load shed is mostly during the early morning hours. The ELCC of onshore wind is in the 30-40% range while the ELCC of offshore wind was calculated to be north of 60%. This is driven by the ERA-5 shapes provided by the Company which show extremely high wind output during the coldest winter mornings. The average winter values should be used for reserve margin accounting and the marginal winter values should be used for marginal resource decision making since the needs of the Companies are in the winter.

II. Technical Modeling Appendix

The following sections include a discussion on the setup and assumptions used to perform the ELCC study. The Study utilized the framework from the 2020 Resource Adequacy study and updated the following inputs.

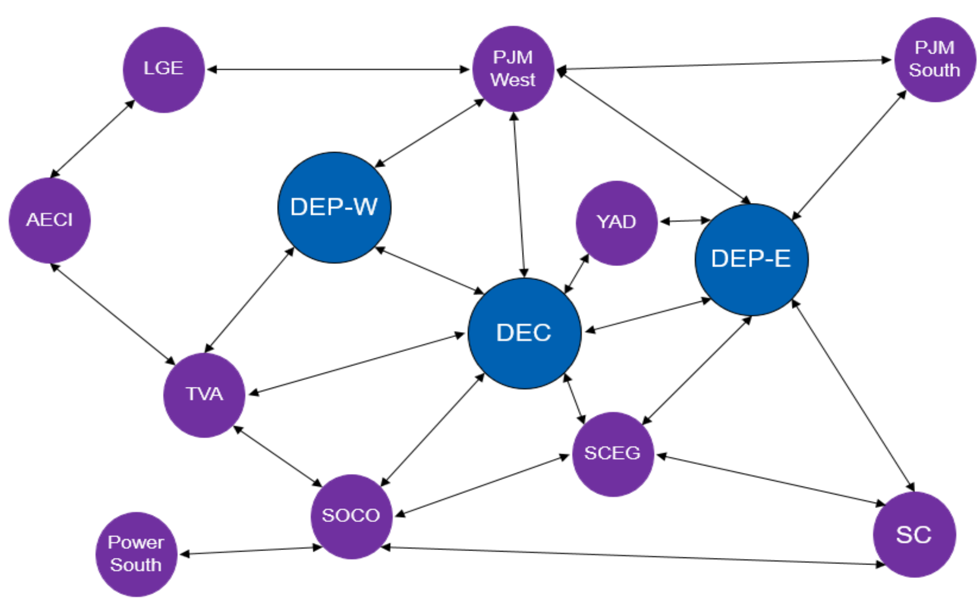
A. SERVM Framework and Cases

The study uses the same framework as the Base Case 2020 Resource Adequacy Study but was updated to model study year 2026 and included forty-one weather years (1980 – 2020), five load forecast error multipliers, and Monte Carlo generator outages.

B. Study Topology

The 2020 Resource Adequacy study was updated to include the additional SEEM entities Louisiana Gas and Electric (LGE), Associated Electric Cooperative Incorporated (AECI), and Power South. The study topology is shown below in Figure 1.

Figure 1. Study Topology



In order to reduce the simulation time for the ELCC analysis, the neighbors were tuned to 0.1 reliability in a calibration study. Purchases were derived from this calibration study to simulate the benefit received from the market. This allowed DEC and DEP to be simulated as islands for all the ELCC analyses.

C. Load Modeling

The load modeling was updated to model forty-one historical weather years (1980- 2020). The same methods used in the 2020 Resource Adequacy Study were used for this update. Based on the last five years of historical weather and load, a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from weather stations across the DEC and DEP service territories. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last forty-one years of weather to develop forty-one synthetic load shapes for 2026. Extreme peaks were corrected based on regression analysis examining extreme peak periods for both winter and summer. Equal probabilities were given to each of the forty-one load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Company's projected thirty-year weather normal load forecast for 2026.

D. Economic Load Forecast Error

Economic load forecast error multipliers from the 2020 Resource Adequacy were updated to reflect additional historical data. The updated values are shown in Table 14. Because the system is driven to 0.1 before the analysis begins, these assumptions don't drive the ELCC analysis significantly.

Table 14. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.96	10.4%
0.98	23.3%
1.00	32.5%
1.02	23.3%
1.04	10.4%

E. Conventional Resource Modeling

The resource mixes for DEC, DEP-E, and DEP-W were all updated to reflect any changes in the fleets since the 2020 Resource Adequacy Study was performed. Additionally, all modeled outage rates for the thermal fleet were updated to reflect the five most recent years of GADS data.

F. Renewable Resource Modeling

The solar units were modeled with updated forty-one solar shapes that represent forty-one years of weather data. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. Figure 2 below shows the county locations that were used and then Figure 3 shows the average August output for different fixed-tilt and single-axis-tracking inverter loading ratios.

Figure 2. Solar Location Map

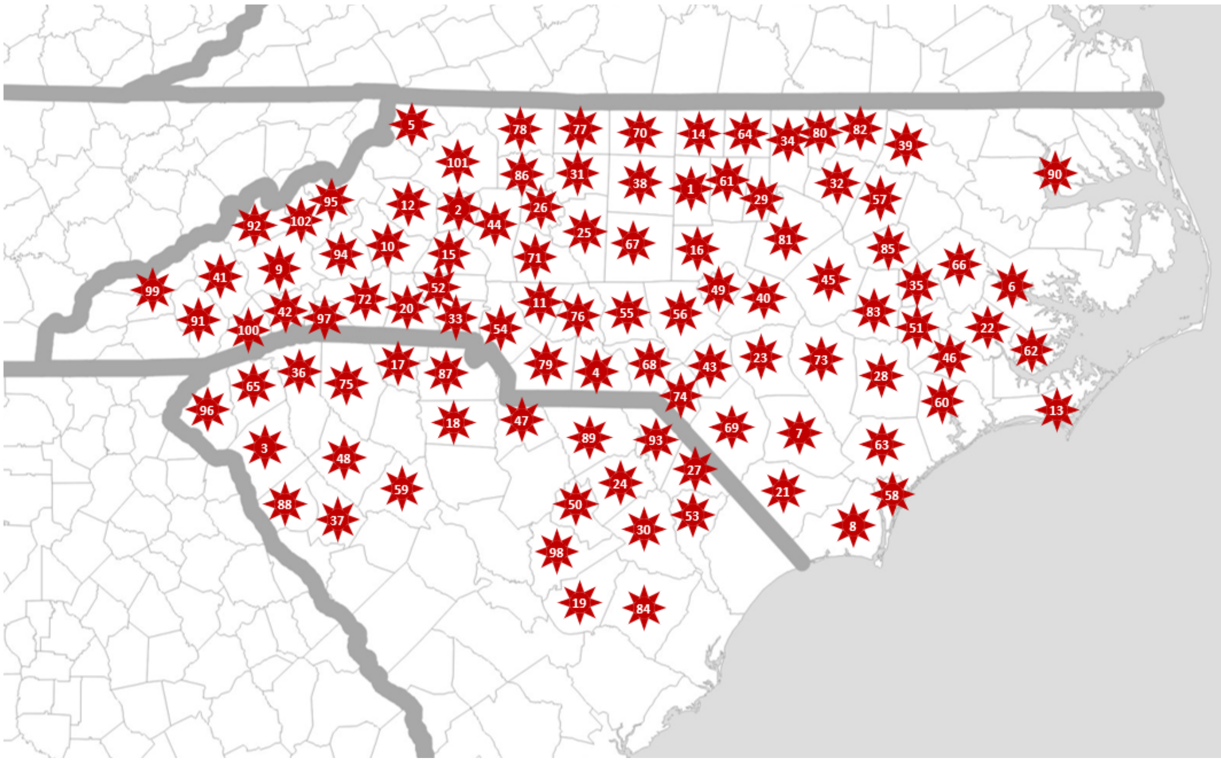
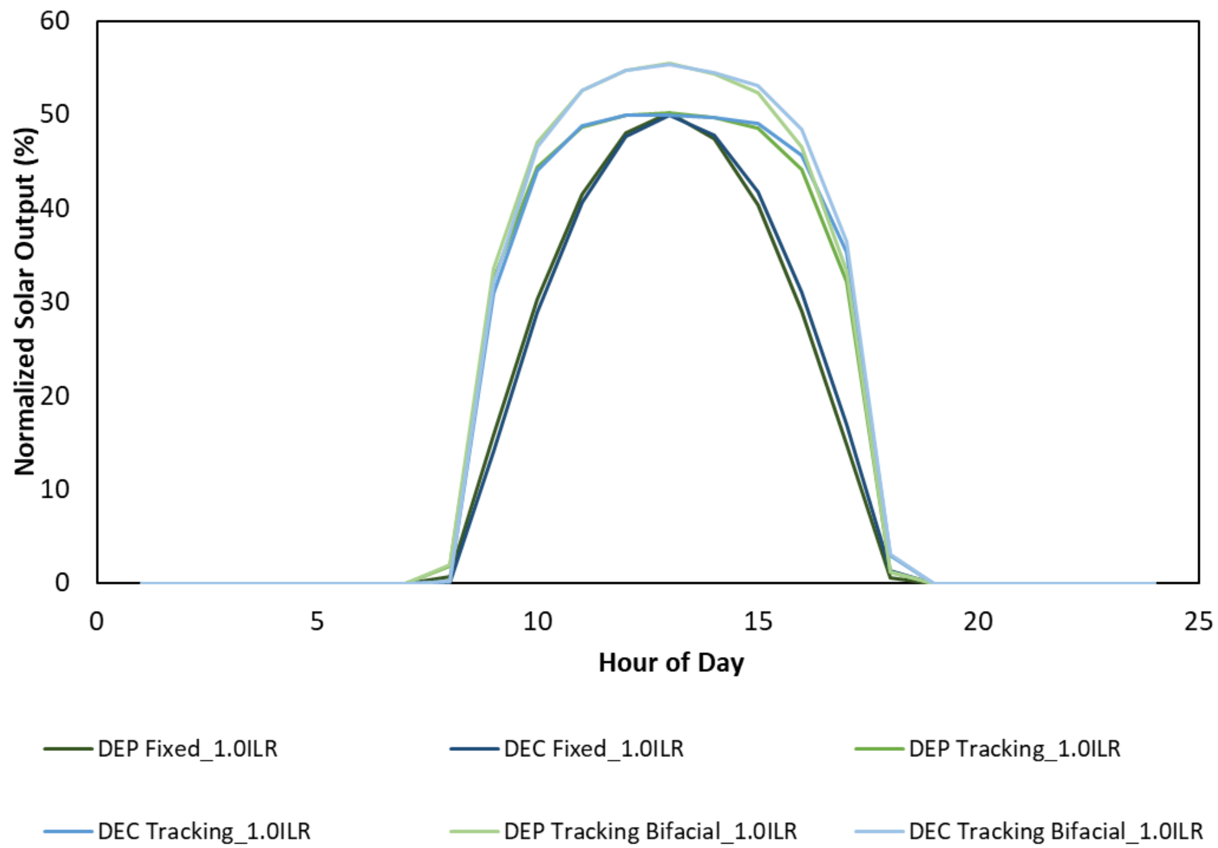


Figure 3. Average January Solar



The onshore and offshore wind profiles were provided by DEC and DEP and were derived from ERA-5 meteorological data. Figures 4 and 5 outline their average output and then a comparison of their output on peak days. Given the high output of offshore profiles on peak days, it is understandable that these profiles would result in a high ELCC value.

Figure 4. Average January Onshore and Offshore Wind Output

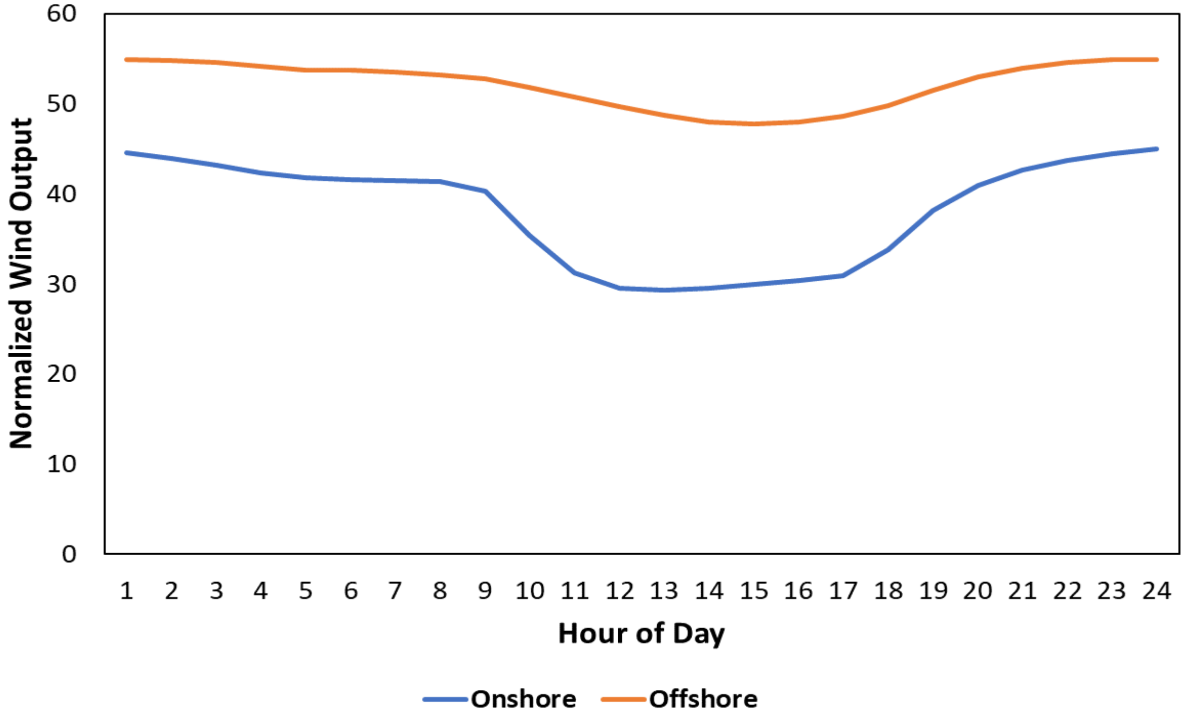
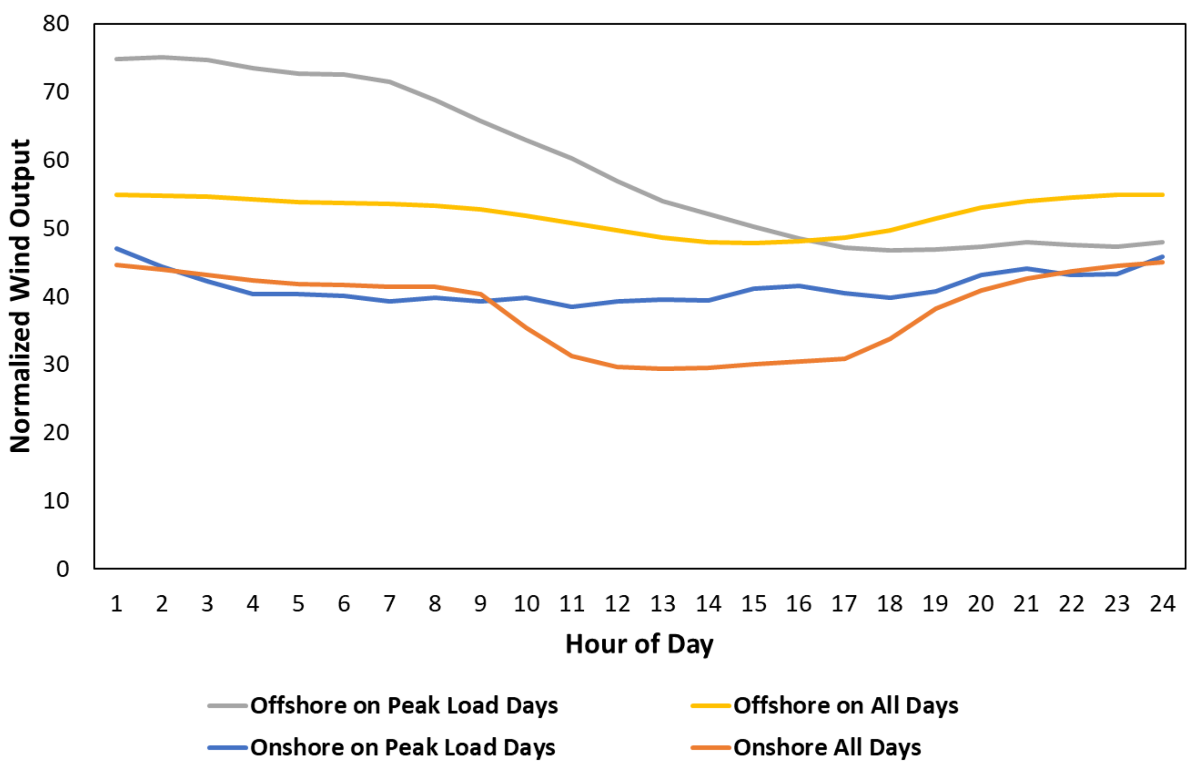


Figure 5. Peak Load Day January Onshore/Offshore Wind Output



G. Summer Solar and Wind ELCC Values

While summer was not the focus of this study, summer ELCC values were calculated for solar and wind for reserve margin accounting purposes. The Solar ELCC values are listed in Table 15 below. This analysis was only performed for DEC since there was summer LOLE in the Base Case before any solar was added. There was essentially zero LOLE in the summer in DEP even before solar is added so additional runs were not performed DEP because it would require manipulating the Base Case further to produce summer LOLE. These summer values give reasonable estimates for reserve margin accounting purposes and can be reasonably used for both Companies. But as discussed previously, because solar increases summer capacity more than winter capacity, summer reserve margins are increasing faster making future resource decisions driven by winter capacity need.

Table 15. Summer Solar ELCC Values

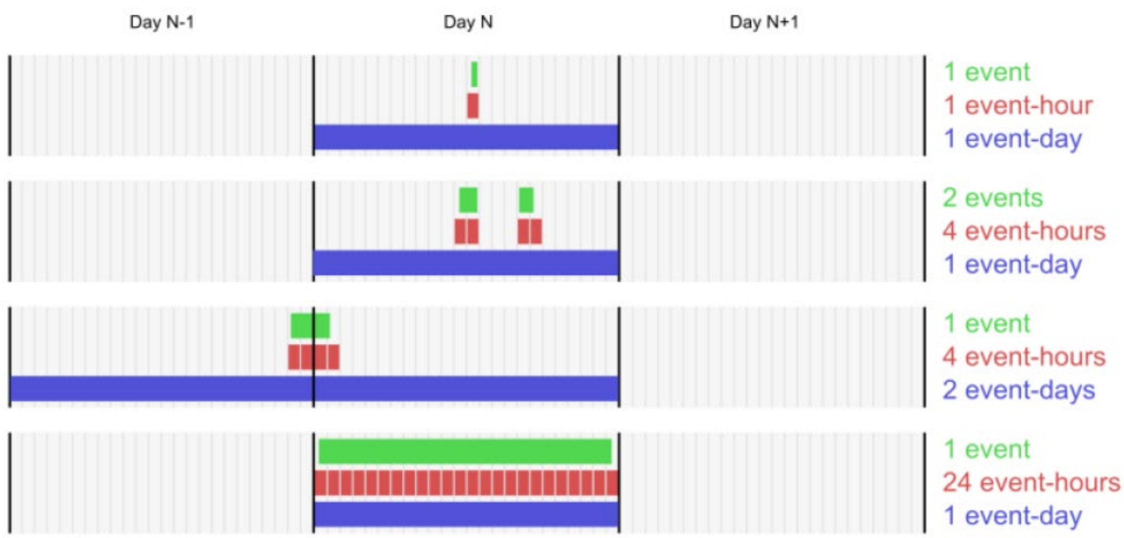
Solar MW	Storage (MW)	Summer Solar Average ELCC	Summer Solar Marginal ELCC
2000	300	67%	37.9%
3000	600	56%	34.3%
4000	1,200	51%	30.8%
5000	2,400	46%	24.0%
6000	3,200	42%	18.6%
8000	3,200	35%	7.9%

Onshore wind was found to provide approximately 11% in the summer and offshore wind was found to provide approximately 37% in the summer.

H. Discussion of Reliability Metrics (LOLE vs. EUE)

As part of the analysis, Astrapé did examine the impact the reliability metric used had on the ELCC values. Traditional resource adequacy only considers LOLE which counts the number of days customers are not served. LOLE is counted as one day whether the day has one hour or ten hours of load shed. Under this metric, two portfolios can have the same number of days of load shed but one portfolio could have substantially more load shed from an energy standpoint. This is illustrated in Figure 6 below where the first, second and fourth portfolios have the same number of days from a LOLE perspective but may differ in the number of hours and customer energy unserved.

Figure 6. LOLE Illustration[11]



Expected Unserved Energy (EUE) is another reliability metric which measures all customer energy demand not served. To better understand the impact a change in reliability metric may have on the results, Astrapé analyzed battery capacity values using EUE instead of LOLE as the ELCC

[11] Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric-2021 NERC Probabilistic Analysis Forum October 5th, 2021

metric. The winter results seen in Table 16 show that for short term storage, the capacity values based on EUE are substantially lower than of the LOLE results. This is logical because a 2-hour battery may still eliminate some events that a fully dispatchable resource can eliminate, but during events that remain it is likely that there will be more EUE with short duration battery. This is an interesting finding of the study that should be noted for future analysis. The opposite occurs for solar because solar cannot typically eliminate the entire event since most of the load shed in the winter events are before the sun rises, but it can eliminate EUE in hours 8 and 9. These results are shown in Table 17. For this reason, using EUE as the metric actually benefits solar. Planning reserve margin studies across the industry have used LOLE and the 1-day in 10-year standard so changing metrics for ELCC would create an accounting disconnect that would require further adjustments to the overall resource adequacy framework.

Table 16. DEC LOLE vs EUE Winter Battery ELCC Results

Battery (MW)	Duration(hours)	Average Battery Capacity Values with no solar included LOLE Base Results	Average Battery Capacity Values with no solar included EUE Results	Delta (EUE - LOLE)
400	2	97.8%	60.7%	-37.1%
600	2	96.4%	60.0%	-36.4%
800	2	95.1%	57.8%	-37.3%
600	4	99.8%	82.1%	-17.8%
1,200	4	98.5%	77.5%	-21.0%
2,400	4	87.3%	75.4%	-11.9%
3,200	4	73.5%	59.6%	-14.0%
600	6	99.4%	93.4%	-6.1%
1,200	6	97.4%	90.1%	-7.3%
2,400	6	88.7%	78.3%	-10.4%
3,200	6	79.2%	70.2%	-9.0%
600	8	99.6%	95.1%	-4.4%
1,200	8	98.1%	94.0%	-4.1%
2,400	8	89.6%	84.7%	-4.9%
3,200	8	79.8%	69.7%	-10.1%
600	12	99.8%	98.2%	-1.7%
1,200	12	99.5%	93.1%	-6.4%
2,400	12	97.7%	93.7%	-4.0%
3,200	12	90.2%	84.4%	-5.8%

Table 17. DEC LOLE vs EUE Winter Solar ELCC Results

Solar (MW)	Average Solar Capacity Value with no storage included LOLE Results	Average Solar Capacity Value with no storage included EUE Results
2,000	6.1%	8.2%
3,000	5.0%	6.2%
4,000	4.1%	5.7%
5,000	3.4%	5.1%
5,000	2.9%	4.9%
5,000	2.4%	3.8%

/A

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Duke Energy North Carolina EE and DSM Market Potential Study

Submitted to Duke Energy

June, 2020

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1 Executive Summary

In November, 2019, Duke Energy retained Nexant, Inc., to determine the potential energy and demand savings that could be achieved by energy efficiency (EE) and demand-side management (DSM) programs in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) service territories. This report describes the potential for DSM savings among these two service territories in North Carolina. The main objectives of the study include:

- Providing a market potential study, which estimates the technical, economic and realistic achievable market potential energy savings over the short term (5 year projection), medium term (10 year projection), and long term (25 year projection).
- Estimating the potential energy and demand savings for Duke Energy's North Carolina service territory.
- Developing of savings estimates with a focus on different perspectives: compliance and system planning.

1.1 Methodology

This study utilized Nexant's Microsoft Excel-based modeling tool, TEAPot (Technical, Economic, and Achievable Potential). This modeling tool was built on a platform that provides the ability to calculate multiple scenarios and recalculate potential savings based on variable inputs such as sales/load forecasts, electricity prices, discount rates, and actual program savings. The assessment started with the current Duke Energy load and sales forecasts, which were disaggregated into customer-class and end use components. Opportunities for reducing electricity consumption among Duke Energy customers were developed by examining the full range of commercially available energy efficiency measures and practices. Nexant examined measures for each end use, taking into account fuel shares, current market saturations, technical feasibility, and costs. Measure savings impacts were applied to each customer class, segment, and end use to estimate EE and DSM potential at the end use, customer class, and system levels.

1.2 Savings Potential

Technical potential as a share of 2044 electricity sales indicates the theoretical upper limit on savings from EE is approximately 32% in the DEC territory and 34% in the DEP territory. These estimates of cumulative technical potential ignore measure costs and focus on energy savings wherever technically feasible. Cumulative economic potential reflects current trends of declining avoided energy costs for utilities, with 13% savings in DEC and 11% savings in DEP. Economic potential is attributable to measures that are cost effective using the Total Resource Cost test (TRC), in keeping with the rules of the NC Public Utilities Commission. The results of economic screening indicate that many measures currently offered by Duke Energy through EE and DSM programs may not continue to be cost-effective from the standpoint of the TRC. Economic screening also demonstrates that Duke Energy programs currently offer all measures identified as cost-effective.

These baseline conditions and market trends, coupled with projected achievable participation for cost-effective measures, produced estimates of annual achievable program energy savings that average approximately 0.78% of annual Base Sales in DEC and 0.87% of annual Base Sales in DEP over the 25-year period covered in this study.

Nexant examined three scenarios for achievable potential: base, enhanced, and an avoided energy cost sensitivity. These scenarios provide a sensitivity for EE costs and benefits to understand how market conditions and trends affect the costs and benefits of utility-sponsored programs over the study's time horizon of twenty-five years:

- Base scenario – aligns with existing program portfolio, and includes existing EE programs and measures currently offered by DEC or DEP
- Enhanced scenario – includes the base scenario, but with increased program spending (via incentives) designed to attract new customers into the market for EE technology and program participation
- Avoided Energy Cost Sensitivity scenario – covers the base scenario, but with a sensitivity analysis around enhanced EE benefits, such as may occur if avoided energy costs were higher than current values. Higher benefits for EE may lead to additional cost-effective measures and increased achievable potential

1.2.1 Energy Efficiency Potential

The estimated technical and economic potential scenarios for DEC are summarized in Table 1-1, which lists cumulative energy and demand savings for each type of potential. Savings percentages are presented as a share of end year sales over 25 years. These projected sales values were adjusted to remove opt-out customers.

Table 1-1: DEC Energy Efficiency Technical and Economic Potential

	Energy Efficiency Potential (2020-2044)			
	Energy (GWh)	% of End Year Sales	Demand (MW)	
			Summer	Winter
Technical Potential	15,034	32%	5,226	1,064
Economic Potential	5,992	13%	1,268	582

Table 1-2 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) DEC portfolio EE program potential for the base, enhanced, and avoided energy cost sensitivity scenarios. Impacts are presented as **the average of annual impacts** achieved over the stated time horizon (5 years, 10 years, or 25 years).

Table 1-2: DEC Energy Efficiency Achievable Program Potential

Scenario Milestones	Energy (GWh)	Demand (MW)		Average Annual % of Base Sales[1]
		Summer	Winter	
DEC Achievable Program Potential – Base Scenario				
5-yr sum of annuals (2024)	1,730	598	159	0.88%
10-yr sum of annuals (2029)	3,321	1,159	304	0.84%
25-Yr sum of annuals (2044)	8,257	2,945	754	0.78%
DEC Achievable Program Potential – Enhanced Scenario				
5-yr sum of annuals	1,878	620	175	0.95%
10-yr sum of annuals	3,563	1,197	326	0.90%
25-yr sum of annuals	8,663	3,008	789	0.82%
DEC Achievable Program Potential – Avoided Energy Cost Sensitivity Scenario				
5-yr sum of annuals	1,754	602	162	0.89%
10-yr sum of annuals	3,363	1,168	306	0.85%
25-yr sum of annuals	8,336	2,962	758	0.79%

Technical and economic for DEP are presented in Table 1-3. As above, cumulative energy impacts are presented as a share of end year sales for 2024, 2029, and 2044 and sales are adjusted to remove opt-out customers.

[1] Average annual energy savings as percentage of annual base sales per period.

Table 1-3: DEP Energy Efficiency Technical and Economic Potential

	Energy Efficiency Potential (2020-2044)			
	Energy (GWh)	% of End Year Sales	Demand (MW)	
			Summer	Winter
Technical Potential	10,350	34%	4,509	588
Economic Potential	3,414	11%	970	248

Table 1-4 presents achievable program potential in terms of the sum of annual incremental energy for the stated time horizon. The table also presents demand savings and average annual percentage of base sales.

Table 1-4: DEP Energy Efficiency Achievable Potential

Scenario Milestones	Energy (GWh)	Demand (MW)		Average Annual % of Base Sales[2]
		Summer	Winter	
DEP Achievable Program Potential – Base Scenario				
5-yr sum of annuals (2024)	1,176	522	84	0.94%
10-yr sum of annuals (2029)	2,289	1,024	160	0.91%
25-Yr sum of annuals (2044)	5,910	2,686	412	0.87%
DEP Achievable Program Potential – Enhanced Scenario				
5-yr sum of annuals	1,250	535	90	1.00%
10-yr sum of annuals	2,409	1,045	169	0.96%
25-yr sum of annuals	6,107	2,720	425	0.90%
DEP Achievable Program Potential – Avoided Energy Cost Sensitivity Scenario				
5-yr sum of annuals	1,197	526	85	0.96%
10-yr sum of annuals	2,325	1,030	164	0.92%
25-yr sum of annuals	5,972	2,698	416	0.88%

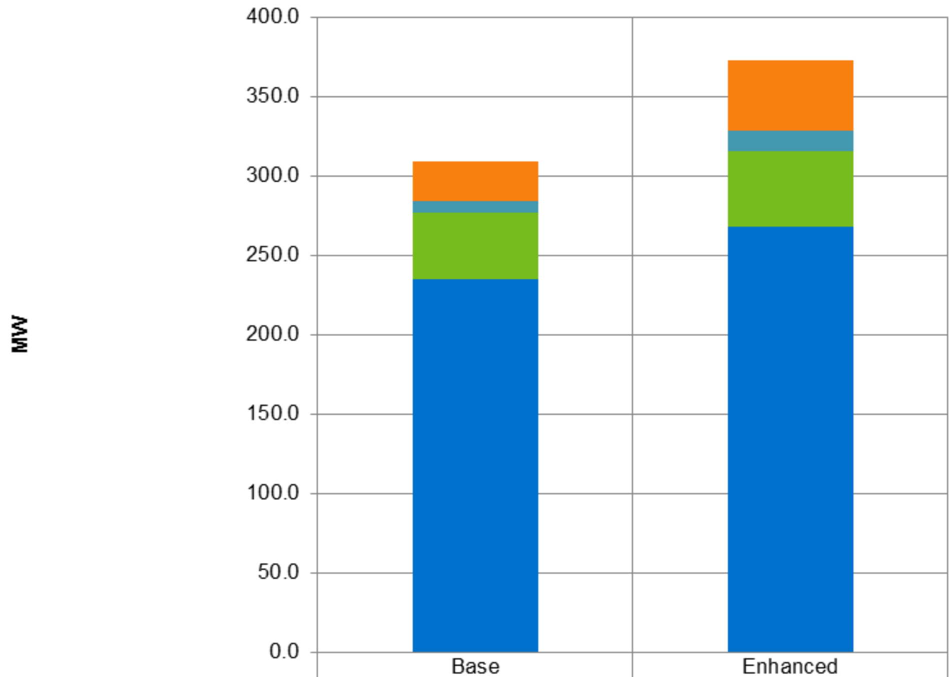
1.2.2 Demand-side Management Potential

DSM opportunities were analyzed for DEC's North Carolina service territory to determine the amount of summer and winter peak capacity that could be reduced through DSM initiatives from a technical, economic, and program potential perspective. While technical and economic potential are theoretical upper limits, for program-based DSM, participation rates are calculated as a function of the incentives offered to each customer group. For a given incentive level and participation rate, the cost-effectiveness of each customer segment is evaluated to determine whether the aggregate DSM potential from that segment should be included in the achievable potential.

[2] Average annual energy savings as percentage of annual Base Sales per period.

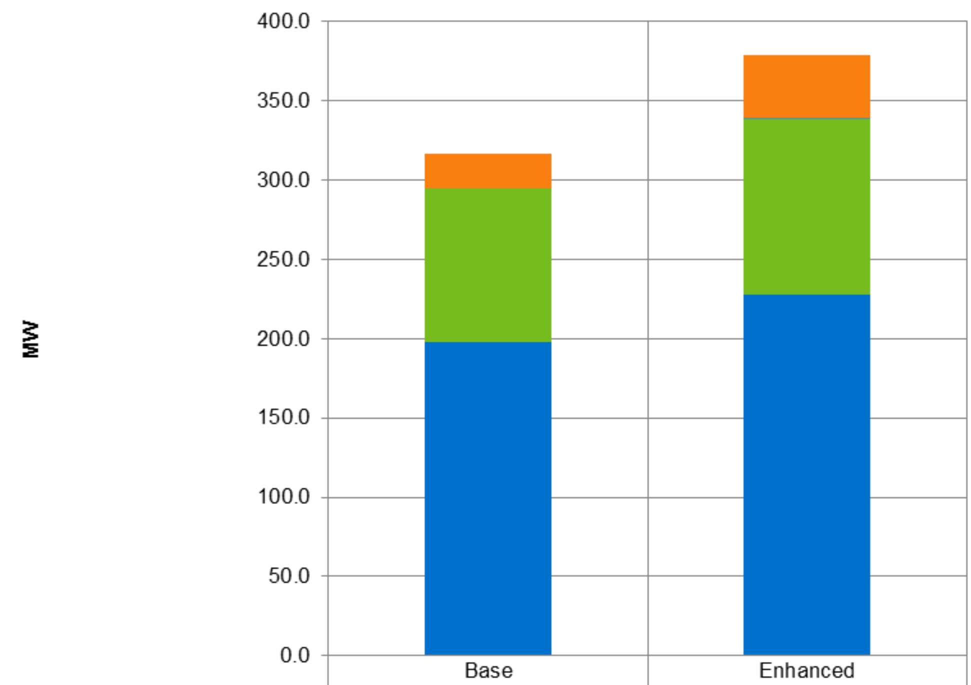
Figure 1-1 and Figure 1-2 summarize the summer peak and winter peak DSM potential estimated for two program scenarios that affect DSM results. The avoided energy cost sensitivity scenario did not consider changes to capacity costs, so the results are the same as for the base scenario.

Figure 1-1 DEC DSM Summer Peak Capacity Program Potential



	Base	Enhanced
Large C&I - 1 MW and Up	24.5	44.8
Small and Medium Business	7.3	12.8
Residential Multi-Family	41.9	48.0
Residential Single Family	235.0	267.4

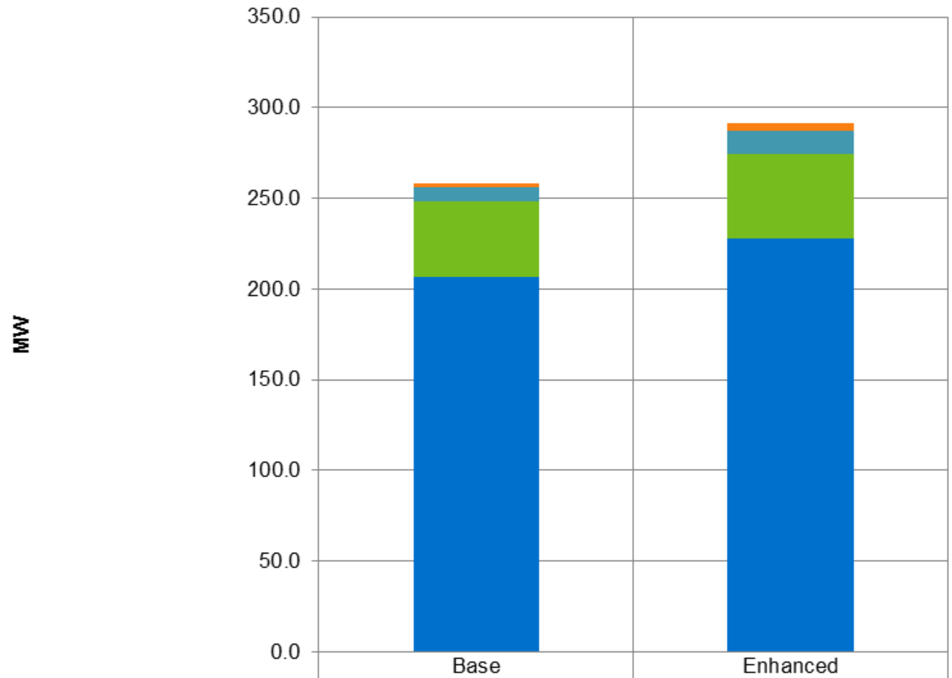
Figure 1-2 DEC DSM Winter Peak Capacity Program Potential



	Base	Enhanced
Large C&I - 1 MW and Up	21.6	39.5
Small and Medium Business	0.4	0.8
Residential Multi-Family	96.6	110.7
Residential Single Family	198.1	227.6

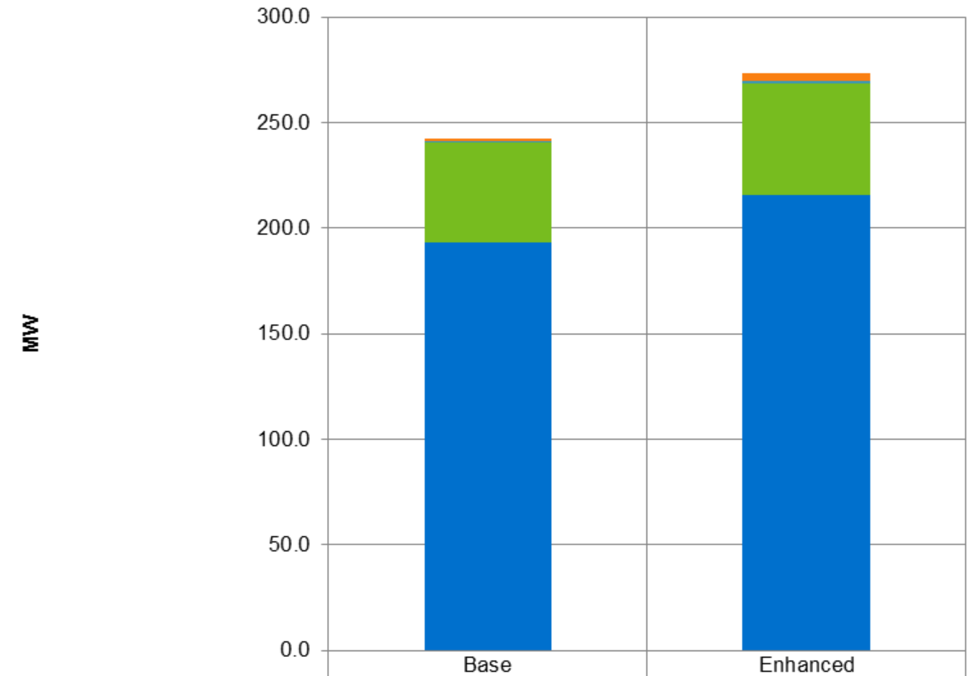
Figure 1-3 and Figure 1-4 summarize the summer peak and winter peak DSM potential estimated for DEP for the two program scenarios that affect DSM results.

Figure 1-3 DEP DSM Summer Peak Capacity Program Potential



	Base	Enhanced
Large C&I - 1 MW and Up	1.8	3.7
Small and Medium Business	7.5	12.8
Residential Multi-Family	42.1	46.6
Residential Single Family	206.5	228.1

Figure 1-4 DEP DSM Winter Peak Capacity Program Potential



	Base	Enhanced
Large C&I - 1 MW and Up	1.7	3.3
Small and Medium Business	0.5	1.1
Residential Multi-Family	47.3	53.1
Residential Single Family	193.2	215.6

2 Introduction

This section describes the objectives and deliverables Nexant generated to provide Duke Energy with an Energy Efficiency and Demand-side Management Market Potential Study covering the years 2020 – 2044. Section 2.1 describes the goals and study output, while Section 2.2 presents an overview and background for market potential studies.

2.1 Objectives and Deliverables

In November, 2019, Duke Energy retained Nexant, Inc., to determine the potential energy and demand savings that could be achieved by energy efficiency (EE) and demand-side management (DSM) programs in Duke Energy's North Carolina service territory (DEC and DEP). The main objectives of the study included:

- Providing a market potential study (MPS), which estimates the technical, economic and realistic achievable market potential energy savings over the short term (5 year projection), medium term (10 year projection), and long term (25 year projection).
- Estimating the potential savings of both energy and demand savings for Duke Energy's North Carolina service territory.
- Development of savings estimates with a focus on two different perspectives: compliance and system planning.

In developing the market potential for DEC and DEP, the following deliverables were developed by Nexant as part of the project and are addressed in this report:

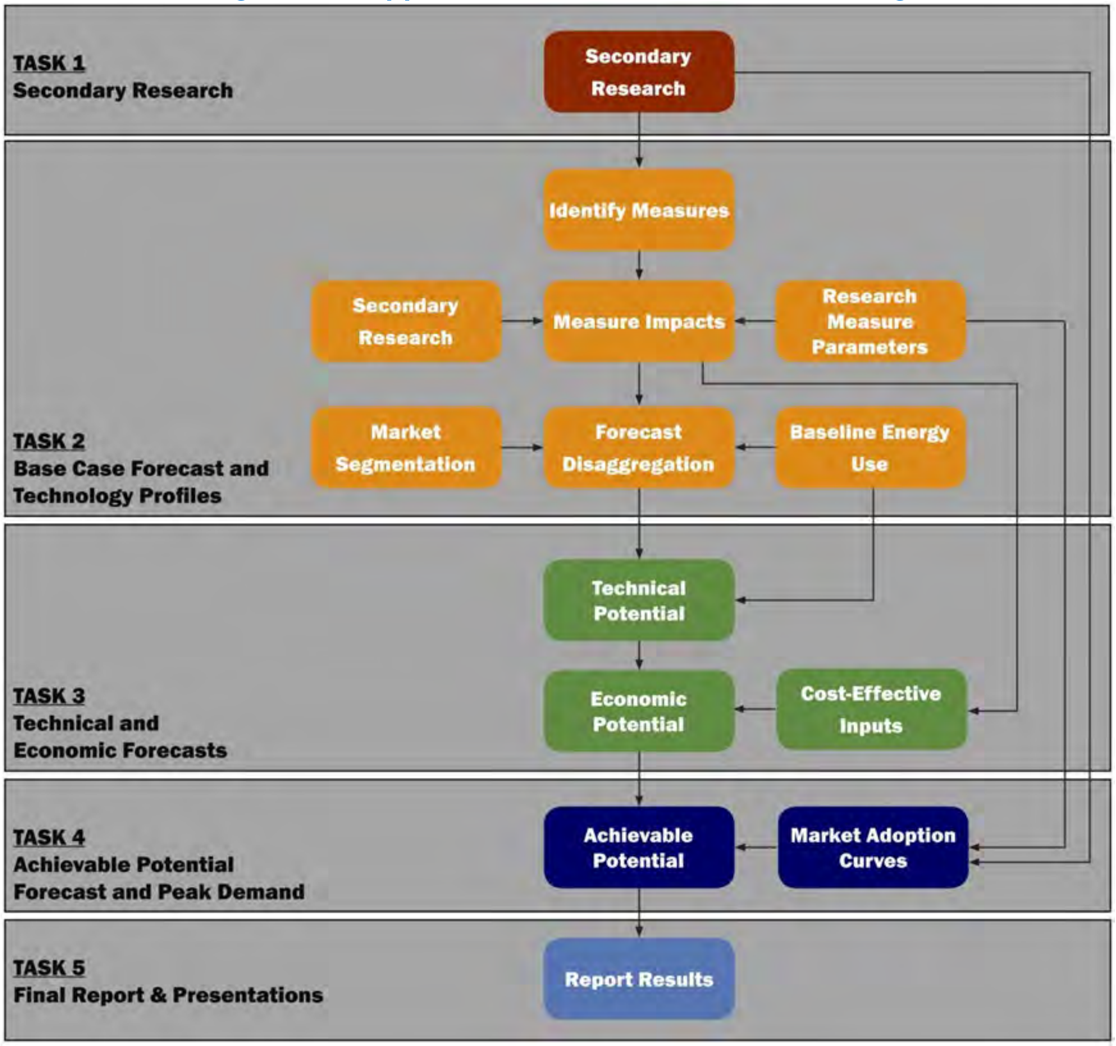
- Project plan.
- Measure list and detailed assumption workbooks.
- Summary of major assumptions utilized.
- Disaggregated baseline by year, state, sector, end use, technology saturations, and energy and demand consumptions.
- List of cost-effective energy efficiency measures and DSM technologies and products.
- Market potential energy savings for technical, economic and realistic program achievable potential scenarios for short, medium and long-term periods.
- Supporting calculation spreadsheets.

2.2 Methodology

Energy efficiency and market potential studies involve a number of analytical steps to produce estimates of each type of energy efficiency potential: technical, economic, and achievable. A market potential study is an assessment of current market conditions and trends, as observed with available secondary data sources. All components of the study, such as baseline energy consumption, expected utility sales forecasts, and available EE and DSM measures, among others, are determined on the basis of available data. A market potential study is therefore a discrete estimate of EE and DSM potential based on current market conditions and savings opportunities. An MPS does not contemplate potential changes in utility rates, changes in technology costs, nor changes in underlying economic conditions that provide a context for current consumption trends. This study considers existing technology and market trends as observed with currently available data and does not speculate on the potential impact of unknown, emerging technologies that are not yet market-ready.

This study utilized Nexant's Microsoft Excel-based modeling tool, TEAPot (Technical, Economic, and Achievable Potential). This modeling tool was built on a platform that provides the ability to calculate multiple scenarios and recalculate potential savings based on variable inputs such as sales/load forecasts, electricity prices, discount rates, and actual program savings. The model provides transparency into the assumptions and calculations for estimating market potential. Nexant's TEA-POT model is continuously refined to accommodate and advance industry best practices, with the most recent upgrade occurring in 2019. The methodology for the energy efficiency potential assessment is based on a hybrid "top-down/bottom-up" approach.

Figure 2-1: Approach to Market Potential Modeling



As illustrated in Figure 2-1, the assessment started with the current load forecast, then disaggregated it into its constituent customer-class and end use components. Nexant examined the effect of energy efficiency measures and practices on each end use, taking into account fuel shares, current market saturations, technical feasibility, and costs. These unique impacts were aggregated to produce estimates of potential at the technology, end use, customer class, and system levels.

The market potential in the North Carolina territory can be characterized by levels of opportunity. The ceiling or theoretical maximum is based on commercialized technologies and behavioral measures, whereas the realistic savings that may be achieved through DSM programs reflect real world market constraints such as utility budgets, customer perspectives and energy efficiency policy. This analysis defines these levels of energy efficiency potential according to the Environmental Protection Agency's (EPA) National Action Plan for Energy Efficiency (NAPEE) as illustrated in Figure 2-2.

Figure 2-2: Energy Efficiency Potential

EPA – National Guide for Resource Planning

- Technical Potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- Economic Potential is the amount of energy and capacity that could be reduced by efficiency measures that pass a cost-effectiveness test. The Total Resource Cost (TRC) Test estimates the measure costs to both the utility and customer.
- Achievable Potential is the energy savings that can feasibly be achieved in the market with consideration of market barriers and customer adoption of DSM technologies, and the influence of incentive levels on adoption rates. For this study, achievable potential is organized into generalized utility program offerings, and therefore referred to as Achievable Program Potential.
- Program Potential delivered by programs is often less than achievable potential due to real-world constraints, such as utility program budgets, effectiveness of outreach, and market delays. In this study, Duke Energy is currently offering all measure identified as cost effective, so achievable potential and program potential are practically the same.

This study explored technical, economic, and achievable program potential over a 25-year period from January, 2020, to December, 2044. The quantification of these three levels of energy efficiency potential is an iterative process reflecting assumptions on cost effectiveness that drill down the opportunity from the theoretical maximum to realistic program savings. The California Standard Practice Manual (SPM) provides the methodology for estimating cost effectiveness of energy efficiency measures, bundles, programs or portfolios based on a series of tests representing the perspectives of the utility, customers, and societal stakeholders. In this potential study, individual measures were screened for cost-effectiveness using the total resource cost (TRC) from the Standard Practice Manual.

Naturally occurring conservation is captured by this analysis in the load forecast. Effects of energy codes and equipment standards were considered by incorporating changes to codes and standards and marginal efficiency shares in the development of the base-case forecasts. Additionally, the model accounted for known or planned future federal code changes that will impact efficiencies, and therefore overall potential energy savings, of specific measures and end uses such as motors and lighting.

Nexant estimated program savings potential based on a combination of market research, analysis, and a review of Duke Energy's existing programs, all in coordination with Duke Energy. The programs that Nexant examined included both energy efficiency (EE) and demand-side management (DSM) programs; therefore, this report is organized to offer detail on both types of programs.

The remainder of the report provides detailed methodologies for each step in the potential analysis process, together with the results and analyses, according to the following sections:

- Market Characterization
- DSM Measure List
- Technical Potential
- Economic Potential
- Program Potential
- Conclusions and Recommendations

3 End Use Market Characterization

The base year energy use and sales forecast provided the reference point to determine potential savings. The end use market characterization of the base year energy use and reference case forecast included customer segmentation and load forecast disaggregation. The characterization is described in this section, while the subsequent section addresses the measures and market potential energy savings scenarios.

3.1 Customer Segmentation

In order to estimate energy efficiency (EE) and demand side management (DSM) potential, the sales forecast and peak load forecasts were segmented by customer characteristics. Assessing the savings potential required an understanding of which types of EE and DSM measures apply to the wide array of electricity customers. As electricity consumption patterns vary by customer type, Nexant segmented customers into homogenous groups to identify which customer groups are eligible to adopt specific energy efficiency technologies or to provide DSM grid services.

Customer segmentation also addressed the business need to deliver cost-effective EE and DSM programs. Significant cost efficiency can be achieved through strategic EE and DSM program designs that recognize and address the similarities of EE and DSM potential that exists within each customer group. Nexant segmented DEC and DEP customers according to the following:

1) By Sector – how much of the Duke Energy's energy sales, summer peak, and winter peak load forecast is attributable to the residential, commercial, and industrial sectors?
2) By Customer – how much electricity does each customer typically consume annually and during system peaking conditions?
3) By End Use – within a home or business, what equipment is using electricity during the peak? How much energy does this end-use consume over the course of a year?

This analysis identified the segments of customers ineligible for EE and DSM, such as Opt Out commercial and industrial customers.

Table 3-1 summarizes the segmentation within each sector. Residential customer segments were further segmented by fuel type (electric, natural gas, or unknown) and by annual consumption deciles within each sub-segment for the EE and DSM analysis. The goal of this further segmentation was to understand which customer groups were most cost-effective to recruit and allow for more targeted marketing of EE and DSM programs.

Table 3-1: Customer Segments and Sub-Sectors

Residential	Commercial		Industrial	
Single Family	Assembly	Lodging/ Hospitality	Chemicals and plastics	Primary resource industries
Multi Family	College and University	Miscellaneous	Construction	Stone, clay, glass, and concrete
Mobile Home	Data Center	Offices	Electrical and electronic equipment	Textiles and leather
	Grocery	Restaurant	Lumber, furniture, pulp, and paper	Transportation equipment
	Healthcare	Retail	Metal products and machinery	Water and wastewater
	Hospitals	Schools K-12	Miscellaneous manufacturing	
	Institutional	Warehouse		

From an equipment and energy use perspective, each segment has variation within each building type or sub-sector. For example, the energy consuming equipment in a convenience store will vary significantly from the equipment found in a supermarket. To account for this variation, the selected end uses describe energy savings potential that are consistent with those typically studied in national or regional surveys. These end uses are listed in Table 3-2.

Table 3-2: End Uses

Residential End Uses	Commercial End Uses	Industrial End Uses
Space heating	Space heating	Process heating
Space cooling	Space cooling	Process cooling
Domestic hot water	Domestic hot water	Compressed air
Ventilation and circulation	Ventilation and circulation	Motors, pumps
Lighting	Interior lighting	Motors, fans, blowers
Cooking	Exterior lighting	Process-specific
Refrigerators	Cooking	Lighting
Freezers	Refrigeration	HVAC
Clothes washers	Office equipment	Other
Clothes dryers	Miscellaneous	
Dishwashers		
Plug load		
Miscellaneous		

For the DSM assessment, the end uses targeted were limited to end-uses with controllable load for residential customers and small/medium businesses (small C&I). For large commercial and industrial (large C&I) customers who would potentially reduce large amounts of electricity consumption for a limited time, all load during peak hours was included. For residential customers, AC/heating loads, as well as pool pumps and electric water heaters for certain program potential scenarios, were studied. For small C&I customers, the analysis was limited to AC/heating loads.

3.2 Forecast Disaggregation

Although the primary focus of the EE potential study was the electricity consumption forecast and the primary focus of the DSM potential study was the peak load forecasts, the accuracy of the demand impacts and cost-effectiveness screening in the EE potential study is enhanced by a detailed approach to peak load disaggregation. Therefore, during the development of all the baselines, the energy efficiency and DSM teams coordinated with each other, to ensure consistent assumptions and to avoid double counting of potential.

Additionally, a common understanding of the assumptions and granularity in the baseline load forecast was developed with input with Duke Energy. Key discussion topics reviewed with Duke Energy included:

- How are Duke Energy's current program offerings reflected in the energy and demand forecast?
- What are the assumed weather conditions and hour(s) of the day when the system is projected to peak?
- How much of the load forecast is attributable to accounts that are not eligible for EE and DSM programs or have opted-out of the EE and DSM riders?
- How are projections of population increase, changes in appliance efficiency, and evolving distribution of end use load shares accounted for in the 25 year peak demand forecast?
- If separate forecasts are not developed by region or sector, are there trends in the load composition that Nexant should account for in the study?

3.2.1 Electricity Consumption (kWh) Forecast

Nexant segmented the DEC and DEP electricity consumption forecasts into electricity consumption load shares by customer class and end use. The baseline customer segmentation represents the North Carolina electricity market by describing how electricity was consumed within the service territory. Nexant developed these forecasts for the years 2020–2044 and based it on data provided by Duke Energy. The data addressed current baseline consumption, system load and sales forecasts.

3.2.2 Peak Demand (kW) Forecast

A fundamental component of DSM potential was establishing a baseline forecast of what loads or operational requirements would be absent existing dispatchable DSM. This baseline was necessary to assess how DSM can assist in meeting specific planning and operational requirements. Nexant used Duke Energy's summer and winter peak demand forecast, which was developed for system planning purposes.

3.2.3 Estimating Consumption by End-Use Technology

As part of the forecast disaggregation, Nexant developed a list of electricity end uses by sector (Table 3-2). To develop this list, Nexant began with Duke Energy's estimates of average end-use consumption by customer and sector. Nexant combined these data with other information, such as 2019 Duke Energy's residential appliance saturation surveys, to develop estimates of customers' baseline consumption. Nexant augmented the Duke Energy data with data available from public sources, such as the Energy Information Agency's (EIA) recurring data-collection efforts that describe energy end-use consumption for the residential, commercial, and manufacturing sectors.

To develop estimates of end-use electricity consumption by customer segment and end use, Nexant applied estimates of end-use saturation, energy fuel share, and equipment-type saturation to the average energy consumption for each sector. The following data sources and adjustments were used in developing the base year 2019 sales by end use:

Residential sector:

- The disaggregation was based on DEC and DEP rate class load shares and intensities; adjustments were made for dwelling type.
- Adjustments were made to the baseline intensity to account for differences in end use saturation, fuel source, and equipment saturation as follows:
  - Duke Energy rate class load share is based on average per customer.
  - Nexant estimates of end use consumption calibrated to disaggregated Duke Energy forecast conversions to usage data provided from individual customer accounts.
  - Outcome is designed to reflect customers' fuel-specific and equipment-specific savings opportunities.

Commercial sector:

- The disaggregation was based on DEC and DEP rate class load shares, intensities, and EIA Commercial Buildings Energy Consumption Survey (CBECS) data.
- Segment data from EIA, DEC and DEP.
- Adjustments were made to the baseline intensity for end use saturation, fuel source, and equipment saturation as follows:
  - Duke Energy rate class load share is based on average per customer.
  - Nexant estimates of end use consumption calibrated to disaggregated Duke Energy forecast conversions to usage data provided from individual customer accounts.
  - Outcome reflects customers' fuel-specific and equipment-specific savings opportunities.

Industrial sector:

- The disaggregation was based on DEC and DEP rate class load shares, intensities, and EIA Manufacturers Energy Consumption Survey (MECS) data.
- Segment data from EIA, DEC and DEP.

- Adjustments were made to the baseline intensity for end use saturation, fuel source, and equipment saturation as follows:
  - Duke Energy rate class load share based on EIA MECS and end use forecasts from DEC and DEP.
  - Nexant estimates of end use consumption calibrated to disaggregated Duke Energy forecast conversions to usage data provided from individual customer accounts.
  - Outcome reflects customers' fuel-specific and equipment-specific savings opportunities.

3.3 Analysis of Customer Segmentation

Customer segmentation is important to ensure that an MPS examines EE and DSM measure savings potential in a manner that reflects the diversity of energy savings opportunities existing across Duke Energy's customer base. Duke Energy provided Nexant with data concerning the premises type and load characteristics for all customers for the MPS analysis. Nexant examined the received data from multiple perspectives to identify customer segments. Nexant's approach to segmentation varied slightly for commercial and residential accounts, but the overall logic was consistent with the concept of expressing the accounts in terms that were relevant to EE and DSM opportunities. The following three sections describe the segmentation analysis and results for commercial and industrial C&I accounts (Section 3.3.1) and residential accounts (Section 3.3.2).

3.3.1 Commercial and Industrial Accounts

Nexant segmented C&I accounts according to two approaches: North American Industry Classification System (NAICS) codes and peak energy demand.

3.3.1.1 North American Industry Classification System Codes

The approach to examining DEC and DEP's C&I accounts was based on the NAICS codes, which Duke Energy provided as part of the customer data. Nexant further classified the customers in this group as *either* commercial or industrial, on the basis of DSM measure information available and applicable to each. For example, agriculture and forestry DSM measures are commonly considered industrial savings opportunities; therefore, small farms with relatively low energy demand were included in this group, regardless of their rate schedule classification. Nexant based this classification on the types of DSM measures applicable by segment, rather than on the annual energy consumption or maximum instantaneous demand from the segment as a whole.

3.3.1.2 Peak Energy Demand Categories

Nexant also classified C&I accounts according to their maximum energy demand in kilowatts. Customers' maximum instantaneous demand is a basic driver of demand-response potential. Nexant created five customer groups for the C&I sector based on maximum energy demand (Table 3-3 and Table 3-4).

Table 3-3: Number of DEC Commercial Accounts by Demand Segment

< 30 kW	30 – 70 kW	75 – 500 kW	500 kW – 1 MW	> 1 MW	Total
215,608	25,429	17,317	1,760	1,416	261,530

Table 3-4: Number of DEP Commercial Accounts by Demand Segment

< 30 kW	30 – 70 kW	75 – 500 kW	500 kW – 1 MW	> 1 MW	Total
159,860	14,805	11,455	1,283	963	188,366

Table 3-5 and Table 3-6 present the percentage of customers, annual consumption, and maximum demand for each demand segment. All consumption and demand values are based on the period January 2018–January 2019.

Table 3-5: Summary of DEC Commercial and Industrial Market Characteristics

Attribute	< 30 kW	30 – 70 kW	75 – 500 kW	500 kW – 1 MW	> 1 MW
Customer #	83.89%	8.67%	6.34%	0.62%	0.48%
Consumption	7.42%	6.46%	21.14%	9.43%	55.55%
Demand	8.05%	9.31%	25.86%	10.25%	46.54%

Table 3-6: Summary of DEP Commercial and Industrial Market Characteristics

Attribute	< 30 kW	30 – 70 kW	75 – 500 kW	500 kW – 1 MW	> 1 MW
Customer #	84.78%	7.05%	6.87%	0.76%	0.55%
Consumption	9.90%	5.69%	20.44%	10.19%	53.78%
Demand	1.44%	8.13%	27.43%	12.75%	50.26%

Figure 3-1 and Figure 3-2 presents a graphical summary of these data. The lower demand segment contains the most customers, but the larger demand segments make up the highest shares of consumption and demand.

Figure 3-1: DEC Market Composition by Demand Segment

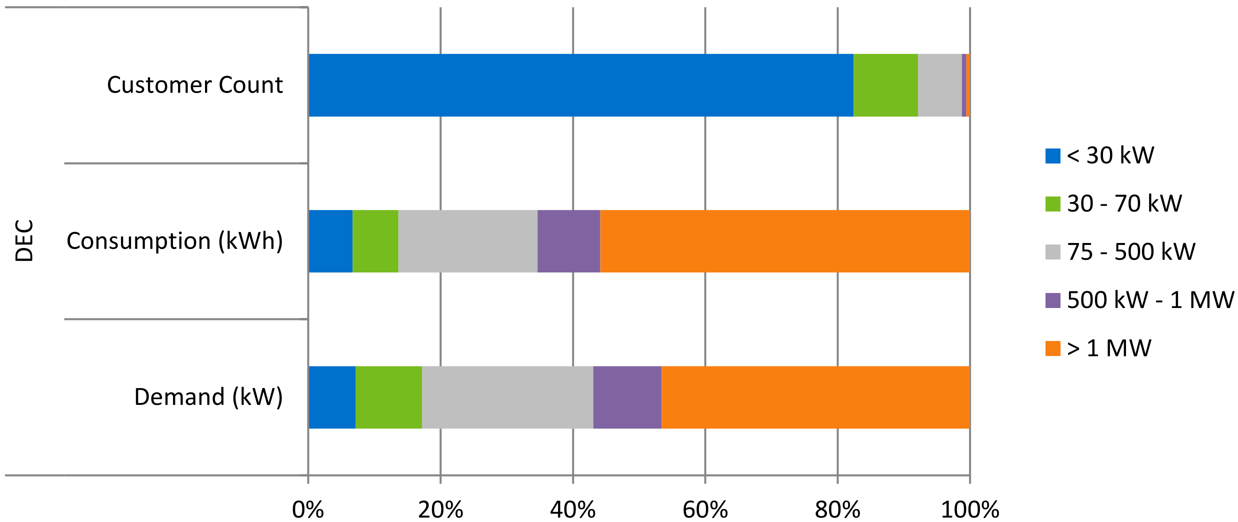
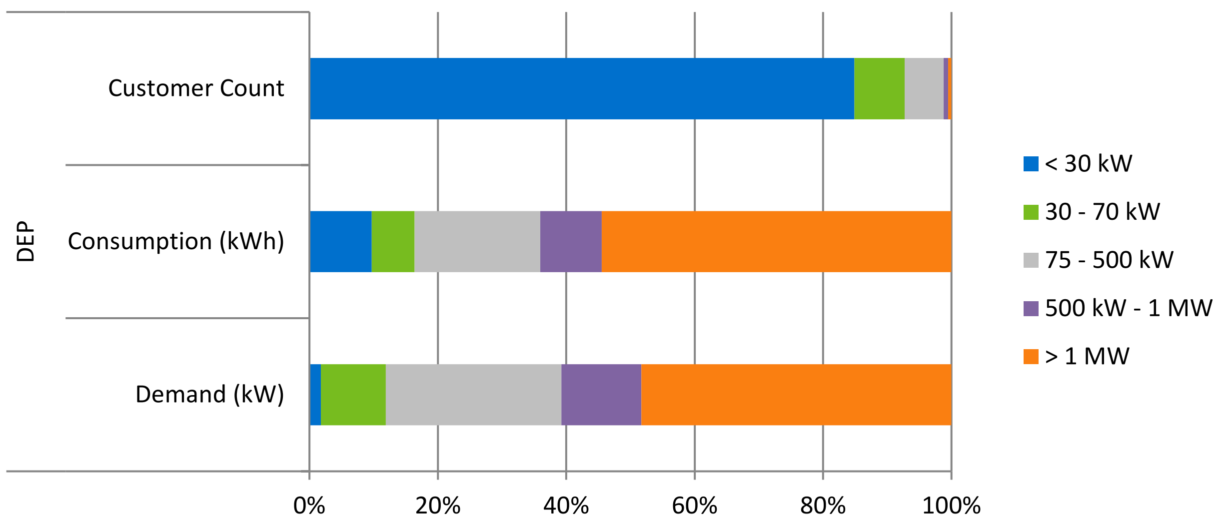


Figure 3-2: DEP Market Composition by Demand Segment



Based on the analysis, Nexant described commercial and industrial DSM potential according to the economic segments summarized in Table 3-1. For details concerning customer demand characteristics according to these commercial and industrial segments, see Appendix C.

3.3.2 Residential Accounts

Segmentation of residential customer accounts enabled Nexant to align DSM opportunities with appropriate DSM measures. Nexant segmented the residential sector according to two fields provided in the Duke Energy data: customer dwelling type (single family, multi-family or mobile home), and space heat fuel source (electric, gas, and “unknown”). The resulting distribution of customers and total electricity consumption by each segment is presented below in Table 3-7 and Table 3-8. Figure 3-3 and Figure 3-4 present this information graphically.

Table 3-7: DEC Residential Customer Market Composition by Space Heat Fuel Source

Attribute	Electricity	Gas
Customer Count	38.62%	61.38%
Total kWh Consumption	41.36%	58.64%

Table 3-8: DEP Residential Customer Market Composition by Space Heat Fuel Source

Attribute	Electricity	Gas
Customer Count	58.07%	41.93%
Total kWh Consumption	61.38%	38.62%

Figure 3-3: DEC Residential Market Segmentation by Space Heat Fuel Source

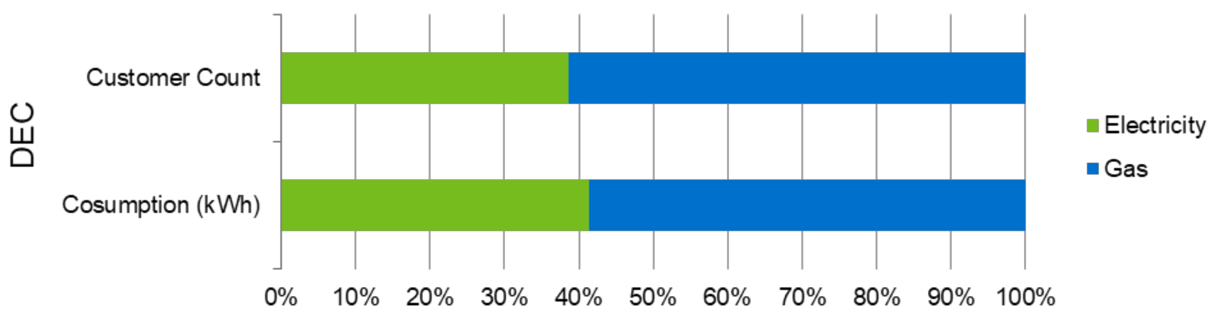
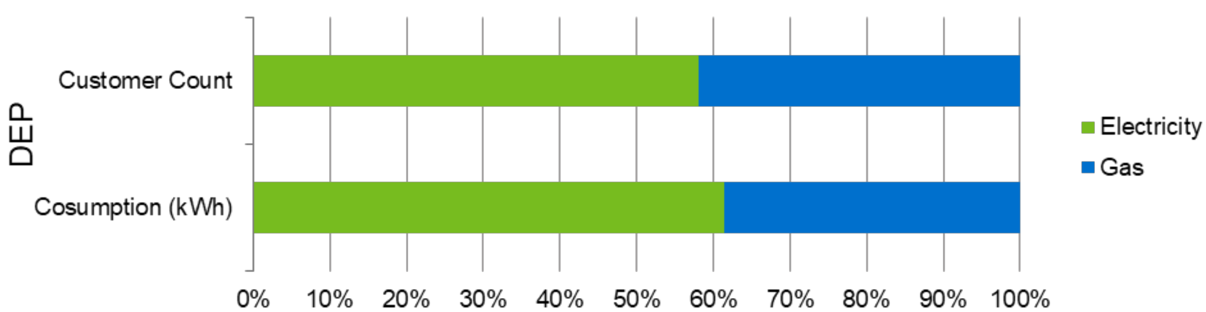


Figure 3-4: DEP Residential Market Segmentation by Space Heat Fuel Source



Segmentation according to dwelling unit type is presented in Table 3-9, Table 3-10, and is presented graphically in Figure 3-5 and Figure 3-6Figure 3-6: DEP Residential Market Characteristics by Type of Dwelling Unit.

Table 3-9: DEC Residential Market Characteristics by Type of Dwelling Unit

Attribute	Single Family	Multi-Family	Mobile Home
Customer Count	84.41%	14.02%	1.57%
Total kWh Consumption	88.61%	9.58%	1.81%

Table 3-10: DEP Residential Market Characteristics by Type of Dwelling Unit

Attribute	Single Family	Multi-Family	Mobile Home
Customer Count	86.06%	10.18%	3.76%
Total kWh Consumption	89.18%	6.41%	4.42%

Figure 3-5: DEC Residential Market Characteristics by Type of Dwelling Unit

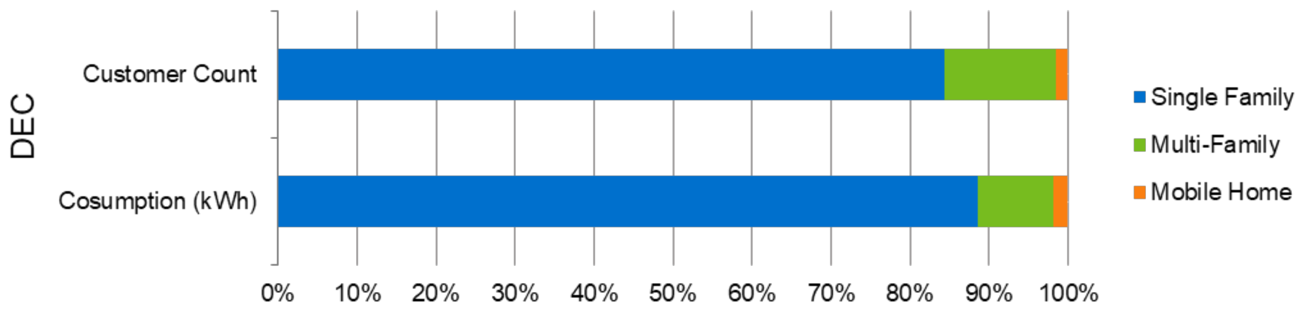
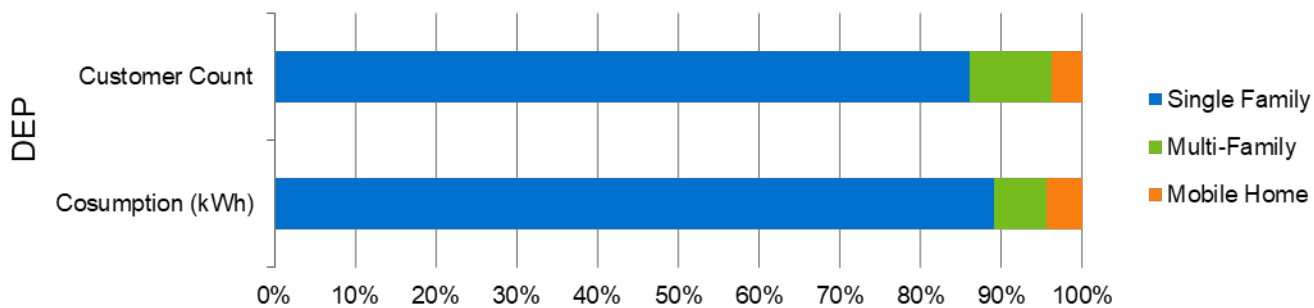


Figure 3-6: DEP Residential Market Characteristics by Type of Dwelling Unit



For the DSM analysis, residential accounts were also segmented based on their rate class, so that Nexant could separately analyze customers on a time-of-use rate and customers enrolled in an electric heating rate where available. For the remainder of this report, the residential rate classes for DEC are defined as:

- RS – Residential Service;
- RE – Residential Service, Electric Water Heater and Space Heating; and
- RT – Residential Time-of-Use.

DEP does not have a rate specifically for customers with electric end-uses. Therefore, the residential rate classes for DEP are defined as:

- RES – Residential Service (electric and non-electric heating); and
- TOU – Residential Time-of-Use.

3.4 DEC Base Year 2019 Disaggregated Load

The DEC's disaggregated loads for the base year 2019 by sector and end use are summarized in Figure 3-7, Figure 3-8 and Figure 3-9. Load disaggregation is based on Duke Energy end use forecast data. These forecasts are based in part on the Energy Information Administration (EIA) research activities in the residential, commercial, and manufacturing sectors. The following secondary data sources were used by Nexant to disaggregate each sector's loads:

- Residential load disaggregation is based on Duke Energy's estimates of residential end use load shares; this information in turn is derived from the EIA Residential End Use Consumption Survey (RECS), vintage 2015.
- Commercial load disaggregation is based on the Commercial Building Energy Consumption Survey (CBECS), 2012 vintage.
- Industrial load disaggregation is based on Manufacturers' Energy Consumption Survey (MECS), vintage 2014

The data provided by these products represents the best available secondary data sources for end use consumption within each economic sector.

Figure 3-7: DEC Residential Baseline Load Shares

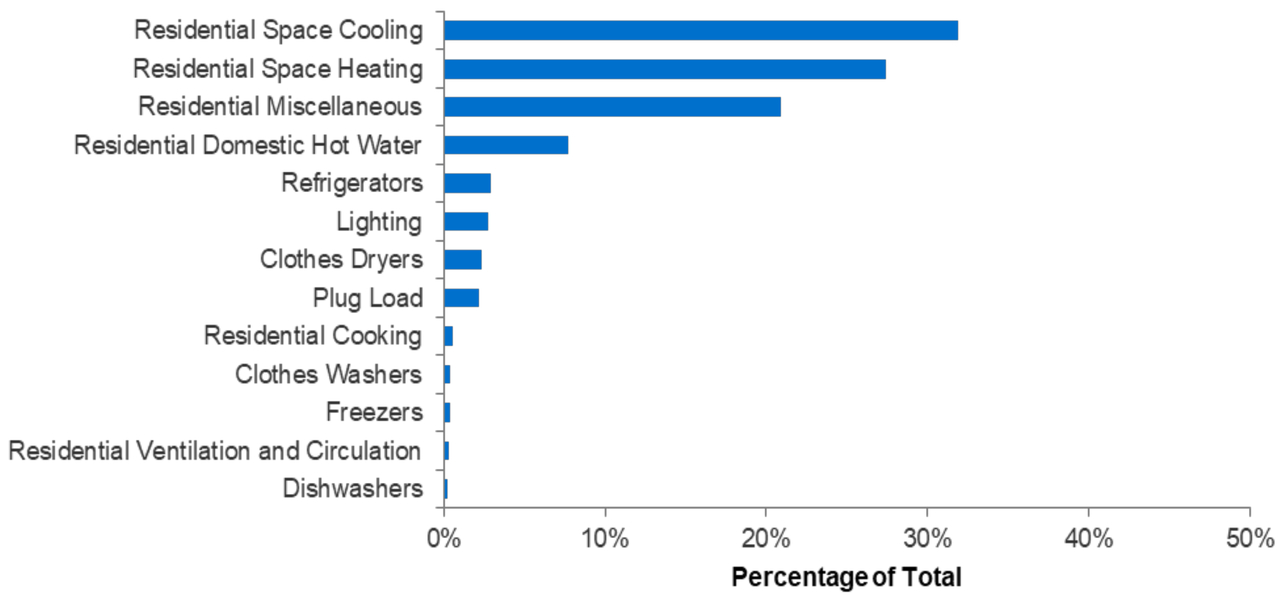


Figure 3-8: DEC Commercial Baseline Load Shares

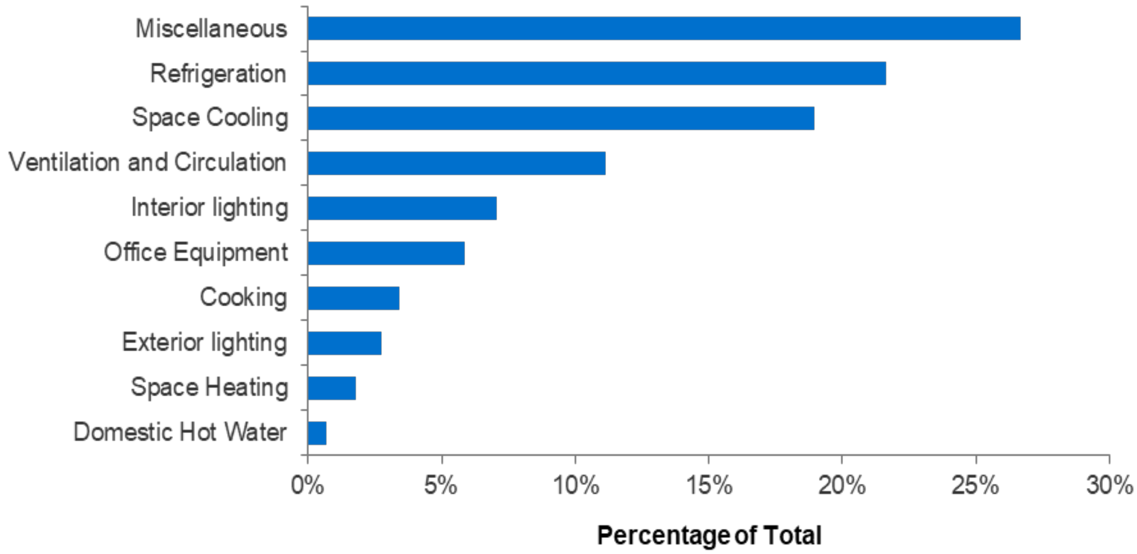
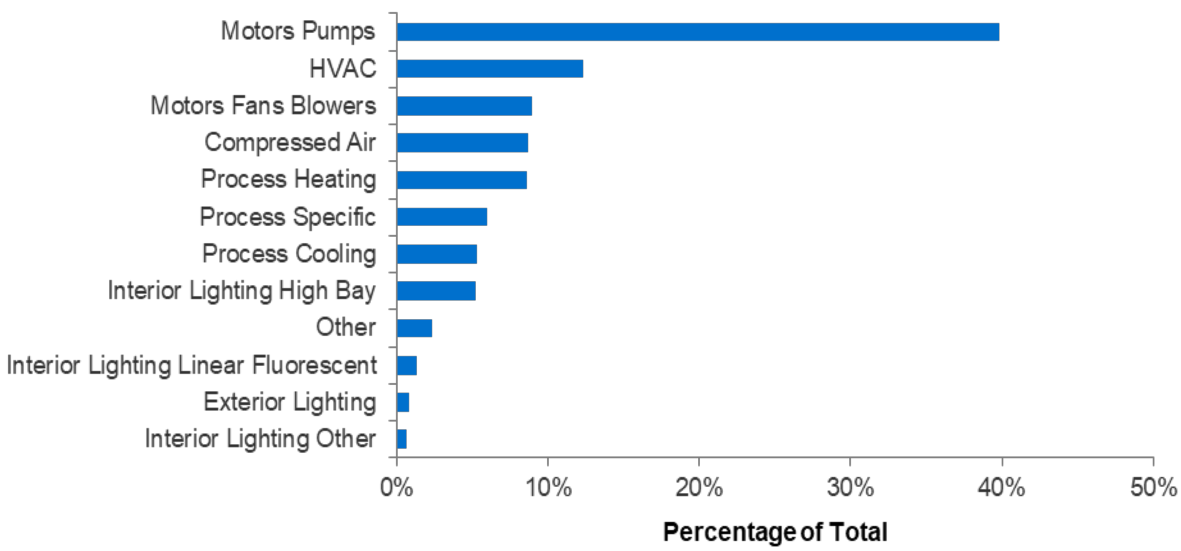


Figure 3-9: DEC Industrial Baseline Load Shares



In the base year 2019, the DEC top load share categories are:

- ***Residential:*** space cooling, space heating, and miscellaneous.
- ***Commercial:*** miscellaneous, refrigeration, and space cooling.
- ***Industrial:*** motors pumps, HVAC, and motors fans blowers.

3.5 DEP Base Year 2019 Disaggregated Load

The DEP's disaggregated loads for the base year 2019 by sector and end use are summarized in Figure 3-10, Figure 3-11, and Figure 3-12.

Figure 3-10: DEP Residential Baseline Load Shares

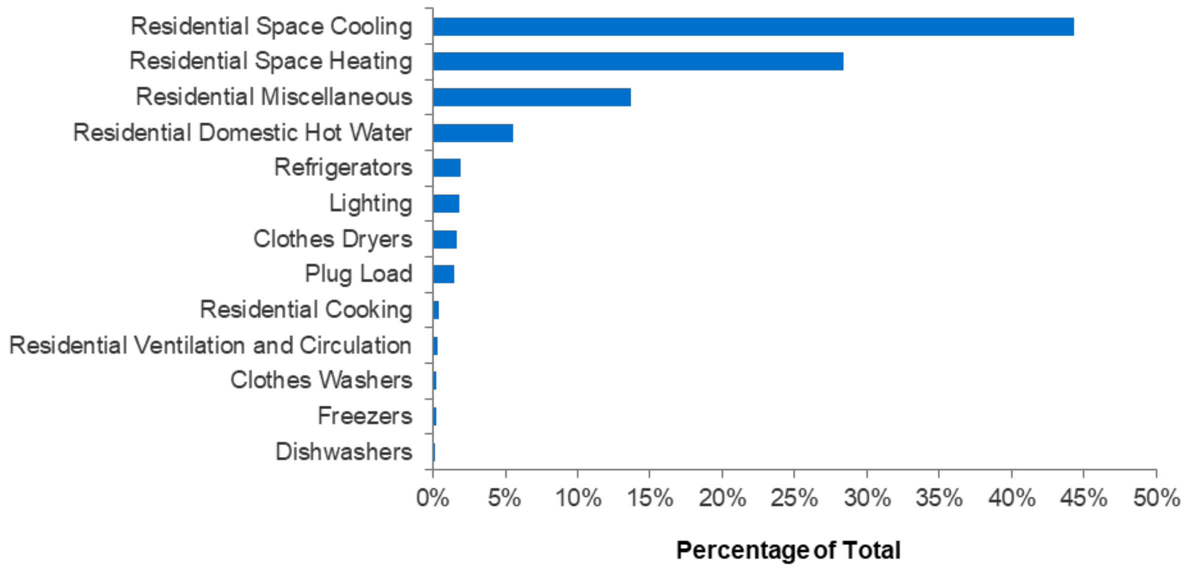


Figure 3-11: DEP Commercial Baseline Load Shares

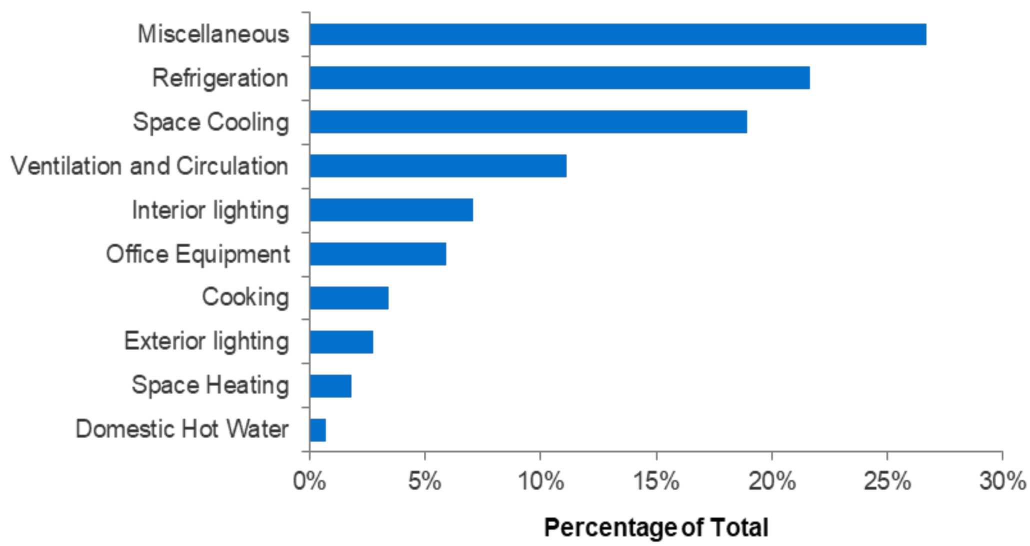
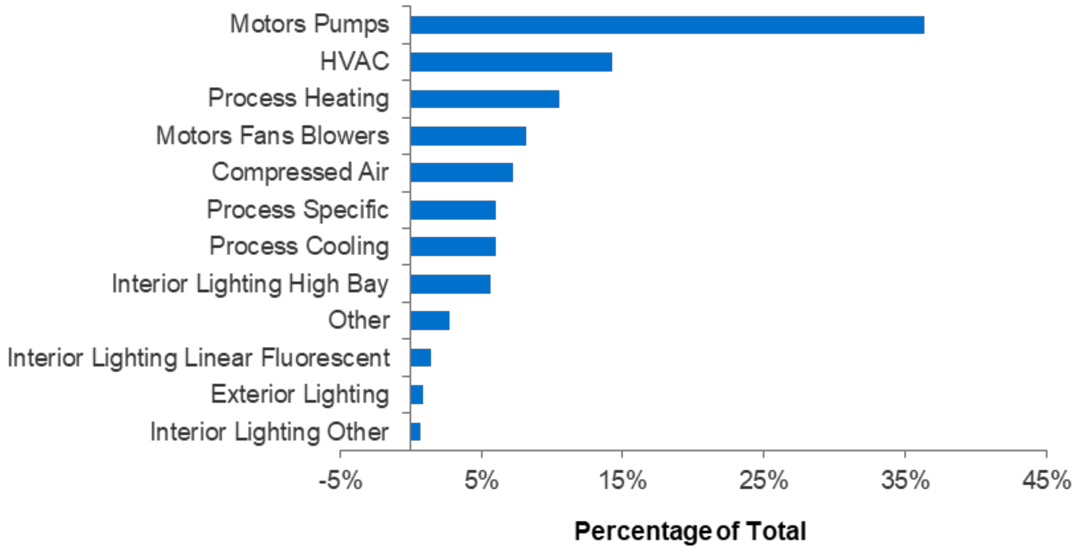


Figure 3-12: DEP Industrial Baseline Load Shares



In the base year 2019, the DEP top load share categories are:

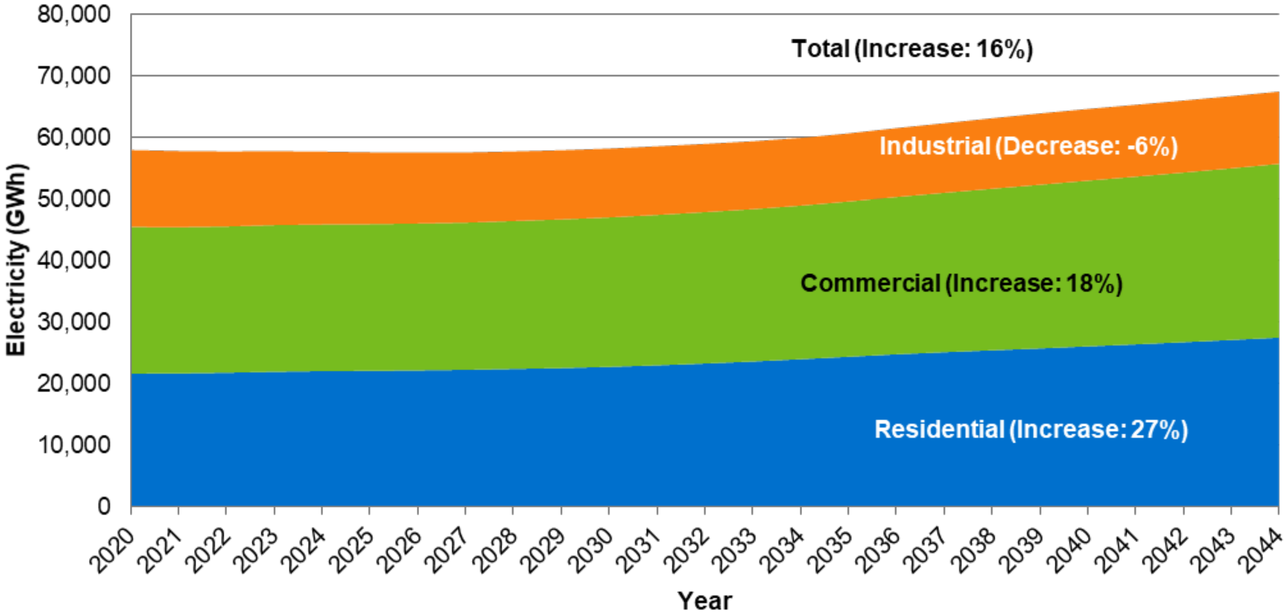
- ***Residential:*** space cooling, space heating, and miscellaneous.
- ***Commercial:*** miscellaneous, refrigeration, and space cooling.
- ***Industrial:*** motors pumps, HVAC, and process heating.

3.6 DEC System Load Forecast 2020 - 2044

3.6.1 DEC System Energy Sales

The DEC electricity use is forecasted to increase by 9,486 GWh (a change of 16%) from 2020 to 2044, to a total of 67,454 GWh in 2044 (see Figure 3-13). The residential sector is expected to account for the largest share of the increase, growing by 5,843 GWh to reach 27,508 GWh (an increase of 27%) over the 25 year period. The commercial sector is expected to increase by 4,404 GWh to reach 28,219 GWh (a change of 18%) over the 25 year period. The industrial sector is forecasted to decrease by 762 GWh (a decrease of 6%) from 2020 to 2044, to 11,727 GWh in 2044. In 2044 the commercial sector accounts for 42% (28,219 GWh) of total electricity sales, the residential sector 41% (27,508 GWh) and the industrial sector 17% (11,727 GWh). Nexant worked with Duke Energy to ensure the forecasts did not include the expected future impacts of planned EE and DSM technologies.

Figure 3-13: DEC Electricity Sales Forecast by Sector for 2020 - 2044[3]



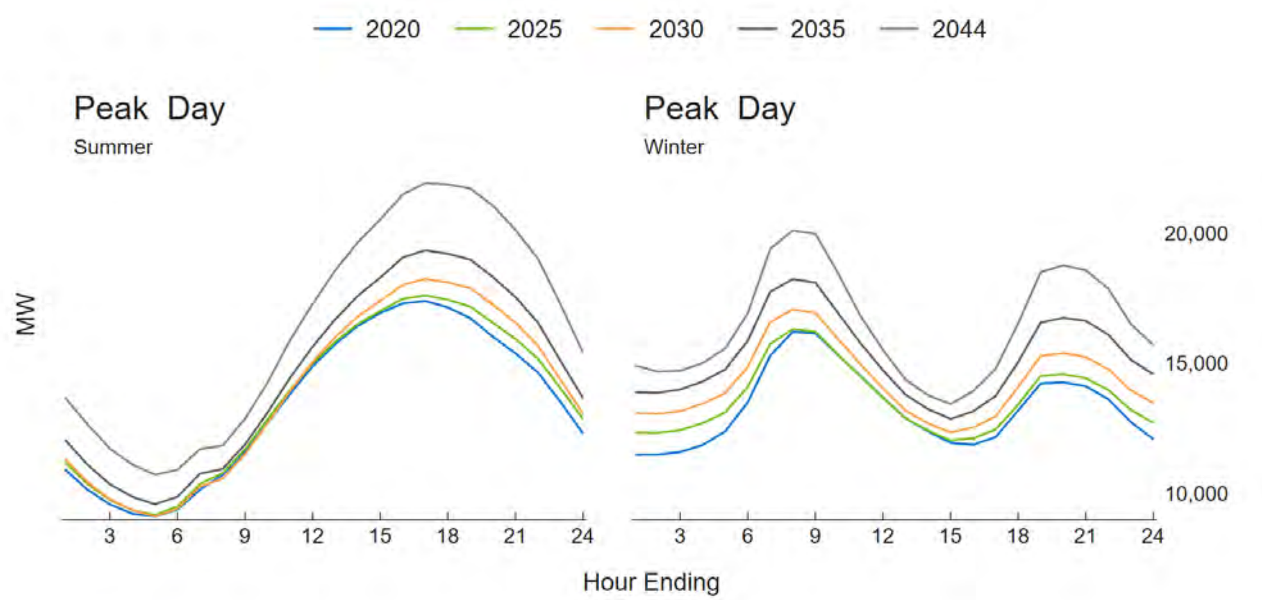
3.6.2 DEC System Demand

Estimating technical potential for DSM resources requires not only knowing how much load is available to be curtailed or shifted, but also understanding when it is needed. Because the benefits of DSM stem from avoiding costly investments to meet peak loads, load reductions will not have any value unless they occur during hours of peak system usage. Therefore, the first order of business in estimating the market potential for DSM is to establish when load reductions will most likely be needed throughout the year.

The primary data source used to determine when DSM resources will be needed was the DEC system load forecast. This forecast contains forecasted loads for all 8,760 hours of each year in the study period (2020-2044). Figure 3-14 represents an initial inspection of the data. Each figure shows the expected average load profiles for two distinct types of days – peak summer days and peak winter days. Summer was defined as April-October, while the peak days refer to day with the maximum demand during the year and season.

[3] Sales forecast based on DEC(NC) 2019 forecast—the current forecast at the time of Nexant's analysis.

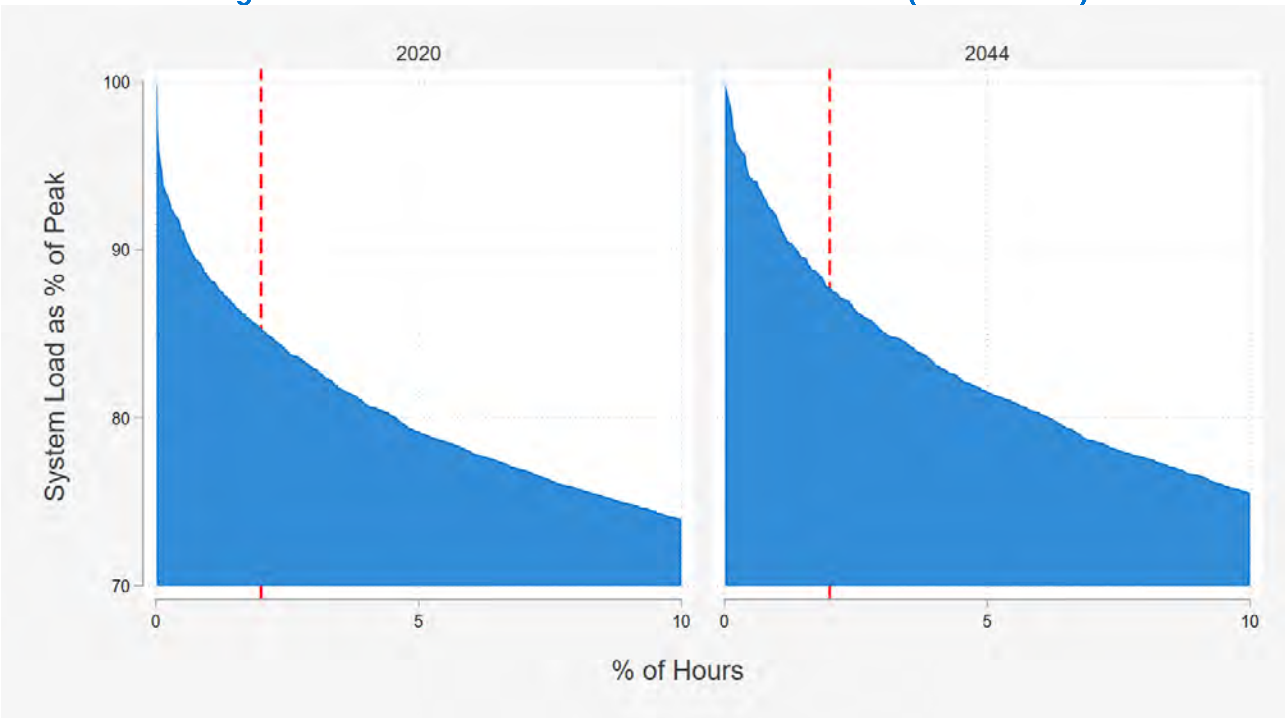
Figure 3-14 DEC System Load Forecast (2020 - 2044)



Several patterns are apparent from examining the figure above. First and foremost, forecasted loads shapes are relatively unchanged over time as the total magnitude of projected load increases. In addition, the summer loads have a similar maximum to winter loads. Thus the potential study focuses on the current summer peak hour, 4-5 pm, and the current winter peak hour, 7-8 am.

Though useful for assessing patterns in system loads, Figure 3-14 does not provide very much information about the concentration of peak loads. A useful tool to examine peak load concentration is a load duration curve, which is presented for 2020 and 2044 in Figure 3-15. This curve shows the top 10% of hourly loads as a percentage of the system's peak hourly usage, sorted from highest to lowest.

Figure 3-15 DEC Forecasted Load Duration Curve (2020 v 2044)



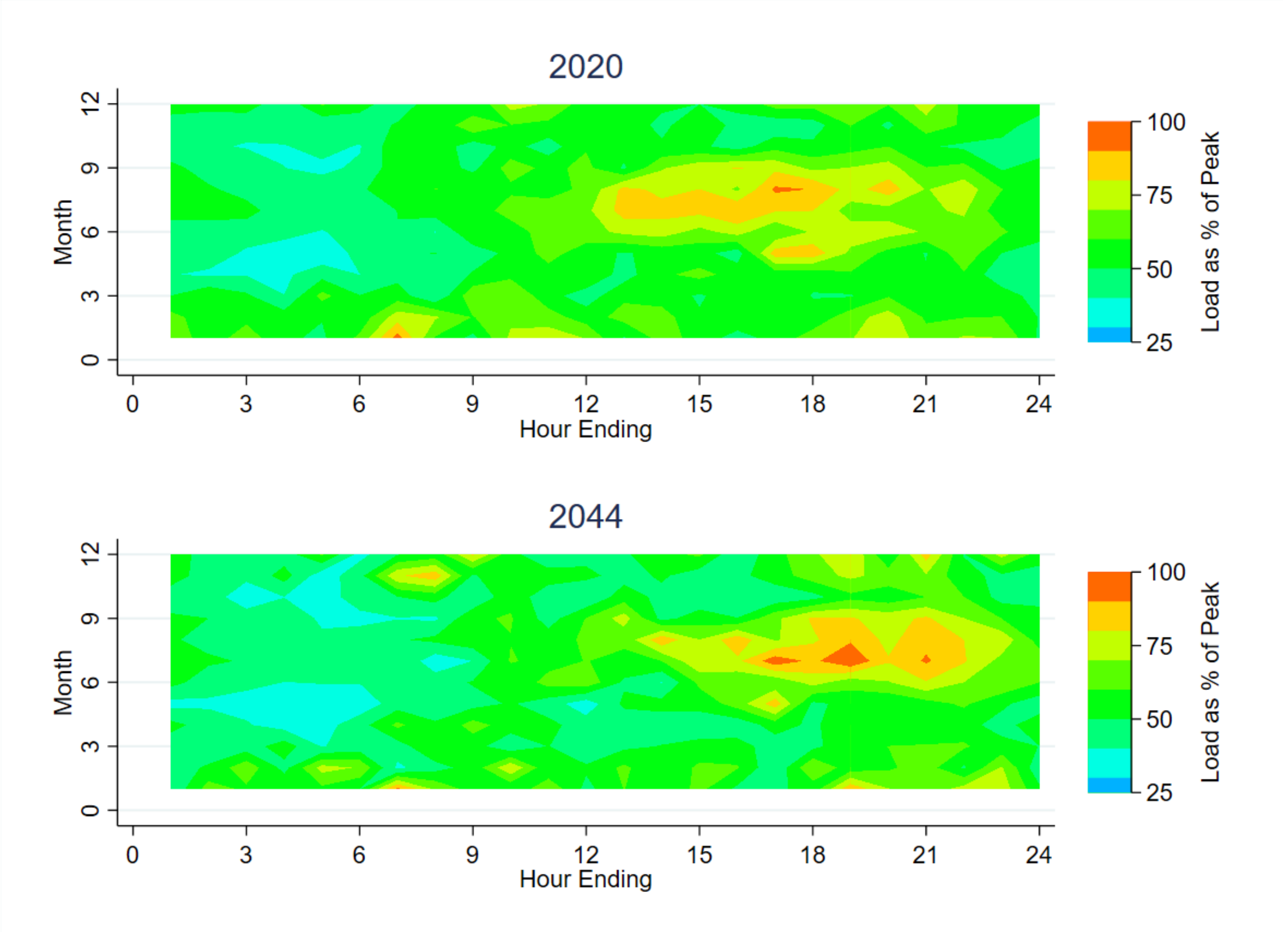
The x-axis in Figure 3-15 is depicted as the cumulative percentage of hours. The red line drawn at 2% serves as a helpful reference point for interpretation by showing the amount of peak capacity needed to serve the 2% of hours with the highest usage.[4] The DEC system currently uses 15% of peak capacity to serve only 2% of hours, and is projected to use 13% of peak capacity to serve 2% of hours by 2044. This means that overall DEC's peak is expected to become slightly less concentrated over time, and so resources such as DSM will have to be dispatched for a larger number of hours to provide the same benefit that they do now.

Another valuable tool for studying peak loads is a contour plot. Often referred to as "heat maps", these plots show frequencies or intensities of a particular variable for different combinations of two other variables. Figure 3-16 contains the same hourly data as a percentage of peak system load that is presented in Figure 3-15; however, it shows the months and hours when each hourly load occurs for all hours instead of only the top 10% of hours.

The results in Figure 3-16 show the highest hours of usage are concentrated in summer evening hours. Actual weather patterns reflect year to year variation in loads and, depending on the extreme temperatures for a year, winter peaks can still be of concern. Another consideration is market prices, which can be high in winter if natural gas is used both for heating and electricity generation.

[4] Another interpretation of the load duration curve data would be the amount that peak load capacity could be reduced by shaving demand during 2% of the hours throughout the year.

Figure 3-16: Forecasted Patterns in DEC System Load (2020 vs 2044)

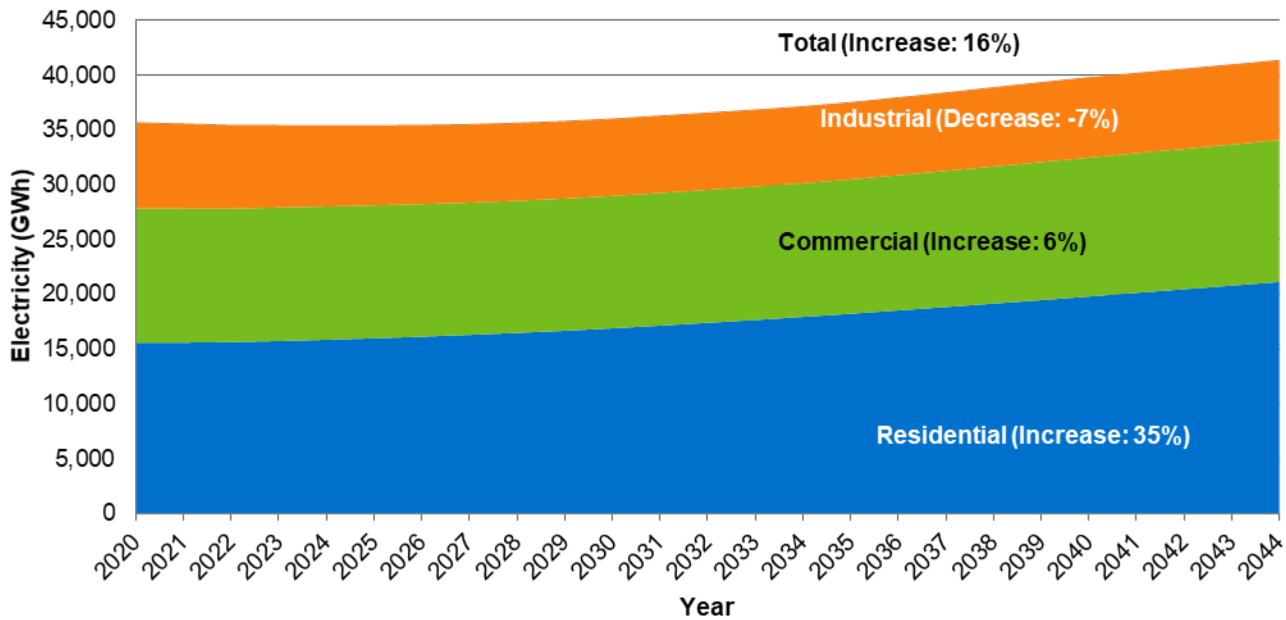


3.7 DEP System Load Forecast 2020 - 2044

3.7.1 DEP System Energy Sales

The DEP electricity use is forecasted to increase by 5,691 GWh (a change of 16%) from 2020 to 2044, to a total of 41,404 GWh in 2044 (see Figure 3-17). The residential sector is expected to account for the largest share of the increase, growing by 5,536 GWh to reach 21,138 GWh (an increase of 35%) over the 25 year period. The commercial sector is expected to increase by 689 GWh to reach 12,957 GWh (a change of 6%) over the 25 year period. The industrial sector is forecasted to decrease by 534 GWh (a change of 7%) from 2020 to 2044, to 7,309 GWh in 2044. In 2044 the residential sector accounts for 51% (21,138 GWh) of total electricity sales, the commercial sector 31% (12,957 GWh) and the industrial sector 18% (7,309 GWh). Nexant worked with Duke Energy to ensure the forecasts did not include the expected future impacts of planned EE and DSM technologies.

Figure 3-17: DEP Electricity Sales Forecast by Sector for 2020 - 2044[5]

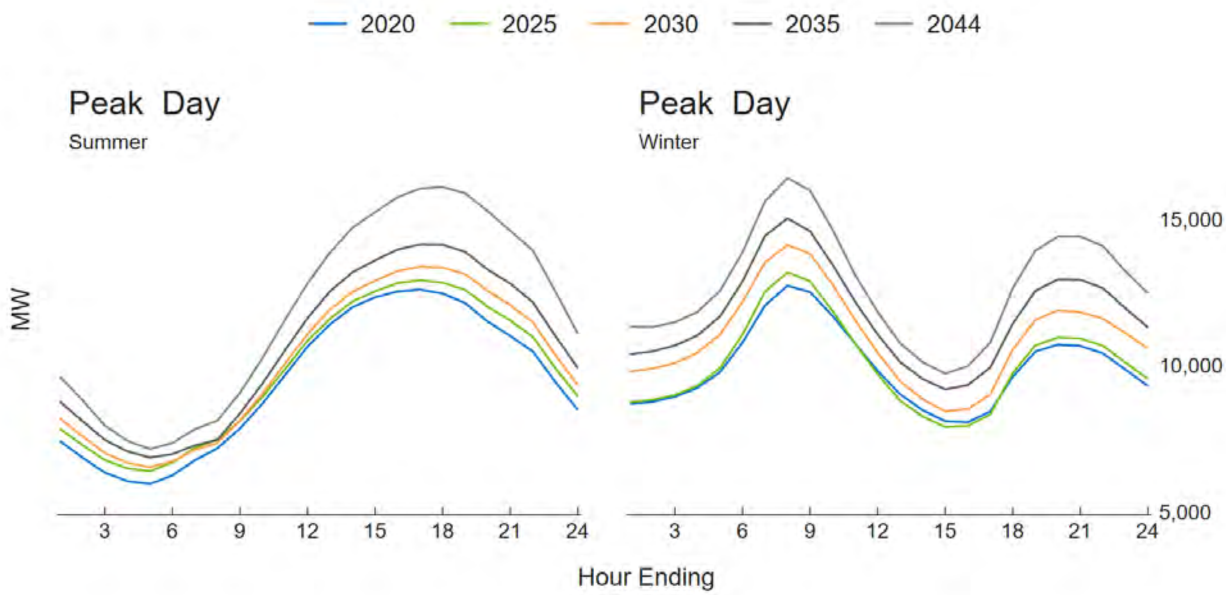


3.7.2 DEP System Demand

As with DEC, the primary data source used to determine when DSM resources will be needed was the DEP system load forecast. This forecast contains forecasted loads for all 8,760 hours of each year in the study period (2020-2044). Figure 3-18 represents an initial inspection of the data. Each figure shows the expected average load profiles for two distinct types of days – peak summer days and peak winter days. Summer was again defined as April-October, while the peak days refer to day with the maximum demand during the year and season.

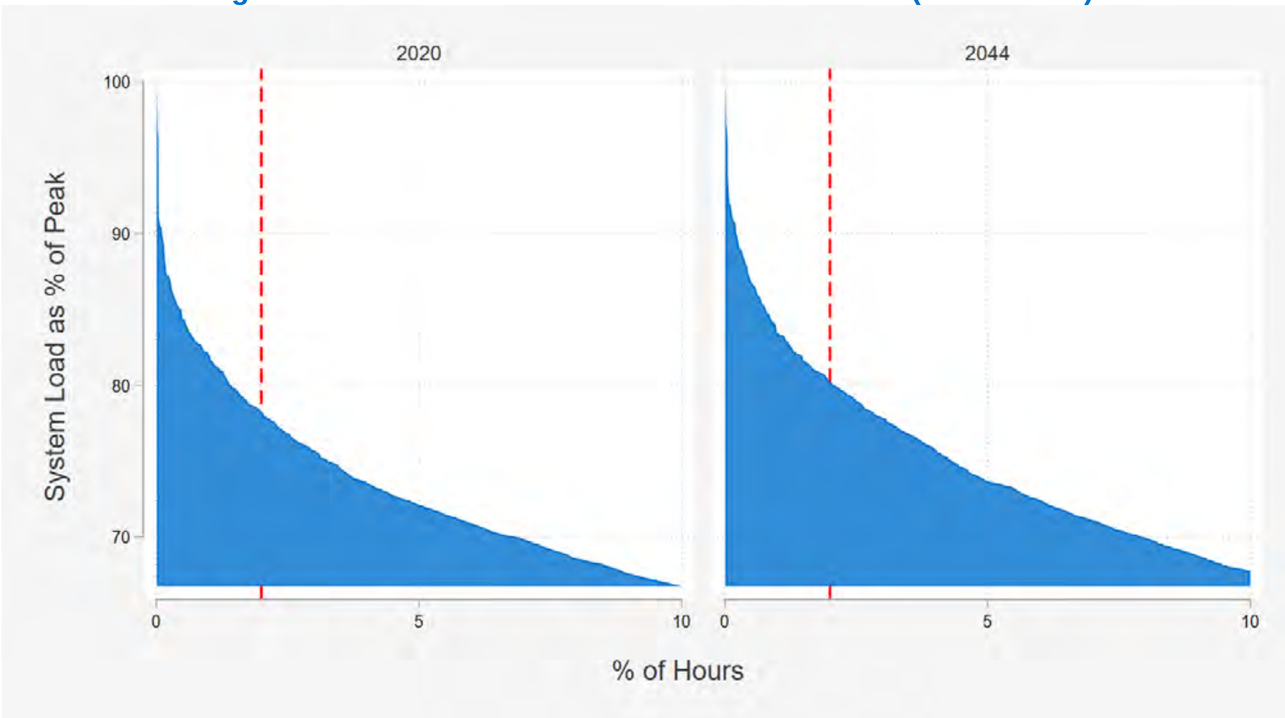
[5] Sales forecast based on DEP(NC) 2019 forecast—the current forecast at the time of Nexant's analysis.

Figure 3-18: DEP System Load Forecast (2020 - 2044)



Several patterns are apparent from examining the figure above. First and foremost, forecasted loads shapes are relatively unchanged over time as the total magnitude of projected load increases. In addition, the summer loads have a similar maximum to winter loads. Thus the potential study focuses on the current summer peak hour, 4-5 pm, and the current winter peak hour, 7-8 am. The DEP load duration curve is presented for 2020 and 2044 in Figure 3-19. This curve shows the top 10% of hourly loads as a percentage of the system's peak hourly usage, sorted from highest to lowest.

Figure 3-19: DEP Forecasted Load Duration Curve (2020 v 2044)



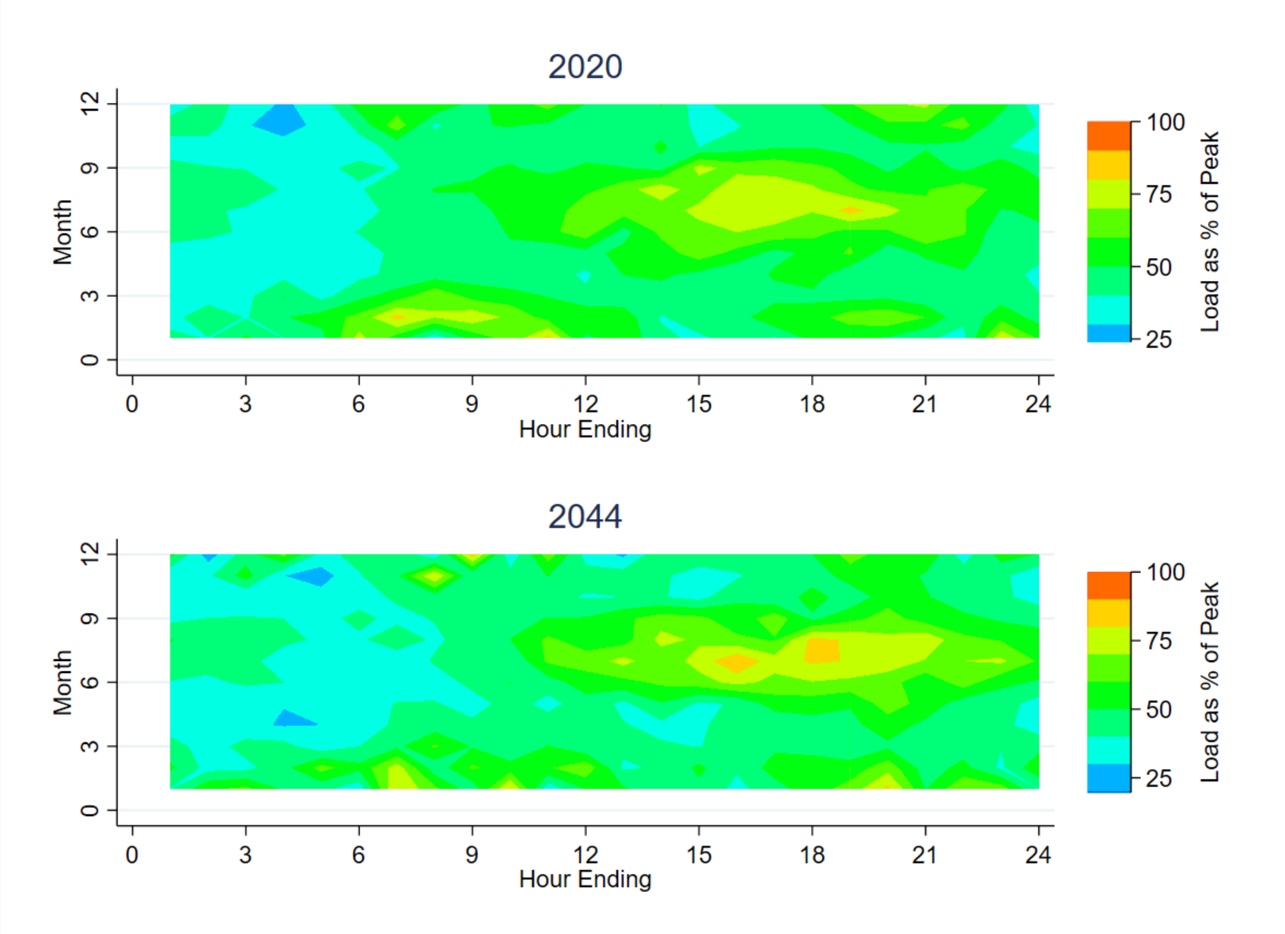
The x-axis in Figure 3-19 is depicted as the cumulative percentage of hours. The red line drawn at 2% serves as a helpful reference point for interpretation by showing the amount of peak capacity needed to serve the 2% of hours with the highest usage.[6] The DEP system currently uses 22% of peak capacity to serve only 2% of hours, and is projected to be 20% by 2044. Therefore, DEP is much "peakier" than DEC, although both utilities expect their peak hours to become less concentrated over time.

Another valuable tool for studying peak loads is a contour plot. Often referred to as "heat maps", these plots show frequencies or intensities of a particular variable for different combinations of two other variables. Figure 3-20 contains the same hourly data as a percentage of peak system load that is presented in Figure 3-19; however, it shows the months and hours when each hourly load occurs for all hours instead of only the top 10% of hours.

The results in Figure 3-20 show the highest hours of usage are concentrated in summer evening hours and winter morning hours. In winter, we see the peak is particularly concentrated during the 7-8 AM window when a high residential heating load is expected.

[6] Another interpretation of the load duration curve data would be the amount that peak load capacity could be reduced by shaving demand during 2% of the hours throughout the year.

Figure 3-20: Forecasted Patterns in DEP System Load (2020 vs 2044)



3.8 Customer Opt-Outs

Duke Energy’s energy efficiency programs in North Carolina include an “opt-out” provision approved by the North Carolina Utilities Commission. This provision allows all industrial customers and commercial class customers with annual energy consumption exceeding one million kWh to opt out, which exempts the customer from cost recovery mechanism but also eliminates that customer’s eligibility for participation in the program.

In order to incorporate the impact of opt-outs into the study, Duke provided Nexant with current opt-out information in North Carolina, which showed an opt-out rate of approximately 40% of commercial kWh sales and 73% of industrial kWh sales in the DEC service territory; whereas DEP data indicate 30% of commercial kWh sales and 91% of industrial kWh have opted out. Nexant incorporated this opt-out rate into the model by reducing the non-residential sales estimates by the appropriate percentage for each service territory and applying the applicable energy efficiency technologies and market adoption rates to the remaining sales forecast.

4 Measure List

Nexant maintains a database of energy efficiency measures for use in MPS studies. Measure data are developed and refined as new information on, or methods for, estimating measure impacts become available. The current list of savings opportunities, or "measures," incorporates the measure list that used in the 2016 MPS study Nexant conducted on behalf of Duke Energy Carolinas but added new measures where conditions changed. An example of measure list updates is that Nexant consolidated the lighting opportunities by excluding all CFLs and Metal Halides but keeping the LEDs to better reflect market trends. This section describes how the measure data is developed and applied in the study for energy efficiency and DSM services and products.

The EE measure data used in the 2016 MPS study included a list of proposed measures provided by Duke Energy, which included all Duke Energy measures currently offered by existing programs at that time, as well as measures Duke Energy developed with its own gap analysis of program offerings. Nexant reviewed the Duke Energy list to develop an initial qualitative screening for applicability in the North Carolina territories. Nexant also reviewed the Duke Energy program measure lists against the Nexant EE measure library to ensure that the study covered a robust and comprehensive set of measures, and supplemented the list with Nexant-identified measures where appropriate.

The final measure list included energy efficiency technologies, and products that enable DSM opportunities. DSM initiatives that do not rely on installing a specific technology or measure (such as a voluntary curtailment program) are not reflected in the measure list. See Appendix B for the final measure list.

4.1 Energy Efficiency Measures

Nexant's measure data represents savings opportunities for all electricity end uses and customer types. EE program measure offers are typically more specific than those required to assess EE potential. For example, Duke Energy programs have multiple instances of LED lamps with varying characteristics (candelabra base, globe base, A-line, etc.). Although these distinctions are important during program delivery, this level of granularity is not necessary to identify the market potential for EE savings.

Nexant used a qualitative screening approach to address the applicability of measures to the North Carolina service territories. The qualitative screening criteria that Nexant used included: difficult to quantify savings, no longer current practice, better measure available, immature or unproven technology, limited applicability, poor customer acceptance, health and environmental concerns, and end-use service degradation.

Nexant updated its online measure database to support this study. Nexant's database contains the following information for each measure:

- Classification of measure by type, end use, and subsector
- Description of the base-case and the efficiency-case scenarios
- Measure life
- Savings algorithms and calculations per subsector, taking weather zones and subsectors into consideration
- Input values for variables used to calculate energy savings
- Measure costs
- Output to be used as input in Nexant's TEA-POT model.

Detailed measure assumptions in this database are provided to Duke Energy in supplemental electronic files, MS Excel format. As shown in Table 4-1, the study included 329 unique energy-efficiency measures. Expanding the measures to account for all appropriate combinations of segments, end uses, and construction types resulted in 8,994 measure permutations. Appendix B includes the final measure list used for the study.

Table 4-1: EE Measure Counts by Sector

Sector	Unique Measures	Permutations
Residential	88	1,121
Commercial	142	5,138
Industrial	99	2,735

4.2 DSM Services and Products

Nexant and Duke Energy worked together to determine which DSM products and services were included in the MPS, and addressed the following:

- **Direct load control.** Customers receive incentive payments for allowing the utility a degree of control over equipment, such as air conditioners or water heaters. This includes both switch-based programs and smart thermostat programs.
- **Emergency load response.** Customers receive payments for committing to reduce load if called upon to do so by the grid operator.
- **Economic load response:** Utilities provide customers with incentives to reduce energy consumption when marginal generation costs are higher than the incentive amount required to achieve the needed energy reduction.
- **Base interruptible DSM**. Customers receive a discounted rate for agreeing to reduce load to a firm service level upon request.

5 Technical Potential

Technical potential is based on base year load shares and reference case load forecasts for 2020 to 2044. This information, along with data on measures available to capture savings opportunities, provide inputs for estimating technical potential. The technical potential scenario estimates the savings potential when all technically feasible energy efficiency measures are fully implemented, while accounting for equipment turnover. This savings potential can be considered the maximum reduction attainable with available technology and current market conditions (e.g. currently available technology, building stock, customer preferences as reflected in Duke Energy forecasted sales). EE and DSM potential scenarios that account for measures' costs and benefits and market adoption are discussed in subsequent report sections for economic potential and achievable potential, respectively.

5.1 Approach and Context

Technical potential represents a straightforward application of EE and DSM measures to the baseline market context for Duke Energy Carolinas. Technical potential is determined by two main considerations: the energy intensity of baseline consumption, and the savings opportunities represented by EE and DSM measures. Baseline conditions for electricity consumption are based on historic and current economic conditions, the current configuration of the power system, policy context, and customer preferences.

Current and projected sales and load are based on the current and projected numbers of accounts served by economic sector. The types of loads present at these accounts is reflective of customers' economic sector, segment, and final demand for electricity services. Final demand for electricity is reflective of numerous, complex factors such as the set of available technologies that produce electricity end uses (e.g. HVAC for heating, cooling, and ultimately: comfort); the cost of technologies that produce electricity end uses; the price of electricity and other energy sources; customer demand for electricity services; and, behavioral or other contextual factors that collectively drive customer decisions about energy consumption.

5.1.1 Energy Efficiency

Energy efficiency technical potential provides a theoretical maximum for electricity savings. Technical potential ignores all non-technical constraints on electricity savings, such as cost-effectiveness and customer willingness to adopt energy efficiency, except insofar as these trends are captured in Duke Energy's baseline sales and load forecasts. For an electricity potential study, technical potential refers to delivering less electricity to the same end uses. In other words, technical potential might be summarized as "doing the same thing with less energy, regardless of the cost."

Technical potential results from the application of EE measures to the disaggregated North Carolina electricity sales forecasts. Nexant applied estimated energy savings from equipment or non-equipment measures to all electricity end uses and customers. Since technical potential does not consider the costs or time required to achieve these electricity savings, the estimates provide an upper limit on savings potential. Nexant reported technical potential as a single numerical value for the DEC service territory and for the DEP service territory.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 5-1 below, while the core equation used in the nonresidential sector technical potential analysis for each individual efficiency measure is shown in Equation 5-2, below.

Equation 5-1: Core Equation for Residential Sector Technical Potential

$$\text{Technical Potential of Efficient Measures} = \text{Total Number of Households} \times \text{Base Case Equipment Energy Use Intensity (kWh/unit)} \times \text{Saturation Share} \times \text{Remaining Factor} \times \text{Applicability Factor} \times \text{Savings Factor}$$

Where:

Base Case Equipment Energy Use Intensity = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

Applicability Factor = the fraction of units that is technically feasible for conversion to the most efficient available technology .

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

Equation 5-2: Core Equation for Nonresidential Sector Technical Potential

$$\text{Technical Potential of Efficient Measures} = \text{Total Stock Sq. Footage by Building Type by EDC} \times \text{Base Case Equipment Energy Use Intensity (kWh/unit)} \times \text{Equipment Saturation Share} \times \text{Remaining Factor} \times \text{Applicability Factor} \times \text{Savings Factor}$$

Where:

Total Stock Square Footage by Building Type = the forecasted square footage level for a given building type (e.g., square feet of office buildings).

Base Case Equipment Energy Use Intensity = the electricity used per square foot per year by each base-case equipment type in each market segment.

Equipment Saturation Share = the fraction of total end use energy consumption associated with the efficient technology in a given market segment. For example, for room air conditioners, the saturation share would be the fraction of all space cooling kWh in a given market segment that is associated with room air conditioner equipment.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. For example, the fraction of electric water heaters that is not already energy efficient.

Applicability Factor = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (i.e., it may not be possible to install VFDs on all motors in a given market segment).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

It is important to note that the technical potential estimate represents electricity savings potential at a specific point in time. In other words, the technical potential estimate is based on data describing *status quo* customer electricity use and technologies known to exist today. As technology and electricity consumption patterns evolve over time, the baseline electricity consumption will also change accordingly. For this reason, technical potential is a discrete estimate of a dynamic market. Nexant reported technical potential over a defined time period, based on currently known DSM measures and observed electricity consumption patterns.

Addressing Naturally-Occurring Energy Efficiency

Because the anticipated impacts of efficiency actions that may be taken even in the absence of utility intervention are included in the baseline forecast, savings due to naturally-occurring efficiency were considered separately in the potential estimates. Nexant worked with Duke Energy's forecasting group to ensure that the sales forecasts incorporated two known sources of naturally-occurring efficiency:

- **Codes and Standards:** The sales forecasts incorporated the impacts of known code changes. While some code changes have relatively little impact on overall sales, others—particularly the Energy Independence and Security Act (EISA) and other federal legislation—will have noticeable influence. Given the uncertainty associated with the implementation of the EISA backstop and current market trends, Nexant adjusted the future lighting baseline to the EISA-compliant standard.

- **Baseline Measure Adoption:** Sales forecasts typically exclude the projected impacts of future DSM efforts, but account for baseline efficiency penetration (this can be a delicate process given that some of these adopters are likely programmatic free-riders).

By properly accounting for these factors, the potential study estimated the net penetration rates, representing the difference between the anticipated adoption of efficiency measures as a result of DSM efforts and the "business as usual" adoption rates absent DSM intervention. This is true even in the technical and economic scenarios, where adoption was assumed to be 100%, and was particularly important in the achievable potential analysis, where Nexant estimated the measure adoption and associated savings that can be expected to occur above baseline measure adoption rates.

5.1.2 DSM

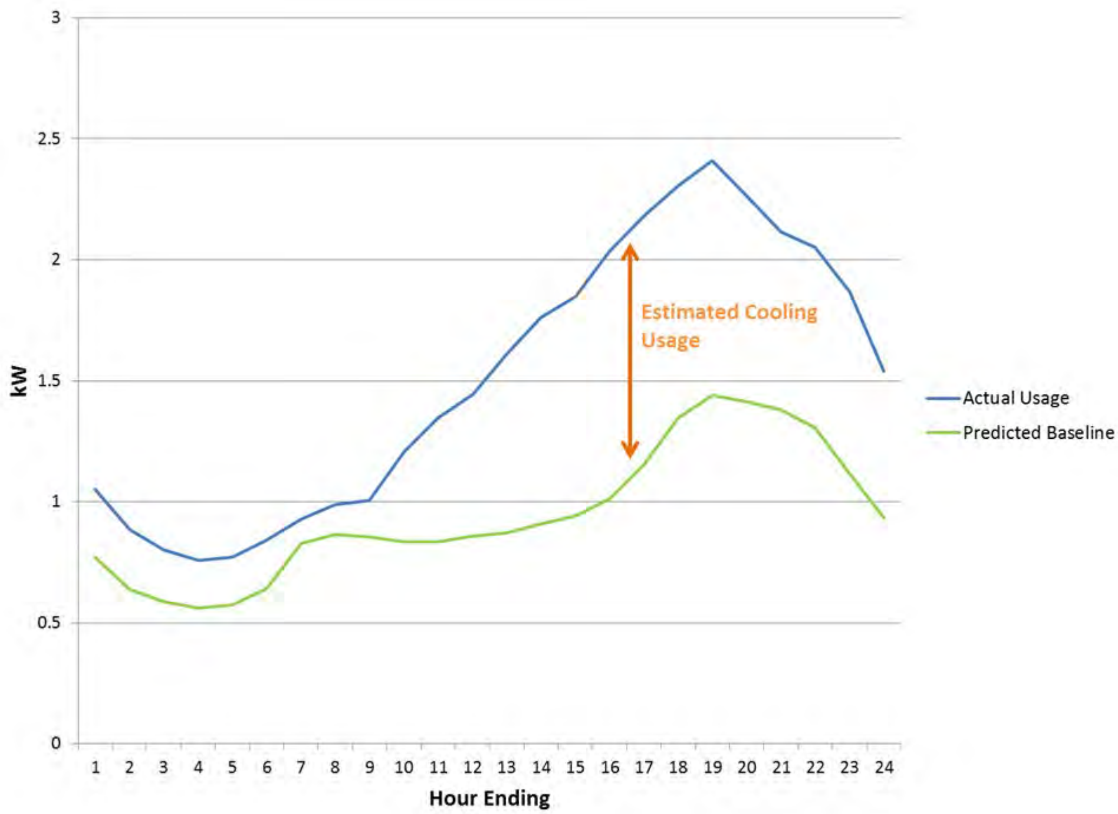
The concept of technical potential differs when applied to DSM. Technical potential for DSM is effectively the magnitude of loads that can be managed during conditions when grid operators need peak capacity, ancillary services, or when wholesale energy prices are high. The goal of a DSM technical potential analysis is to identify the accounts and end uses that consume electricity during those times and determine which end uses can be reduced. For residential and small C&I accounts where DSM generally takes the form of direct utility control, technical potential for DSM is limited by the loads that can be controlled remotely at scale. Large C&I accounts generally do not provide the utility with direct control over end-uses. However, for enough money, businesses will forego virtually all electricity consumption temporarily. Therefore, all end uses are considered for large C&I technical potential.

To determine what curtailable load is available during system peaks, Nexant analyzed interval data for all large C&I customers and relied on average load shapes from load research samples as the starting point for analysis of residential and smaller C&I customers. Instead of disaggregating annual consumption or peak demand, Nexant produced end-use load disaggregation for all 8,760 hours in a year. This was needed because the loads available at times when different grid applications are needed can vary substantially. In the context of this study, DSM capacity is defined as the amount of curtailable load that is available during the system peak hour for the summer and winter seasons. Thus, two sets of capacity values are estimated: a summer capacity and a winter capacity.

As previously mentioned, all large C&I load is considered dispatchable, while residential and small C&I DSM capacity is based on specific end uses. "Dispatchable" loads are those that can be directly and centrally controlled by a utility (subject to customers' permission) For this study, Nexant assumed that summer DSM capacity for residential customers would be comprised of AC, pool pumps, and water heaters. For small C&I customers, summer capacity was based on AC load. For winter capacity, residential DSM capacity was based on electric heating loads and water heaters. For small C&I customers, winter capacity was based on heating load.

AC and heating load profiles were generated for residential and small C&I customers using the load research sample provided by Duke. The aggregate load profile for each customer class was combined with historical weather data and used to estimate hourly load as a function of weather conditions. AC and heating loads were estimated by calculating the baseline load on days when cooling degree days (CDD) and heating degree days (HDD) were equal to zero, then by subtracting this baseline load from the load that occurred on days when temperatures were more extreme. This methodology is illustrated by Figure 5-1.

Figure 5-1: Methodology for Estimating Cooling Loads



This method was only able to produce estimates for average AC/heating load profiles for the residential and small C&I sector as a whole (the load research samples provided were at an aggregate level), so each segment's relative contribution to the total cooling and heating load for residential and small C&I sectors were based on the segment's size and the segment's end use saturation. Segment size was determined using 2018 billing data.

Profiles for residential pool pump loads were estimated by utilizing end use load data from CPS Energy's Home Manager Program. This data was validated against end use data provided by Duke Energy Florida. Consumption associated with these end uses is fairly similar across different geographic regions; so data from CPS Energy's territory in San Antonio were considered a valid proxy. The only difference was that pool pump loads were assumed to be zero in the winter season for DEC and DEP, whereas these loads are fairly constant year round for CPS Energy. Water heater load profiles were completed based on end-use metered data from OpenEI, which provided end use data for each weather station in the Carolinas. The water heater data was then averaged using the same weather stations and weights as the weather data used in the analysis.

For all eligible loads, the technical potential was defined as the amount that was coincident with system peak hours for each season. System peak hours were identified using 2018 system load data. The 2018 summer peak for DEC territory occurred July 11th during hour ending 17. The 2018 summer peak for DEP territory occurred June 19th during hour ending 17. The 2018 winter peak for DEC territory occurred January 5th during hour ending 8. The 2018 winter peak for DEP territory occurred January 2nd during hour ending 8.

5.2 DEC Energy Efficiency Technical Potential

This section provides the results of the DEC and DEP energy efficiency technical potential for each of the three segments.

5.2.1 Summary

Table 5-1 summarizes the energy efficiency technical potential by sector and levelized cost associated with the identified potential. Nexant calculated levelized cost as the discounted sum of incremental cost over the study period divided by the discounted sum of lifetime energy savings over the period.

Table 5-1: DEC Energy Efficiency Technical Potential by Sector

Sector	Technical Potential (2020-2044)				
	Energy (GWh)	% of 2044 Base Sales	Demand (MW)		Levelized Cost ($/kWh)
			Summer	Winter	
Residential	10,072	37%	4,380	734	$0.29
Commercial	4,085	24%	723	212	$0.29
Industrial	877	28%	122	119	$0.17
Total	**15,034**	**32%**	**5,226**	**1,064**	**$0.28**

5.2.2 Sector Details

Figure 5-2 summarizes the DEC residential sector energy efficiency technical potential by end use.

Figure 5-2: DEC Residential EE Technical Potential– Cumulative 2044 by End-Use

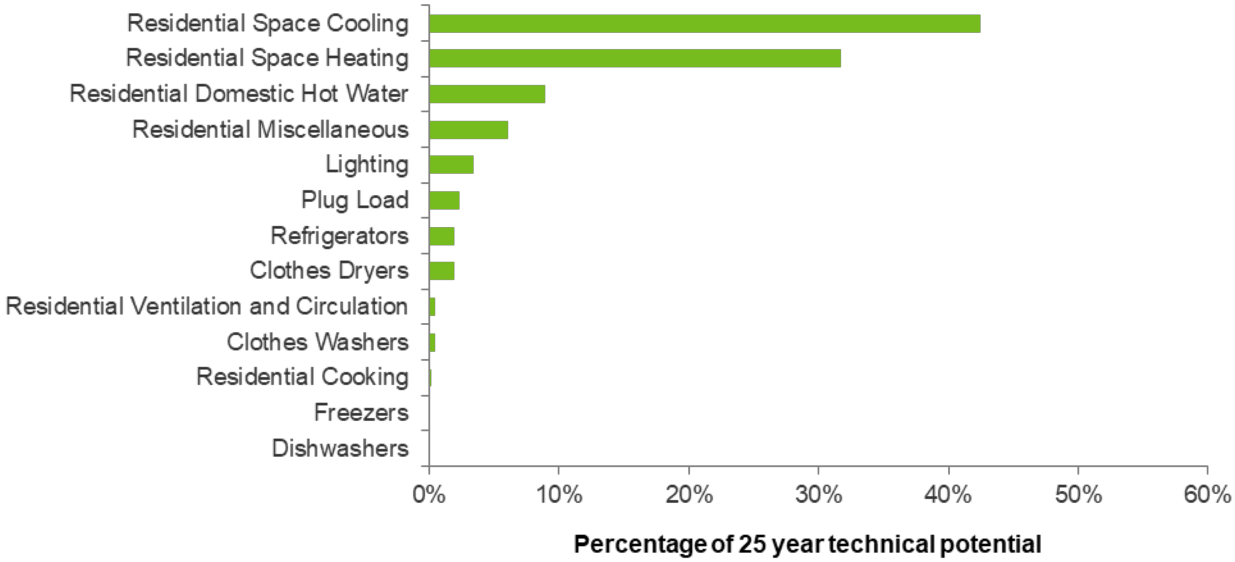


Figure 5-3 summarizes the DEC commercial sector EE technical potential by end use.

Figure 5-3: DEC Commercial EE Technical Potential – Cumulative 2044 by End-Use

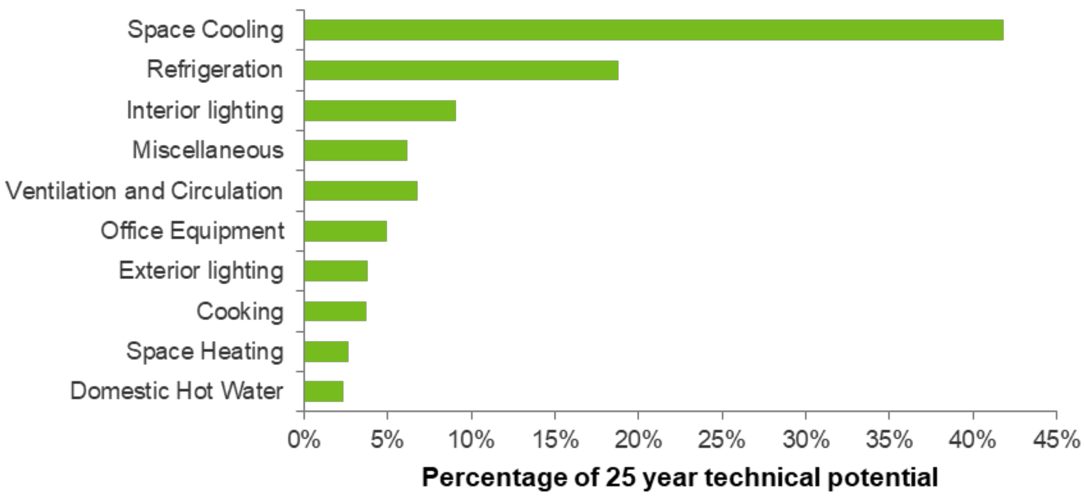


Figure 5-4 provides a summary of DEC energy efficiency technical potential contributions by commercial facility types analyzed in this study.

Figure 5-4: DEC Commercial EE Technical Potential by Segment

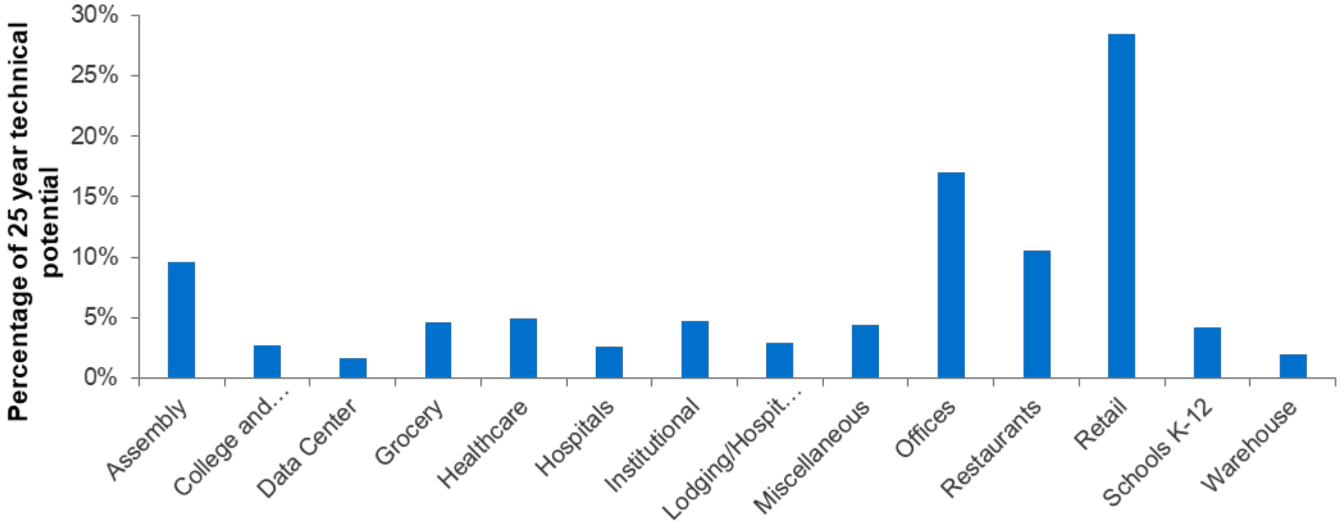


Figure 5-5 summarizes the DEC industrial sector energy efficiency technical potential by end use.

Figure 5-5: DEC Industrial EE Technical Potential – Cumulative 2044 by End-Use

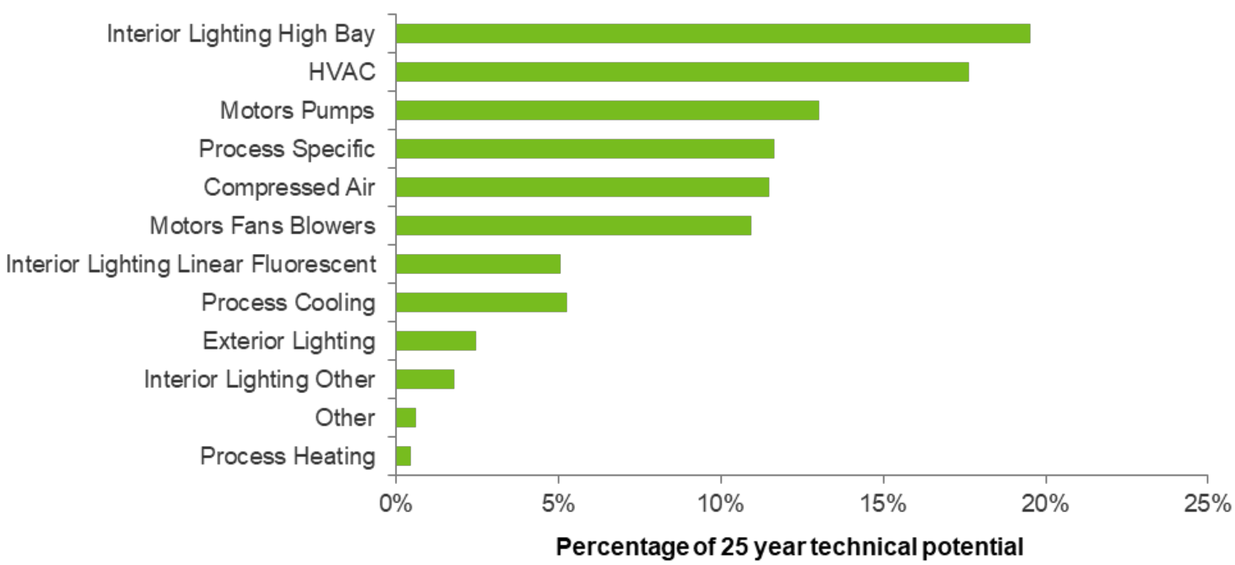
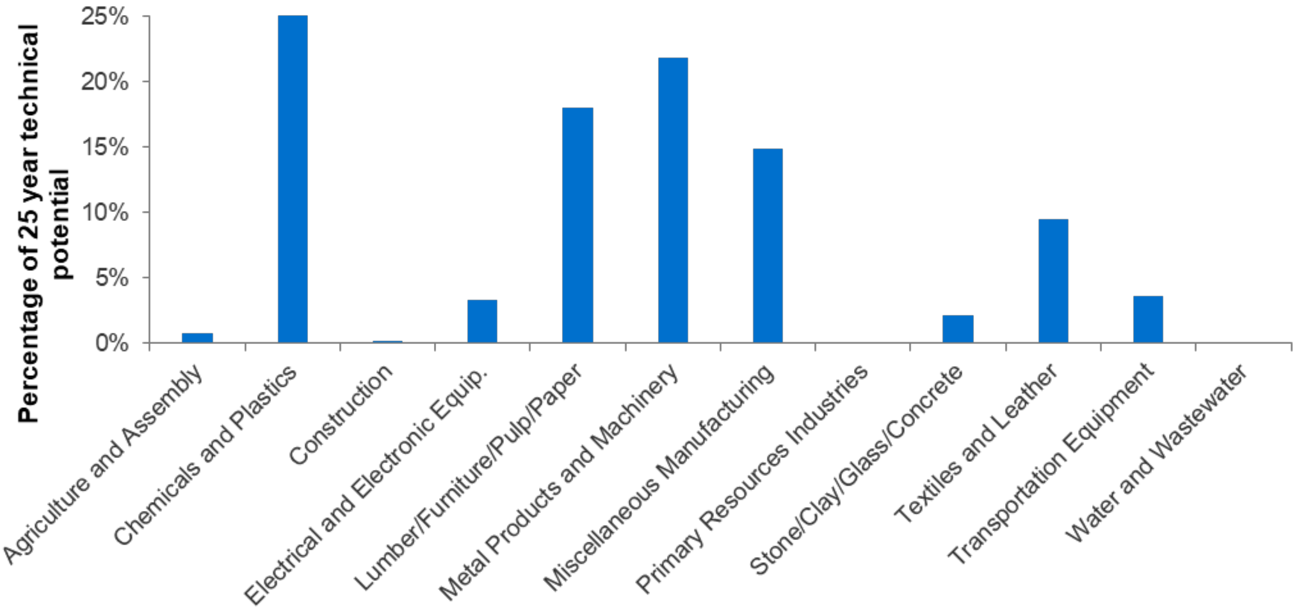


Figure 5-6 provides a summary of DEC energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 5-6: DEC Industrial EE Technical Potential by Segment



5.3 DEP Energy Efficiency Technical Potential

This section provides the results of the DEP energy efficiency technical potential for each of the three segments.

5.3.1 Summary

Table 5-2 summarizes the DEP energy efficiency technical potential by sector and levelized cost associated with the identified potential. Nexant calculated levelized cost as the sum of incremental cost over the study period divided by the discounted sum of lifetime energy savings over the period.

Table 5-2: DEP Energy Efficiency Technical Potential by Sector

Sector	Technical Potential (2020-2044)				
	Energy (GWh)	% of 2044 Base Sales	Demand (MW)		Levelized Cost ($/kWh)
			Summer	Winter	
Residential	7,879	37%	4,080	445	$0.24
Commercial	2,276	25%	401	117	$0.29
Industrial	195	28%	27	26	$0.19
Total	**10,350**	**34%**	**4,509**	**588**	**$0.25**

5.3.2 Sector Details

Figure 5-7 summarizes the DEP residential sector EE technical potential by end use.

Figure 5-7: DEP Residential EE Technical Potential – Cumulative 2044 by End-Use

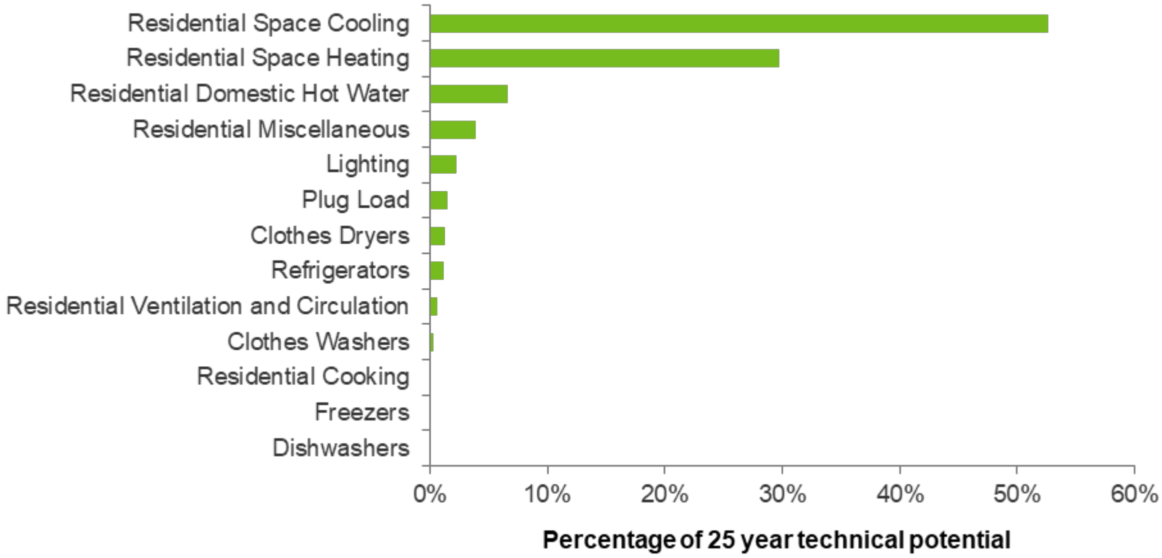


Figure 5-8 summarizes the DEP commercial sector energy efficiency technical potential by end use.

Figure 5-8: DEP Commercial EE Technical Potential – Cumulative 2044 by End-Use

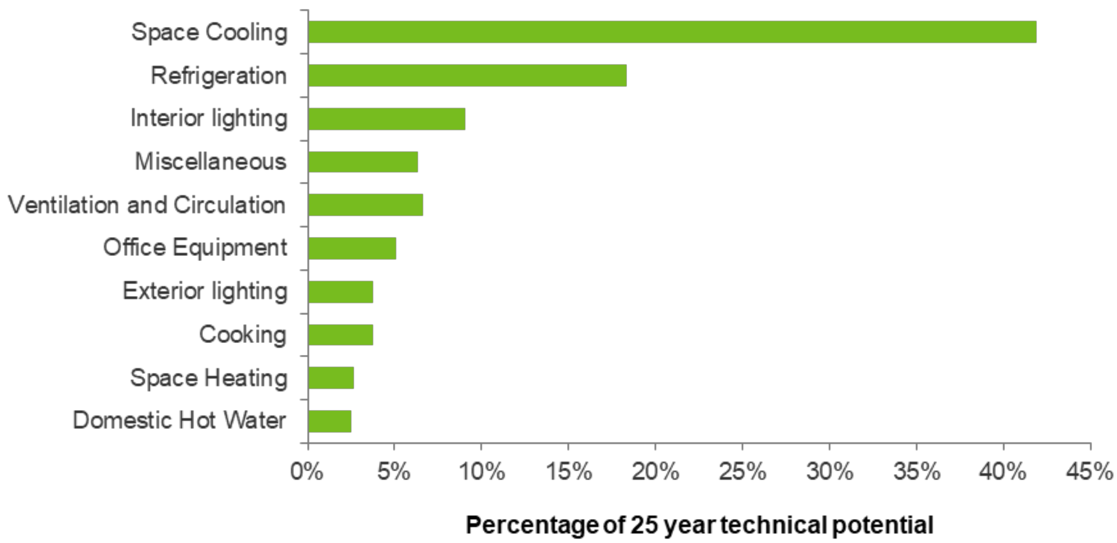


Figure 5-9 provides a summary of DEP energy efficiency technical potential contributions by commercial facility types analyzed in this study.

Figure 5-9: DEP Commercial EE Technical Potential by Segment

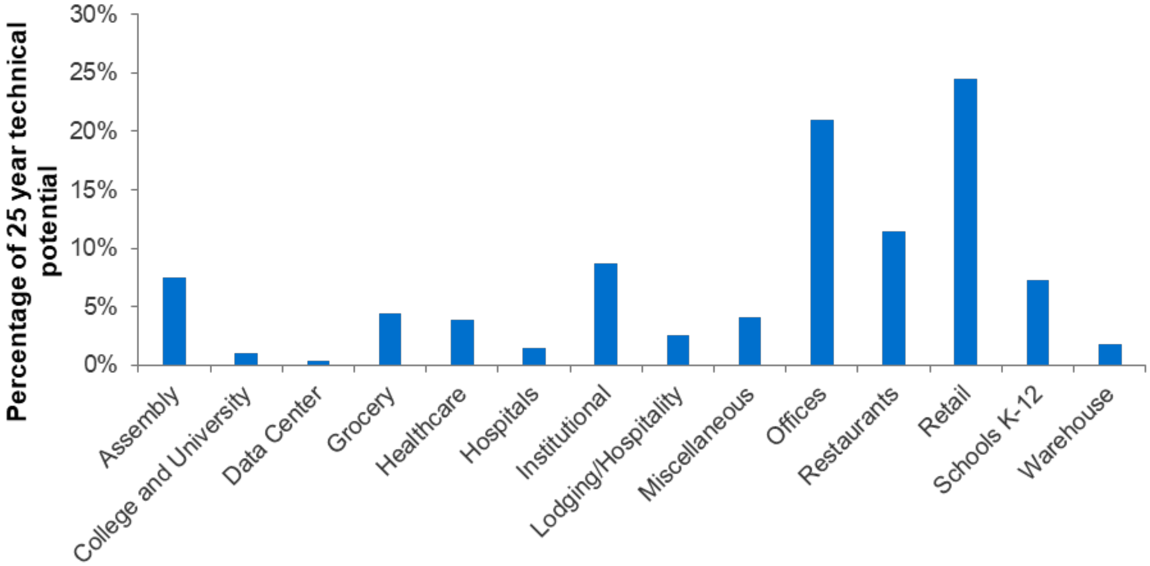


Figure 5-10 summarizes the DEP industrial sector energy efficiency technical potential by end use.

Figure 5-10: DEP Industrial EE Technical Potential – Cumulative 2044 by End-Use

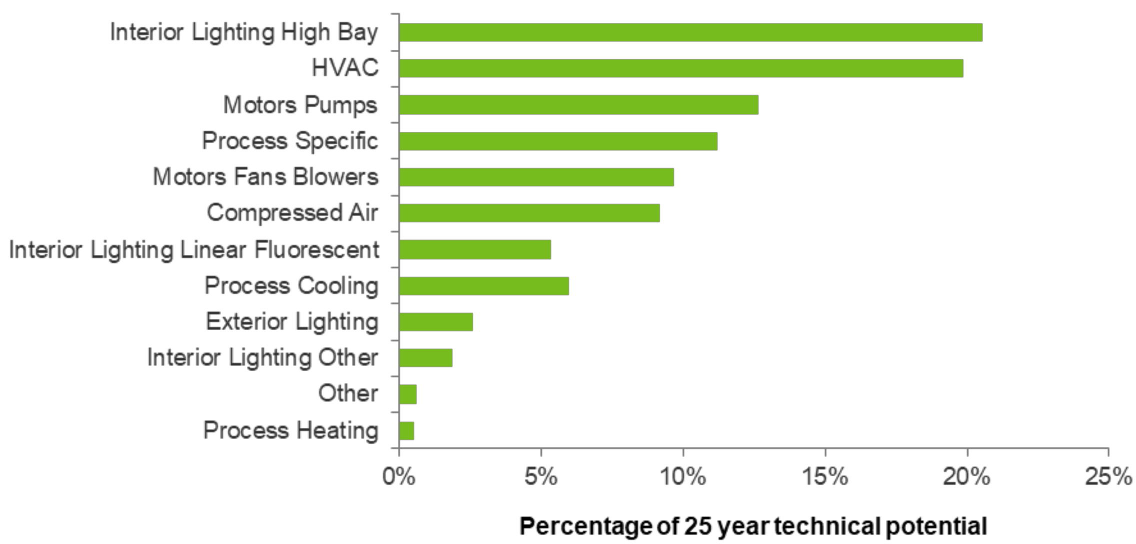
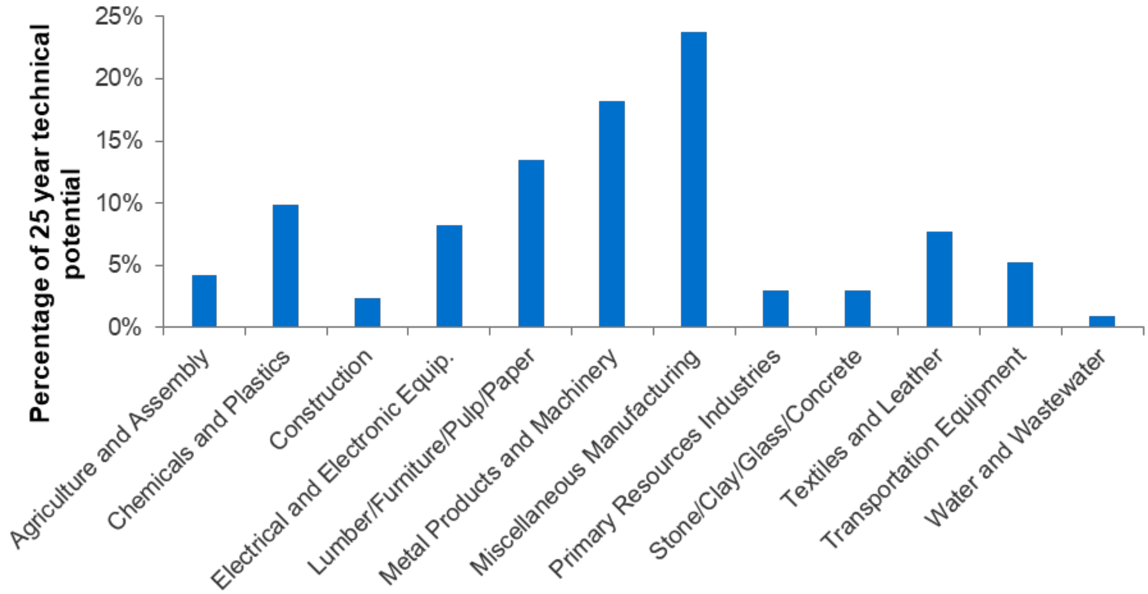


Figure 5-11 provides a summary of DEP energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 5-11: DEP Industrial EE Technical Potential by Segment



5.4 DEC Controllable Peak Load, by Customer Type

Technical potential for DSM is defined for each class of customers as follows:

- **Residential & Small C&I customers** – Technical potential is equal to the aggregate load for all end uses that can participate in Duke Energy's current and planned DSM programs in which the utility uses specialized devices to control loads (i.e. direct load control programs). This includes AC/heating loads for residential and small C&I customers, and also water heater and pool pump loads for residential customers. The study excluded DSM programs that explicitly target behavior (i.e., they are not automated or dispatchable).
- **Large C&I customers** – Technical potential is equal to the total amount of load for each customer segment. This reflects the behavioral nature of most large C&I programs and the fact that for a large enough payment and small enough number of events, large C&I customers would be willing to reduce their usage to zero.

Table 5-3 summarizes the seasonal DSM technical potential by sector:

Table 5-3: DEC DSM Technical Potential by Sector

Sector	Annual Technical Potential	
	Summer (Agg MW)	Winter (Agg MW)
Residential	3,231	3,497
Small C&I	437	441
Large C&I	238	218
Total	3,905	4,155

5.4.1 Residential and Small C&I Customers

Residential technical potential is summarized in Table 5-4. The potential is broken down by end use and building type. A more detailed breakdown of the AC and heating loads by customer segment is provided in the economic potential section, along with the cost-effectiveness of each customer segment.

Table 5-4: DEC Residential Demand Technical Potential

Rate Classes	Season	End Uses	Single Family Residential		Multi Family Residential		Total
			Avg. kw	Agg. MW	Avg. kw	Agg. MW	Agg. MW
RS	Summer	AC Cooling	2.03	1614.1	2.03	138.0	**1752.1**
	Winter	Heating					
	Summer/Winter	Water Heater	0.30 / 0.82	181.5 / 498.0	0.30 / 0.82	14.0 / 38.5	**195.6 / 536.5**
	Summer	Pool Pump	1.00	47.7			**47.7**
RE	Summer	AC Cooling	1.50	693.0	1.50	372.0	**1064.9**
	Winter	Heating	3.58	1675.9	3.58	899.6	**2575.4**
	Summer/Winter	Water Heater	0.30 / 0.82	90.9 / 249.4	0.30 / 0.82	48.8 / 133.9	**139.7 / 383.3**
	Summer	Pool Pump	1.00	23.9			**23.9**
RT	Summer	AC Cooling	3.36	6.5	3.36	0.1	**6.5**
	Winter	Heating	4.44	0.3			**0.3**
	Summer/Winter	Water Heater	0.30 / 0.82	0.38 / 1.0	0.30 / 0.82	0.004 / 0.01	**0.38 / 1.05**
	Summer	Pool Pump	1.00	0.1			**0.1**

Small Business technical potential is provided in Table 5-5.

Table 5-5: DEC Small C&I Demand Technical Potential

Segment	AC Cooling		Heating	
	Avg. kw	Agg. MW	Avg. kw	Agg. MW
Assembly	3.12	63.41	21.57	20.85
Colleges and Universities	4.73	4.31	36.25	2.75
Data Centers	4.43	2.16	29.59	0.67
Grocery	6.40	9.73	37.90	25.95
Healthcare	4.24	24.43	31.54	16.66
Hospitals	4.96	2.06	39.11	0.59
Institutional	1.76	10.67	14.71	4.20
Lodging (Hospitality)	2.99	6.41	22.02	9.49
Miscellaneous	0.99	27.07	7.57	40.78
Office	1.90	84.85	14.97	66.24
Restaurants	10.85	59.48	56.83	33.24
Retail	2.27	116.34	15.87	112.61
Schools K-12	3.46	7.14	38.18	3.86
Warehouse	2.04	3.80	16.03	1.49
Agriculture & Forestry	4.49	0.16	28.41	1.01
Chemicals & Plastics	5.42	1.23	35.72	8.12
Construction	3.30	0.04	12.17	0.14
Electrical & Electronic Equipment	3.69	0.95	25.16	6.47
Lumber, Furniture, Pulp and Paper	3.77	3.15	26.98	22.54
Metal Products & Machinery	4.23	4.07	28.76	27.69
Misc. Manufacturing	4.17	3.26	27.30	21.34
Primary Resource Industries	-	-	-	-
Stone, Clay, Glass and Concrete	3.52	0.50	25.20	3.57
Textiles & Leather	4.14	0.97	29.00	6.81
Transportation Equipment	1.92	0.56	13.44	3.91
Water and Wastewater	-	-	-	-
Total		**436.75**		**440.98**

5.4.2 Large C&I Customers

Technical potential for C&I customers, broken down by customer segments, is given in Table 5-6. In DEC's territory, nonresidential customers either qualified as small C&I customers or were large enough to qualify as large C&I customers. Much of the technical potential for large C&I customers comes from a handful of industries, particularly textiles & leathers, chemicals/plastics, offices, data centers, and lumber/furniture/pulp/paper.

Table 5-6: DEC Large C&I Demand Technical Potential

Segment	1 MW and Up	
	Summer (MW)	Winter (MW)
Agriculture and Assembly	0.7	0.6
Chemicals and Plastics	50.2	43.5
College and University	10.0	5.6
Construction	0.0	0.0
Data Center	17.3	15.5
Electrical and Electronic Equip.	1.6	1.5
Grocery	0.0	0.0
Healthcare	2.2	2.2
Hospitals	1.8	1.1
Institutional	2.5	3.0
Lodging/Hospitality	0.0	0.0
Lumber/Furniture/Pulp/Paper	16.9	17.3
Metal Products and Machinery	10.2	9.0
Miscellaneous	27.5	37.6
Miscellaneous Manufacturing	8.3	6.7
Office	18.9	14.1
Primary Resources Industries	0.0	0.0
Restaurants	0.0	0.0
Retail	8.1	7.7
Schools K-12	1.2	0.8
Stone/Clay/Glass/Concrete	0.5	0.8
Textiles and Leather	53.2	45.8
Transportation Equipment	6.5	4.9
Warehouse	0.0	0.0
Water and Wastewater	0.0	0.0
Total	**237.6**	**217.9**

5.5 DEP Controllable Peak Load, by Customer Type

Technical potential for DSM is defined for each class of customers as follows: Residential and Small C&I Customers, and Large C&I Customers.

Table 5-7 summarizes the seasonal DSM technical potential by sector:

Table 5-7: DEP DSM Technical Potential by Sector

Sector	Annual Technical Potential	
	Summer (Agg MW)	Winter (Agg MW)
Residential	2,414	2,925
Small C&I	737	776
Large C&I	27	24
Total	3,179	3,725

5.5.1 Residential and Small C&I Customers

Residential technical potential is summarized in Table 5-8. The potential is broken down by end use and building type. A more detailed breakdown of the AC and heating loads by customer segment is provided in the economic potential section, along with the cost-effectiveness of each customer segment.

Table 5-8: DEP Residential Demand Technical Potential

Rate Classes	Season	End Uses	Single Family Residential		Multi Family Residential		Total
			Avg. kw	Agg. MW	Avg. kw	Agg. MW	Agg. MW
RES	Summer	AC Cooling	1.96	1690.9	1.96	319.4	**2010.3**
	Winter	Heating	3.06	1702.5	3.06	444.7	**2147.2**
	Summer/Winter	Water Heater	0.32 / 0.79	235.6 / 581.1	0.32 / 0.79	38.9 / 95.8	**274.5 / 676.9**
	Summer	Pool Pump	1.00	50.1			**50.1**
TOU	Summer	AC Cooling	3.31	71.9	3.31	0.8	**72.8**
	Winter	Heating	5.71	86.5	5.71	1.2	**87.7**
	Summer/Winter	Water Heater	0.32 / 0.79	5.1 / 12.5	0.32 / 0.79	0.06 / 0.15	**5.1 / 12.6**
	Summer	Pool Pump	1.00	1.08			**1.1**

Small Business technical potential is provided on the following page in Table 5-9.

Table 5-9: DEP Small C&I Demand Technical Potential

Segment	MGS		SGS		SGS-TOU	
	AC Cooling	Heating	AC Cooling	Heating	AC Cooling	Heating
	Agg. MW	Agg. MW	Agg. MW	Agg. MW	Agg. MW	Agg. MW
Assembly	53.28	13.13	16.60	10.26	0.48	0.03
Colleges and Universities	4.63	1.74	0.67	0.84	0.40	0.05
Data Centers	0.36	0.06	0.54	0.26	0.05	0.00
Grocery	8.48	12.63	3.44	14.22	1.56	1.01
Healthcare	29.36	13.18	10.44	11.95	0.95	0.14
Hospitals	5.77	0.81	0.96	0.46	0.49	0.02
Institutional	22.62	4.91	9.73	6.19	1.10	0.08
Lodging (Hospitality)	14.68	13.65	3.67	10.40	0.55	0.21
Miscellaneous	27.99	17.94	12.21	31.33	0.30	0.09
Office	105.92	47.21	70.15	94.35	2.25	0.38
Restaurants	64.37	21.72	18.93	16.46	1.45	0.19
Retail	70.65	39.32	40.67	65.52	3.36	0.66
Schools K-12	33.65	7.16	2.66	2.24	0.90	0.06
Warehouse	4.04	0.79	1.80	1.30	0.05	0.00
Agriculture & Forestry	0.29	1.48	0.10	1.50	0.10	0.15
Chemicals & Plastics	9.72	30.88	0.25	3.20	0.67	0.84
Construction	1.77	6.80	0.02	0.19	0.10	0.11
Electrical & Electronic Equipment	1.17	4.91	0.06	0.87	0.22	0.33
Lumber, Furniture, Pulp and Paper	18.07	68.39	0.36	5.49	0.49	0.76
Metal Products & Machinery	18.28	64.62	0.25	3.49	0.41	0.53
Misc. Manufacturing	6.37	23.74	0.21	2.57	0.74	0.91
Primary Resource Industries	8.49	23.88	0.14	2.69	0.04	0.07
Stone, Clay, Glass and Concrete	9.85	32.69	0.22	3.31	0.11	0.16
Textiles & Leather	3.88	14.28	0.18	2.78	0.15	0.28
Transportation Equipment	2.09	8.54	0.04	0.54	0.18	0.24
Water and Wastewater	0.19	1.30	0.03	0.34	0.05	0.09
Total	**525.96**	**475.75**	**194.35**	**292.75**	**17.13**	**7.39**

5.5.2 Large C&I Customers

Technical potential for C&I customers, broken down by customer segments, is given in Table 5-10. In DEP's territory, nonresidential customers either qualified as small C&I customers or were large enough to qualify as large C&I customers. Many of the segments are zero due to customers opting out of DSM programs. Much of the technical potential for large C&I customers comes from a handful of industries, particularly institutional, metal products and machinery and retail.

Table 5-10: DEP Large C&I Demand Technical Potential

Segment	1 MW and Up	
	Summer (MW)	Winter (MW)
Agriculture and Assembly	1.1	0.8
Chemicals and Plastics	0.0	0.0
College and University	0.0	0.0
Construction	0.0	0.0
Data Center	1.4	1.1
Electrical and Electronic Equip.	1.4	2.0
Grocery	0.0	0.0
Healthcare	0.0	0.0
Hospitals	0.0	0.0
Institutional	9.3	8.2
Lodging/Hospitality	0.0	0.0
Lumber/Furniture/Pulp/Paper	0.0	0.0
Metal Products and Machinery	4.5	3.3
Miscellaneous	0.0	0.0
Miscellaneous Manufacturing	2.5	3.0
Office	3.0	3.4
Primary Resources Industries	0.0	0.0
Restaurants	0.0	0.0
Retail	4.0	2.6
Schools K-12	0.0	0.0
Stone/Clay/Glass/Concrete	0.0	0.0
Textiles and Leather	0.0	0.0
Transportation Equipment	0.0	0.0
Warehouse	0.0	0.0
Water and Wastewater	0.0	0.0
Total	**27.2**	**24.3**

6 Economic Potential

Economic potential compares the expected costs and benefits of energy and demand savings provided by EE and DSM measures and applies the total resource cost (TRC) test to determine whether measures meet the scenario screening criterion of a benefit-cost ratio greater than 1. The economic potential is the sum of the energy savings associated with all measure permutations passing the economic screening.

The benefits of EE and DSM measures under the TRC test are primarily associated with avoided utility costs. These include avoided energy generation costs, avoided transmission and distribution costs, and avoided costs associated with lower peak capacity demands. Regarding peak capacity avoided costs, Nexant notes that DEC and DEP system characteristics have changed; the system is now a winter-peaking system, that is to say the highest period of generation capacity utilization now occurs in the winter months. Previously DEC and DEP were still considered summer-peaking.

6.1 EE and DSM Cost-Effective Screening Criteria

Based on discussions with Duke Energy, the total resource cost (TRC) test was used for the economic screening of energy efficiency measures in the MPS. The TRC is calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to that measure's incremental cost. The incremental cost is relative to the cost of the measure's appropriate baseline technology. DSM program delivery and administrative costs, which are included in program-level TRC calculations, were not included in the measure-level economic screening conducted in this study.

For EE screening, the TRC test is applied to each energy efficiency measure based on installation of the measure in Year 1 of the study (i.e. avoided cost benefits begin in Year 1 and extend through the useful life of the measure; incremental costs are also incurred in Year 1). By using DSMore outputs for lifetime avoided cost benefits, the screening aligns with Duke Energy's avoided cost forecast and allows for a direct comparison of measure costs with these avoided cost benefits. The screening included measures with a TRC ratio of 1.0 or higher for determining economic potential.

For DSM screening, Nexant also used the TRC perspective, with the assumption that the incremental cost of implementing DSM is equivalent to the utility program costs. DSM participants do not incur any equipment costs to join a DSM program, so it is necessary to include a proxy participant cost for the TRC test. In accordance with how cost-effectiveness is generally modeled for DSM, Nexant used customer incentives as a proxy for the participant cost. The logic is that since consuming electricity benefits electric customers, reducing demand reduces those benefits. If a utility asks consumers to voluntarily reduce their peak demand, then doing so brings a cost to those customers, and any rational customer will wish to be compensated. Therefore, the incentive serves as a proxy for what the participant gives up by reducing peak demand in terms of comfort, production, etc.

However, cost-effectiveness screening for DSM potential is inherently of limited usefulness. Economic potential only answers the question, “Is a customer segment worth pursuing based on the marginal net benefits they provide?” However, because DSM capacity is determined by participation levels, which is in turn a function of the incentive level, a full cost-effectiveness screening cannot be performed without considering incentive levels, which is a key variable for the various scenarios of the program potential. As such, cost-effectiveness screening for the economic potential only considers non-incentive costs. In other words, customer segments are screened based on whether the marginal cost-effectiveness of enrolling a customer of that segment provides positive net benefits when only considering marketing, equipment, installation, and program operation costs.

For this analysis, the non-incentive costs for each sector is detailed in Table 6-1. These values are based on the costs assumed for a similar DSM potential study conducted for SMUD, and represent reasonable cost estimates in today’s dollars with current technology. Another key assumption that is part of the program potential analysis is the degree to which these costs are expected to decline in future years. However, economic potential screening is conducted using today’s technology costs.

Table 6-1: Non-Incentive Costs

	One-Time				Recurring (per year)
	Equipment	Installation	Acquisition Marketing	Other	Maintenance Marketing
Residential ($/customer)	$ 250.00	$ 200.00	$ 2.50	$ 4.50	$ 1.20
Small C&I ($/customer)	$ 300.00	$ 300.00	$ 20.00	$ 4.50	$ 1.20
Large C&I ($/MW)	$ 150.00		$ 10.00		

The cost of enrolling customers from each customer segment is compared to the marginal benefits provided by enrolling customers in that segment. Because DSM programs are called relatively infrequently, very little benefit is derived from avoided energy costs, to the point where they are insignificant. Instead, DSM derives its value from avoided generation capacity and avoided transmission and distribution capacity.

Forecasts of these values were provided by Duke Energy and formed the basis for the benefit calculations. Because these values were given as annual values, while this study aims to evaluate DSM capacity for summer and winter separately, the annual avoided capacity values were allocated between summer and winter. To that end, capacity values were allocated between summer and winter seasons based on Duke Energy’s recommendations. For DEC, 10% was allocated to summer and 90% to winter. For DEP, 0% was allocated to summer and 100% to winter. Duke Energy indicated these changes were required by recent orders from the North Carolina Public Utilities Commission (NCPUC).

6.2 DEC Energy Efficiency Economic Potential

This section provides the results of the DEC energy efficiency economic potential for each of the three sectors.

6.2.1 Summary

Table 6-2 summarizes the DEC's cumulative energy efficiency economic potential by sector and levelized cost associated with the identified potential:

Table 6-2: DEC EE Economic Potential by Sector

Sector	Economic Potential (2020-2044)				
	Energy (GWh)	% of 2044 Base Sales	Demand (MW)		Levelized Cost ($/kWh)
			Summer	Winter	
Residential	3,130	11%	794	353	$0.06
Commercial	2,173	13%	376	134	$0.03
Industrial	689	22%	97	95	$0.03
Total	5,992	13%	1,268	582	$0.04

6.2.2 Sector Details

Figure 6-1 summarizes the DEC residential sector energy cumulative efficiency economic potential by end use.

Figure 6-1: DEC Residential EE Economic Potential – Cumulative 2044 by End-Use

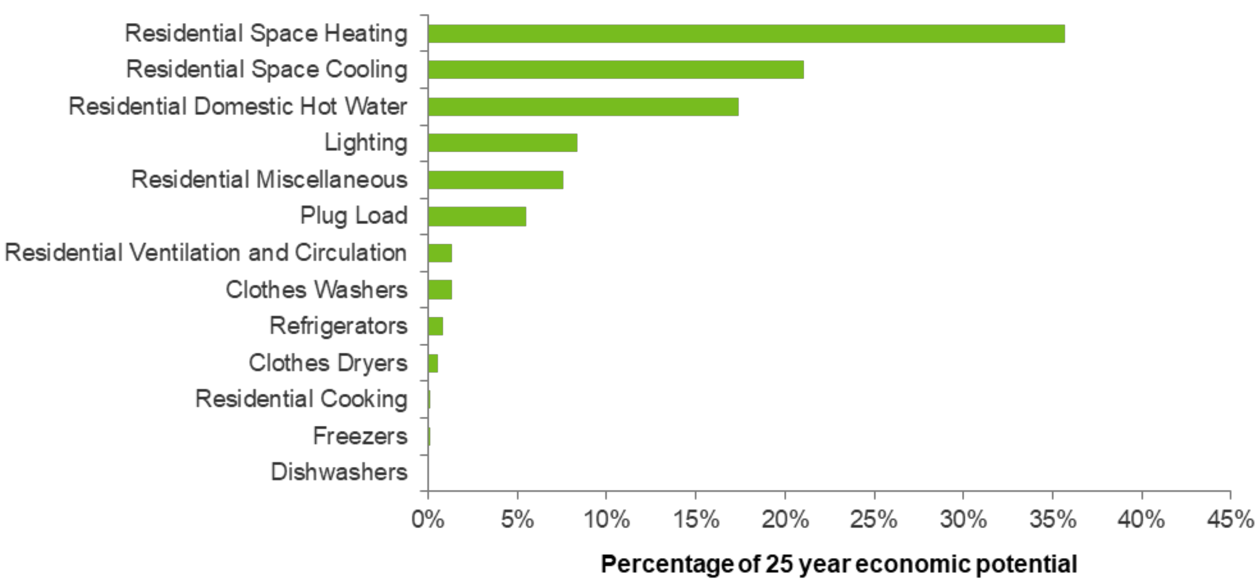


Figure 6-2 summarizes the DEC commercial sector EE economic potential by end use.

Figure 6-2: DEC Commercial EE Economic Potential – Cumulative 2044 by End-Use

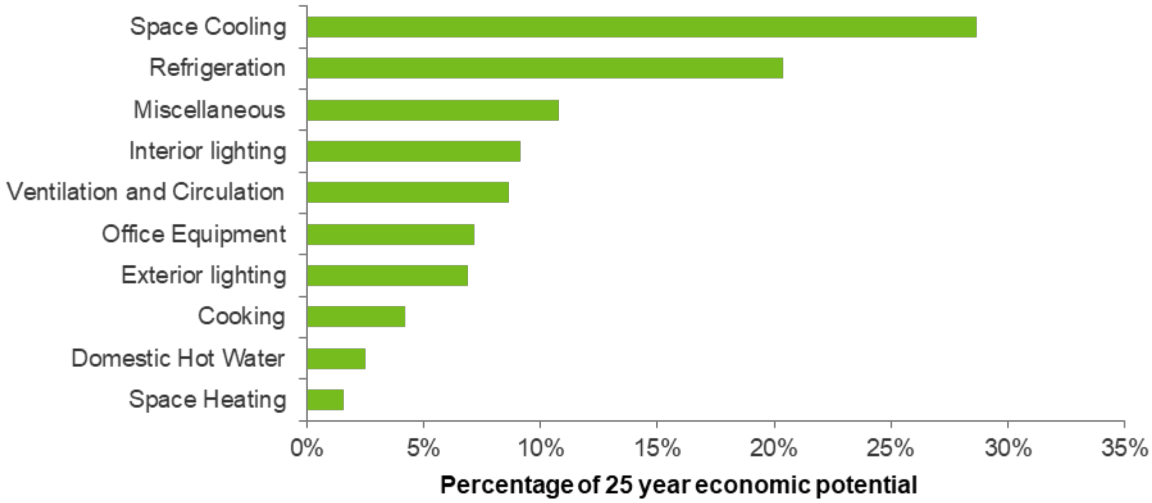


Figure 6-3 provides a summary of DEC energy efficiency economic potential contributions by commercial facility types analyzed in this study.

Figure 6-3: DEC Commercial EE Economic Potential by Segment

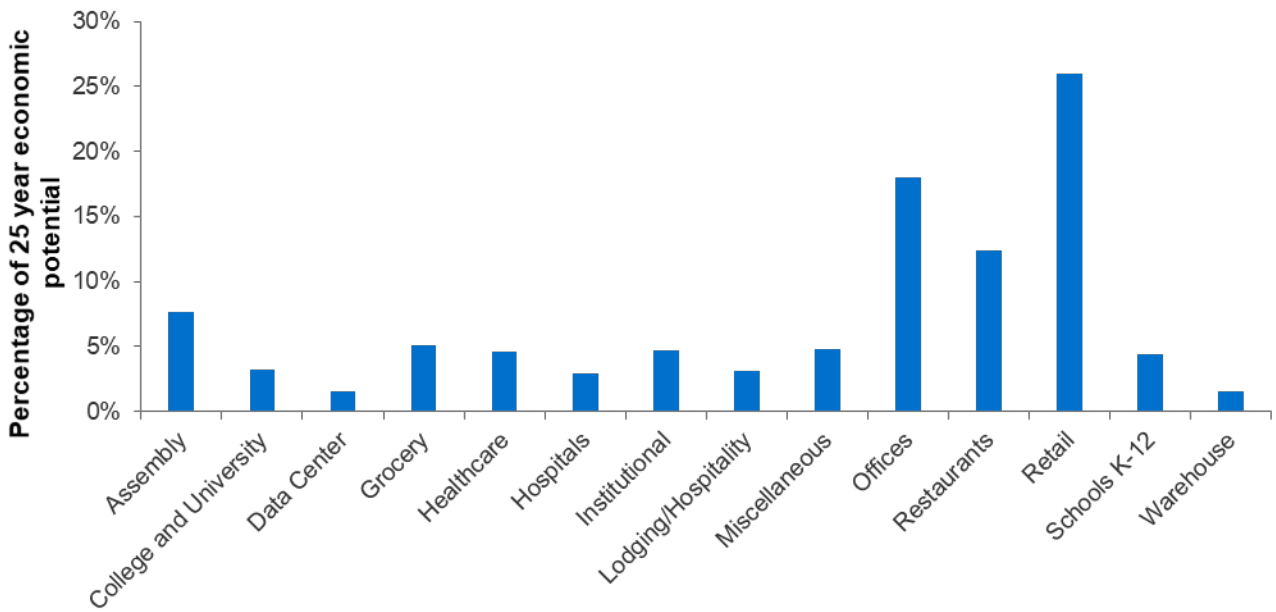


Figure 6-4 summarizes the DEC industrial sector energy efficiency economic potential by end use.

Figure 6-4: DEC Industrial EE Economic Potential – Cumulative 2044 by End-Use

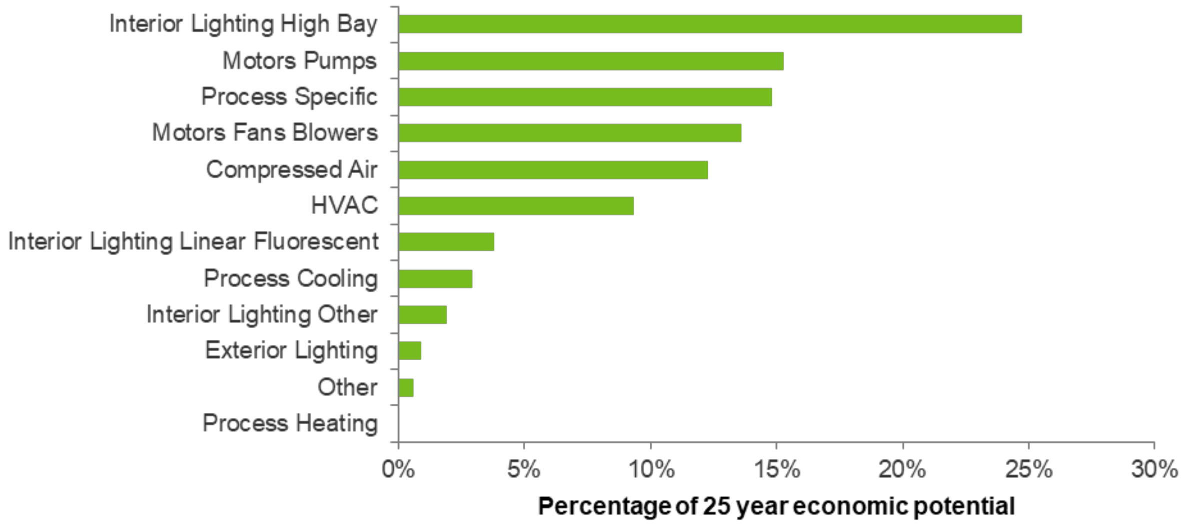
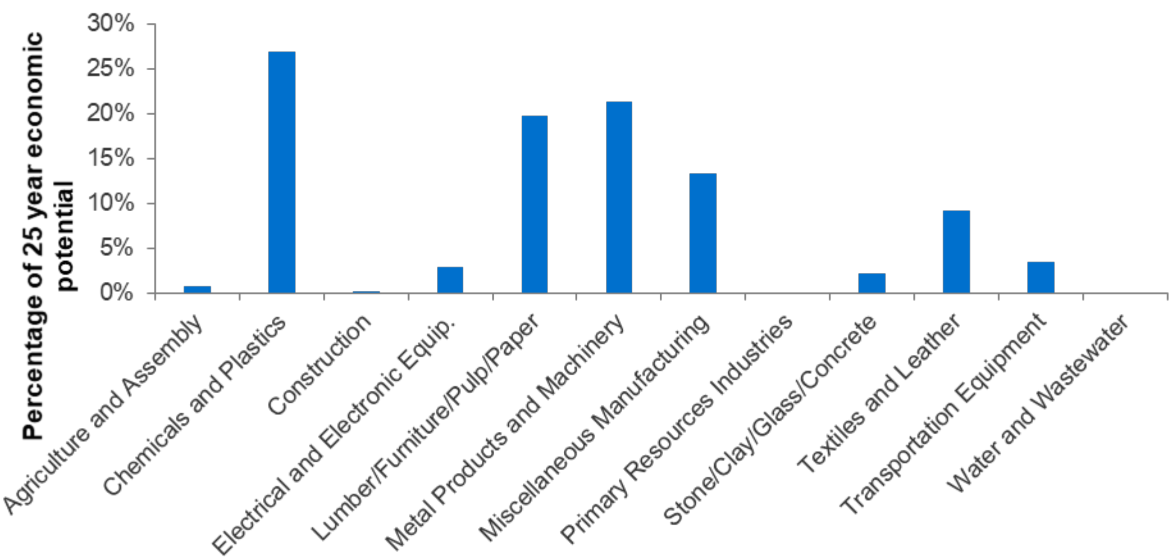


Figure 6-5 provides a summary of DEC energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 6-5: DEC Industrial EE Economic Potential by Segment



6.3 DEP Energy Efficiency Economic Potential

This section provides the results of the DEP energy efficiency economic potential for each of the three sectors.

6.3.1 Summary

Table 6-3 summarizes the DEP energy efficiency cumulative economic potential by sector and levelized cost associated with the identified potential:

Table 6-3: DEP EE Economic Potential by Sector

Sector	Economic Potential (2020-2044)				
	Energy (GWh)	% of 2044 Base Sales	Demand (MW)		Levelized Cost ($/kWh)
			Summer	Winter	
Residential	2,143	10%	756	157	$0.04
Commercial	1,120	12%	192	71	$0.02
Industrial	151	22%	21	21	$0.02
Total	3,414	11%	970	248	$0.03

6.3.2 Sector Details

Figure 6-6 summarizes the DEP residential sector energy efficiency economic potential by end use.

Figure 6-6: DEP Residential EE Economic Potential – Cumulative 2044 by End- Use

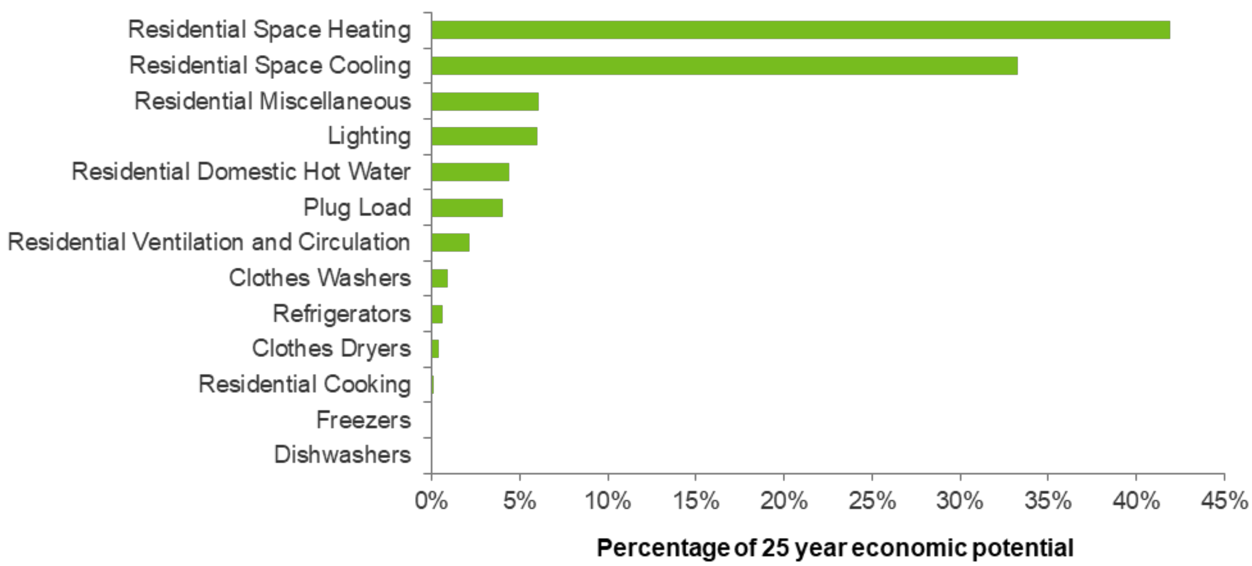


Figure 6-7 summarizes the DEP commercial sector energy efficiency economic potential by end use.

Figure 6-7: DEP Commercial EE Economic Potential – Cumulative 2044 by End-Use

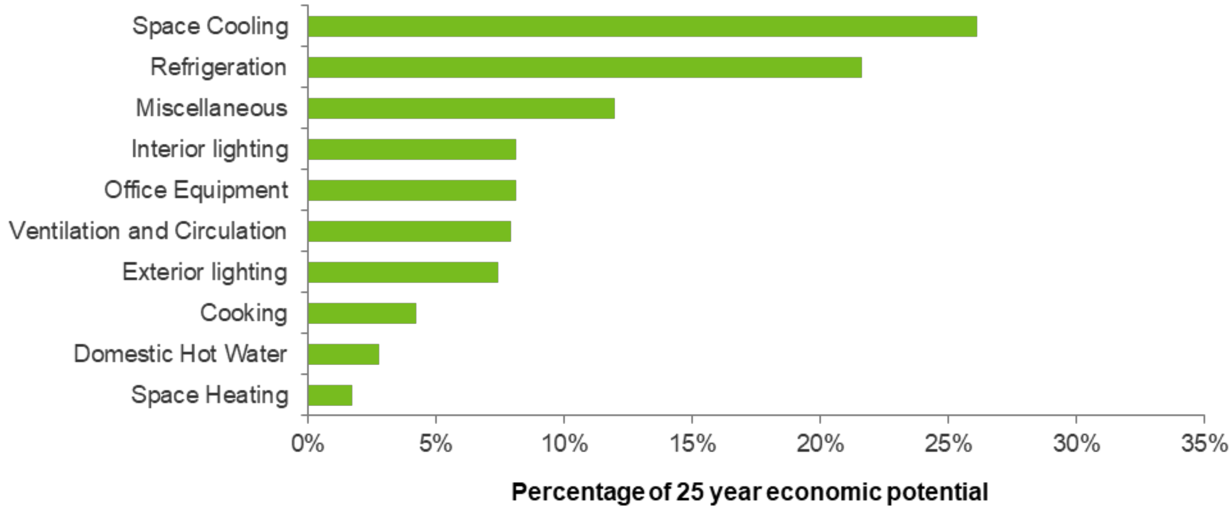


Figure 6-8 provides a summary of energy efficiency economic potential contributions by commercial facility types analyzed in this study.

Figure 6-8: DEP Commercial EE Economic Potential by Segment

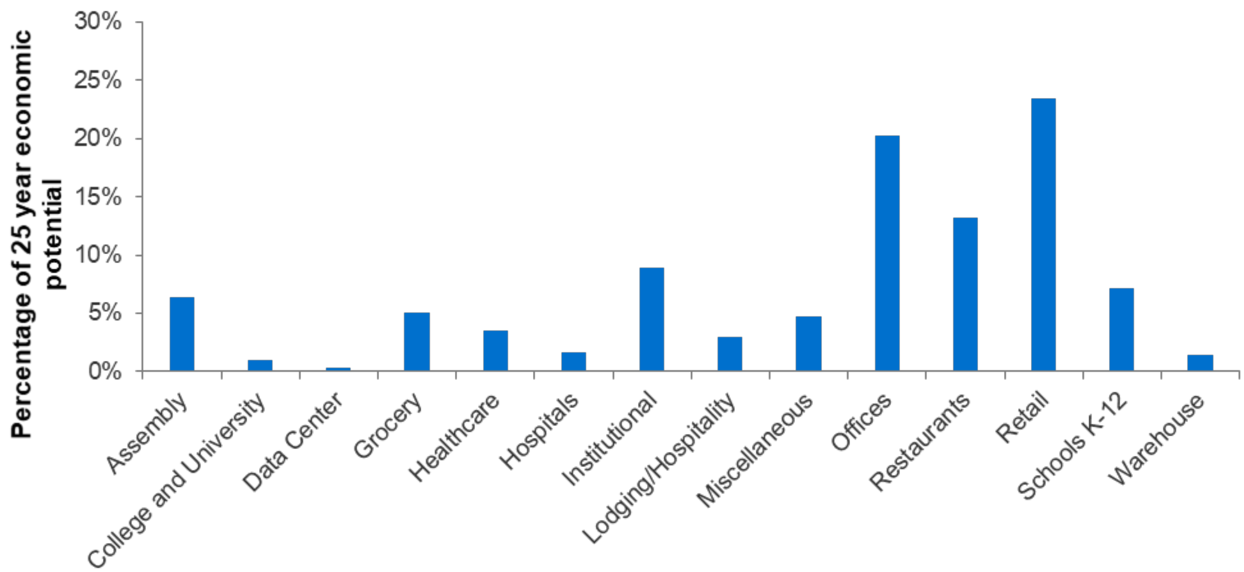


Figure 6-9 summarizes the DEP industrial sector energy efficiency economic potential by end use.

Figure 6-9: DEP Industrial EE Economic Potential – Cumulative 2044 by End-Use

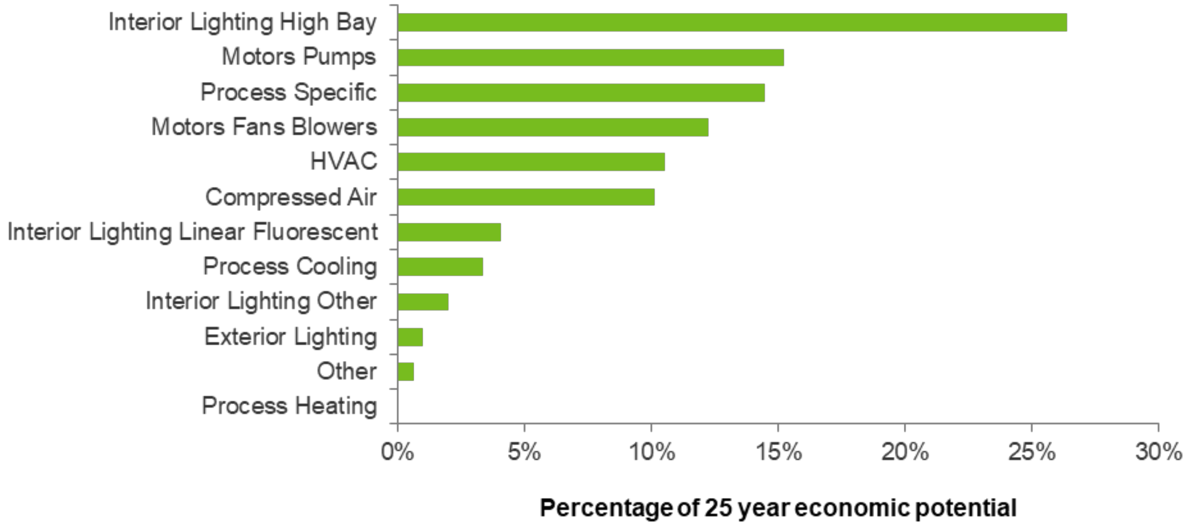
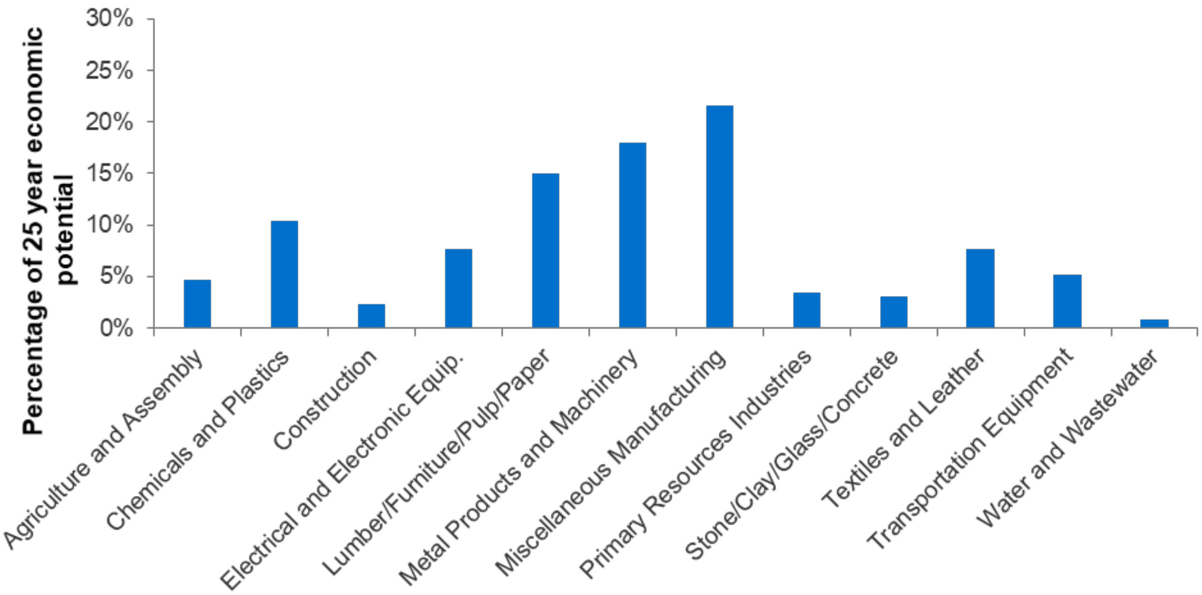


Figure 6-10 provides a summary of DEP energy efficiency technical potential contributions by industrial facility types analyzed in this study.

Figure 6-10: DEP Industrial EE Economic Potential by Segment



6.4 DEC DSM Economic Potential

Cost effectiveness screening for economic potential revealed that the vast majority of the technical potential presented in the prior chapter is cost-effective on a marginal basis. Summary results for the economic potential for DEC are presented in Table 6-4. Comparing these numbers to the DEC technical potential by sector in Table 5-3 shows that the only significant amount of technical potential that is uneconomic is summer capacity from the residential sector.

While some segments of the Large C&I and Small C&I sectors are also uneconomic, they do not add up to a significant amount of capacity.

Table 6-4: DEC DSM Economic Potential by Sector

Sector	Annual Economic Potential	
	Summer (Agg MW)	Winter (Agg MW)
Residential	2,975	3,495
Small C&I	410	441
Large C&I	238	218
Total	3,623	4,154

Results for single family residential customer segments are presented in Table 6-5, which summarizes the aggregate capacity each customer segment would be able to provide during summer and winter peaks, along with the benefits associated with that capacity, based on avoided generation and T&D costs. The net benefits per customer are presented on the right side of the table. Customer segments that do not pass the cost effectiveness screen have negative net benefits in red font. For single family residential customers, there are three segments that do not pass the screen in the summer. In the winter, the Residential Time-of-Use (RT) rate class does not pass for any segments due to the relatively small number of customers on the TOU rate, which leads to minimal load that can be curtailed during peak hours.

Table 6-5: DEC Residential Single Family Economic Potential Results

	Single Family		Summer		Winter		
	Usage bin	Cooling Customer Counts	Agg. MW	Total Net Benefit per Customer	Heating Customer Counts	Agg. MW	Total Net Benefit per Customer
RS	1	93,357	48.8	($215)	-	-	$0
	2	93,357	93.8	$20	-	-	$0
	3	93,357	115.6	$134	-	-	$0
	4	93,357	132.8	$224	-	-	$0
	5	93,357	148.3	$305	-	-	$0
	6	93,357	163.1	$383	-	-	$0
	7	93,357	178.9	$466	-	-	$0
	8	93,357	196.8	$559	-	-	$0
	9	93,357	223.8	$701	-	-	$0
	10	93,357	312.3	$1,164	-	-	$0
RE	1	46,747	26.8	($191)	46,747	66.2	$775
	2	46,747	41.7	($34)	46,747	103.5	$1,477
	3	46,747	49.5	$47	46,747	122.5	$1,835
	4	46,747	56.2	$117	46,747	137.7	$2,121
	5	46,747	62.2	$179	46,747	152.7	$2,403
	6	46,747	68.6	$247	46,747	167.1	$2,674
	7	46,747	75.3	$317	46,747	183.4	$2,982
	8	46,747	84.0	$408	46,747	203.4	$3,357
	9	46,747	96.7	$540	46,747	232.0	$3,896
	10	46,747	131.9	$908	46,747	307.5	$5,316
RT	1	194	0.2	$119	194	0.0	($437)
	2	194	0.3	$400	194	0.0	($398)
	3	194	0.4	$535	194	0.0	($381)
	4	194	0.4	$609	194	0.0	($363)
	5	194	0.5	$760	194	0.0	($373)
	6	194	0.5	$854	194	0.0	($319)
	7	194	0.6	$932	194	0.0	($331)
	8	194	0.6	$1,044	194	0.0	($298)
	9	194	0.8	$1,504	194	0.0	($313)
	10	194	2.1	$4,773	194	0.1	($187)
Total AC/Heating Economic Potential (only included if economic)			2,196.2			1,675.9	
Additional Potential from WH and PP			344.5			747.4	
Total Potential			**2,540.7**			**2,423.3**	

Similar tables are presented for multifamily residential, small C&I, and large C&I customers. With the exception of several smaller multi-family residential customer segments, nearly all of the multi-family residential customers are economic. Almost all small C&I industries are economic and all of the Large C&I customers are economic.

Table 6-6: DEC Residential Multifamily Economic Potential Results

	Multifamily		Summer		Winter		
	Usage bin	Cooling Customer Counts	Agg. MW	Total Net Benefit per Customer	Heating Customer Counts	Agg. MW	Total Net Benefit per Customer
RS	1	7,210	4.4	($170)	-	-	$0
	2	7,210	7.7	$54	-	-	$0
	3	7,210	9.5	$177	-	-	$0
	4	7,210	11.3	$294	-	-	$0
	5	7,210	12.5	$379	-	-	$0
	6	7,210	14.1	$485	-	-	$0
	7	7,210	15.7	$596	-	-	$0
	8	7,210	17.3	$700	-	-	$0
	9	7,210	19.2	$832	-	-	$0
	10	7,210	26.1	$1,297	-	-	$0
RE	1	25,093	14.8	($183)	25,093	35.2	$762
	2	25,093	21.3	($56)	25,093	51.0	$1,319
	3	25,093	25.4	$23	25,093	61.2	$1,674
	4	25,093	29.2	$99	25,093	69.6	$1,970
	5	25,093	32.7	$166	25,093	79.3	$2,308
	6	25,093	36.7	$243	25,093	88.2	$2,622
	7	25,093	41.0	$327	25,093	99.3	$3,012
	8	25,093	46.2	$429	25,093	111.7	$3,445
	9	25,093	53.6	$573	25,093	130.0	$4,089
	10	25,093	71.2	$916	25,093	174.1	$5,636
RT	1	-	-	$0	-	-	$0
	2	-	-	$0	-	-	$0
	3	-	-	$0	-	-	$0
	4	-	-	$0	-	-	$0
	5	-	-	$0	-	-	$0
	6	-	-	$0	-	-	$0
	7	-	-	$0	-	-	$0
	8	-	-	$0	-	-	$0
	9	-	-	$0	-	-	$0
	10	-	-	$0	-	-	$0
Total AC/Heating Economic Potential (only included if economic)			372.0			899.6	
Additional Potential from WH and PP			62.8			172.3	
Total Potential			**434.8**			**1,071.9**	

Table 6-7: DEC Small C&I Economic Potential Results

SMB	Summer			Winter		
Segment	# Accounts	Agg. MW	Total Net Benefit per Customer	# Accounts	Agg. MW	Total Net Benefit per Customer
Assembly	20,352	63.4	$884	967	20.9	$18,344
Colleges and Universities	913	4.3	$1,671	76	2.7	$31,255
Data Centers	487	2.2	$1,525	23	0.7	$25,402
Grocery	1,519	9.7	$2,491	685	26.0	$32,715
Healthcare	5,759	24.4	$1,434	528	16.7	$27,116
Hospitals	414	2.1	$1,787	15	0.6	$33,778
Institutional	6,070	10.7	$221	285	4.2	$12,306
Lodging (Hospitality)	2,144	6.4	$822	431	9.5	$18,739
Miscellaneous	27,252	27.1	($153)	5,387	40.8	$6,023
Office	44,775	84.9	$288	4,424	66.2	$12,536
Restaurants	5,482	59.5	$4,664	585	33.2	$49,365
Retail	51,273	116.3	$471	7,094	112.6	$13,329
Schools K-12	2,064	7.1	$1,053	101	3.9	$32,958
Warehouse	1,866	3.8	$357	93	1.5	$13,462
Agriculture & Forestry	35	0.2	$1,554	35	1.0	$24,361
Chemicals & Plastics	227	1.2	$2,009	227	8.1	$30,793
Construction	11	0.0	$973	11	0.1	$10,071
Electrical & Electronic Equipment	257	0.9	$1,166	257	6.5	$21,499
Lumber, Furniture, Pulp and Paper	835	3.1	$1,203	835	22.5	$23,105
Metal Products & Machinery	963	4.1	$1,429	963	27.7	$24,667
Misc. Manufacturing	782	3.3	$1,399	782	21.3	$23,380
Primary Resource Industries	-	-	$0	-	-	$0
Stone, Clay, Glass and Concrete	142	0.5	$1,081	142	3.6	$21,531
Textiles & Leather	235	1.0	$1,385	235	6.8	$24,878
Transportation Equipment	291	0.6	$301	291	3.9	$11,191
Water and Wastewater	-	-	$0	-	-	$0
Total		**409.7**			**441.0**	

Table 6-8: DEC Large C&I (1 MW and Up) Economic Potential Results

Large C&I			Summer		Winter			
Segment	MW of Tech Potential for cost calc (max of winter and summer)	Total Cost	Agg. MW	Total Benefit	Agg. MW	Total Benefit	Total Aggregate Net Benefit	Total Net Benefit per MW
Agriculture and Assembly	0.7	$ 115.58	0.7	$ 353,041	0.6	$ 285,323	$ 638,248	$ 883,510.29
Chemicals and Plastics	50.2	$ 8,032.18	50.2	$ 24,533,554	43.5	$ 19,137,376	$ 43,662,898	$ 869,759.78
College and University	10.0	$ 1,603.87	10.0	$ 4,898,882	5.6	$ 2,472,267	$ 7,369,545	$ 735,175.41
Construction	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Data Center	17.3	$ 2,762.11	17.3	$ 8,436,621	15.5	$ 6,826,088	$ 15,259,947	$ 883,958.18
Electrical and Electronic Equip.	1.6	$ 251.39	1.6	$ 767,854	1.5	$ 661,924	$ 1,429,526	$ 909,830.95
Grocery	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Healthcare	2.2	$ 352.51	2.2	$ 106,418	2.2	$ 1,938,625	$ 2,044,691	$ 928,055.07
Hospitals	1.8	$ 295.94	1.8	$ 903,910	1.1	$ 468,980	$ 1,372,594	$ 742,103.03
Institutional	3.0	$ 487.87	2.5	$ 122,702	3.0	$ 2,683,032	$ 2,805,246	$ 919,994.20
Lodging/Hospitality	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Lumber/Furniture/Pulp/Paper	17.3	$ 2,775.35	16.9	$ 825,877	17.3	$ 15,262,933	$ 16,086,035	$ 927,365.48
Metal Products and Machinery	10.2	$ 1,634.00	10.2	$ 4,990,905	9.0	$ 3,964,104	$ 8,953,375	$ 876,707.46
Miscellaneous	37.6	$ 6,018.00	27.5	$ 1,343,914	37.6	$ 33,095,724	$ 34,433,620	$ 915,483.91
Miscellaneous Manufacturing	8.3	$ 1,330.15	8.3	$ 4,062,834	6.7	$ 2,963,156	$ 7,024,660	$ 844,974.24
Office	18.9	$ 3,017.21	18.9	$ 9,215,789	14.1	$ 6,212,532	$ 15,425,304	$ 817,990.87
Primary Resources Industries	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Restaurants	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Retail	8.1	$ 1,302.23	8.1	$ 3,977,541	7.7	$ 3,372,119	$ 7,348,358	$ 902,865.13
Schools K-12	1.2	$ 191.12	1.2	$ 583,749	0.8	$ 365,361	$ 948,919	$ 794,419.83
Stone/Clay/Glass/Concrete	0.8	$ 135.17	0.5	$ 22,005	0.8	$ 743,351	$ 765,221	$ 905,801.47
Textiles and Leather	53.2	$ 8,519.62	53.2	$ 26,022,396	45.8	$ 20,142,382	$ 46,156,258	$ 866,823.25
Transportation Equipment	6.5	$ 1,046.13	6.5	$ 3,195,323	4.9	$ 2,139,052	$ 5,333,329	$ 815,700.75
Warehouse	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Water and Wastewater	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Total	**249.2**		**237.6**		**217.9**			

6.5 DEP DSM Economic Potential

Cost effectiveness screening for economic potential revealed that the vast majority of the technical potential presented in the prior chapter is cost-effective on a marginal basis. Summary results for the economic potential for DEC are presented in Table 6-9. Comparing these numbers to the DEC technical potential by sector in Table 5-7 shows that the only significant amount of technical potential that is uneconomic is summer capacity from the residential sector. This can be attributed to DEP allocating 100% of avoided generation capacity benefits to the winter. All of the segments that have capacity in Small and Large C&I are economic.

Table 6-9: DEP DSM Economic Potential by Sector

Sector	Annual Economic Potential	
	Summer (Agg MW)	Winter (Agg MW)
Residential	1,594	2,925
Small C&I	737	776
Large C&I	27	24
Total	2,359	3,725

Results for single family residential customer segments are presented in Table 6-10. This table summarizes the aggregate capacity each customer segment would be able to provide during summer and winter peaks, along with the net benefits associated with that capacity, based on avoided generation and T&D costs. The segments are binned by consumption decile. Because DEP does not have an electric heating rate, the number of customers assumed to have electric heating for each rate was based on the same end-use saturation studies used for the energy efficiency analysis.

Customer segments that do not pass the cost effectiveness screen have negative net benefits in red font. For single family residential customers, there are several customer segments that are uneconomic to pursue for DSM implementation: customers that fall in the lower half of electricity consumption in the RES rate and the first consumption decile of the TOU rate.

Table 6-10: DEP Residential Single Family Economic Potential Results

	Single Family	Summer			Winter		
	Usage bin	Cooling Customer Counts	Agg. MW	Total Net Benefit per Customer	Heating Customer Counts	Agg. MW	Total Net Benefit per Customer
RES	1	102,062	53.6	($334)	56,013	61.8	$345
	2	102,062	93.1	($232)	56,013	101.0	$862
	3	102,062	115.3	($175)	56,013	122.9	$1,150
	4	102,062	133.7	($128)	56,013	140.7	$1,385
	5	102,062	151.4	($83)	56,013	156.4	$1,591
	6	102,062	168.2	($40)	56,013	172.5	$1,804
	7	102,062	187.8	$10	56,013	190.3	$2,039
	8	102,062	210.3	$68	56,013	210.3	$2,303
	9	102,062	243.0	$152	56,013	238.2	$2,671
	10	102,062	334.5	$386	56,013	308.3	$3,595
TOU	1	2,196	2.9	($121)	1,514	3.8	$1,394
	2	2,196	4.3	$39	1,514	5.4	$2,148
	3	2,196	5.0	$122	1,514	6.2	$2,576
	4	2,196	5.6	$200	1,514	7.0	$2,923
	5	2,196	6.2	$264	1,514	7.7	$3,298
	6	2,196	6.9	$347	1,514	8.4	$3,640
	7	2,196	7.6	$431	1,514	9.3	$4,049
	8	2,196	8.4	$535	1,514	10.3	$4,538
	9	2,196	10.0	$721	1,514	11.8	$5,300
	10	2,196	15.0	$1,321	1,514	16.6	$7,635
Total AC/Heating Economic Potential (only included if economic)			1,044.6			1,789.1	
Additional Potential from WH and PP			291.9			593.6	
Total Potential			**1,336.4**			**2,382.7**	

Similar tables are presented for multifamily residential, small C&I and large C&I customers. With the exception of several smaller multi-family residential customer segments, nearly all of these customers are economic.

Table 6-11: DEP Residential Multifamily Economic Potential Results

	Multifamily	Summer			Winter		
	Usage bin	Cooling Customer Counts	Agg. MW	Total Net Benefit per Customer	Heating Customer Counts	Agg. MW	Total Net Benefit per Customer
RES	1	16,829	11.4	($293)	14,583	15.8	$331
	2	16,829	17.2	($204)	14,583	23.7	$731
	3	16,829	20.9	($145)	14,583	28.9	$992
	4	16,829	24.3	($93)	14,583	33.3	$1,215
	5	16,829	27.6	($42)	14,583	38.1	$1,457
	6	16,829	31.4	$18	14,583	42.8	$1,699
	7	16,829	35.6	$82	14,583	48.5	$1,988
	8	16,829	40.2	$154	14,583	55.9	$2,360
	9	16,829	47.2	$262	14,583	66.4	$2,891
	10	16,829	63.6	$517	14,583	91.3	$4,153
TOU	1	26	0.0	($249)	21	0.0	$665
	2	26	0.0	$30	21	0.0	$803
	3	26	0.0	$21	21	0.1	$2,176
	4	26	0.1	$179	21	0.1	$2,809
	5	26	0.1	$333	21	0.1	$2,698
	6	26	0.1	$565	21	0.1	$3,319
	7	26	0.1	$283	21	0.2	$5,045
	8	26	0.1	$634	21	0.2	$4,793
	9	26	0.1	$529	21	0.2	$7,306
	10	26	0.2	$1,533	21	0.2	$7,889
Total AC/Heating Economic Potential (only included if economic)			218.8			445.9	
Additional Potential from WH and PP			38.9			96.0	
Total Potential			**257.7**			**541.9**	

Table 6-12: DEP Small C&I Economic Potential Results

SMB	Summer			Winter		
Segment	# Accounts	Agg. MW	Total Net Benefit per Customer	# Accounts	Agg. MW	Total Net Benefit per Customer
Assembly	13,486	70.4	$726	640	23.4	$26,381
Colleges and Universities	528	5.7	$2,184	44	2.6	$43,579
Data Centers	250	0.9	$342	12	0.3	$19,753
Grocery	1,179	13.5	$2,352	531	27.9	$38,093
Healthcare	5,208	40.8	$1,409	478	25.3	$38,445
Hospitals	486	7.2	$3,248	18	1.3	$53,395
Institutional	8,989	33.5	$335	423	11.2	$18,888
Lodging (Hospitality)	3,933	18.9	$618	790	24.3	$22,029
Miscellaneous	11,816	40.5	$258	2,336	49.4	$14,971
Office	59,406	178.3	$147	5,870	141.9	$17,223
Restaurants	5,579	84.8	$3,335	595	38.4	$46,978
Retail	27,099	114.7	$468	3,750	105.5	$20,145
Schools K-12	2,478	37.2	$3,289	121	9.5	$56,938
Warehouse	1,640	5.9	$300	82	2.1	$18,235
Agriculture & Forestry	39	0.5	$2,642	39	3.1	$58,697
Chemicals & Plastics	156	10.6	$17,233	156	34.9	$165,005
Construction	56	1.9	$8,215	56	7.1	$93,496
Electrical & Electronic Equipment	29	1.4	$12,546	29	6.1	$157,153
Lumber, Furniture, Pulp and Paper	351	18.9	$13,441	351	74.6	$156,261
Metal Products & Machinery	296	18.9	$16,113	296	68.6	$170,853
Misc. Manufacturing	229	7.3	$7,711	229	27.2	$87,011
Primary Resource Industries	54	8.7	$41,464	54	26.6	$364,349
Stone, Clay, Glass and Concrete	216	10.2	$11,701	216	36.2	$123,277
Textiles & Leather	146	4.2	$6,891	146	17.3	$87,185
Transportation Equipment	40	2.3	$14,486	40	9.3	$171,190
Water and Wastewater	16	0.3	$3,698	16	1.7	$80,888
Total		**737.4**			**775.9**	

Table 6-13: DEP Large C&I (1 MW and Up) Economic Potential Results

Large C&I			Summer		Winter			
Segment	MW of Tech Potential for cost calc (max of winter and summer)	Total Cost	Agg. MW	Total Benefit	Agg. MW	Total Benefit	Total Aggregate Net Benefit	Total Net Benefit per MW
Agriculture and Assembly	1.1	$ 178.98	1.1	$ 292,572	0.8	$ 362,068	$ 654,461	$ 585,058.62
Chemicals and Plastics	0.0	$ -	-	$ -	-	$ -	$ -	$ -
College and University	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Construction	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Data Center	1.4	$ 225.08	1.4	$ 367,932	1.1	$ 537,653	$ 905,360	$ 643,580.09
Electrical and Electronic Equip.	2.0	$ 320.55	1.4	$ -	2.0	$ 1,479,917	$ 1,479,596	$ 738,536.96
Grocery	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Healthcare	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Hospitals	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Institutional	9.3	$ 1,485.03	9.3	$ 2,427,533	8.2	$ 3,890,690	$ 6,316,738	$ 680,575.94
Lodging/Hospitality	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Lumber/Furniture/Pulp/Paper	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Metal Products and Machinery	4.5	$ 720.34	4.5	$ 1,177,510	3.3	$ 1,587,176	$ 2,763,966	$ 613,927.04
Miscellaneous	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Miscellaneous Manufacturing	3.0	$ 477.68	2.5	$ -	3.0	$ 2,205,392	$ 2,204,915	$ 738,536.96
Office	3.4	$ 537.23	3.0	$ -	3.4	$ 2,480,298	$ 2,479,761	$ 738,536.96
Primary Resources Industries	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Restaurants	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Retail	4.0	$ 644.53	4.0	$ 1,053,597	2.6	$ 1,246,179	$ 2,299,131	$ 570,739.69
Schools K-12	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Stone/Clay/Glass/Concrete	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Textiles and Leather	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Transportation Equipment	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Warehouse	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Water and Wastewater	0.0	$ -	-	$ -	-	$ -	$ -	$ -
Total	**28.7**		**27.2**		**24.3**			

6.6 Utility Cost Test Sensitivity

At Duke Energy's request, Nexant conducted a sensitivity analysis for economic potential, using the utility cost test criterion to screen measures. Nexant used current measure incentive rates, or proxy rates for non-program or non-cost effective measures in similar end uses to current program measures. The utility cost test compares the cost for a utility to provide incentives and administer a program against the avoided cost benefits of energy efficiency. The UCT does not consider customers' perspectives when comparing cost and benefits. The results of this sensitivity indicate an increase of economic potential by 37%, 46%, and 15% for the residential, commercial, and industrial sectors in DEC. The results indicate an increase of economic potential by 51%, 51%, and 8% for the residential, commercial, and industrial sectors in DEP. For DSM, the UCT and TRC yield the same results, as incentives are used as a proxy participant cost for TRC for DSM analysis.

7 Program Potential

Program potential is the subset of economic potential describing EE and DSM measure adoption by customers participating in utility-sponsored programs operating within the subject market or jurisdiction. Customers may not choose to implement all cost-effective EE and DSM measures, for a variety of reasons, some of which may include: customer preferences or opportunity costs; time and effort required to acquire and install new measures (transaction costs); or, high measure costs and lack of capital. Many customers may not meet these “market requirements” for EE and DSM; yet, others may face market barriers such as: lack of knowledge about electricity consumption and associated technology; principal-agent issues, a.k.a. “split incentive,” problems; externalities; or, imperfect marketplace competition that potentially limits availability of some measures, increases measure costs, or affects customers’ incomes.

Program potential is based on estimating the share of customers that may choose to participate in utility-sponsored programs. The primary source of data on for such estimates is the programs themselves. Duke Energy has been offering EE and DSM programs to customers for over ten years. Program participation data collected by Duke Energy over the years can be used to estimate the share of customers within their territory that seeks to adopt EE and DSM under the portfolio of offered programs.

7.1 Program Potential Scenario Descriptions

Nexant met with program staff to identify current program and measure offerings, as well as measures that are planned to be added to the program in the next one to two years. Duke Energy provided Nexant this information to ensure Nexant’s MPS measures were appropriately mapped to existing programs, and captured the measure offerings currently being contemplated by Duke Energy. This effort was used to develop a base case scenario for program potential.

Nexant also worked with Duke Energy to define an enhanced scenario and an avoided cost sensitivity scenario. The results of TRC screening for economic potential showed that numerous residential equipment measures, such as high efficiency HVAC equipment, were not cost effective. Recent market trends towards more efficient LED lighting and declining utility avoided costs of energy also lead to fewer commercial measures passing the TRC screening. Nexant has also observed this trend in other jurisdictions and recent studies.

Nexant also defined an enhanced scenario to explore whether additional potential would be present with higher utility program spending. Utility-sponsored programs generally reduce costs or barriers in an effort to increase market adoption of EE and DSM. A program can do this in a variety of ways: increased incentives, improved marketing, etc. Nexant’s model describes program spending categorically, as either incentive costs or administrative costs. Program design improvements and strategic management are an important part of the EE and DSM program lifecycle. Duke Energy conducts rigorous program evaluation activities designed to improve program impacts and processes. Nexant's review of historic program evaluation, measurement, and verification (EM&V) and recent program activities is included in Appendix E. While program design and optimization is outside the scope of this MPS, Nexant's enhanced scenario describes the expected market response to higher incentives that reduce participant costs for EE and DSM.

The avoided cost sensitivity scenario therefore provides an opportunity to explore what magnitude of change in avoided energy costs would be necessary to significantly increase EE and DSM potential (e.g. produce more EE measures with a passing TRC score).

7.2 Summary of Current Programs

Nexant reviewed existing Duke Energy programs to identify the objectives, target markets, existing measures, and delivery mechanisms for each. This review included recent program evaluation reports and publicly available program information on Duke's website or in program marketing literature. Nexant coordinated multiple meetings with Duke Energy product development and program staff to clarify our understanding of current and proposed initiatives and details of North Carolina market conditions.

Nexant assigned each EE measure to one or more program offerings across the residential, commercial, and industrial customer segments, and DSM opportunities were classified into specific offerings across the customer segments. Nexant did not identify any measure gaps in Duke Energy's EE portfolio.

Based on Nexant's measure database and review of Duke Energy programs, Duke Energy is offering (or will offer in the next one to two years) all cost-effective EE measures through one of their current programs. Table 7-1 presents a summary of Duke Energy's residential programs.

Table 7-1: Residential EE Program Offerings

Program	Description	Targeted Segments	Delivery Approach
Smart $aver	Contractor-driven program addressing need for HVAC equipment, water heating equipment, building envelope, and pool measures	All residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate
Audits and EE Kits	Focuses on distribution and installation of highly cost-effective measures.	All residential building types; note: decision-maker varies by building type	*Marketing strategy:* mass marketing *Customer experience:* direct install & behavior *Incentive type:* giveaway
EE Products (Online Store)	Designed to deliver energy efficiency upgrades on typical residential appliances that can be self-installed by residential customers.	All residential building types	*Marketing strategy:* mass marketing & joint marketing *Customer experience:* self-directed, online store *Incentive type:* midstream rebate (discount)
Income Qualified	Leverages existing resources and outreach for low income community to support energy efficiency.	All residential building types, demographic limitations	*Marketing strategy:* target customer segment *Customer experience:* technical assistance & direct install *Incentive type:* direct install
New Construction	Targets energy efficiency whole building measures and individual high cost measures for new homes.	All residential building types (new construction)	*Marketing strategy:* joint marketing *Customer experience:* technical assistance *Incentive type:* customer rebate
Behavioral	Provides customers with data on their home energy consumption and tips to reduce energy use. Information provided through periodic usage reports as well as direct feedback with real-time usage information for their home.	All residential building types	*Marketing strategy:* opt-out; direct marketing *Customer experience:* behavioral *Incentive type:* social
Energy Efficiency Education	A third party contractor provides educational theater programs for school children and distributes low-cost EE savings kits upon request	All residential building types	*Marketing strategy:* joint marketing *Customer experience:* behavioral, direct install *Incentive type:* social, giveaway

Table 7-2 summarizes Duke Energy's Commercial and Industrial program offerings. Duke Energy offers both sectors a wide variety of measure options and participation channels.

Table 7-2: Non-Residential EE Program Offerings

Program	Description	Targeted Segments	Delivery Approach
Smart $aver-Prescriptive	Reduced costs and increases efficiency of commercial and industrial equipment.	All non-residential building types	*Marketing strategy:* target customer segment *Customer experience:* self-directed *Incentive type:* customer rebate
Smart $aver – Custom	Non-typical or variable savings; larger projects.	All non-residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate
Small Business Energy Saver	Free audit and aggressively discounted measures; lowers customers' participation burden with a direct install approach.	Non-residential small business customers (less than 200 kW demand)	*Marketing strategy:* target customer segment *Customer experience:* direct install *Incentive type:* upstream incentive/mark-down
New Construction	Influences the design and construction phase of the commercial real estate market. Offers design assistance and cash incentives for a package of whole-building energy opportunities.	All non-residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate
Pay-for-Performance	Offering measures are similar to Smart $aver-Custom Program with part of the incentives paid a year later to customers.	All non-residential building types	*Marketing strategy:* target customer segment *Customer experience:* technical assistance *Incentive type:* customer rebate

Duke Energy has been offering DSM services for over 10 years, and the program offers cover a variety of approaches for load management such as direct utility control; contractual programs for guaranteed load drop and emergency load management; and load control programs that incentivize economic load response. These programs are described in Table 7-3.

Table 7-3: Proposed DSM Program Offerings

Type of DSM	Sector	Technology
Utility controlled loads	Residential	▪ Central AC switches ▪ Smart thermostat ▪ Water heater switches ▪ Home gateway (control HVAC, water heater, pool pumps, power strips) ▪ Pool pumps
	Non-Residential	▪ Lighting controls (EMS or lighting ballasts) ▪ HVAC controls (EMS) ▪ Pump loads ▪ Auto DSM for process loads ▪ Battery storage ▪ Backup generation
Contractual	Non-Residential	▪ Interruptible rates – Firm service levels ▪ Guaranteed Load Drop ▪ Emergency Load Response ▪ Economic Load Response

7.3 Approach and Assumptions of Program Potential

Program potential describes a subset of customers expected to take advantage of Duke Energy EE and DSM programs. Data concerning individual customer purchases of EE and DSM equipment are not widely available and may be sparse in their coverage of EE and DSM measure opportunities. EPA's ENERGY STAR program estimates the market penetration of certified products, and EIA's periodic market assessments provide the primary basis for understanding current market penetration of EE technology.

In addition to these sources, Duke Energy conducts residential appliance saturation surveys (RASS) to better understand the energy consumption of residential customers in the Duke Energy service territory. Commercial and industrial building and equipment baselines are limited to the modeling and analysis available from EIA. Nexant makes use of this available data when conducting a market potential study.

Nexant applies widely accepted economic theory and practice to make projections for future program adoption within this market setting, and on the basis of these available data sources. Duke Energy's historic program participation data provides the best insight into how customers in North Carolina will respond to utility-sponsored EE and DSM program offers. Nexant's projections are grounded in observed participation trends and vetted modeling frameworks that describe product diffusion.

7.3.1 Market Adoption Rates

Utility-sponsored DSM programs offer incentives for energy efficiency measures that are designed to lower customers' costs and increase the rate at which the market adopts energy efficiency technologies. Nexant analyzed Duke Energy's EE and DSM program participation data to estimate the market penetration for EE measures offered over the past ten years in North Carolina by Duke Energy. Nexant's estimates of market penetration follow economic and marketing theory on product diffusion, or "diffusion of innovations."

Nexant used EPA ENERGY STAR data, EIA end use intensity estimates, and Duke Energy program participation data to derive estimates of baseline market saturation and savings opportunities. Participation in Duke Energy's most recent program year prior to the MPS (2019) is taken as the baseline cumulative program saturation, which describes that share of customers that have previously participated in Duke Energy programs. Projections of future participation and the ultimate maximum market saturation are determined by the historic rate of program participation and the imposed functional form of market adoption under theories of product diffusion.

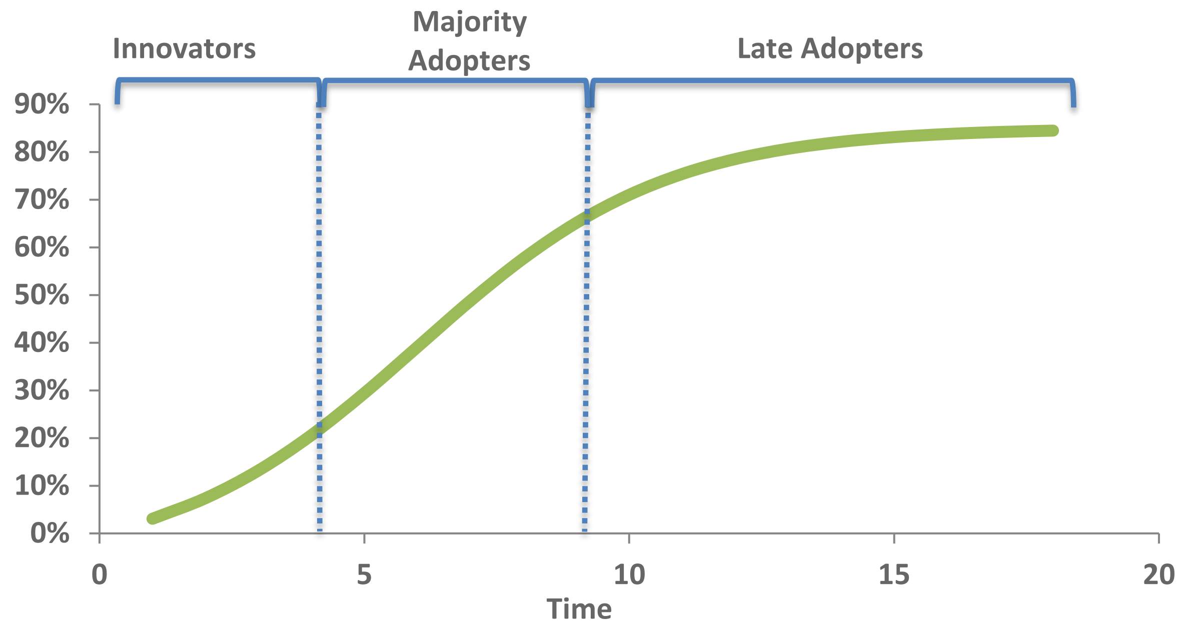
We apply a structured model of market adoption, referred to as the Bass diffusion model. The Bass model is a widely accepted mathematical description of how new products and innovations spread through an economy over time. It was originally published in 1969, and in 2004 was voted one of the top 10 most influential papers published in the 50 year history of the peer-reviewed publication *Management Science*[1]. More recent publications by Lawrence Berkeley National Laboratories have illustrated the application of this model to conservation and demand management (CDM) in the energy industry[2]. Nexant used historic Duke Energy program participation data to develop and apply Bass Model diffusion parameters in the North Carolina jurisdiction.

According to product diffusion theory, the rate of market adoption for a product changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of cumulative market saturation is illustrated in Figure 7-1.

[1] Bass, F. 2004. Comments on "A New Product Growth for Model Consumer Durables the Bass Model" (sic). *Management Science* 50 (12_supplement): 1833-1840. http://pubsonline.informs.org/doi/abs/10.1287/mnsc.1040.0300. Accessed 01/08/2016.

[2] Buskirk, R. 2014. Estimating Energy Efficiency Technology Adoption Curve Elasticity with Respect to Government and Utility Deployment Program Indicators. LBNL Paper 6542E. Sustainable Energy Systems Group, Environmental Energy Technologies Division. Ernest Orlando Lawrence Berkeley National Laboratory. http://escholarship.org/uc/item/2vp2b7cm#page-1. Accessed 01/14/2016.

Figure 7-1: Bass Model Cumulative Market Penetration



The Bass Diffusion model is a mathematical description of how the rate of new product diffusion in a market changes over time. Figure 1 depicts the cumulative market adoption with respect to time, $S(t)$. The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters. The following equation describes this relationship:

$$\frac{dS(t)}{dt} = \left(p + \frac{q}{m} * S(t-1)\right) * (m - S(t-1))$$

Where:

$\frac{dS(t)}{dt} =$ the rate of adoption for any discrete time period, *t*

$p =$ external influences on market adoption

$q =$ internal influences on market adoption

$m =$ the maximum market share for the product

$S(t-1) =$ the cumulative market share of the product, from product introduction to time period *t-1*

Marketing is the quintessential external influence. The internal influences are characteristics of the product and market; for example: the underlying market demand for the product, word of mouth, product features, market structure, and other factors that determine the product's market performance. Nexant's approach applied literature reviews and analysis of secondary data sources to estimate the Bass model parameters. We then extrapolated the model to future years; the historic participation and predicted future market evolution serve as the program adoption curve applied to each proposed offering.

7.3.2 Scenario Analysis

Section 7.2 described Duke Energy's current or proposed program offers for North Carolina. Nexant estimated market potential for these program offerings under three program potential scenarios, each of which is summarized below:

- Base scenario – aligns with existing program portfolio, and includes existing EE programs and measures currently offered by DEC or DEP
- Enhanced scenario – Include the base scenario, but with increased program spending (via incentives) designed to attract new customers into the market for EE technology and program participation[3]
- Avoided Energy Cost Sensitivity scenario – covers the base scenario, but with a sensitivity analysis around enhanced EE benefits, such as may occur if avoided energy costs were higher than current values.

Duke Energy currently offers customers a wide array of cost-effective opportunities for implementing energy efficiency. Residential offers are packaged into discrete products and services, but nearly any intervention that can be shown to generate cost-effective savings is available to commercial and industrial customers that have not opted-out of EE programs.

Furthermore, Duke Energy has offered EE and DSM programs in North Carolina since 2008, during which time they have followed best practices for managing the EE and DSM program life cycle. These practices include periodic assessments of market potential; strategic program design that includes a variety of program implementation approaches; rigorous program evaluations of impacts and processes; and, iterating over the EE and DSM program life cycle to continually improve programs.

Nexant developed Base and Enhanced alternative scenarios in conjunction with Duke Energy to examine the underlying drivers of EE and DSM economic potential in North Carolina. The higher avoided energy cost sensitivity scenario look at sensitivities associated with the costs and benefits of investments in EE and DSM technology, recognizing the work Duke Energy is doing to separately focus on adaptive management approaches of the EE and DSM program lifecycle framework.

7.4 DSM Market Potential Methodology

7.4.1 Estimation of Participation Rates for DSM Programs

While economic potential merely considers whether a given customer segment is worth pursuing based on the marginal net benefits provided by those customers, achievable potential takes into account the estimated participation rate and how that affects the overall cost-effectiveness of the customer segment.

[3] Incentive rates were doubled, but subject to a maximum rate of 75% of measure incremental cost.

The magnitude of DSM resources that can be acquired is fundamentally the result of customer preferences, program or offer characteristics (including incentive levels), and how programs are marketed. How predisposed are specific customers to participate in DSM? What are details of specific offers and how do they influence enrollment rates? What is the level of marketing intensity and what marketing tactics are employed?

For program-based DSM, participation rates are calculated as a function of the incentives offered to each customer group. For a given incentive level and participation rate, the cost-effectiveness of each customer segment is evaluated to determine whether the aggregate DSM potential from that segment should be included in the achievable potential.

The following subsections describe how marketing/incentive level, participation rates, and technology costs are handled by this study.

7.4.2 Marketing and Incentive Levels for Programs

Several underlying assumptions are used to define the marketing level for program potential. The number of marketing attempts and the method of outreach are described in Table 7-4. Nexant assumed that Duke's existing marketing methods would remain constant for all three scenarios.

The specific tactics included in the table are not prescriptive but are instead designed to provide concrete details about the assumptions used in the study. There is a wide range of strategies and tactics that can attain the same enrollment levels and the best approach for a jurisdiction is best developed through testing and optimizing the mix of marketing tactics and incentives.

Table 7-4: Marketing Inputs for Residential Program Enrollment Model

		Input
Marketing Components	Number of marketing attempts (Direct mail)	3
	Outreach mode	Direct Mail + Phone
	Installation required (%)	40%

The incentive level and marketing inputs for each scenario determine the participation rate, assuming that the incentive is uniform across all customer segments within a given customer class. For the base scenario, Nexant assumed the existing incentives for DSM programs would continue to be used. For the enhanced scenario, Nexant assumed that the existing incentive levels for each program would double.

7.4.3 Participation Rates

The participation models for the residential and nonresidential customer segments use a bottom up approach to estimate participation rates. These estimates have been crosschecked with mature programs in other utilities and Duke Energy jurisdictions to ensure that the estimated participation rates are reasonable.

Many DSM potential studies rely on top down approaches which benchmark programs against enrollment rates that have been attained by mature programs. However, aggregated program results often do not provide enough detail to calibrate achievable market potential. In many cases, programs are not marketed to all customers, either because it is not cost-effective to market to all customers or budgets are capped by regulators. Enrollment rates are a function of specific offers and the extensiveness of marketing over many years. They also vary based on the degree to which DSM resources are utilized and tend to be higher when payments are high but actual events are infrequent, particularly among large C&I customers.

For residential customers, the Nexant approach to estimate participation rates involves five steps. The initial step required some modification due to the data provided (or lack thereof).

1) Estimate an econometric choice model based on who has and has not enrolled in DSM programs. The goal is to estimate the pre-disposition or propensity of different customers to participate in DSM based on their characteristics. Because micro-level acquisition marketing data were not provided, Nexant relied on differences in participation rates by usage level, electric heating and income level. This information is based on prior micro-level analysis of program participation by Nexant and supplemented by outbound acquisition marketing that Nexant implements for load control programs.
2) Incorporate information about how different offer characteristics influence enrollment likelihood. What is the incremental effect of incentives? How do requirements for on-site installation affect enrollment rates? The two questions above have been analyzed using California specific data for residential customers. In each case, regression coefficients describe the incremental effect of each of the above factors on participation rates.
3) Incorporate information about how marketing tactics and intensity of marketing influence participation rates. What is the effect of incremental acquisition attempts? Is there a bump in enrollment rates when phone and/or door-to-door recruitment is added to direct mail recruitment? This relies on data from side-by-side testing designed to explicitly quantify the effect of marketing tactics on enrollment rates.
4) Calibrate the models to reflect actual enrollment rates attained with mature programs. To calibrate the models, the constant is adjusted so that the model produces exactly the enrollment rates observed by mature programs used for benchmarking.
5) Predict participation rates using specific tactics and incentive levels for programs with and without installation requirements. The enrollment estimates were produced for low, medium, and high marketing levels, where specific marketing tactics are specified for each scenario. All estimates reflect enrollment rates for eligible customers.

For small C&I customers (1 MW or less), a similar approach was used to estimate participation levels. However, these customers tend to have lower enrollments than larger nonresidential customers, and were scaled accordingly based on existing participation seen in DEC and DEP small C&I DSM programs.

For large nonresidential customers, enrollment levels were predicted as a function of load rather than the number of customers, since large customers tend to have relatively high participation rates and commit to relatively large demand reductions on a percentage basis. For these customers, publicly available data on DSM programs offered by California utilities were used to model program participation rates. Participation data were combined with data from the utilities on customer size and industry to generate a breakdown of participation rates, which is summarized in Table 7-5.

Table 7-5: Large Nonresidential Participation Rates by Size and Industry

Industry	Annual Max Demand (Non-coincident)				Total
	100kw - 300kW*	300 - 500kW	500kW - 1MW	1 MW or more	
Agriculture, Mining & Construction	19.8%	43.2%	57.9%	60.7%	**44.6%**
Manufacturing	24.2%	44.8%	52.3%	74.0%	**64.6%**
Wholesale, Transport & Other Utilities	27.9%	50.1%	55.7%	60.8%	**49.7%**
Retail Stores	28.1%	53.0%	53.8%	48.0%	**42.7%**
Offices, Hotels, Finance, Services	13.0%	26.9%	34.3%	40.2%	**30.0%**
Schools	15.0%	30.5%	40.3%	52.5%	**35.7%**
Institutional/Government	13.7%	34.1%	42.8%	62.3%	**40.4%**
Other or Unknown	9.4%	25.3%	29.6%	29.5%	**18.6%**
Total	**19.7%**	**40.8%**	**45.6%**	**60.8%**	**45.4%**

These programs have been marketed to every large nonresidential customer in California, which is why California specific data reflect a saturated market and a good representation of the total potential. The main gap in applying these participation rates is the ability to use back-up generation for DSM. California does not allow the use of backup generation for DSM while North Carolina does.

For each large nonresidential customer segment, participation was estimated as a function of incentive level and number of dispatch hours, based on publicly available information on program capacity, dispatch events, and incentive budgets.

Finally, these models were calibrated to reflect actual enrollment from DEC marketing initiatives for the Power Manager® (residential) and PowerShare® (nonresidential) programs and DEP marketing initiatives for EnergyWise® and DEP's DSM Automation Program.

7.5 DEC Energy Efficiency Program Potential

This section provides the results of the DEC EE achievable program potential for each of the three segments.

7.5.1 Summary

Table 7-6 summarizes the short-term (5-year), medium (10-year) and long-term (25-year) DEC portfolio EE program potential for the base enhanced incentive, and the avoided energy cost sensitivity scenarios. Impacts are presented as both **cumulative impacts**, which represent the savings that occur in the respective year based on measures installed in that year and measures installed in prior years that have not reached the end of their useful life and **the sum of annual impacts**, which represent the total annual incremental savings achieved over the stated time horizon (5 years, 10 years, or 25 years). The cumulative impacts view is important when using MPS results for resource planning purposes because it accounts for how the incremental addition of EE savings will impact the overall system load and load impacts likely to occur as measures reach the end of their useful lives. The sum of annual impacts view aligns with how utilities report their EE achievements in annual cost recovery filings, which is to show the annual incremental additions each year.

Table 7-6: DEC EE Program Potential

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Load	Total Potential	% of Load	Total Potential	% of Load
5-yr (2024) impacts						
Cumulative MWh	643,285	1.63%	789,335	1.99%	667,402	1.69%
Cumulative MW Summer	164		186		168	
Cumulative MW Winter	63		78		65	
Sum of Annual MWh	1,730,115	4.37%	1,878,329	4.75%	1,753,985	4.43%
Sum of Annual MW Summer	598		620		602	
Sum of Annual MW Winter	159		175		162	
10-yr (2029) impacts						
Cumulative MWh	811,485	2.02%	1,022,887	2.55%	847,915	2.12%
Cumulative MW Summer	192		225		200	
Cumulative MW Winter	76		96		78	
Sum of Annual MWh	3,321,151	8.28%	3,563,292	8.89%	3,362,501	8.39%
Sum of Annual MW Summer	1,159		1,197		1,168	
Sum of Annual MW Winter	304		326		306	
25-yr (2044) impacts						
Cumulative MWh	623,693	1.31%	743,436	1.56%	655,483	1.38%
Cumulative MW Summer	174		194		180	
Cumulative MW Winter	54		63		55	
Sum of Annual MWh	8,256,699	17.34%	8,662,531	18.19%	8,336,137	17.51%
Sum of Annual MW Summer	2,945		3,008		2,962	
Sum of Annual MW Winter	754		789		758	

Figure 7-2, Figure 7-3, and Figure 7-4 show DEC achievable energy savings potential by sector for each scenario.

Figure 7-2: DEC 2024 Achievable Program Potential by Sector – Base Scenario

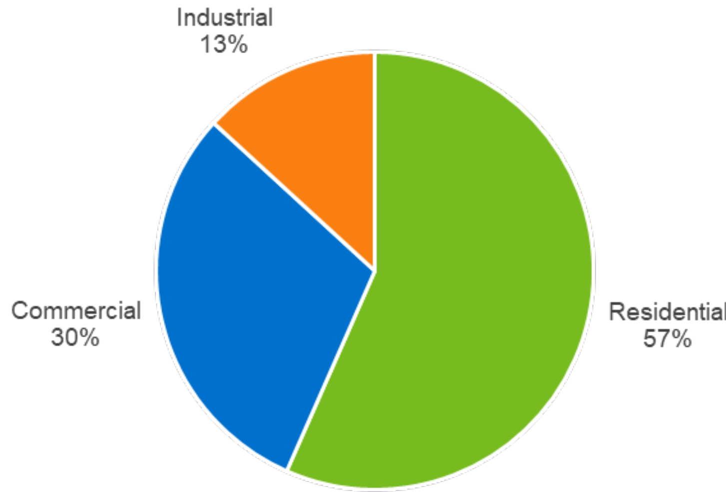


Figure 7-3: DEC 2024 Achievable Program Potential by Sector – Enhanced Scenario

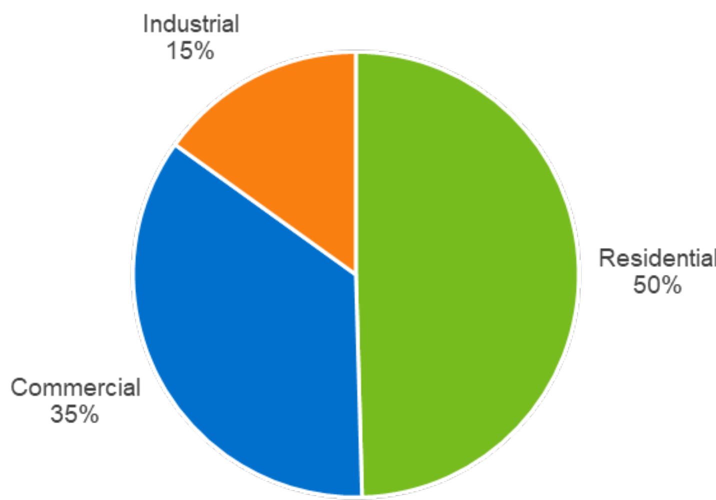
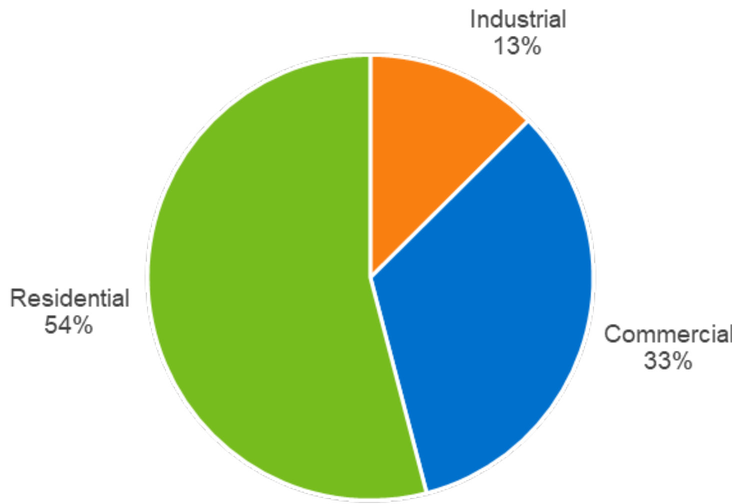


Figure 7-4: DEC 2024 Achievable Program Potential by Sector – Avoided Energy Cost Sensitivity



Participant and program costs associated with achievable program potential scenarios include the following:

- **Program incentives:** Financial incentives paid by energy-efficiency programs to subsidize purchases of energy-efficiency measures.
- **Program administration costs:** Administrative, marketing, promotional, and other costs associated with managing programs designed to achieve energy-efficiency savings.
- **Total program acquisition costs:** Total incentive and non-incentive program costs per sum of annual incremental energy savings achieved.
- **Participant costs:** Incremental costs to purchase, install, and maintain energy-efficiency measures.

Table 7-7 lists estimated participant and program costs associated with the theoretically achievable scenarios over the first 5 program years.

Table 7-7: DEC Participation and Program Costs by Scenario (cumulative through 2024)

Program Sector	Program Incentives ($M)	Program Admin ($M)	Participant Costs ($M)	Levelized Cost[4] ($/kWh)
Base Scenario				
Residential	$8.80	$97.34	$7.15	$0.06
Non-Residential	$16.17	$12.98	$27.11	$0.03
Total	$24.97	$110.32	$34.26	$0.05
Enhanced Scenario				
Residential	$15.62	$104.00	$6.28	$0.06
Non-Residential	$43.22	$18.09	$17.92	$0.03
Total	$58.84	$122.09	$24.20	$0.04
Avoided Energy Cost Sensitivity Scenario				
Residential	$9.21	$97.69	$7.73	$0.07
Non-Residential	$19.39	$14.28	$33.22	$0.03
Total	$28.60	$111.97	$40.95	$0.05

7.5.2 Residential Program Details

Table 7-8 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for the base, enhanced, and avoided energy cost sensitivity scenarios. Impacts are presented as both **cumulative impacts**, which represent the savings that occur in the respective year based on measures installed in that year and measures installed in prior years that have not reached the end of their useful life and **the sum of annual impacts**, which represent the total annual incremental savings achieved over the stated time horizon (5 years, 10 years, or 25 years):

[4] Levelized cost presented from the TRC perspective as the sum of incremental measure costs and program admin costs divided by the discounted sum of lifetime energy savings. Program potential costs include both incremental measure costs and program delivery and administrative costs.

Table 7-8: EE Residential Program Potential

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Res Load	Total Potential	% of Res Load	Total Potential	% of Res Load
5-yr (2024) impacts						
Cumulative MWh	364,168	1.65%	397,316	1.80%	366,502	1.66%
Cumulative MW Summer	125		133		126	
Cumulative MW Winter	39		44		39	
Sum of Annual MWh	1,448,270	6.56%	1,482,478	6.72%	1,450,324	6.56%
Sum of Annual MW Summer	559		566		559	
Sum of Annual MW Winter	135		141		136	
10-yr (2029) impacts						
Cumulative MWh	380,585	1.69%	417,354	1.85%	384,568	1.70%
Cumulative MW Summer	133		143		135	
Cumulative MW Winter	39		44		39	
Sum of Annual MWh	2,835,161	12.56%	2,880,544	12.76%	2,838,869	12.58%
Sum of Annual MW Summer	1,092		1,104		1,094	
Sum of Annual MW Winter	262		268		262	
25-yr (2044) impacts						
Cumulative MWh	351,859	1.28%	361,150	1.31%	353,455	1.28%
Cumulative MW Summer	135		140		136	
Cumulative MW Winter	31		32		31	
Sum of Annual MWh	7,391,458	26.87%	7,445,484	27.07%	7,397,651	26.89%
Sum of Annual MW Summer	2,826		2,842		2,829	
Sum of Annual MW Winter	681		688		681	

Figure 7-5, Figure 7-6, and Figure 7-7 illustrate the relative contributions to the overall residential program potential by program for the base and enhanced scenarios.

Figure 7-5: DEC Residential 5-Yr Cumulative Potential by Program – Base Scenario

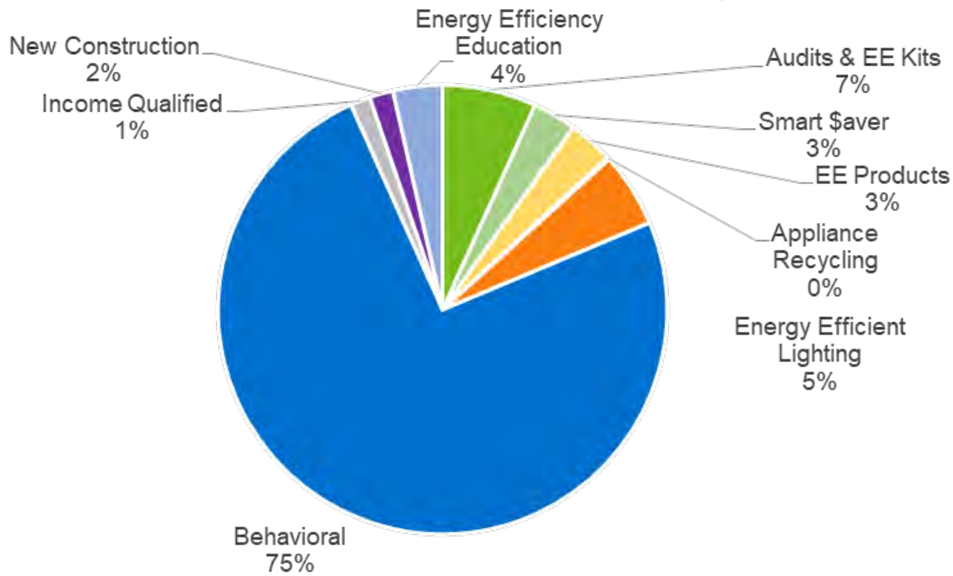


Figure 7-6: DEC Residential 5-Yr Cumulative Potential by Program – Enhanced Scenario

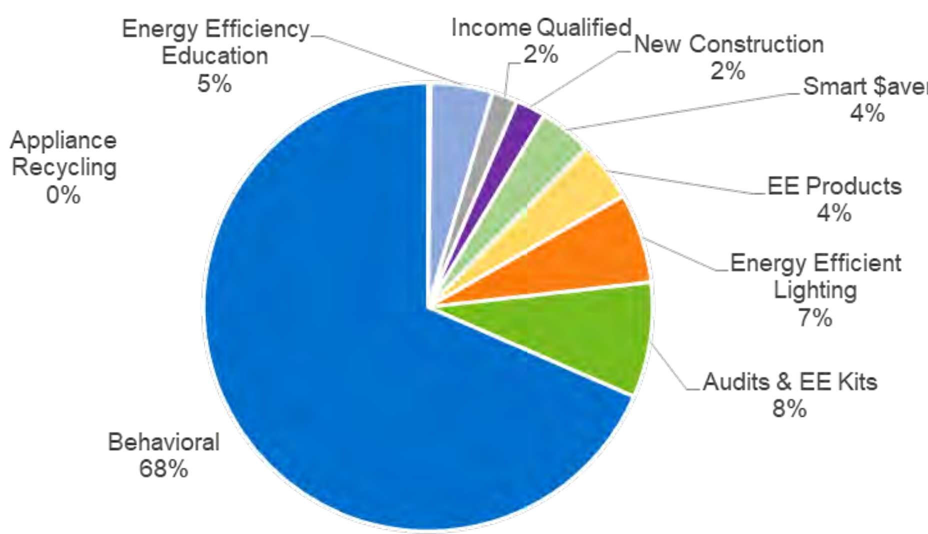
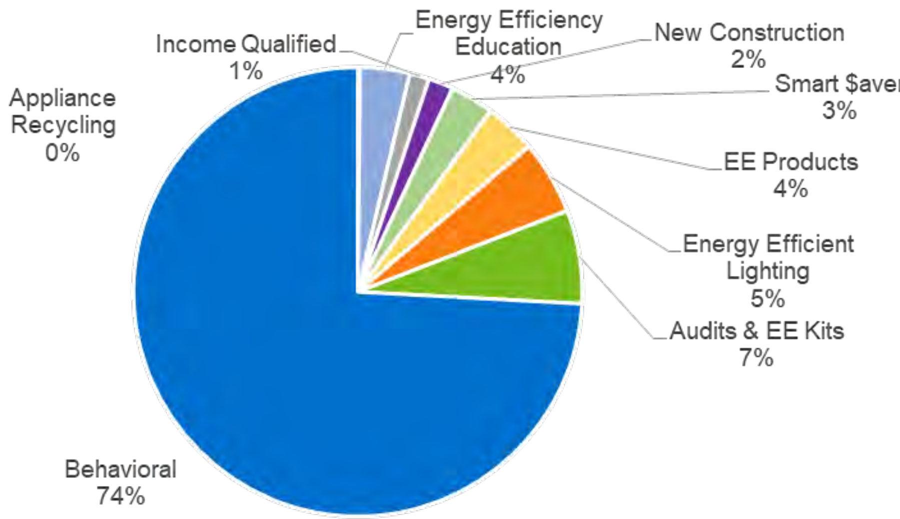


Figure 7-7: DEC Residential 5-Yr Cumulative Potential by Program – Avoided Energy Cost Sensitivity Scenario



Detailed program results for the short-term residential EE programs are provided in Table 7-9:

Table 7-9: DEC Residential Program Potential (cumulative through 2024)

	Audits & EE Kits	Smart $aver	EE Products	Appliance Recycling	Energy Efficient Lighting	Behavioral	Income Qualified	New Const.	EE. Education
5-yr (2024) impacts – Base scenario									
MWh savings (cumulative)	24,640	11,483	11,785	541	19,548	271,802	5,186	6,246	12,936
Summer MW savings (cumulative)	2.28	3.12	4.92	0.42	0.73	105.89	0.98	2.08	4.93
Winter MW savings (cumulative)	6.50	0.95	0.68	0.02	3.44	24.61	1.09	0.75	1.18
Program costs (cumulative) ($M)	$3.30	$6.45	$2.17	$0.31	$3.12	$79.08	$3.82	$2.93	$4.96
Levelized Cost ($/kWh)	$0.02	$0.12	$0.05	$0.10	$0.02	$0.07	$0.10	$0.09	$0.08
5-yr (2024) impacts – Enhanced scenario									
MWh savings (cumulative)	33,027	15,256	16,970	779	25,737	271,982	7,239	8,603	17,725
Summer MW savings (cumulative)	3.06	4.00	7.09	0.60	0.96	105.96	1.37	2.86	6.75
Winter MW savings (cumulative)	8.72	1.33	0.98	0.02	4.53	24.63	1.53	1.02	1.62
Program costs (cumulative) ($M)	$4.46	$10.54	$4.29	$0.49	$4.04	$79.10	$5.36	$4.57	$6.77
Levelized Cost ($/kWh)	$0.02	$0.12	$0.05	$0.10	$0.02	$0.07	$0.10	$0.09	$0.10

	Audits & EE Kits	Smart $aver	EE Products	Appliance Recycling	Energy Efficient Lighting	Behavioral	Income Qualified	New Const.	EE. Education
5-yr (2024) impacts – Avoided Energy Cost Sensitivity scenario									
MWh savings (cumulative)	24,640	11,534	13,592	541	19,555	271,774	5,231	6,548	13,088
Summer MW savings (cumulative)	2.28	3.12	5.83	0.42	0.73	105.87	1.00	2.20	4.99
Winter MW savings (cumulative)	6.50	0.96	0.74	0.02	3.42	24.61	1.09	0.77	1.20
Program costs (cumulative) ($M)	$3.30	$6.48	$2.57	$0.31	$3.12	$79.07	$3.87	$3.18	$5.01
Levelized Cost ($/kWh)	$0.02	$0.13	$0.06	$0.10	$0.02	$0.07	$0.21	$0.21	$0.08

To analyze the costs and benefits of the program potential scenarios, Nexant used a number of common test perspectives in the MPS, consistent with the California Standard Practice Manual5:

- Total resource cost (TRC): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to that measure's incremental cost. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Utility cost test (UCT): Calculated by comparing total avoided electricity production and avoided delivery costs from installing a measure, to the utility's cost of delivering a program containing that measure. Costs include incentive and non-incentive costs.
- Participant cost test (PCT): Calculated by dividing electricity bill savings for each installed measure, by the incremental cost of that measure. The incremental cost is relative to the cost of the measure's appropriate baseline technology.
- Ratepayer Impact Measure (RIM): Calculated by comparing the total avoided electricity production and the avoided delivery costs from installing a measure, to the utility's revenue impacts from lost sales and program delivery.

Nexant shows achievable program potential estimates and benefits cost ratios according to current administrative cost data provided to Nexant by Duke Energy. Detailed program design is not part of this scope of work, and Nexant has no examined the components of the administrative costs provided by Duke Energy and applied by Nexant on a dollar-per-kilowatt-

[5] California Standard Practice Manual: Economic Analysis of Demand-Side Program and Projects. California Public Utilities Commission. San Francisco, CA. October 2001.

hour basis. Table 7-10 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-10: DEC Cost-Benefit Results – Residential Programs (cumulative through 2024)

	Audits & EE Kits	Smart $aver	EE Products	Appliance Recycling	Energy Efficient Lighting	Behavioral	Income Qualified	New Const.	EE Education
5-yr (2024) impacts – Base scenario									
TRC – Net Benefits($M)	$7.36	-$4.29	$1.23	-$0.08	$6.34	$12.85	-$1.27	-$0.35	-$1.10
TRC – B/C ratio	3.23	0.60	1.30	0.79	3.03	1.16	0.67	0.91	0.78
UCT – Net Benefits ($M)	$7.36	-$0.07	$3.12	-$0.01	$6.34	$12.85	-$1.27	$0.62	-$1.10
UCT – B/C ratio	3.23	0.99	2.44	0.96	3.03	1.16	0.67	1.21	0.78
PCT – Net Benefits ($M)	$13.88	$4.36	$4.99	$0.23	$14.84	$93.19	$3.23	$3.42	$7.84
PCT – B/C ratio	N/A	2.03	3.65	4.47	N/A	N/A	N/A	4.54	N/A
RIM – Net Benefits ($M)	-$6.52	-$8.65	-$3.76	-$0.31	-$8.50	-$80.34	-$4.50	-$3.77	-$8.94
RIM – B/C ratio	0.62	0.42	0.58	0.48	0.53	0.53	0.36	0.49	0.30
5-yr (2024) impacts – Enhanced scenario									
TRC – Net Benefits($M)	$9.76	-$5.72	$1.77	-$0.11	$8.42	$12.97	-$1.80	-$0.49	-$1.49
TRC – B/C ratio	3.19	0.60	1.30	0.79	3.08	1.16	0.67	0.91	0.78
UCT – Net Benefits ($M)	$9.76	-$1.89	$3.33	-$0.07	$8.42	$12.97	-$1.80	$0.36	-$1.49
UCT – B/C ratio	3.19	0.82	1.77	0.87	3.08	1.16	0.67	1.08	0.78
PCT – Net Benefits ($M)	$18.53	$7.78	$8.35	$0.38	$19.53	$93.33	$4.51	$5.24	$10.74
PCT – B/C ratio	N/A	3.03	6.38	8.94	N/A	N/A	N/A	7.22	N/A
RIM – Net Benefits ($M)	-$8.77	-$13.50	-$6.58	-$0.50	-$11.11	-$80.36	-$6.30	-$5.73	-$12.23
RIM – B/C ratio	0.62	0.39	0.54	0.46	0.53	0.53	0.36	0.46	0.30

	Audits & EE Kits	Smart $aver	EE Products	Appliance Recycling	Energy Efficient Lighting	Behavioral	Income Qualified	New Const.	EE Education
5-yr (2024) impacts – Avoided Energy Cost Sensitivity scenario									
TRC – Net Benefits($M)	$9.97	-$2.48	$2.79	-$0.03	$5.40	$35.66	-$0.66	$0.47	$1.58
TRC – B/C ratio	4.03	0.77	1.57	0.92	2.73	1.45	0.83	1.11	1.32
UCT – Net Benefits ($M)	$9.97	$1.76	$5.15	$0.04	$5.40	$35.66	-$0.66	$1.55	$1.58
UCT – B/C ratio	4.03	1.27	3.01	1.13	2.73	1.45	0.83	1.49	1.32
PCT – Net Benefits ($M)	$13.88	$4.39	$5.61	$0.23	$14.85	$93.17	$3.26	$3.53	$7.93
PCT – B/C ratio	N/A	2.04	3.38	4.47	N/A	N/A	N/A	4.27	N/A
RIM – Net Benefits ($M)	-$3.91	-$6.87	-$2.83	-$2.61	-$9.45	-$57.51	-$3.91	-$3.05	$6.35
RIM – B/C ratio	0.77	0.55	0.73	0.57	0.47	0.67	0.45	0.61	0.51

7.5.3 Non-Residential Program Details

Table 7-11 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for the base and enhanced scenarios, presented as both cumulative and sum of annual impacts:

Table 7-11: DEC EE Non-Residential Program Potential

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load
5-yr (2024) impacts						
Cumulative MWh	279,117	1.60%	392,019	2.24%	300,900	1.72%
Cumulative MW Summer	38		53		42	
Cumulative MW Winter	24		34		26	
Sum of Annual MWh	281,845	1.61%	395,851	2.26%	303,661	1.74%
Sum of Annual MW Summer	39		54		43	
Sum of Annual MW Winter	24		34		26	
10-yr (2029) impacts						
Cumulative MWh	430,900	2.46%	605,533	3.46%	463,347	2.64%
Cumulative MW Summer	59		82		65	
Cumulative MW Winter	37		52		39	
Sum of Annual MWh	485,990	2.77%	682,748	3.90%	523,632	2.99%
Sum of Annual MW Summer	67		93		74	
Sum of Annual MW Winter	42		58		44	

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load
25-yr (2044) impacts						
Cumulative MWh	271,834	1.35%	382,286	1.90%	302,028	1.50%
Cumulative MW Summer	39		54		44	
Cumulative MW Winter	23		31		24	
Sum of Annual MWh	865,241	4.30%	1,217,047	6.05%	938,486	4.67%
Sum of Annual MW Summer	119		166		133	
Sum of Annual MW Winter	73		101		77	

Figure 7-8, Figure 7-9, and Figure 7-10 illustrate the relative contributions to the overall non-residential program potential by program for the base, enhanced, and avoided energy cost sensitivity scenarios.

Figure 7-8: Non-Residential 5-Yr Cumulative Potential by Program – Base Scenario

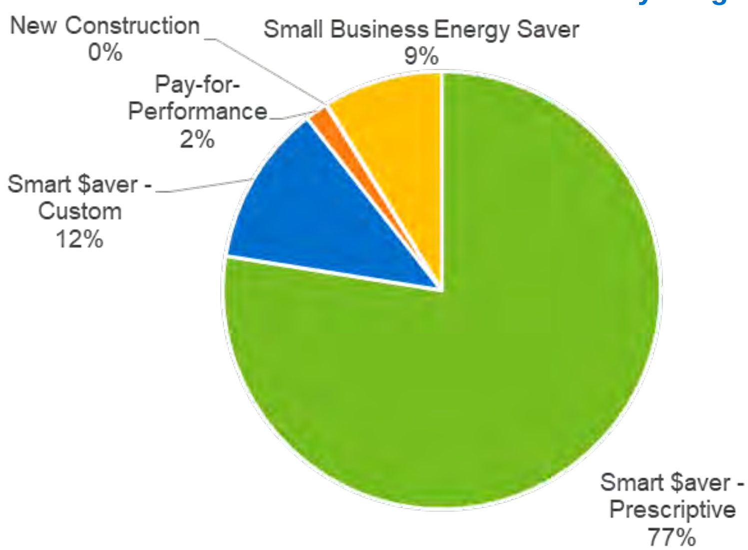


Figure 7-9: Non-Residential 5-Yr Cumulative Potential by Program – Enhanced Scenario

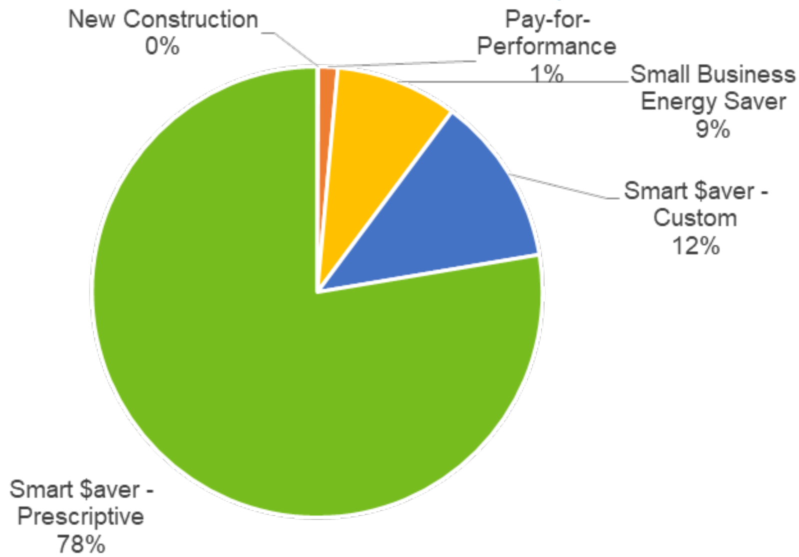
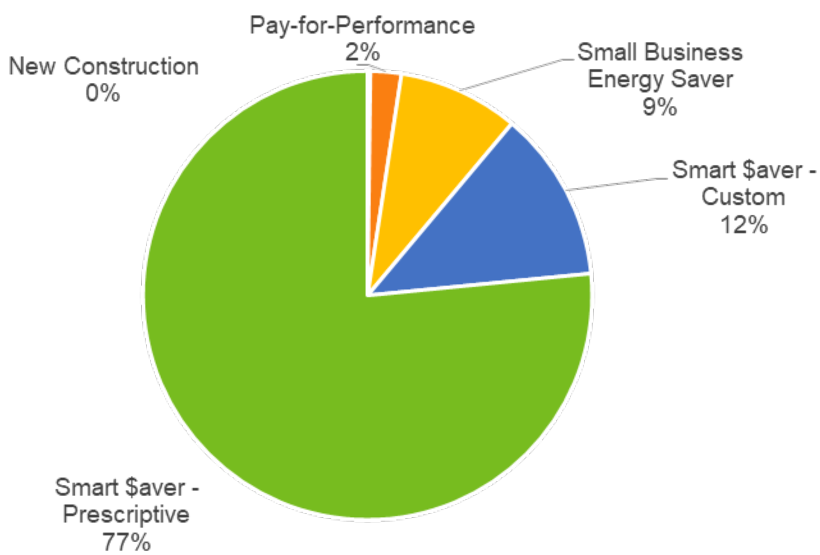


Figure 7-10: Non-Residential 5-Yr Cumulative Potential by Program – Avoided Energy Cost Sensitivity Scenario



Detailed program results for the short-term non-residential EE programs are provided in Table 7-12:

Table 7-12: DEC Non-Residential Program Potential (cumulative through 2024)

	Prescriptive	Custom	Pay-for-Performance	New Construction	Small Business Energy Saver
5-yr (2024) impacts – Base Scenario					
MWh savings (cumulative)	216,342	33,265	4,688	186	24,636
Summer MW savings (cumulative)	29.81	4.11	0.75	0.03	3.52
Winter MW savings (cumulative)	18.68	2.72	0.27	0.03	2.53
Program costs (cumulative) ($M)	$21.91	$3.89	$1.08	$0.02	$2.26
Levelized Cost ($/kWh)	$0.03	$0.03	$0.06	$0.02	$0.02
5-yr (2024) impacts – Enhanced Scenario					
MWh savings (cumulative)	304,427	47,588	5,463	268	34,273
Summer MW savings (cumulative)	41.50	5.87	0.86	0.04	4.89
Winter MW savings (cumulative)	25.91	3.85	0.37	0.04	3.53
Program costs (cumulative) ($M)	$48.79	$7.17	$1.44	$0.02	$3.88
Levelized Cost ($/kWh)	$0.03	$0.03	$0.06	$0.02	$0.02

	Prescriptive	Custom	Pay-for-Performance	New Construction	Small Business Energy Saver
5-yr (2024) impacts – Avoided Energy Cost Sensitivity Scenario					
MWh savings (cumulative)	230,354	37,108	6,676	600	26,162
Summer MW savings (cumulative)	32.55	4.78	1.12	0.09	3.81
Winter MW savings (cumulative)	19.69	2.98	0.27	0.09	2.59
Program costs (cumulative) ($M)	$24.64	$4.62	$1.70	$0.08	$2.64
Levelized Cost ($/kWh)	$0.03	$0.03	$0.08	$0.09	$0.02

Table 7-13 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-13: DEC Cost-Benefit Results – Non-Residential Programs (through 2024)

	Prescriptive	Custom	Pay-for-Performance	New Construction	Small Business Energy Saver
5-yr (2024) impacts – Base Scenario					
TRC – Net Benefits($M)	$28.67	$3.64	-$0.38	$0.04	$4.52
TRC – B/C ratio	1.62	1.63	0.72	3.39	2.75
UCT – Net Benefits ($M)	$53.22	$5.58	-$0.08	$0.03	$4.85
UCT – B/C ratio	3.43	2.43	0.92	1.68	3.15
PCT – Net Benefits ($M)	$85.28	$12.17	$1.14	$0.11	$11.43
PCT – B/C ratio	4.47	7.29	4.86	65.11	35.92
RIM – Net Benefits ($M)	-$56.62	-$8.53	-$1.52	-$0.08	-$6.91
RIM – B/C ratio	0.57	0.53	0.40	0.43	0.51

	Prescriptive	Custom	Pay-for-Performance	New Construction	Small Business Energy Saver
5-yr (2024) impacts – Enhanced Scenario					
TRC – Net Benefits($M)	$41.64	$5.19	-$0.35	$0.06	$6.12
TRC – B/C ratio	1.65	1.62	0.78	3.39	2.27
UCT – Net Benefits ($M)	$57.32	$6.34	-$0.19	$0.04	$7.06
UCT – B/C ratio	2.17	1.88	0.86	1.98	2.82
PCT – Net Benefits ($M)	$138.49	$18.97	$1.61	$0.15	$15.33
PCT – B/C ratio	9.84	17.51	11.19	104.18	17.23
RIM – Net Benefits ($M)	-$96.85	-$13.78	-$1.96	-$0.11	-$9.21
RIM – B/C ratio	0.52	0.50	0.39	0.44	0.54
5-yr (2024) impacts – Avoided Energy Cost Sensitivity Scenario					
TRC – Net Benefits($M)	$50.07	$6.62	-$0.55	$0.30	$6.89
TRC – B/C ratio	1.94	1.92	0.77	3.82	2.76
UCT – Net Benefits ($M)	$78.67	$9.19	$0.20	$0.30	$8.17
UCT – B/C ratio	4.19	2.99	1.12	3.96	4.10
PCT – Net Benefits ($M)	$89.68	$12.83	$1.30	$0.36	$11.13
PCT – B/C ratio	4.14	6.00	2.72	15.90	9.71
RIM – Net Benefits ($M)	-$39.61	-$6.21	-$1.86	-$0.08	-$4.24
RIM – B/C ratio	0.72	0.69	0.51	0.83	0.72

7.6 DEP Energy Efficiency Program Potential

This section provides the results of the DEP energy efficiency economic potential for each of the three segments.

7.6.1 Summary

Table 7-14 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) DEP portfolio EE program potential for the base, enhanced, and avoided energy cost sensitivity scenarios. Impacts are presented as both **cumulative impacts**, which represent the savings that occur in the respective year based on measures installed in that year and measures installed in prior years that have not reached the end of their useful life and **the sum of annual impacts**, which represent the total annual incremental savings achieved over the stated time horizon (5 years, 10 years, or 25 years).

Table 7-14: DEP EE Program Potential

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Load	Total Potential	% of Load	Total Potential	% of Load
5-yr (2024) impacts						
Cumulative MWh	381,182	1.52%	454,367	1.81%	402,234	1.60%
Cumulative MW Summer	128		140		132	
Cumulative MW Winter	31		37		32	
Sum of Annual MWh	1,175,628	4.69%	1,250,335	4.99%	1,196,581	4.77%
Sum of Annual MW Summer	522		535		526	
Sum of Annual MW Winter	84		90		85	
10-yr (2029) impacts						
Cumulative MWh	467,423	1.81%	572,165	2.22%	499,762	1.94%
Cumulative MW Summer	146		164		153	
Cumulative MW Winter	35		44		39	
Sum of Annual MWh	2,288,803	8.87%	2,409,439	9.34%	2,324,702	9.01%
Sum of Annual MW Summer	1,024		1,045		1,030	
Sum of Annual MW Winter	160		169		164	
25-yr (2044) impacts						
Cumulative MWh	388,416	1.26%	447,064	1.45%	410,631	1.33%
Cumulative MW Summer	147		158		151	
Cumulative MW Winter	26		31		28	
Sum of Annual MWh	5,909,981	19.13%	6,106,975	19.77%	5,971,508	19.33%
Sum of Annual MW Summer	2,686		2,720		2,698	
Sum of Annual MW Winter	412		425		416	

Figure 7-11, Figure 7-12, and Figure 7-13 show DEP achievable energy savings potential by sector for each scenario. The commercial sector accounts for more than half of the energy-savings potential, and almost two-thirds of the peak reduction potential. The industrial sector accounts for the majority of the remaining potential for electricity sales, while the residential sector accounts for the majority of the remaining peak demand reduction.

Figure 7-11: DEP 2024 Achievable Program Potential by Sector – Base Scenario

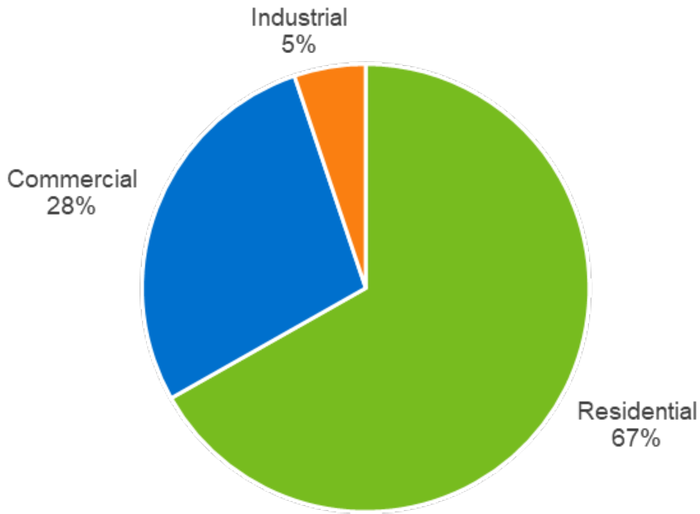


Figure 7-12: DEP 2024 Achievable Program Potential by Sector – Enhanced Scenario

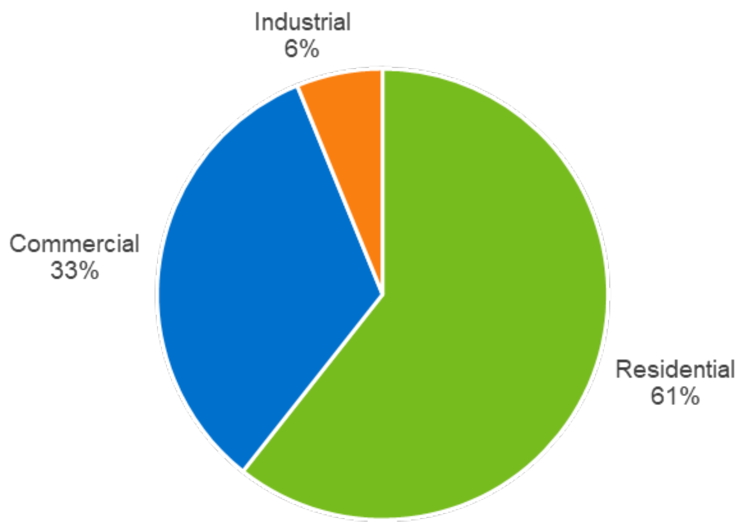
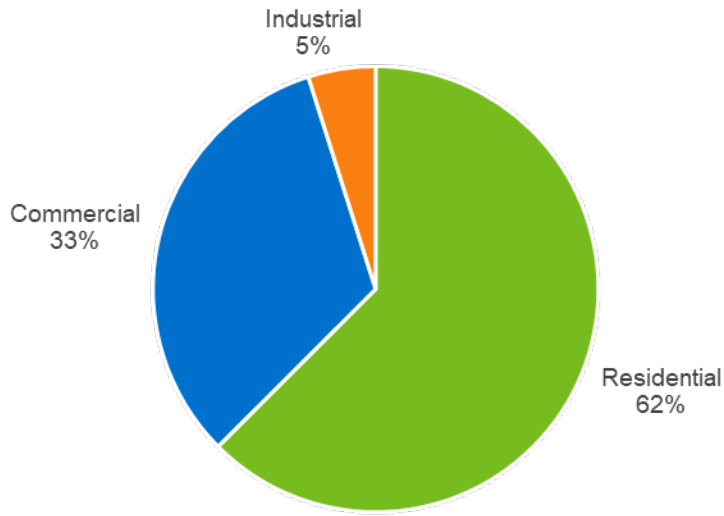


Figure 7-13: DEP 2024 Achievable Program Potential by Sector – Avoided Energy Cost Sensitivity Scenario



Participant and program costs associated with achievable program potential scenarios include the following:

- **Program incentives:** Financial incentives paid by energy-efficiency programs to subsidize purchases of energy-efficiency measures.
- **Program administration costs:** Administrative, marketing, promotional, and other costs associated with managing programs designed to achieve energy-efficiency savings.
- **Total program acquisition costs:** Total incentive and non-incentive program costs per sum of annual incremental energy savings achieved.
- **Participant costs:** Incremental costs to purchase, install, and maintain energy-efficiency measures.

Table 7-15 lists estimated participant and program costs associated with the theoretically achievable scenarios over the first 5 program years.

Table 7-15: DEP Participation and Program Costs by Scenario (cumulative through 2024)

Program Sector	Program Incentives ($M)	Program Admin ($M)	Participant Costs ($M)	Levelized Cost ($/kWh)
Base Scenario				
Residential	$4.95	$69.56	$4.01	$0.06
Non-Residential	$6.80	$5.80	$11.73	$0.03
Total	$11.75	$75.36	$15.74	$0.05
Enhanced Scenario				
Residential	$8.85	$73.80	$3.48	$0.06
Non-Residential	$18.56	$8.13	$7.73	$0.03
Total	$27.41	$81.93	$11.21	$0.05
Avoided Energy Cost Sensitivity Scenario				
Residential	$5.12	$69.95	$4.36	$0.06
Non-Residential	$9.76	$6.81	$16.87	$0.03
Total	$14.88	$76.76	$21.23	$0.05

7.6.2 Residential Program Details

Table 7-16 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for base, enhanced, and avoided energy cost sensitivity scenarios:

Table 7-16: DEP EE Residential Program Potential

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Res Load	Total Potential	% of Res Load	Total Potential	% of Res Load
5-yr (2024) impacts						
Cumulative MWh	254,681	1.61%	275,495	1.74%	255,645	1.61%
Cumulative MW Summer	112		118		112	
Cumulative MW Winter	22		24		22	
Sum of Annual MWh	1,047,400	6.61%	1,069,041	6.74%	1,048,244	6.61%
Sum of Annual MW Summer	505		512		505	
Sum of Annual MW Winter	74		77		74	

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load
10-yr (2029) impacts						
Cumulative MWh	272,983	1.64%	297,029	1.78%	275,029	1.65%
Cumulative MW Summer	121		130		122	
Cumulative MW Winter	21		24		22	
Sum of Annual MWh	2,069,468	12.41%	2,099,284	12.59%	2,071,424	12.42%
Sum of Annual MW Summer	995		1,006		995	
Sum of Annual MW Winter	144		147		145	
25-yr (2044) impacts						
Cumulative MWh	272,252	1.29%	282,477	1.34%	274,320	1.32%
Cumulative MW Summer	131		136		131	
Cumulative MW Winter	18		19		18	
Sum of Annual MWh	5,525,984	26.14%	5,563,540	26.32%	5,528,274	26.15%
Sum of Annual MW Summer	2,636		2,651		2,636	
Sum of Annual MW Winter	384		387		384	

Figure 7-14, Figure 7-15, and Figure 7-16 illustrate the relative contributions to the overall residential program potential by program for the base, enhanced, and avoided energy cost sensitivity scenarios.

Figure 7-14: DEP Residential 5-Yr Cumulative Potential by Program – Base Scenario

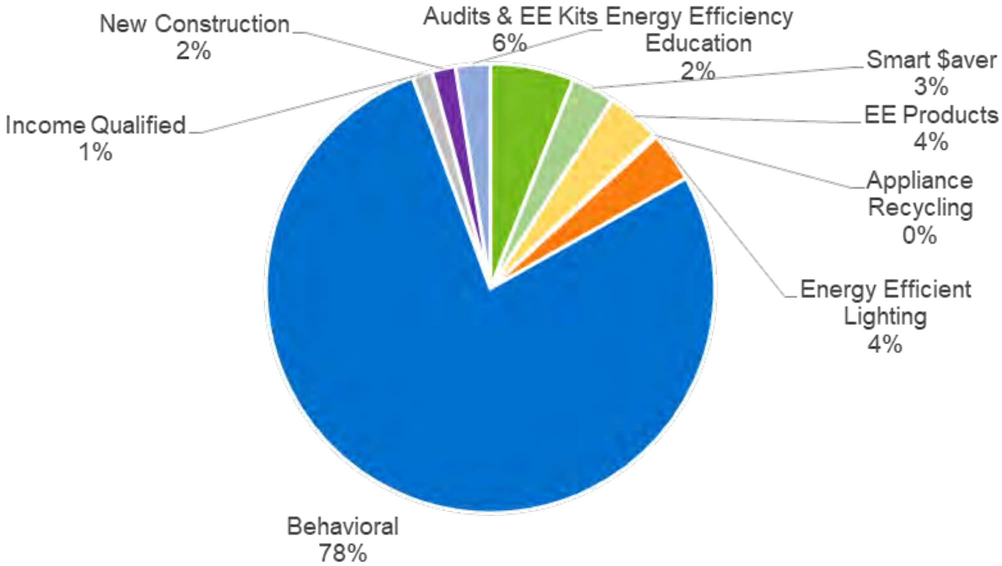


Figure 7-15: DEP Residential 5-Yr Cumulative Potential by Program – Enhanced Scenario

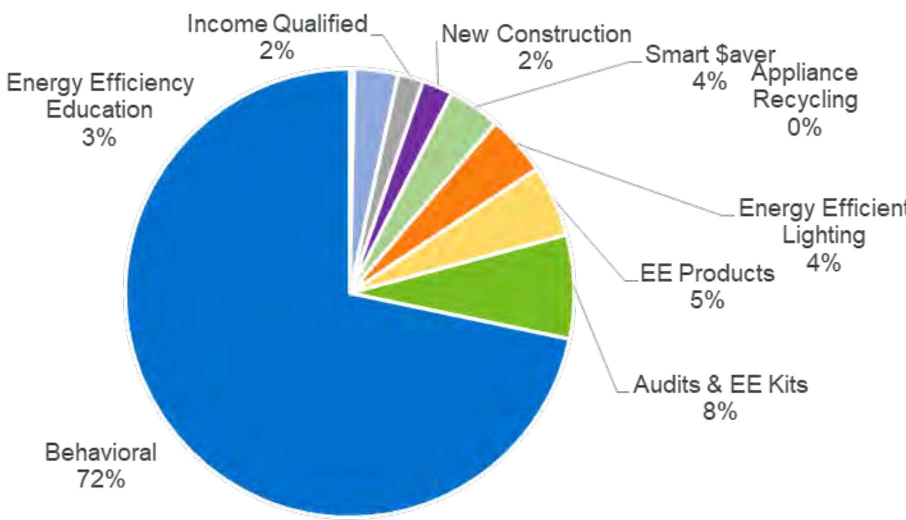
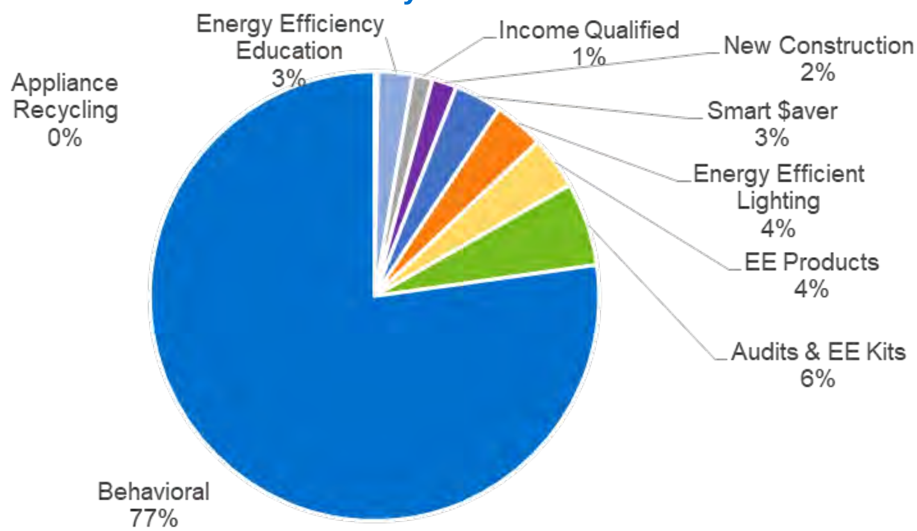


Figure 7-16: DEP Residential 5-Yr Cumulative Potential by Program – Avoided Energy Cost Sensitivity Scenario



Detailed program results for the short-term residential energy efficiency programs are provided in Table 7-17:

Table 7-17: DEP Residential Program Potential (cumulative through 2024)

	Audits & EE Kits	Smart $aver	EE Products	Appliance Recycling	Energy Efficient Lighting	Behavioral	Income Qualified	New Const.	EE. Education
5-yr (2024) impacts – Base scenario									
MWh savings (cumulative)	15,342	7,948	9,810	607	9,206	197,421	3,601	4,379	6,367
Summer MW savings (cumulative)	1.45	2.95	5.04	0.53	0.34	95.76	0.87	1.75	3.02
Winter MW savings (cumulative)	4.10	0.40	0.42	0.01	1.62	13.41	0.70	0.44	0.44
Program costs (cumulative) ($M)	$2.02	$4.20	$1.64	$0.41	$1.47	$57.91	$2.56	$1.86	$2.44
Levelized Cost ($/kWh)	$0.02	$0.10	$0.04	$0.11	$0.02	$0.07	$0.10	$0.07	$0.10
5-yr (2024) impacts – Enhanced scenario									
MWh savings (cumulative)	20,611	10,424	14,125	874	12,122	197,551	5,032	6,031	8,724
Summer MW savings (cumulative)	1.95	3.75	7.26	0.76	0.45	95.82	1.21	2.41	4.14
Winter MW savings (cumulative)	5.51	0.56	0.61	0.01	2.13	13.42	0.98	0.61	0.60
Program costs (cumulative) ($M)	$2.75	$6.49	$3.14	$0.66	$1.91	$57.92	$3.60	$2.85	$3.34
Levelized Cost ($/kWh)	$0.02	$0.10	$0.04	$0.11	$0.02	$0.07	$0.10	$0.07	$0.10

	Audits & EE Kits	Smart $aver	EE Products	Appliance Recycling	Energy Efficient Lighting	Behavioral	Income Qualified	New Const.	EE. Education
5-yr (2024) impacts – Avoided Energy Cost Sensitivity scenario									
MWh savings (cumulative)	15,341	8,703	9,784	606	9,206	197,409	3,578	4,560	6,458
Summer MW savings (cumulative)	1.45	3.01	5.03	0.53	0.34	95.75	0.87	1.83	3.07
Winter MW savings (cumulative)	4.10	0.62	0.42	0.01	1.62	13.41	0.69	0.46	0.45
Program costs (cumulative) ($M)	$2.02	$4.63	$1.64	$0.41	$1.47	$57.90	$2.54	$1.99	$2.48
Levelized Cost ($/kWh)	$0.02	$0.10	$0.04	$0.11	$0.02	$0.07	$0.10	$0.08	$0.10

Table 7-18 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-18: Cost-Benefit Results – Residential Programs (cumulative through 2024)

	Audits & EE Kits	Smart $aver	EE Products	Appliance Recycling	Energy Efficient Lighting	Behavioral	Income Qualified	New Const.	EE Education
5-yr (2024) impacts – Base scenario									
TRC – Net Benefits($M)	$3.98	-$2.48	$0.68	-$0.25	$2.59	-$1.89	-$1.01	-$0.36	-$0.90
TRC – B/C ratio	2.97	0.61	1.24	0.51	2.76	0.97	0.60	0.85	0.63
UCT – Net Benefits ($M)	$3.98	-$0.35	$1.94	-$0.15	$2.59	-$1.89	-$1.01	$0.18	-$0.90
UCT – B/C ratio	2.97	0.92	2.18	0.63	2.76	0.97	0.60	1.10	0.63
PCT – Net Benefits ($M)	$8.98	$4.36	$4.87	$0.30	$7.37	$71.34	$2.36	$2.71	$4.06
PCT – B/C ratio	N/A	3.05	4.89	3.97	N/A	N/A	N/A	6.01	N/A
RIM – Net Benefits ($M)	-$4.99	-$6.83	-$4.19	-$0.55	-$4.78	-$73.22	-$3.37	-$3.08	-$4.97
RIM – B/C ratio	0.55	0.36	0.46	0.32	0.46	0.43	0.31	0.40	0.24
5-yr (2024) impacts – Enhanced scenario									
TRC – Net Benefits($M)	$5.29	$1.38	$2.58	$0.08	$3.44	-$1.82	-$1.01	$0.93	-$1.24
TRC – B/C ratio	2.93	1.36	2.00	1.30	2.81	0.97	0.60	1.50	0.63
UCT – Net Benefits ($M)	$5.29	-$1.30	$2.01	-$0.29	$3.44	-$1.82	-$1.43	-$0.03	-$1.24
UCT – B/C ratio	2.93	0.80	1.64	0.56	2.81	0.97	0.60	0.99	0.63
PCT – Net Benefits ($M)	$12.01	$6.78	$7.79	$0.50	$9.70	$71.44	$3.30	$4.04	$5.57
PCT – B/C ratio	N/A	4.56	8.56	7.94	N/A	N/A	N/A	9.57	N/A
RIM – Net Benefits ($M)	-$6.72	-$9.99	-$6.80	-$0.86	-$6.26	-$73.26	-$4.74	-$4.55	-$6.80
RIM – B/C ratio	0.54	0.34	0.43	0.30	0.46	0.43	0.31	0.38	0.24

	Audits & EE Kits	Smart $aver	EE Products	Appliance Recycling	Energy Efficient Lighting	Behavioral	Income Qualified	New Const.	EE Education
5-yr (2024) impacts – Avoided Energy Cost Sensitivity scenario									
TRC – Net Benefits($M)	$5.57	-$1.50	$1.79	-$0.19	$2.23	$15.58	-$0.57	$0.21	$0.28
TRC – B/C ratio	3.76	0.79	1.62	0.63	2.51	1.27	0.78	1.08	1.11
UCT – Net Benefits ($M)	$5.57	$0.91	$3.03	-$0.09	$2.23	$15.58	-$0.57	$0.81	$0.28
UCT – B/C ratio	3.76	1.20	2.85	0.78	2.51	1.27	0.78	1.41	1.11
PCT – Net Benefits ($M)	$8.98	$4.51	$4.86	-$0.30	$7.37	$71.33	$2.35	$2.82	$4.12
PCT – B/C ratio	N/A	2.87	4.89	3.97	N/A	N/A	N/A	5.70	N/A
RIM – Net Benefits ($M)	-$3.40	-$6.01	$3.03	-$0.09	-$5.14	-$55.74	-$2.92	-$2.61	-$3.84
RIM – B/C ratio	0.69	0.48	2.85	0.78	0.42	0.57	0.40	0.52	0.42

7.6.3 Non-Residential Program Details

Table 7-19 summarizes the short-term (5-year), medium term (10-year) and long-term (25-year) cumulative residential energy efficiency program potential for the base, enhanced, and avoided energy cost sensitivity scenarios:

Table 7-19: DEP EE Non-Residential Program Potential

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load
5-yr (2024) impacts						
Cumulative MWh	126,502	1.37%	178,872	1.94%	146,589	1.59%
Cumulative MW Summer	16		22		20	
Cumulative MW Winter	9		13		11	
Sum of Annual MWh	128,228	1.39%	181,294	1.97%	148,337	1.61%
Sum of Annual MW Summer	17		23		21	
Sum of Annual MW Winter	10		13		11	
10-yr (2029) impacts						
Cumulative MWh	194,440	2.13%	275,136	3.02%	224,733	2.46%
Cumulative MW Summer	25		34		31	
Cumulative MW Winter	14		20		17	
Sum of Annual MWh	219,335	2.41%	310,155	3.40%	253,278	2.78%
Sum of Annual MW Summer	29		39		35	
Sum of Annual MW Winter	16		22		19	

	Base Scenario		Enhanced Scenario		Avoided Energy Cost Sensitivity	
	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load	Total Potential	% of Non-Res Load
25-yr (2044) impacts						
Cumulative MWh	116,164	1.19%	164,587	1.69%	136,311	1.40%
Cumulative MW Summer	16		22		20	
Cumulative MW Winter	8		12		9	
Sum of Annual MWh	383,997	3.94%	543,435	5.57%	443,234	4.54%
Sum of Annual MW Summer	50		69		62	
Sum of Annual MW Winter	28		38		32	

Figure 7-17, Figure 7-18, and Figure 7-19 illustrate the relative contributions to the overall non-residential program potential by program for the base, enhanced, and avoided energy cost sensitivity scenarios.

Figure 7-17: DEP Non-Residential 5-Yr Cumulative Potential by Program – Base Scenario

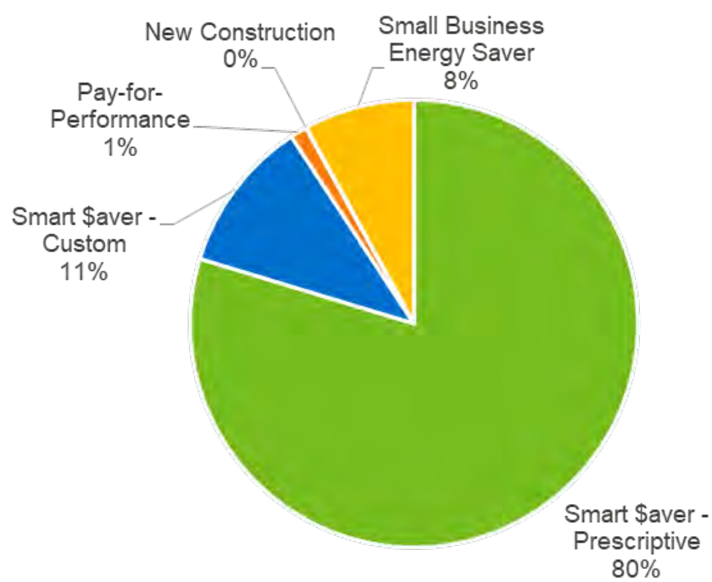


Figure 7-18: DEP Non-Residential 5-Yr Cumulative Potential by Program – Enhanced Scenario

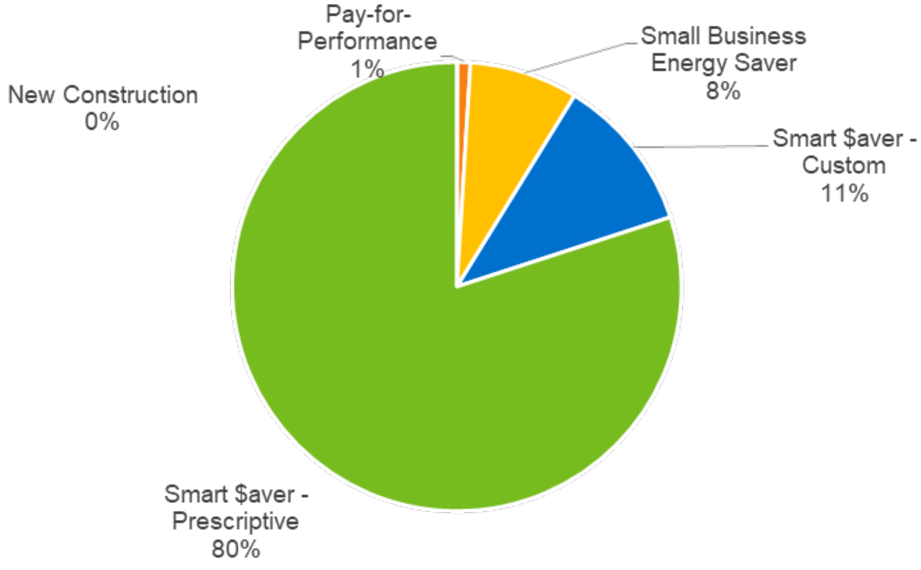
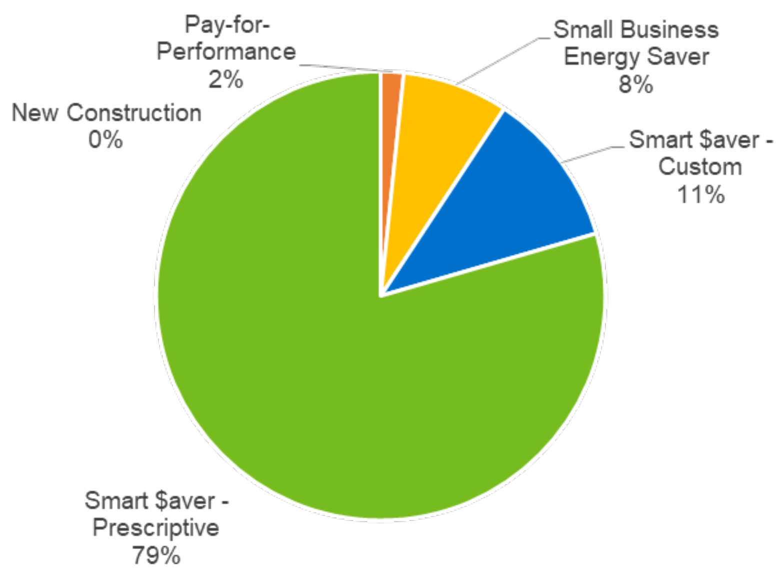


Figure 7-19: DEP Non-Residential 5-Yr Cumulative Potential by Program – Avoided Energy Cost Sensitivity Scenario



Detailed program results for the DEP short-term non-residential EE programs are provided in Table 7-20:

Table 7-20: DEP Non-Residential Program Potential (cumulative through 2024)

	Prescriptive	Custom	Pay-for-Performance	New Construction	Small Business Energy Saver
5-yr (2024) impacts – Base Scenario					
MWh savings (cumulative)	100,789	14,032	1,519	48	10,114
Summer MW savings (cumulative)	13.16	1.56	0.25	0.01	1.41
Winter MW savings (cumulative)	7.51	0.88	0.07	0.01	0.88
Program costs (cumulative) ($M)	$9.73	$1.57	$0.35	$0.00	$0.94
Levelized Cost ($/kWh)	$0.03	$0.03	$0.07	$0.02	$0.02
5-yr (2024) impacts – Enhanced Scenario					
MWh savings (cumulative)	143,128	20,035	1,663	70	13,977
Summer MW savings (cumulative)	17.91	2.22	0.27	0.01	1.87
Winter MW savings (cumulative)	10.31	1.26	0.09	0.01	1.19
Program costs (cumulative) ($M)	$21.87	$2.81	$0.44	$0.01	$1.57
Levelized Cost ($/kWh)	$0.04	$0.03	$0.06	$0.02	$0.02

	Prescriptive	Custom	Pay-for-Performance	New Construction	Small Business Energy Saver
5-yr (2024) impacts – Avoided Energy Cost Sensitivity Scenario					
MWh savings (cumulative)	116,538	16,460	2,410	2	11,178
Summer MW savings (cumulative)	16.34	2.00	0.38	0.00	1.61
Winter MW savings (cumulative)	8.85	1.06	0.07	0.00	0.94
Program costs (cumulative) ($M)	$12.76	$2.04	$0.58	$0.00	$1.19
Levelized Cost ($/kWh)	$0.03	$0.03	$0.08	$0.06	$0.02

Table 7-21 provides the net benefits and benefit-to-cost ratios by sector for each scenario:

Table 7-21: Cost-Benefit Results – Non-Residential Programs (cumulative through 2024)

	Prescriptive	Custom	Pay-for-Performance	New Construction	Small Business Energy Saver
5-yr (2024) impacts – Base Scenario					
TRC – Net Benefits($M)	$10.94	$1.22	-$0.18	$0.01	$1.57
TRC – B/C ratio	1.54	1.54	0.58	2.87	2.14
UCT – Net Benefits ($M)	$21.45	$1.92	-$0.10	-$0.01	$2.01
UCT – B/C ratio	3.2	2.23	0.72	0.58	3.13
PCT – Net Benefits ($M)	$37.55	$5.03	$0.34	$0.02	$4.24
PCT – B/C ratio	4.57	8.20	4.98	38.37	10.64
RIM – Net Benefits ($M)	-$26.61	-$3.81	-$0.52	-$0.03	-$2.67
RIM – B/C ratio	0.54	0.48	0.33	0.32	0.53
5-yr (2024) impacts – Enhanced Scenario					
TRC – Net Benefits($M)	$15.45	$1.75	-$0.18	$0.01	$2.11
TRC – B/C ratio	1.54	1.54	0.62	2.87	2.09
UCT – Net Benefits ($M)	$22.34	$2.16	-$0.14	-$0.01	$2.50
UCT – B/C ratio	2.02	1.77	0.68	0.77	2.59
PCT – Net Benefits ($M)	$61.31	$7.75	$0.44	$0.03	$6.05
PCT – B/C ratio	9.90	19.82	11.14	61.39	16.96
RIM – Net Benefits ($M)	-$45.87	-$6.00	-$0.62	-$0.04	-$3.93
RIM – B/C ratio	0.49	0.45	0.32	0.36	0.51

	Prescriptive	Custom	Pay-for-Performance	New Construction	Small Business Energy Saver
5-yr (2024) impacts – Avoided Energy Cost Sensitivity Scenario					
TRC – Net Benefits($M)	$21.05	$2.34	-$0.27	$0.00	$2.55
TRC – B/C ratio	1.76	1.74	0.65	0.93	2.43
UCT – Net Benefits ($M)	$36.02	$3.46	-$0.07	-$0.02	$3.14
UCT – B/C ratio	3.82	2.70	0.87	0.05	3.63
PCT – Net Benefits ($M)	$41.79	$5.44	$0.42	$0.00	$4.56
PCT – B/C ratio	3.79	5.87	3.16	6.33	8.71
RIM – Net Benefits ($M)	-$20.74	-$3.10	-$0.69	-$0.02	-$2.00
RIM – B/C ratio	0.70	0.64	0.42	0.04	0.68

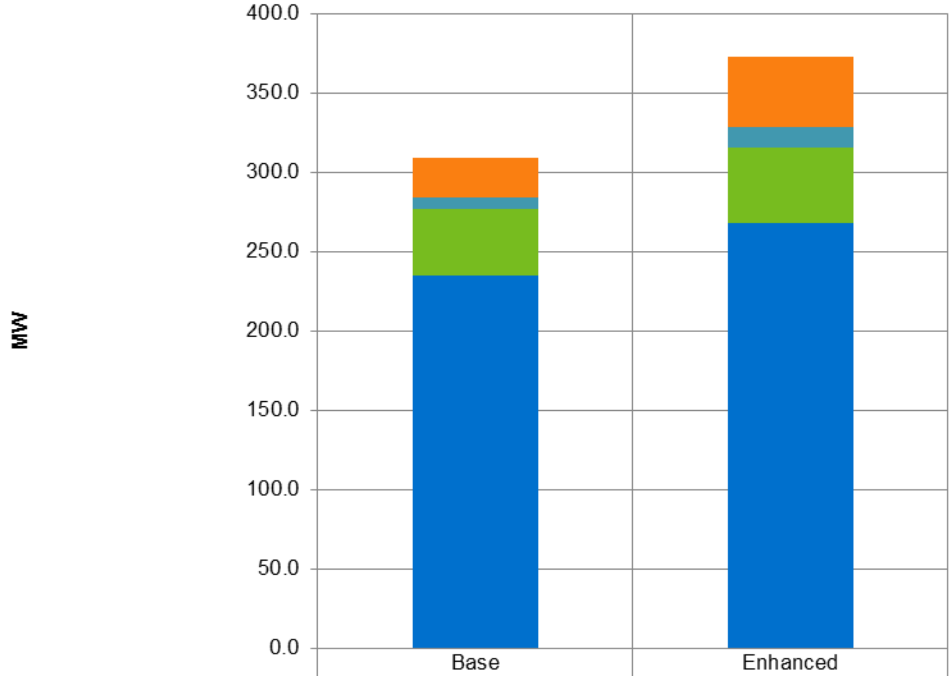
7.7 DEC DSM Program Potential

This section presents the estimated overall potential for the base, enhanced and avoided cost sensitivity scenarios. The results are provided separately for summer and winter peaking capacity. The results are further broken down by customer segment. All results presented reflect the projected achievable DSM potential by 2044.

7.7.1 DEC Summer Peaking Capacity

Figure 7-20 presents the overall summer peak capacity results for each scenario, broken down by customer class. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity ranges from 309 MW to 373 MW across the three scenarios considered. The base scenario equates to 1.7% of Duke North Carolina's summer peak load. The bulk of the capacity is coming from residential customers. Variation in the peak capacity across the various scenarios can be attributed to differences in incentive levels. DSM is not affected by the avoided energy cost sensitivity scenario.

Figure 7-20 DEC DSM Summer Peak Capacity Program Potential



	Base	Enhanced
Large C&I - 1 MW and Up	24.5	44.8
Small and Medium Business	7.3	12.8
Residential Multi-Family	41.9	48.0
Residential Single Family	235.0	267.4

Because the achievable potential is driven by marketing intensity, incentive levels, and technology costs, it is possible to yield non-linear changes in participation level. This can be seen in the program participation results in Table 7-22 DEC DSM Program Participation Rates by Scenario and Customer Class.

Table 7-22 DEC DSM Program Participation Rates by Scenario and Customer Class

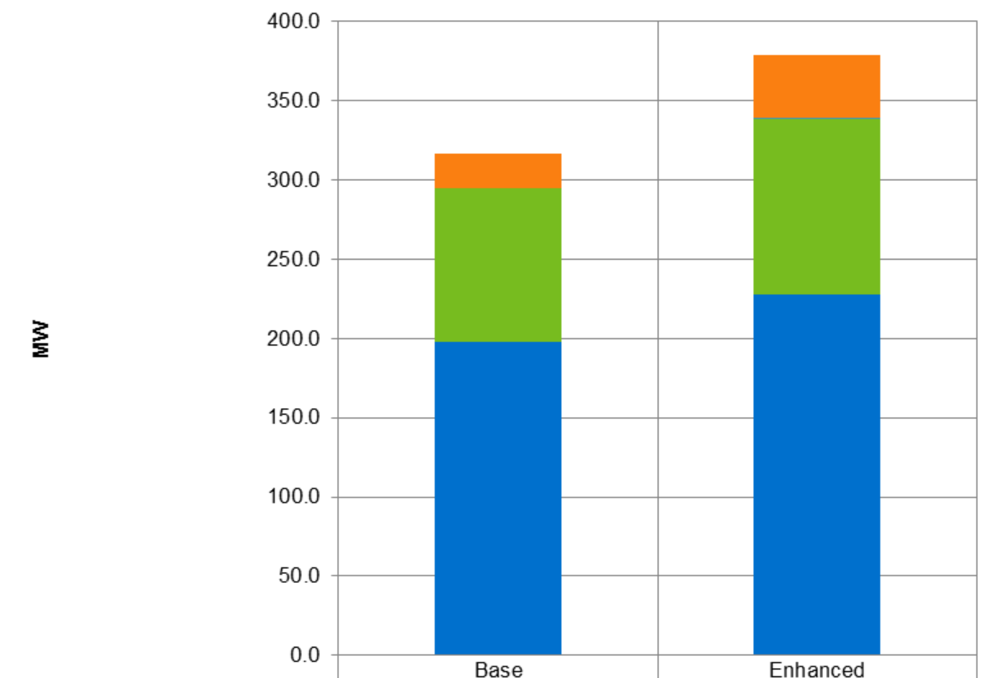
Customer Class	Base		Enhanced		Avoided Cost		Units
	Summer	Winter	Summer	Winter	Summer	Winter	
Residential Single Family	8.4%	7.0%	11.6%	9.2%	8.4%	7.0%	% of Customers
Residential Multi-Family	8.4%	7.0%	10.4%	10.3%	8.4%	7.0%	% of Customers
Small and Medium Business	1.8%	0.1%	3.8%	0.2%	1.8%	0.1%	% of Customers
Large C&I - 1 MW and Up	9.2%	9.2%	19.6%	19.6%	9.2%	9.2%	% of Load

7.7.2 DEC Winter Peaking Capacity

Figure 7-21 presents the overall winter peak capacity results for each scenario, broken down by customer class. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity ranges from 316 MW to 378 MW across the three scenarios considered. The base scenario equates to 1.6% of Duke North

Carolina's winter peak load. The bulk of the capacity is coming from residential customers. Variation in the peak capacity across the various scenarios can be attributed to differences in incentive levels. DSM is not affected by the avoided energy cost sensitivity scenario.

Figure 7-21 DEC DSM Winter Peak Capacity Program Potential



	Base	Enhanced
Large C&I - 1 MW and Up	21.6	39.5
Small and Medium Business	0.4	0.8
Residential Multi-Family	96.6	110.7
Residential Single Family	198.1	227.6

7.7.3 Segment specific results

A total of 111 different customer segments were individually analyzed. This includes 30 segments each for residential single family and multi-family homes (60), 26 small and medium business industries, and 25 industry types for distinct large commercial and industrial customer size categories. The section presents the segment-level results, focusing on the customer segments that are most attractive to pursue, allowing for prioritization and targeted marketing of those customer segments.

These results are fairly similar across the various scenarios that were studied, with only the absolute magnitude of the results changing. For the sake of simplicity, only the results for the base scenario are presented in this section.

Table 7-23 shows residential single family customer segments, ranked in terms of the benefit/cost ratio of their achievable peak capacity. Residential customers who rank in the top decile of consumption provide the greatest benefit/cost ratio. This is not surprising since they tend to have the greatest load available for load reduction, making it possible to enroll significant capacity per marginal dollar spent on acquisition marketing, equipment, and installation costs.

Table 7-24 shows the residential multi-family customer segments; Table 7-25 and Table 7-26 show the segment specific program potential results for each C&I customer class.

Table 7-23: DEC Residential Single Family Segment Specific Program Potential

	Single Family	Summer				Winter			
	Usage bin	# of accounts	Participation	Agg. MW	Total Net Benefit per Customer	# of accounts	Participation	Agg. MW	Total Net Benefit per Customer
RS	1	93,357	11.7%	-	$0	-	11.39%	-	
	2	93,357	11.7%	11.0	$194	-	11.4%	-	
	3	93,357	8.4%	9.8	$300	-	8.2%	-	
	4	93,357	8.4%	11.3	$391	-	8.2%	-	
	5	93,357	8.4%	12.6	$473	-	8.2%	-	
	6	93,357	12.1%	19.9	$560	-	11.8%	-	
	7	93,357	12.1%	21.8	$643	-	11.8%	-	
	8	93,357	12.1%	24.0	$738	-	11.8%	-	
	9	93,357	13.1%	29.6	$882	-	12.8%	-	
	10	93,357	13.1%	41.3	$1,348	-	12.8%	-	
RE	1	46,747	8.6%	-	$0	46,747	8.38%	5.6	946.2
	2	46,747	8.6%	-	$0	46,747	8.4%	8.7	1653.0
	3	46,747	7.7%	3.8	$209	46,747	7.5%	9.2	2010.1
	4	46,747	7.7%	4.4	$280	46,747	7.5%	10.4	2297.9
	5	46,747	7.7%	4.8	$343	46,747	7.5%	11.5	2582.7
	6	46,747	7.4%	5.1	$409	46,747	7.2%	12.1	2853.9
	7	46,747	7.4%	5.6	$480	46,747	7.2%	13.3	3164.1
	8	46,747	7.4%	6.3	$572	46,747	7.2%	14.7	3542.2
	9	46,747	9.9%	9.7	$714	46,747	9.7%	22.6	4094.6
	10	46,747	9.9%	13.2	$1,085	46,747	9.7%	29.9	5525.2
RT	1	194	11.7%	0.0	$294	194	11.39%	-	0
	2	194	11.7%	0.0	$577	194	11.4%	-	0
	3	194	8.4%	0.0	$704	194	8.2%	-	0
	4	194	8.4%	0.0	$778	194	8.2%	-	0
	5	194	8.4%	0.0	$930	194	8.2%	-	0
	6	194	12.1%	0.1	$1,035	194	11.8%	-	0
	7	194	12.1%	0.1	$1,113	194	11.8%	-	0
	8	194	12.1%	0.1	$1,226	194	11.8%	-	0
	9	194	13.1%	0.1	$1,691	194	12.8%	-	0
	10	194	13.1%	0.3	$4,985	194	12.8%	-	0
Total AC/Heating Economic Potential (only included if economic)				235.0				138.1	
Additional Potential from WH and PP								60.0	
Total Potential				**235.0**				**198.1**	

Table 7-24: DEC Residential Multi-Family Segment Specific Program Potential

	Multi-family	Summer				Winter			
	Usage bin	# of accounts	Participation	Agg. MW	Total Net Benefit per Customer	# of accounts	Participation	Agg. MW	Total Net Benefit per Customer
RS	1	7,210	9.9%	-	$0	-	9.69%	-	
	2	7,210	9.9%	0.8	$224	-	9.7%	-	
	3	7,210	9.9%	1.0	$347	-	9.6%	-	
	4	7,210	9.9%	1.1	$466	-	9.6%	-	
	5	7,210	9.9%	1.3	$551	-	9.6%	-	
	6	7,210	6.6%	0.9	$646	-	6.4%	-	
	7	7,210	6.6%	1.0	$757	-	6.4%	-	
	8	7,210	6.6%	1.1	$862	-	6.4%	-	
	9	7,210	7.0%	1.4	$997	-	6.8%	-	
	10	7,210	7.0%	1.8	$1,466	-	6.8%	-	
RE	1	25,093	8.3%	-	$0	25,093	8.06%	2.9	931.4
	2	25,093	8.3%	-	$0	25,093	8.1%	4.1	1492.6
	3	25,093	9.6%	2.4	$192	25,093	9.3%	5.7	1854.4
	4	25,093	9.6%	2.8	$268	25,093	9.3%	6.5	2152.6
	5	25,093	9.6%	3.2	$336	25,093	9.3%	7.4	2493.7
	6	25,093	10.4%	3.9	$416	25,093	10.2%	9.0	2812.2
	7	25,093	10.4%	4.3	$500	25,093	10.2%	10.2	3204.3
	8	25,093	10.4%	4.9	$603	25,093	10.2%	11.4	3640.9
	9	25,093	8.0%	4.3	$740	25,093	7.7%	10.1	4282.1
	10	25,093	8.0%	5.7	$1,086	25,093	7.7%	13.6	5840.6
RT	1	-	9.9%	-	$0	-	9.69%	-	0
	2	-	9.9%	-	$0	-	9.7%	-	0
	3	-	9.9%	-	$0	-	9.6%	-	0
	4	-	9.9%	-	$0	-	9.6%	-	0
	5	-	9.9%	-	$0	-	9.6%	-	0
	6	-	6.6%	-	$0	-	6.4%	-	0
	7	-	6.6%	-	$0	-	6.4%	-	0
	8	-	6.6%	-	$0	-	6.4%	-	0
	9	-	7.0%	-	$0	-	6.8%	-	0
	10	-	7.0%	-	$0	-	6.8%	-	0
Total AC/Heating Economic Potential (only included if economic)				41.9				81.1	
Additional Potential from WH and PP								15.5	
Total Potential				**41.9**				**96.6**	

Table 7-25: DEC Small C&I Segment Specific Program Potential

SMB	Summer				Winter			
Segment	# Accounts	Participation	Agg. MW	Net Benefit per Enrollee	# Accounts	Participation	Agg. MW	Net Benefit per Enrollee
Assembly	20,352	0.49%	0.3	($2,993)	967	0.02%	0.0	($64,905)
Colleges & Universities	913	0.49%	0.0	($2,254)	76	0.02%	0.0	($51,611)
Data Centers	487	2.80%	0.1	$966	23	0.14%	0.0	$8,423
Grocery	1,519	5.44%	0.5	$1,868	685	0.27%	0.1	$24,641
Healthcare	5,759	0.55%	0.1	($2,018)	528	0.03%	0.0	($46,262)
Hospitals	414	0.49%	0.0	($2,145)	15	0.02%	0.0	($51,688)
Institutional	6,070	0.49%	0.1	($3,617)	285	0.02%	0.0	($70,057)
Lodging (Hospitality)	2,144	0.55%	0.0	($2,642)	431	0.03%	0.0	($53,902)
Miscellaneous	27,252	0.53%	-	$0	5,387	0.03%	0.0	($69,095)
Office	44,775	0.55%	0.5	($3,096)	4,424	0.03%	0.0	($60,058)
Restaurants	5,482	0.55%	0.3	$1,018	585	0.03%	0.0	($25,676)
Retail	51,273	5.44%	6.4	$321	7,094	0.27%	0.3	$5,820
Schools K-12	2,064	0.34%	0.0	($4,572)	101	0.02%	0.0	($85,126)
Warehouse	1,866	2.80%	0.1	($132)	93	0.14%	0.0	($1,803)
Agriculture & Forestry	35	2.97%	0.0	$243	35	0.15%	0.0	$10,396
Chemicals & Plastics	227	1.61%	0.0	($106)	227	0.08%	0.0	$5,301
Construction	11	2.97%	0.0	$194	11	0.15%	0.0	($3,466)
Electrical & Electronic Equipment	257	1.61%	0.0	($606)	257	0.08%	0.0	($3,713)
Lumber, Furniture, Pulp & Paper	835	1.61%	0.1	($629)	835	0.08%	0.0	($2,156)
Metal Products & Machinery	963	1.61%	0.1	($460)	963	0.08%	0.0	($641)
Misc. Manufacturing	782	1.61%	0.1	($442)	782	0.08%	0.0	($1,889)
Primary Resource Industries	-	2.97%	-	$0	-	0.15%	-	$0
Stone, Clay, Glass & Concrete	142	1.61%	0.0	($693)	142	0.08%	0.0	($3,682)
Textiles & Leather	235	1.61%	0.0	($513)	235	0.08%	0.0	($437)
Transportation Equipment	291	2.80%	0.0	($565)	291	0.14%	0.0	($3,189)
Water & Wastewater	-	2.80%	-	$0	-	0.14%	-	$0
Total			**7.3**				**0.4**	

Table 7-26: DEC Large C&I (≥1 MW) Segment Specific Program Potential

Large C&I - 1 MW and Up				Summer		Winter			
Segment	MW of Tech Potential for cost calc (max of winter and summer)	Participation	Total Cost	Agg. MW	Total Benefit	Agg. MW	Total Benefit	Total Aggregate Net Benefit	Total Net Benefit per Enrolled MW
Agriculture and Assembly	0.7	8.40%	$ 2,013.21	0.1	$ 29,668	0.1	$ 23,977	$51,631	$850,507
Chemicals and Plastics	50.2	13.68%	$ 227,451.02	6.9	$ 3,356,456	5.9	$ 2,618,200	$5,747,205	$836,803
College and University	10.0	10.68%	$ 35,461.25	1.1	$ 522,971	0.6	$ 263,922	$751,431	$702,198
Construction	0.0	13.68%	$ -	-	$ -	-	$ -	$0	$0
Data Center	17.3	8.40%	$ 48,109.81	1.5	$ 708,966	1.3	$ 573,626	$1,234,481	$850,955
Electrical and Electronic Equip.	1.6	13.68%	$ 7,118.79	0.2	$ 105,051	0.2	$ 90,558	$188,490	$876,874
Grocery	0.0	4.30%	$ -	-	$ -	-	$ -	$0	$0
Healthcare	2.2	2.94%	$ 2,160.20	0.1	$ 3,125	0.1	$ 56,936	$57,901	$894,830
Hospitals	1.8	10.68%	$ 6,543.08	0.2	$ 96,495	0.1	$ 50,065	$140,017	$709,125
Institutional	3.0	10.68%	$ 10,786.74	0.3	$ 13,099	0.3	$ 286,422	$288,734	$887,016
Lodging/Hospitality	0.0	2.94%	$ -	-	$ -	-	$ -	$0	$0
Lumber/Furniture/Pulp/Paper	17.3	13.68%	$ 78,590.99	2.3	$ 112,989	2.4	$ 2,088,135	$2,122,533	$894,408
Metal Products and Machinery	10.2	13.68%	$ 46,270.77	1.4	$ 682,810	1.2	$ 542,332	$1,178,871	$843,750
Miscellaneous	37.6	2.23%	$ 28,066.23	0.6	$ 29,941	0.8	$ 737,344	$739,219	$882,151
Miscellaneous Manufacturing	8.3	13.68%	$ 37,666.60	1.1	$ 555,840	0.9	$ 405,392	$923,565	$812,017
Office	18.9	2.94%	$ 18,489.54	0.6	$ 270,662	0.4	$ 182,458	$434,630	$784,766
Primary Resources Industries	0.0	8.40%	$ -	-	$ -	-	$ -	$0	$0
Restaurants	0.0	2.23%	$ -	-	$ -	-	$ -	$0	$0
Retail	8.1	4.30%	$ 11,638.62	0.3	$ 170,925	0.3	$ 144,909	$304,195	$869,748
Schools K-12	1.2	5.66%	$ 2,244.13	0.1	$ 33,013	0.0	$ 20,662	$51,431	$761,359
Stone/Clay/Glass/Concrete	0.8	13.68%	$ 3,827.62	0.1	$ 3,011	0.1	$ 101,698	$100,881	$872,844
Textiles and Leather	53.2	13.68%	$ 241,254.09	7.3	$ 3,560,146	6.3	$ 2,755,696	$6,074,587	$833,866
Transportation Equipment	6.5	8.40%	$ 18,221.32	0.5	$ 268,517	0.4	$ 179,754	$430,049	$782,698
Warehouse	0.0	8.40%	$ -	-	$ -	-	$ -	$0	$0
Water and Wastewater	0.0	8.40%	$ -	-	$ -	-	$ -	$0	$0
Total				**24.5**		**21.6**			

7.7.4 Key Findings

The overall DSM potential is estimated to be 309 MW of summer peak capacity in the base scenario, and is as high as 373 MW under the assumption doubling the incentive rates. In the winter, DSM capacity is estimated to be 317 MW in the base scenario and as high as 379 MW in the enhanced scenario. These estimates are based on an in-depth, bottom-up assessment of load reduction potential of all customer segments, and includes an analysis of program-based DSM.

The extent to whether these potential figures can be attained in a cost-effective manner by 2044 depends on the ability to implement programs that target all possible end-uses and cost-effective customer segments. These predictions also rely upon certain assumptions around the future value of capacity, as well as technology cost reductions.

The customer segment-level analysis of the program-based DSM potential sheds light on which customer segments can provide the greatest magnitude of capacity, as well as which customer segments are most cost-effective to pursue. Unsurprisingly, the most attractive customer segments from a benefit/cost perspective are customers who have more load available for reduction during peak hours: larger residential customers who live in single-family and multi-family homes. In general, these customers are more capable of shifting load with little inconvenience/cost, and therefore tend to have higher participation levels in DSM programs as well as greater willingness to shed a higher percentage of their load.

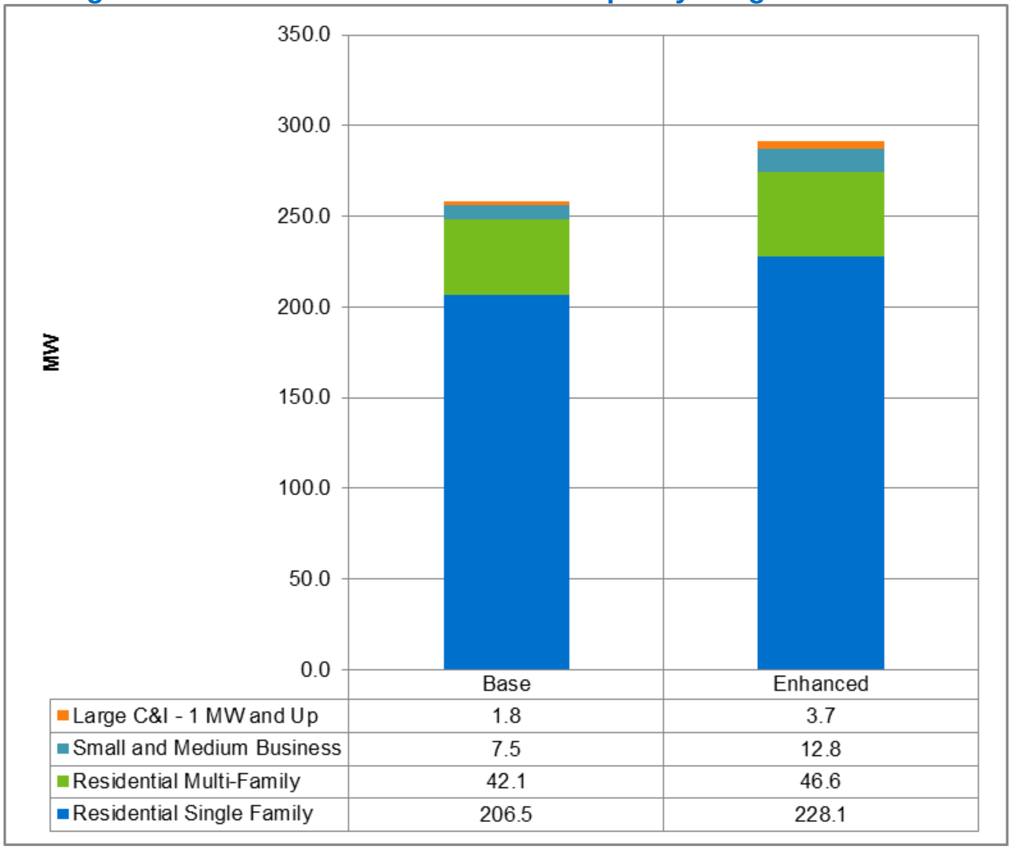
7.8 DEP DSM Program Potential

This section presents the estimated overall potential for the base, enhanced and avoided cost scenarios. The results are provided separately for summer and winter peaking capacity. The results are further broken down by customer segment. All results presented reflect the projected achievable DSM potential by 2044.

7.8.1 DEP Summer Peaking Capacity

Figure 7-22 presents the overall summer peak capacity results for each scenario, broken down by customer class. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity ranges from 258 MW to 291.2 MW across the three scenarios considered. The base scenario equates to 1.9% of Duke North Carolina’s summer peak load. The bulk of the capacity is coming from residential customers. Variation in the peak capacity across the various scenarios can be attributed to differences in incentive levels. DSM is not affected by the avoided energy cost sensitivity scenario.

Figure 7-22 DEP DSM Summer Peak Capacity Program Potential



Because the achievable potential is driven by marketing intensity, incentive levels, and technology costs, it is possible to yield non-linear changes in participation level. This can be seen in the program participation results in Table 7-22 DEC DSM Program Participation Rates by Scenario and Customer Class.

Table 7-27 DEP DSM Program Participation Rates by Scenario and Customer Class

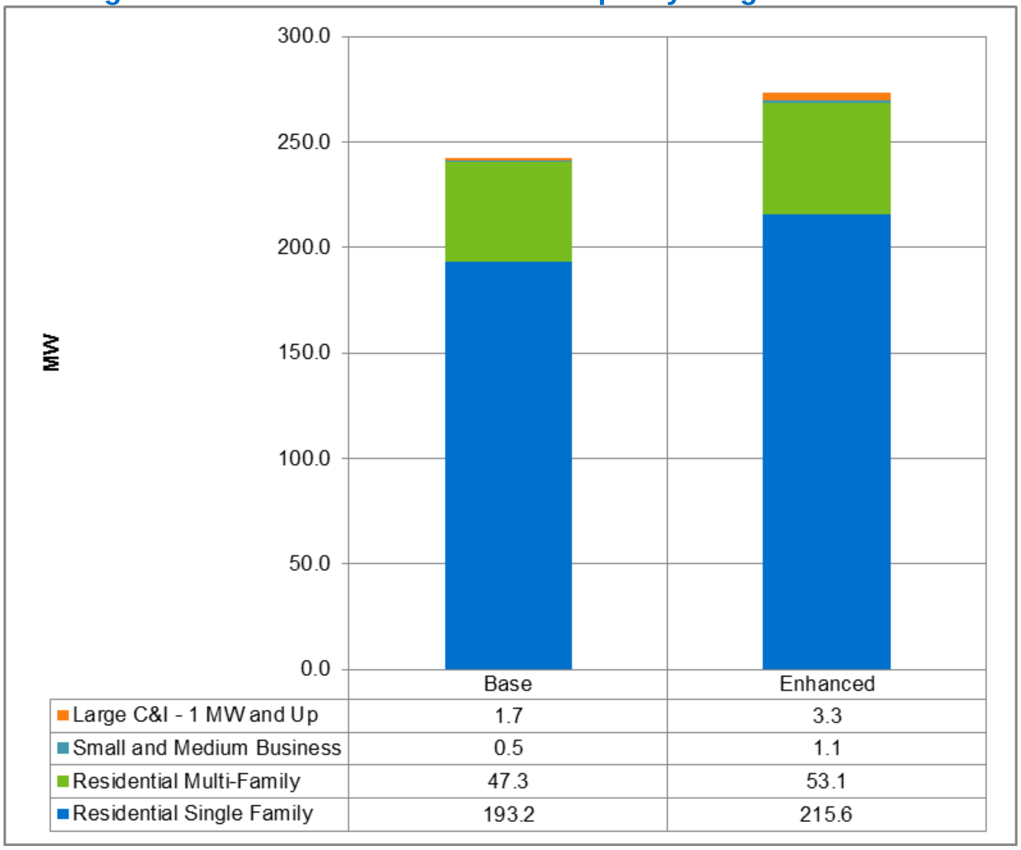
Customer Class	Base		Enhanced		Avoided Cost		Units
	Summer	Winter	Summer	Winter	Summer	Winter	
Residential Single Family	14.4%	7.0%	18.4%	9.4%	14.4%	7.0%	% of Customers
Residential Multi-Family	14.4%	7.0%	20.1%	10.4%	14.4%	7.0%	% of Customers
Small and Medium Business	1.5%	0.1%	2.7%	0.2%	1.5%	0.1%	% of Customers
Large C&I - 1 MW and Up	6.7%	6.7%	16.9%	16.9%	16.9%	6.7%	% of Load

7.8.2 DEP Winter Peaking Capacity

Figure 7-17 presents the overall winter peak capacity results for each scenario, broken down by customer class. The capacity is what is expected to be available during the peak hour of system demand. Overall, the estimated magnitude of peak capacity ranges from 243 MW to 273 MW across the three scenarios considered. The base scenario equates to 1.6% of Duke North Carolina's summer peak load. The bulk of the capacity is coming from residential customers.

Variation in the peak capacity across the various scenarios can be attributed to differences in incentive levels. DSM is not affected by the avoided energy cost sensitivity scenario.

Figure 7-23 DEP DSM Winter Peak Capacity Program Potential



	Base	Enhanced
Large C&I - 1 MW and Up	1.7	3.3
Small and Medium Business	0.5	1.1
Residential Multi-Family	47.3	53.1
Residential Single Family	193.2	215.6

7.8.3 Segment specific results

A total of 91 different customer segments were individually analyzed. This includes 10 different consumption deciles each for two different geographic regions for residential single family and multi-family homes (40), 26 different industries of small and medium businesses, and 25 industry types for large commercial and industrial customer size categories. The section presents the segment-level results, focusing on the customer segments that are most attractive to pursue, allowing for prioritization and targeted marketing of those customer segments.

These results are fairly similar across the various scenarios that were studied, with only the absolute magnitude of the results changing. For the sake of simplicity, only the results for the base scenario are presented in this section.

Table 7-28 shows residential single family customer segments, ranked in terms of the benefit/cost ratio of their achievable peak capacity. Residential customers who rank in the top decile of consumption provide the greatest benefit/cost ratio. This is not surprising since they tend to have the greatest load available for load reduction, making it possible to enroll significant capacity per marginal dollar spent on acquisition marketing, equipment, and installation costs.

Table 7-29 shows the residential multi-family customer segments; Table 7-30 and Table 7-31 show the segment specific program potential results for each C&I customer class.

Table 7-28: DEP Residential Single Family Segment Specific Program Potential

	Single Family	Summer				Winter			
	Usage bin	# of accounts	Participation	Agg. MW	Total Net Benefit per Customer	# of accounts	Participation	Agg. MW	Total Net Benefit per Customer
RES	1	102,062	17.0%	-	$0	56,013	8.48%	5.3	$521
	2	102,062	17.0%	-	$0	56,013	8.5%	8.6	$1,042
	3	102,062	15.5%	-	$0	56,013	7.6%	9.4	$1,328
	4	102,062	15.5%	-	$0	56,013	7.6%	10.7	$1,565
	5	102,062	15.5%	-	$0	56,013	7.6%	11.9	$1,773
	6	102,062	15.0%	-	$0	56,013	7.3%	12.7	$1,986
	7	102,062	15.0%	28.4	$197	56,013	7.3%	14.0	$2,223
	8	102,062	15.0%	31.8	$255	56,013	7.3%	15.4	$2,489
	9	102,062	19.1%	46.7	$343	56,013	9.8%	23.4	$2,868
	10	102,062	19.1%	64.2	$579	56,013	9.8%	30.3	$3,799
TOU	1	2,196	21.8%	-	$0	1,514	11.5%	0.4	$1,586
	2	2,196	21.8%	0.9	$231	1,514	11.5%	0.6	$2,345
	3	2,196	16.7%	0.8	$310	1,514	8.3%	0.5	$2,769
	4	2,196	16.7%	0.9	$389	1,514	8.3%	0.6	$3,118
	5	2,196	16.7%	1.0	$454	1,514	8.3%	0.6	$3,496
	6	2,196	22.4%	1.6	$541	1,514	11.9%	1.0	$3,849
	7	2,196	22.4%	1.7	$626	1,514	11.9%	1.1	$4,262
	8	2,196	22.4%	1.9	$731	1,514	11.9%	1.2	$4,755
	9	2,196	23.9%	2.4	$919	1,514	12.9%	1.5	$5,524
	10	2,196	23.9%	3.6	$1,523	1,514	12.9%	2.2	$7,876
Total AC/Heating Economic Potential (only included if economic)				186.1				151.6	
Additional Potential from WH and PP				20.4				41.6	
Total Potential				**206.5**				**193.2**	

Table 7-29: DEP Residential Multi-Family Segment Specific Program Potential

Multi-family		Summer				Winter			
	Usage bin	# of accounts	Participation	Agg. MW	Total Net Benefit per Customer	# of accounts	Participation	Agg. MW	Total Net Benefit per Customer
RES	1	16,829	16.5%	-	$0	14,583	8.15%	1.3	$505
	2	16,829	16.5%	-	$0	14,583	8.2%	1.9	$909
	3	16,829	18.5%	-	$0	14,583	9.4%	2.7	$1,176
	4	16,829	18.5%	-	$0	14,583	9.4%	3.2	$1,400
	5	16,829	18.5%	-	$0	14,583	9.4%	3.6	$1,645
	6	16,829	19.9%	6.3	$208	14,583	10.3%	4.4	$1,891
	7	16,829	19.9%	7.1	$273	14,583	10.3%	5.0	$2,182
	8	16,829	19.9%	8.0	$345	14,583	10.3%	5.8	$2,556
	9	16,829	15.9%	7.6	$451	14,583	7.8%	5.2	$3,083
	10	16,829	15.9%	10.2	$708	14,583	7.8%	7.2	$4,355
TOU	1	26	19.1%	-	$0	21	9.8%	0.0	$847
	2	26	19.1%	0.0	$220	21	9.8%	0.0	$986
	3	26	19.0%	0.0	$211	21	9.8%	0.0	$2,370
	4	26	19.0%	0.0	$370	21	9.8%	0.0	$3,007
	5	26	19.0%	0.0	$525	21	9.8%	0.0	$2,896
	6	26	13.6%	0.0	$754	21	6.5%	0.0	$3,509
	7	26	13.6%	0.0	$469	21	6.5%	0.0	$5,247
	8	26	13.6%	0.0	$824	21	6.5%	0.0	$4,993
	9	26	14.3%	0.0	$718	21	6.9%	0.0	$7,527
	10	26	14.3%	0.0	$1,730	21	6.9%	0.0	$8,115
Total AC/Heating Economic Potential (only included if economic)				39.4				40.5	
Additional Potential from WH and PP				2.7				6.7	
Total Potential				**42.1**				**47.3**	

Table 7-30: DEP Small C&I Segment Specific Program Potential

SMB	Summer				Winter			
Segment	# Accounts	Participation	Agg. MW	Net Benefit per Enrollee	# Accounts	Participation	Agg. MW	Net Benefit per Enrollee
Assembly	13,486	0.33%	0.2	($5,232)	640	0.02%	0.0	($98,260)
Colleges & Universities	528	0.33%	0.0	($3,980)	44	0.02%	0.0	($81,720)
Data Centers	250	2.33%	0.0	($369)	12	0.12%	0.0	($91)
Grocery	1,179	5.02%	0.7	$1,339	531	0.25%	0.1	$28,671
Healthcare	5,208	0.38%	0.2	($3,896)	478	0.02%	0.0	($70,174)
Hospitals	486	0.33%	0.0	($3,067)	18	0.02%	0.0	($82,675)
Institutional	8,989	0.33%	0.1	($5,568)	423	0.02%	0.0	($104,611)
Lodging (Hospitality)	3,933	0.38%	0.1	($4,628)	790	0.02%	0.0	($84,581)
Miscellaneous	11,816	0.36%	0.1	($5,146)	2,336	0.02%	0.0	($95,970)
Office	59,406	0.38%	0.7	($4,980)	5,870	0.02%	0.0	($89,411)
Restaurants	5,579	0.38%	0.3	($2,243)	595	0.02%	0.0	($63,802)
Retail	27,099	5.02%	5.8	$199	3,750	0.25%	0.3	$11,440
Schools K-12	2,478	0.22%	0.1	($5,944)	121	0.01%	0.0	($133,322)
Warehouse	1,640	2.33%	0.1	($406)	82	0.12%	0.0	($1,269)
Agriculture & Forestry	39	2.49%	0.0	($984)	39	0.12%	0.0	$40,268
Chemicals & Plastics	156	1.25%	0.1	$7,303	156	0.06%	0.0	$125,766
Construction	56	2.49%	0.0	$2,794	56	0.12%	0.0	$73,491
Electrical & Electronic Equipn	29	1.25%	0.0	$2,996	29	0.06%	0.0	$118,269
Lumber, Furniture, Pulp & Par	351	1.25%	0.2	$3,945	351	0.06%	0.0	$117,418
Metal Products & Machinery	296	1.25%	0.2	$5,866	296	0.06%	0.0	$131,348
Misc. Manufacturing	229	1.25%	0.1	$1,828	229	0.06%	0.0	$51,305
Primary Resource Industries	54	2.49%	0.2	$0	54	0.12%	0.0	$0
Stone, Clay, Glass & Concrete	216	1.25%	0.1	$3,933	216	0.06%	0.0	$85,928
Textiles & Leather	146	1.25%	0.1	$992	146	0.06%	0.0	$51,470
Transportation Equipment	40	2.33%	0.1	$4,955	40	0.12%	0.0	$146,562
Water & Wastewater	16	2.33%	0.0	$0	16	0.12%	0.0	$0
Total			**7.5**				**0.5**	

Table 7-31: DEP Large C&I (300-500 kW) Segment Specific Program Potential

Large C&I - 1 MW and Up			Summer		Winter			
Segment	MW of Tech Potential for cost calc (max of winter	Participation	Agg. MW	Total Benefit	Agg. MW	Total Benefit	Total Aggregate Net Benefit	Total Net Benefit per Enrolled MW
Agriculture and Assembly	1.1	5.71%	0.1	$ 16,717	0.0	$ 20,688	$34,899	$545,999
Chemicals and Plastics	0.0	9.76%	-	$ -	-	$ -	$0	$0
College and University	0.0	7.43%	-	$ -	-	$ -	$0	$0
Construction	0.0	9.76%	-	$ -	-	$ -	$0	$0
Data Center	1.4	5.71%	0.1	$ 21,023	0.1	$ 30,721	$48,592	$604,521
Equip.	2.0	9.76%	0.1	$ -	0.2	$ 144,383	$136,731	$699,550
Grocery	0.0	2.76%	-	$ -	-	$ -	$0	$0
Healthcare	0.0	1.83%	-	$ -	-	$ -	$0	$0
Hospitals	0.0	7.43%	-	$ -	-	$ -	$0	$0
Institutional	9.3	7.43%	0.7	$ 180,263	0.6	$ 288,914	$442,175	$641,557
Lodging/Hospitality	0.0	1.83%	-	$ -	-	$ -	$0	$0
Lumber/Furniture/Pulp/Paper	0.0	9.76%	-	$ -	-	$ -	$0	$0
Machinery	4.5	9.76%	0.4	$ 114,880	0.3	$ 154,847	$252,532	$574,940
Miscellaneous	0.0	1.36%	-	$ -	-	$ -	$0	$0
Miscellaneous Manufacturing	3.0	9.76%	0.2	$ -	0.3	$ 215,161	$203,759	$699,550
Office	3.4	1.83%	0.1	$ -	0.1	$ 45,305	$42,877	$699,105
Primary Resources Industries	0.0	5.71%	-	$ -	-	$ -	$0	$0
Restaurants	0.0	1.36%	-	$ -	-	$ -	$0	$0
Retail	4.0	2.76%	0.1	$ 29,033	0.1	$ 34,339	$58,997	$531,493
Schools K-12	0.0	3.71%	-	$ -	-	$ -	$0	$0
Stone/Clay/Glass/Concrete	0.0	9.76%	-	$ -	-	$ -	$0	$0
Textiles and Leather	0.0	9.76%	-	$ -	-	$ -	$0	$0
Transportation Equipment	0.0	5.71%	-	$ -	-	$ -	$0	$0
Warehouse	0.0	5.71%	-	$ -	-	$ -	$0	$0
Water and Wastewater	0.0	5.71%	-	$ -	-	$ -	$0	$0
Total			**1.8**		**1.7**			

7.8.4 Key Findings

The overall DSM potential is estimated to be 258 MW of summer peak capacity in the base scenario, and is as high as 291 MW under the assumption of incentive levels double that of existing incentives. In the winter, DSM potential is estimated to be 243 MW of capacity in the base scenario and 273 MW in the enhanced scenario. These estimates are based on an in-depth, bottom-up assessment of load reduction potential of all customer segments, and includes an analysis of program-based DSM.

The extent to whether these potential figures can be attained in a cost-effective manner by 2044 depends on the ability to implement programs that target all possible end-uses and cost-effective customer segments. These predictions also rely upon certain assumptions around the future value of capacity, as well as technology cost reductions.

The customer segment-level analysis of the program-based DSM potential sheds light on which customer segments can provide the greatest magnitude of capacity, as well as which customer segments are most cost-effective to pursue. Unsurprisingly, the most attractive customer segments from a benefit/cost perspective are customers who have more load available for reduction during peak hours: larger residential customers who live in single-family and multi-family homes. In general, these customers are more capable of shifting load with little inconvenience/cost, and therefore tend to have higher participation levels in DSM programs as well as greater willingness to shed a higher percentage of their load.

8 Appendices

Appendix A Glossary

Within the body of this report, there are several technical terms that require explanation. Additionally, some of the terms may appear to be similar at first review; however, have very different means. Terms such as “reported” and “verified” can easily be confused by the reader and are thus defined as following:

Baseline: Conditions as they exist at the time the study is performed. This includes estimates and forecasts of sales as they exist today; likewise, estimates of currently-installed EE and DSM technology efficiency.

Free-rider: A program participant who would have acquired in the energy efficiency measure in the absence of a program.

Gross Savings: Total amount of a parameter of interest (kWh or kW) saved by a project/program.

Levelized Cost: The cost of the energy efficiency investment on a per kilowatt hour basis levelized over the life of the program.

Net Savings: Total amount of a parameter of interest (kWh, kW) saved by a program that is directly related to the program. It takes into account the realization rate, as well as results of the attribution analysis (free-riders), to provide a value of energy savings directly related to the program influence. Net Savings is calculated by multiplying the gross verified savings by the net-to-gross (NTG) ratio.

Participant Cost: The cost to the participant to participate in an energy efficiency program.

Program: A group of projects with similar technology characteristics that are installed in similar applications.

Turnover: A DSM measure is not implemented until the existing technology it is replacing fails or burns out. An example would be a unitary air conditioning rooftop unit being purchased after the failure of the existing rooftop unit at the end of its useful life.

Appendix B MPS Measure List

For information on how Nexant developed this list, please see Section 4.

B.1 Residential Measures

Residential Measures	
1.5 GPM Bathroom Faucet Aerators	Energy Star Qualified Airtight Can Lights
1.5 GPM Kitchen Faucet Aerators	Energy Star Qualified LED, Recessed Lighting
1.60 GPM Low-Flow Showerhead	Energy Star Refrigerator
Air Sealing	Energy Star Room AC - 12 SEER
Air Source Heat Pump Maintenance	Energy Star Set-Top Receiver
ASHP from Electric Resistance	Energy Star Television
ASHP, 2 Tons, 18 SEER, 9.5 HSPF	Energy Star Windows
Basement or Crawlspace Wall Insulation R-15	Exterior Wall Insulation on Wall Above Grade R-13
Behavior Modification Home Energy Reports	Floor Insulation R-30
Behavior Modification Home Energy Reports - Active Engagement	Freezer Recycling
CEE Tier 2 Clothes Washer	Green Roof
Ceiling Insulation R-49	Heat Pump Clothes Dryer
Central AC Maintenance	Heat Pump Pool Heater
Dehumidifier Recycling	Heat Pump Water Heater 50 Gallons
Drain Water Heat Recovery	Heat Pump Water Heater 80 Gallons
Dual Speed Pool Pump Motors	High Efficiency Bathroom Exhaust Fan
Duct Insulation	Holiday Lights
Duct Sealing	Home Energy Management System
Ductless Mini-Split HP, 2 Tons 15 SEER, 9 HSPF	Hot Water Pipe Insulation
ECM Motor	Indoor Daylight Sensor
Electric Vehicle Supply Equipment (EVSE)	Insulating Tank Wrap on Water Heater
Energy Efficiency Education in Schools	LED Nightlight
Energy Star Air Purifier	Occupancy Sensors, Switch Mounted
Energy Star ASHP, 2 Tons, 15 SEER, 8.5 HSPF	Outdoor Lighting Timer
Energy Star ASHP, 2 Tons, 16 SEER, 9.0 HSPF	Outdoor Motion Sensor
Energy Star Ceiling Fan	Pre-Pay Program
Energy Star Central AC - 15 SEER	Programmable Thermostat
Energy Star Central AC - 16 SEER	Properly Sized CAC
Energy Star Central AC - 18 SEER	RealTime Information Monitoring
Energy Star Central AC - 20 SEER	Refrigerator Recycling
Energy Star Clothes Dryer	Residential New Construction Tier 1 (10% more efficient)
Energy Star Clothes Washer	Residential New Construction Tier 2 (20% more efficient)

Energy Star Dehumidifier	Residential New Construction Tier 3 (30% more efficient)
Energy Star Desktop Computer	Residential Whole House Fan
Energy Star Dishwasher	Room AC Recycling
Energy Star Doors	Smart Strip Entertainment
Energy Star DVD Blu-Ray Player	Smart Strip Home Office
Energy Star GSHP, 2 Tons, 17.1 SEER, 3.60 COP	Smart Thermostat
Energy Star LED, 13 W	Solar Attic Fan
Energy Star LED, 19 W	Solar Thermal Water Heating System
Energy Star LED, 6 W	Thermostatic Shower Restriction Valve
Energy Star LED, 9 W	Variable Speed Pool Pump Motors
Energy Star Manufactured Home	Water Heater Thermostat Setback
Energy Star Monitor	Window Shade Film

B.2 Commercial Measures

Commercial Measures	
Business Energy Report	HE DX 11.25-20.0 Tons Other Heat
Energy Star LED Lamp, 13W	HE DX 5.4-11.25 Tons Elect Heat
1.5 GPM Faucet Aerators	HE DX 5.4-11.25 Tons Other Heat
1.5HP Open Drip-Proof(ODP) Motor	HE DX Less than 5.4 Tons Elect Heat
1.75 GPM Low-Flow Showerhead	HE DX Less than 5.4 Tons Other Heat
10HP Open Drip-Proof(ODP) Motor	HE Water Cooled Chiller - Centrifugal Compressor - 200 Tons
20HP Open Drip-Proof(ODP) Motor	HE Water Cooled Chiller - Centrifugal Compressor - 500 Tons
2x4 LED Troffer	HE Water Cooled Chiller - Rotary or Screw Compressor - 175 Tons
4' 4-Lamp High Bay T5 Fixture (28W)	HE Water Cooled Chiller - Rotary or Screw Compressor - 50 Tons
Advanced Rooftop Controller	Heat Pump Water Heater 50 Gallons
Air Compressor Optimization	High Efficiency Air Compressor
Anti-Sweat Heater Controls (Cooler)	High Efficiency CRAC Unit
Auto Closer on Refrigerator Door	High Efficiency Refrigeration Compressor - Discus
Auto Off Time Switch	High Efficiency Refrigeration Compressor - Scroll
Beverage Vending Machine Controls	High Performance Medium Bay T8 Fixture
Bi-Level Lighting Control	High Speed Fans
Business Energy Report - Active Engagement	Hot Water Pipe Insulation
Ceiling Insulation R40	Hotel Key Card Room Energy Control System
Chilled Water Reset	Indoor Daylight Sensor
CO Sensors for Parking Garage Exhaust	Induction High Bay Lighting
Data Center Server Consolidation	Insulating Tank Wrap on Water Heater
Demand Controlled Circulating Systems	LED Canopy Lighting (Exterior)
Demand Controlled Ventilation	LED Display Lighting
Demand Defrost	LED Exit Sign
Door Gasket (Cooler)	LED Exterior Wall Packs
Door Gasket (Freezer)	LED High Bay
Drain Water Heat Recovery	LED Linear - Lamp Replacement
Dual Entropy Economizer	LEED New Construction Whole Building
Ductless Mini-Split AC, 4 Ton, 16 SEER	Light Tube
Ductless Mini-Split HP, 4 Ton, 16 SEER, 9 HSPF	Lighting Energy Management System
DX Coil Cleaning	Low-Flow Pre-Rinse Sprayers
Efficient New Construction Lighting	Network PC Power Management
Electric Resistance Water Heater	Occupancy Sensors, Ceiling Mounted
Energy Recovery Ventilation System	Occupancy Sensors, Switch Mounted
Energy Star Combination Oven	Outdoor Motion Sensor
Energy Star Commercial Clothes Washer	Packaged Terminal AC
Energy Star Convection Oven	Packaged Terminal HP

Energy Star Copiers	Photocell Dimming Control (Exterior)
Energy Star Dishwasher	Photocell Dimming Control (Interior)
Energy Star Fax	Programmable Thermostat
Energy Star Fryer	PSC to ECM Evaporator Fan Motor (Reach-In)
Energy Star Glass-Door Freezer	PSC to ECM Evaporator Fan Motor (Walk-In, Refrigerator)
Energy Star Glass-Door Refrigerator	RealTime Information Monitoring
Energy Star Griddle	Reduced Wattage (25W) T8 Fixture
Energy Star Hot Food Holding Cabinet	Reduced Wattage (28W) T8 Fixture
Energy Star Ice Machines (Self Contained Units)	Reduced Wattage (28W) T8 Relamping
Energy Star LED Lamp, 9W	Reflective Roof Treatment
Energy Star Monitors	Refrigerated Display Case LED Lighting
Energy Star PCs-Desktop	Refrigerated Display Case Lighting Controls
Energy Star Printers	Refrigeration Commissioning
Energy Star Qualified LED Shelf-Mounted Task Lighting	Retro-Commissioning (Existing Construction)
Energy Star Qualified LED, Recessed Lighting	Small Buildings Retro-Commissioning
Energy Star Room AC - 12 SEER	Smart Strip Plug Outlet
Energy Star Scanners	Smart Thermostat
Energy Star Servers	Solar Thermal Water Heating System
Energy Star Solid-Door Freezer	Solid State Cooking Hood Controls
Energy Star Solid-Door Refrigerator	SP to ECM Evaporator Fan Motor (Walk-In, Refrigerator)
Energy Star Steamer	Strip Curtains - Freezers
Energy Star Uninterruptable Power Supply	Strip Curtains - Refrigerators
Energy Star Vending Machine	Suction Pipe Insulation - Freezers
Energy Star Water Coolers	Suction Pipe Insulation - Refrigerators
Energy Star Windows	Time Clock Control
Escalator Motor Efficiency Controller	VAV System
Exterior Bi-Level Lighting Control	Vertical Night Covers
Facility Commissioning	VFD on Chilled Water Pumps
Facility Energy Management System	VFD on HVAC Fan
Fan Thermostat Controller	VFD on HVAC Pump
Floating Head Pressure Controller	VSD Controlled Compressor
Green Roof	Water Heater Setback
HE Air Cooled Chiller - All Compressor Types - 100 Tons	Water Source Heat Pump
HE DX 11.25-20.0 Tons Elect Heat	Window Shade Film

B.3 Industrial Measures

Industrial Measures	
1.5HP Open Drip-Proof(ODP) Motor	High Bay Occupancy Sensors, Ceiling Mounted
10HP Open Drip-Proof(ODP) Motor	High Efficiency Refrigeration Compressor - Discus
20HP Open Drip-Proof(ODP) Motor	High Efficiency Refrigeration Compressor - Scroll
2x4 LED Troffer	High Efficiency Welder
3-phase High Frequency Battery Charger - 1 shift	High Performance Medium Bay T8 Fixture
4' 4-Lamp High Bay T5 Fixture (28W)	High Speed Fans
Air Compressor Optimization	High Volume Low Speed Fan (HVLS)
Auto Closer on Refrigerator Door	Indoor Daylight Sensor
Auto Off Time Switch	Induction High Bay Lighting
Bi-Level Lighting Control	Injection Mold and Extruder Barrel Wraps
Ceiling Insulation R40	Insulated Pellet Dryer Tanks and Ducts
Chilled Water Reset	LED Canopy Lighting (Exterior)
Cogged Belt on 15HP ODP Motor	LED Exit Sign
Cogged Belt on 40HP ODP Motor	LED Exterior Wall Packs
Compressed Air Storage Tank	LED Display Lighting
Demand Controlled Ventilation	LEED New Construction Whole Building
Demand Defrost	LED Linear - Lamp Replacement
Dew Point Sensor Control for Desicant CA Dryer	Low Energy Livestock Waterer
Drip Irrigation Nozzles	Low Pressure Sprinkler Nozzles
Dual Entropy Economizer	Low Pressure-drop Filters
DX Coil Cleaning	Occupancy Sensors, Ceiling Mounted
Efficient Compressed Air Nozzles	Outdoor Motion Sensor
Efficient New Construction Lighting	Packaged Terminal AC
Electric Actuators	Photocell Dimming Control (Exterior)
Energy Efficient Laboratory Fume Hood	Photocell Dimming Control (Interior)
Energy Efficient Transformers	Process Cooling Ventilation Reduction
Energy Recovery Ventilation System	Programmable Thermostat
Energy Star LED Lamp, 13W	Reduced Wattage (25W) T8 Fixture
Energy Star Qualified LED Shelf-Mounted Task Lighting	Reduced Wattage (28W) T8 Fixture
Energy Star Qualified LED, Recessed Lighting	Reduced Wattage (28W) T8 Relamping
Energy Star Room AC - 12 SEER	Reflective Roof Treatment
Energy Star Windows	Refrigeration Commissioning
Exterior Bi-Level Lighting Control	Retro-Commissioning
Facility Commissioning	Small Buildings Retro-Commissioning
Facility Energy Management System	Smart Thermostat
Fan Thermostat Controller	Synchronous Belt on 15HP ODP Motor
Floating Head Pressure Controller	Synchronous Belt on 5HP ODP Motor
Grain Bin Aeration Control System	Synchronous Belt on 75HP ODP Motor

HE Air Cooled Chiller - All Compressor Types - 100 Tons	Time Clock Control
HE Air Cooled Chiller - All Compressor Types - 300 Tons	VAV System
HE DX 11.25-20.0 Tons Elect Heat	VFD on Air Compressor
HE DX 11.25-20.0 Tons Other Heat	VFD on Chilled Water Pumps
HE DX 5.4-11.25 Tons Elect Heat	VFD on HVAC Fan
HE DX 5.4-11.25 Tons Other Heat	VFD on HVAC Pump
HE DX Less than 5.4 Tons Elect Heat	VFD on Process Pump
HE DX Less than 5.4 Tons Other Heat	VSD Controlled Compressor
HE Water Cooled Chiller - Centrifugal Compressor - 200 Tons	Water Source Heat Pump
HE Water Cooled Chiller - Centrifugal Compressor - 500 Tons	Window Shade Film
HE Water Cooled Chiller - Rotary or Screw Compressor - 175 Tons	LED High Bay
HE Water Cooled Chiller - Rotary or Screw Compressor - 50 Tons	

Appendix C Customer Demand Characteristics

Customer demand on peak days was analyzed by rate classes within each sector. Outputs presentation includes load shapes on peak days and average days, along with the estimates of technical potential by end uses. The two end uses, Air Conditioning and Heating, were studied for both residential and large C&I customers; however, in residential sector, another two end uses were also incorporated into the analyses, which are Water Heaters and Pool Pumps.

Residential

Air Conditioning

The cooling load shapes on the summer peak weekday and average weekdays were generated from hourly load research sample in North Carolina Service territories for the years 2013 and 2014. A regression model was built to estimate relationship between load values and cooling degree days (CDD) (shown as *Equation (1)*). The p-values of the model and coefficient are both less than 0.05, which means that they are of statistically significance. The product of actual hourly CDD values and coefficient would be used as cooling load during that hour in terms of per customer.

Equation (1):

$$Load_t = CDD_t * \beta_1 + i.month + \varepsilon$$

Where:

t	Hours in each day in year 2018
$Load_t$	Load occurred in each hour
CDD_t	Cooling Degree Day value associated with each hour
β_1	Change in average load per CDD
$i.month$	Nominal variable, month
ε	The error term

To study the peak technical potential, a peak day was selected if it has the hour with system peak load during summer period (among April to October). Technical potential for residential customers was then calculated as the aggregate consumption during that summer peak hour.

The Figure 8-1 and Figure 8-2 displays the comparison of cooling load shape on summer peak weekday and average weekdays in NC DEC and DEP territories. By comparing these two load shapes in the Figure 8-1, peak hours in DEC territory could be identified as around 4:00 pm to 8:00 pm in summer time. As cooling load is highly sensitive to weather, the maximum usage per customer during summer peaks is almost 2 times greater than average usage in the same time on normal days for all the rate classes. The least consumption occurs between 6:00 am to 8:00 am in the morning, when houses are cooled down over night and before heated by direct sunshine. The customers in "TOU" rate class have the highest average cooling consumption, followed by the customers in "RS" rate class as second, and the customers in "RE" as the third. Same trends are examined in the Figure 8-2, and the customers in "TOU" rate class consumes more energy on cooling than those customers in "RES" rate class.

Figure 8-1: Average Cooling Load Shapes for DEC Customers

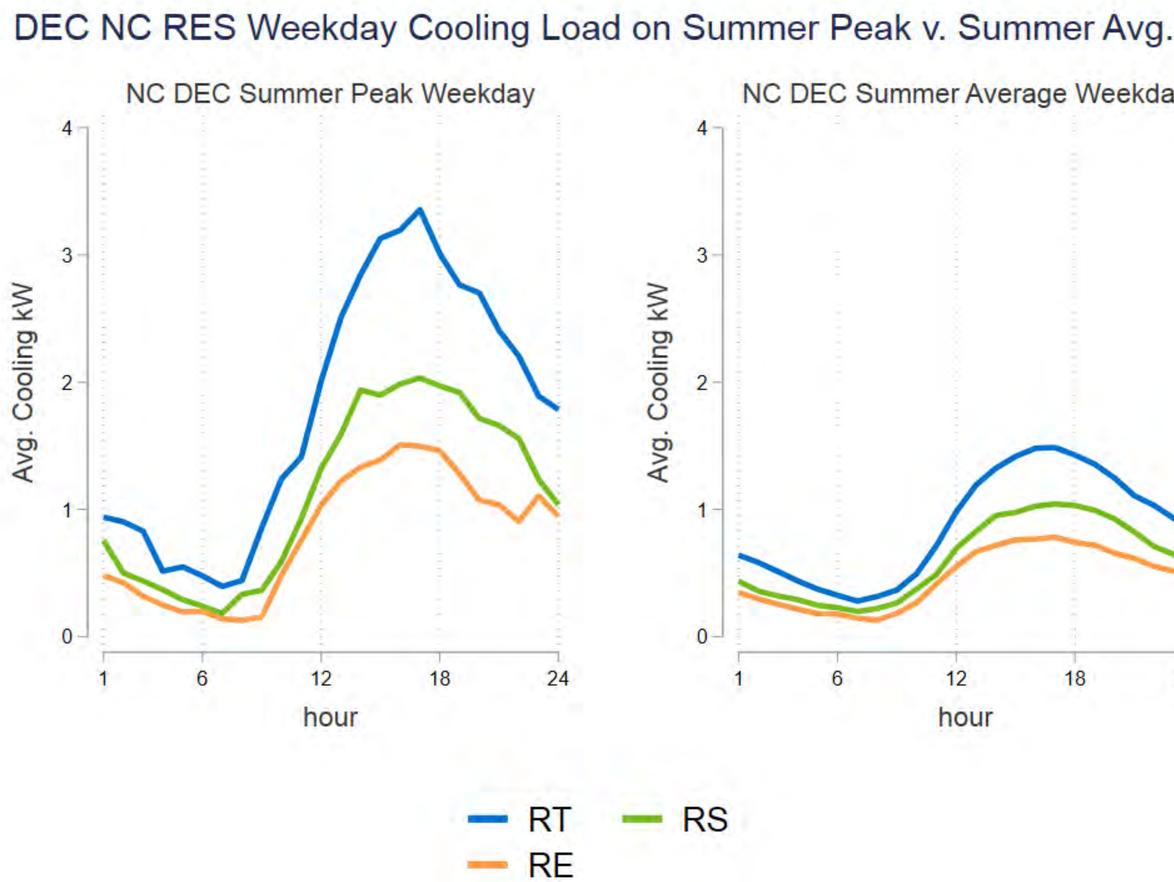
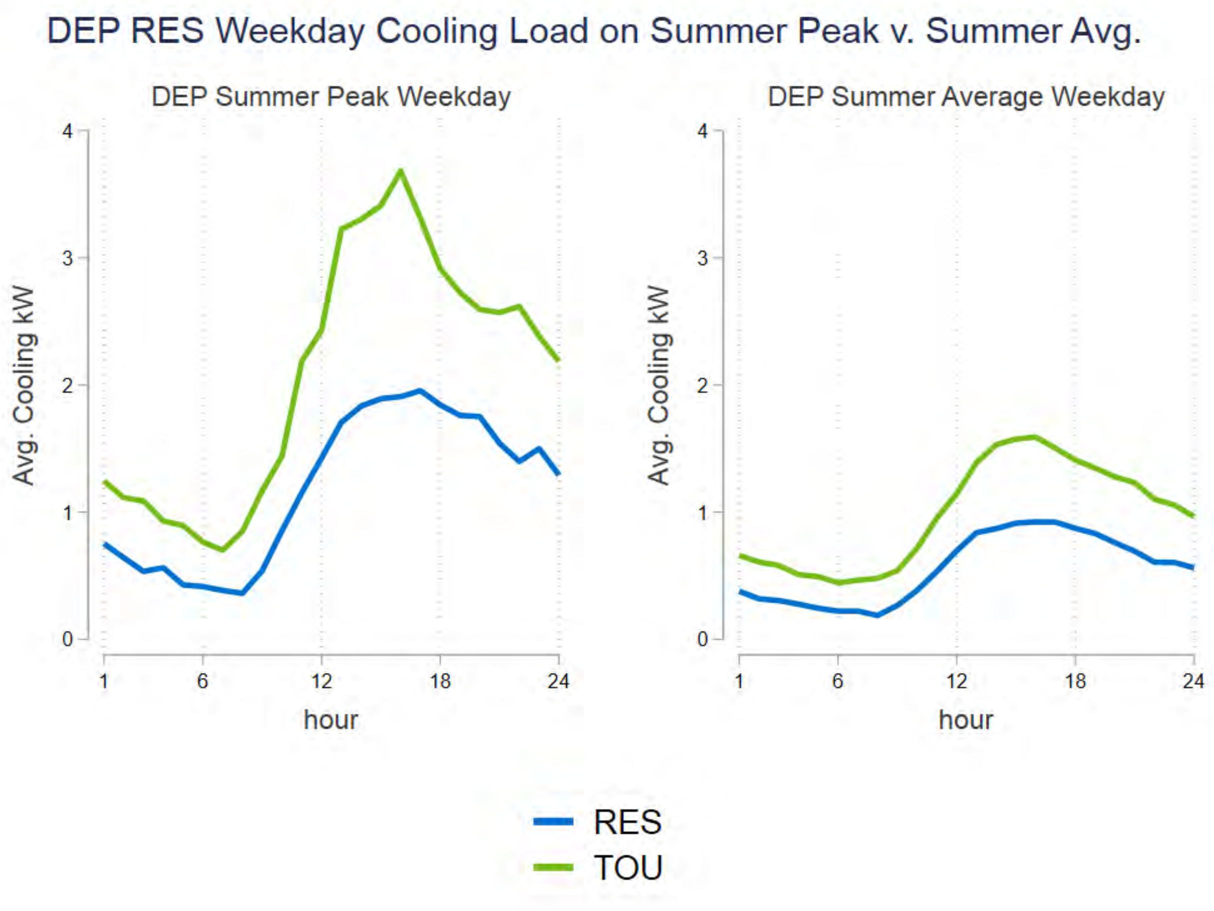


Figure 8-2: Average Cooling Load Shapes for DEP Customers



Space Heating

Similar to the analyses for air conditioning, the heating load shapes on peak day and average days were obtained from the same hourly load research profile in 2018, and the peak day was defined as the day with system peak load during winter period. The regression model was modified to evaluate relationship between energy consumption and heating degree days (HDD) (shown as Equation (2)), but the technical potential was calculated in the same way as illustrated earlier.

Equation (2):

$$Load_t = HDD_t * \beta_1 + i.month + \varepsilon$$

Where:

t	Hours in each day in year 2018
$Load_t$	Load occurred in each hour

HDD_t	Heating Degree Day value associated with each hour
β_1	Change in average load per HDD
$i.month$	Nominal variable, month
ε	The error term

The Figure 8-3 and Figure 8-4 capture hourly peak usage and average usage for NC DEC and DEP territories. The load shape on winter average weekdays shows that space heating consumes more energy after midnight to early morning. Customers in “RS” rate class are assumed not to consume energy on heating end use, as almost all of them are using gas as their heating source.

Figure 8-3: Average Heating Load Shapes for DEC Customers

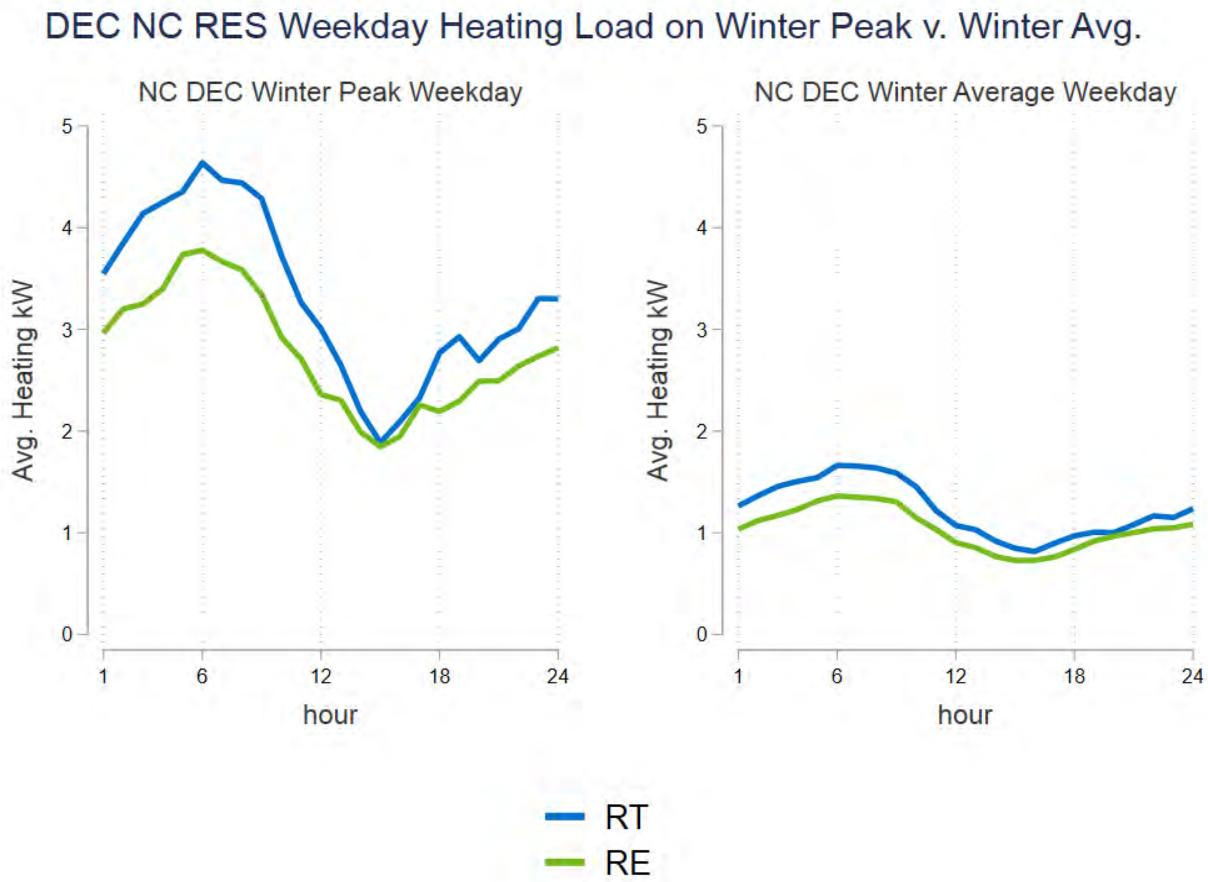


Figure 8-4: Average Heating Load Shapes for DEP Customers

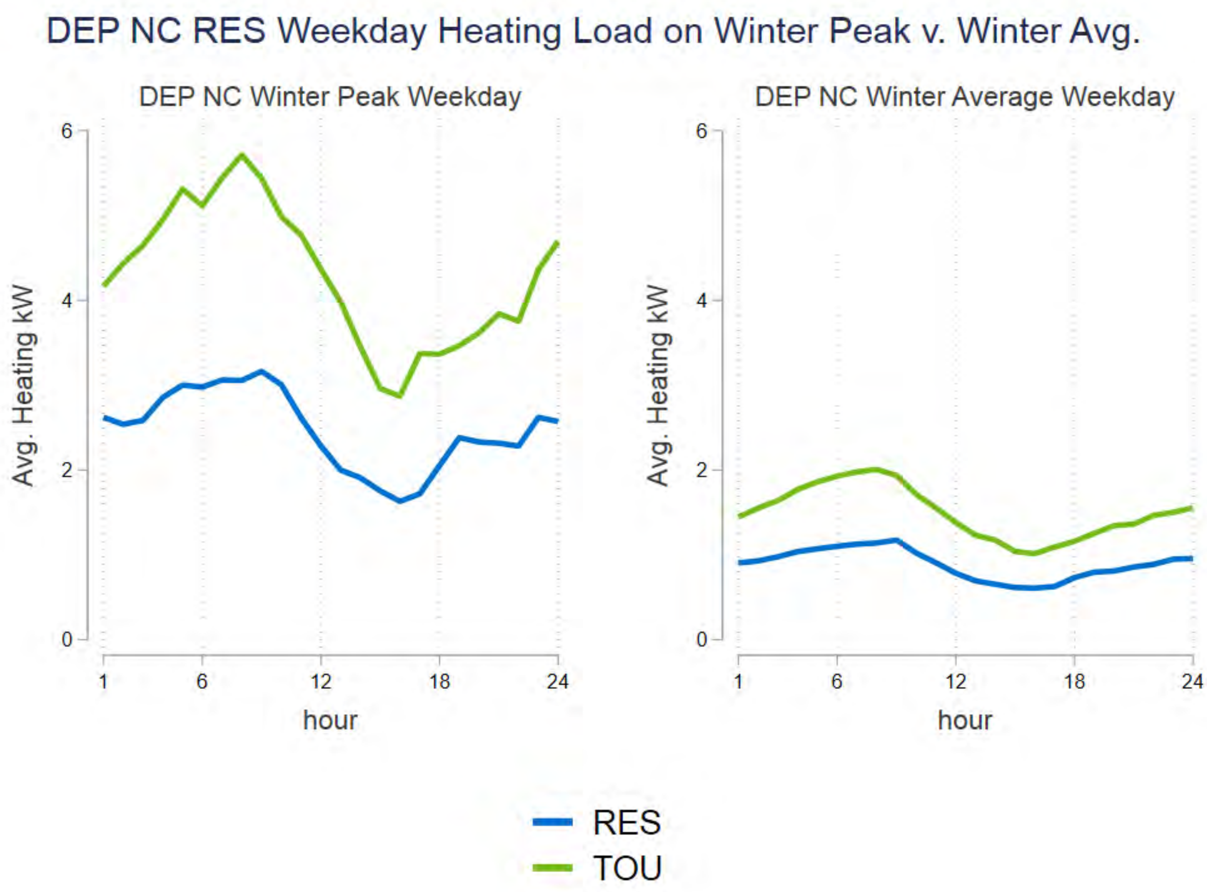


Table 8-3 and Table 8-4 show the technical potentials by rate class on peak day for those two territories.

Table 8-1: DEC Technical DSM Potential for Residential Heating

DEC - Residential					
Hour Ending	MW		Hour Ending	MW	
	RE	RT		RE	RT
1	2131	7	**13**	1656	5
2	2299	8	**14**	1432	4
3	2335	8	**15**	1326	4
4	2443	8	**16**	1401	4
5	2684	9	**17**	1622	5

6	2715	9	**18**	1576	5
7	2635	9	**19**	1648	6
8	2575	9	**20**	1789	5
9	2402	8	**21**	1792	6
10	2101	7	**22**	1897	6
11	1946	6	**23**	1966	6
12	1695	6	**24**	2026	6

Table 8-2: DEP Technical DSM Potential for Residential Heating

DEP - Residential					
Hour Ending	MW		Hour Ending	MW	
	RES	TOU		RES	TOU
1	2,076	64	**13**	1,701	61
2	2,069	68	**14**	1,572	53
3	2,126	71	**15**	1,415	45
4	2,322	76	**16**	1,332	44
5	2,455	82	**17**	1,455	52
6	2,414	79	**18**	1,641	52
7	2,509	84	**19**	1,839	53
8	2,545	88	**20**	1,833	56
9	2,565	83	**21**	1,858	59
10	2,410	77	**22**	1,827	58
11	2,160	73	**23**	2,104	67
12	1,916	67	**24**	2,126	72

Water Heaters

Interval load data by end-use are not available for individual customers in Duke territory, so the analyses of water heaters was completed based on end-use metered data from https://openei.org. The water heater data are from the same cities and use the same weights as the weather stations used in this analysis. The monthly average was used corresponding to the system peak load of each jurisdiction.

Figure 8-5: Average Water Heaters Load Shapes for DEC Customers

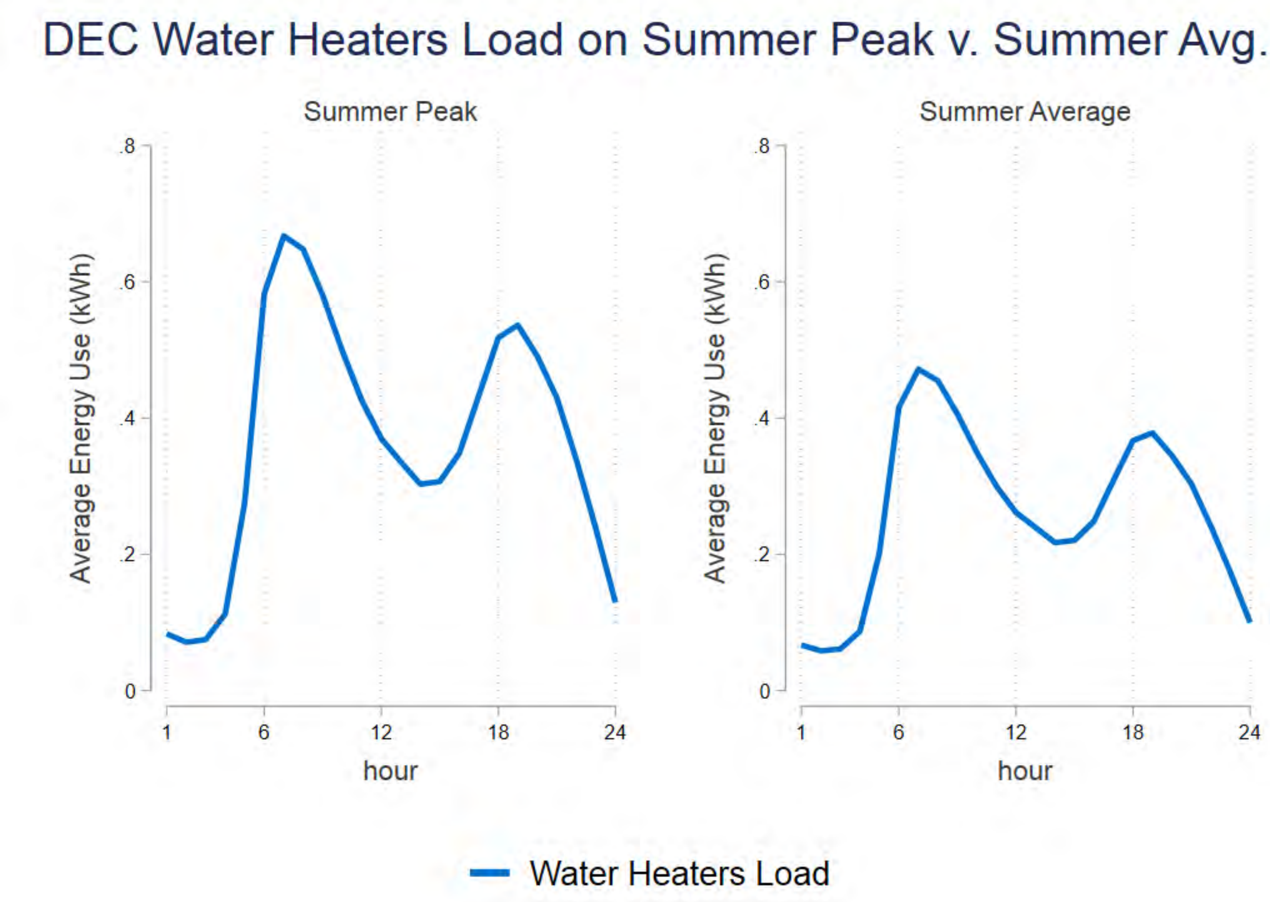
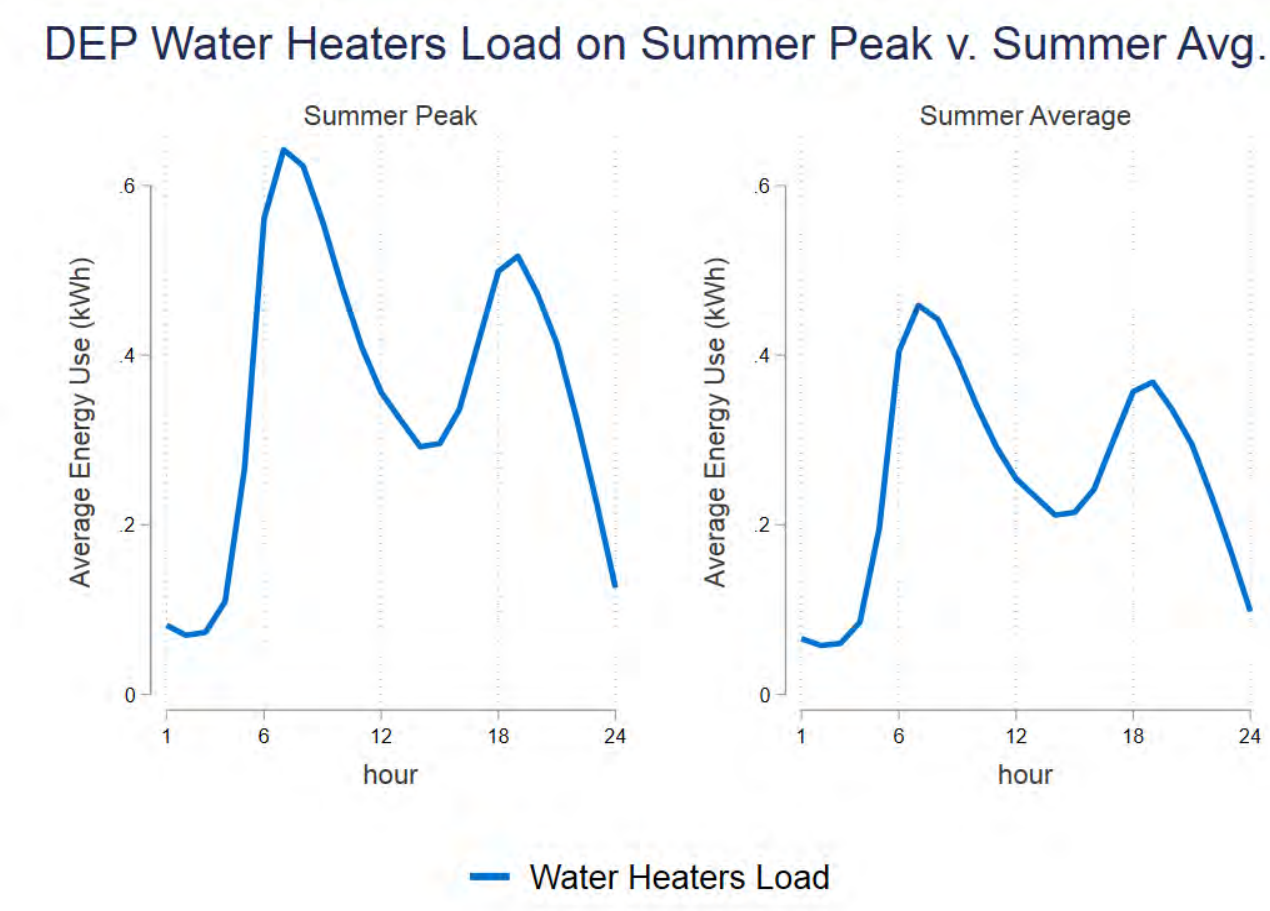


Figure 8-6: Average Water Heaters Load Shapes for DEP Customers

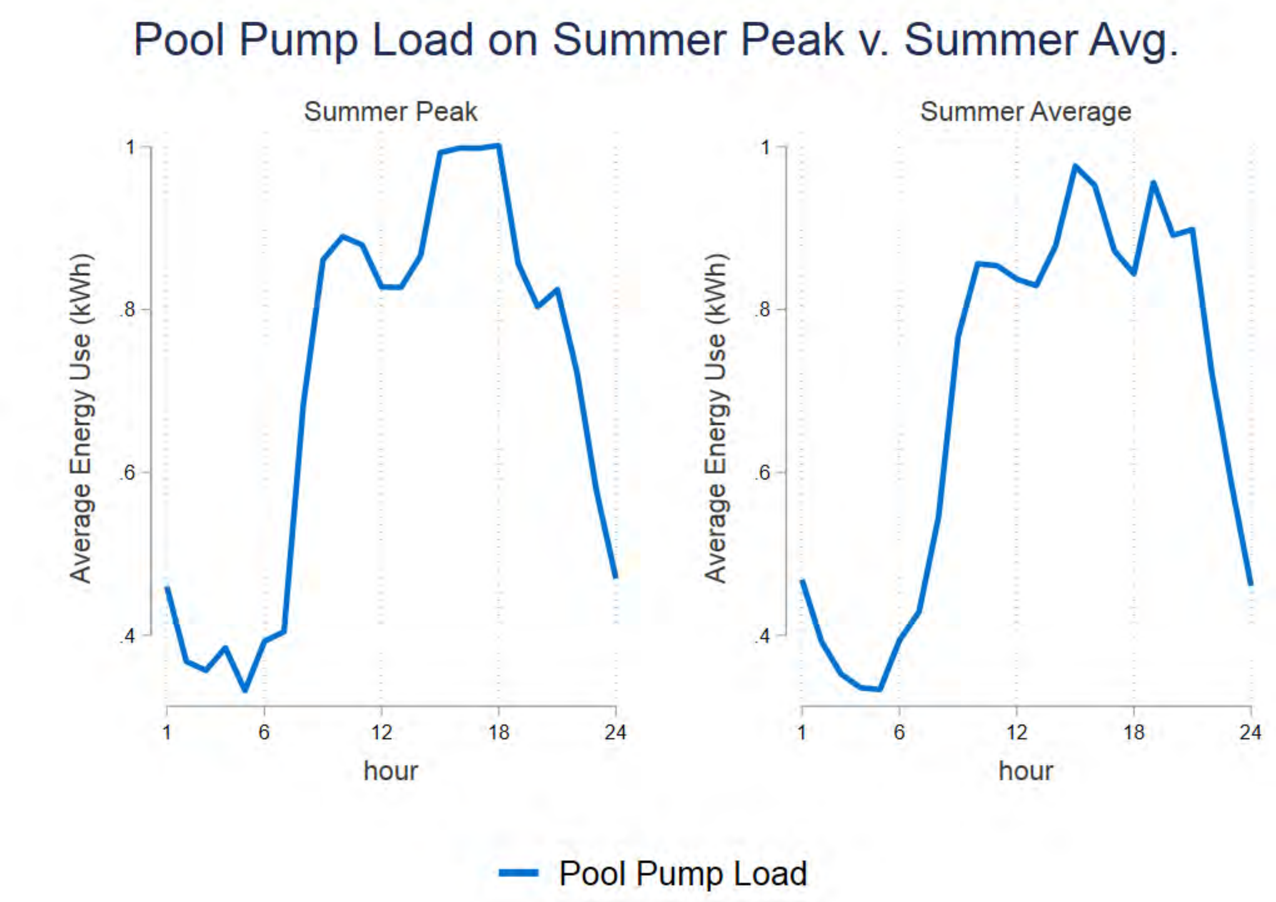


It is apparent from the Figure 8-6 that there is not much difference from peak usage and average usage, which proves that water heater loads has low sensitivity to weather. There are two spikes in a day, indicating two shifts when people would be likely to take showers. The time periods with highest consumption are 5:00 am – 7:00 am and 5:00 pm – 8:00 pm.

Pool Pumps

Likewise, pool pump loads were assumed to be fairly constant throughout the summer time as well, so the average load profiles for pool pumps from CPS's project were also used to represent for residential customers in Duke jurisdictions.

Figure 8-7: Average Pool Pumps Load Shapes for DEC Customers



According to the Figure 8-4, the peak hours for pool pumps are 3:00 pm to 6:00 pm, and there is minor sensitivity with weather observed by comparing peak loads and average loads.

Large C&I Customers

Estimates of technical potential were based on one year of interval data (2018) for all non-residential customers. Customers were categorized into one of 23 industry segments for the purpose of analysis. Technical potential for these customers was defined as the aggregate usage within each segment during summer and winter peak system hours.

Visual presentations of the results are shown below. These graphs are useful to identify the segments with the highest potential as well as examine the weather-sensitivity of each segment by comparing peak usage to the average usage in each season. For example, the chemicals and lumber segments are more weather sensitive in DEP than textiles and miscellaneous.

Figure 8-8: Aggregate Load Shapes for DEC Large C&I Customers

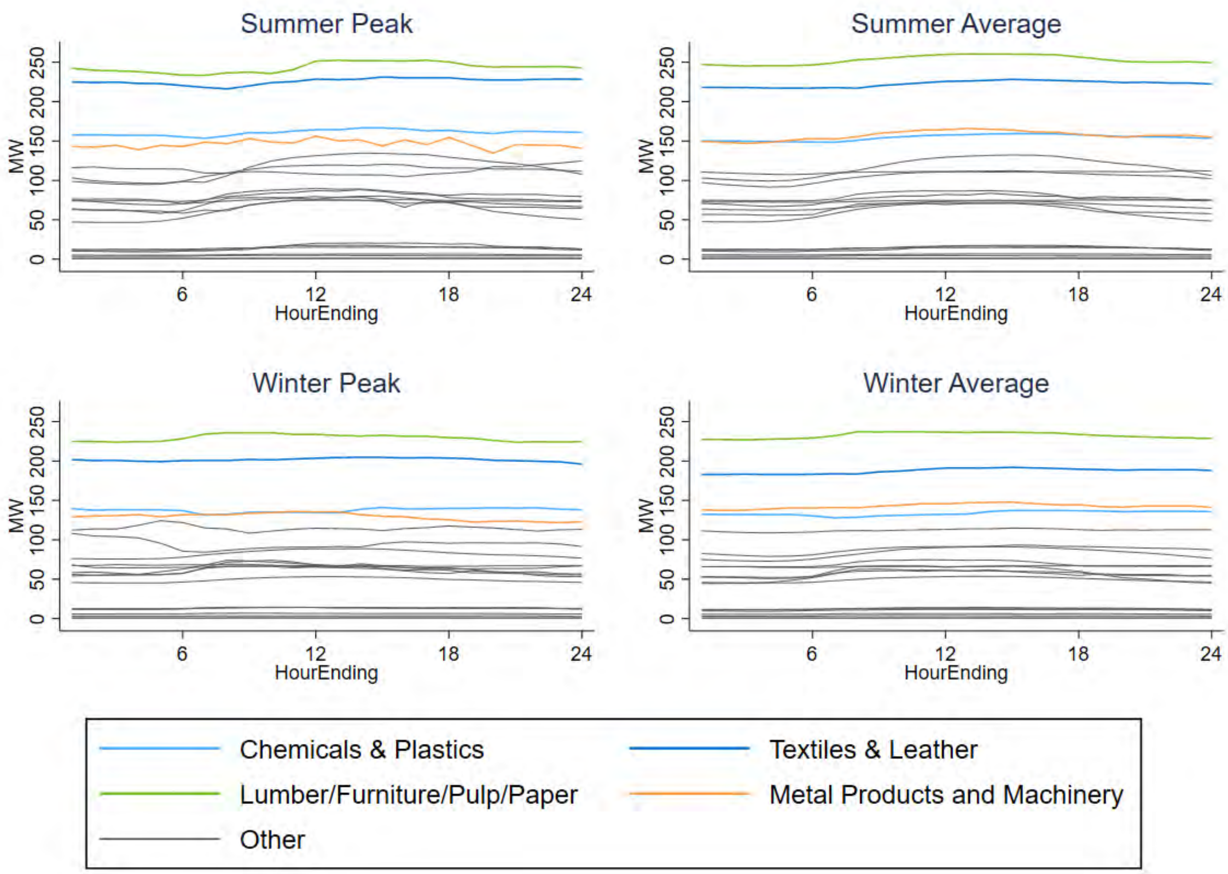
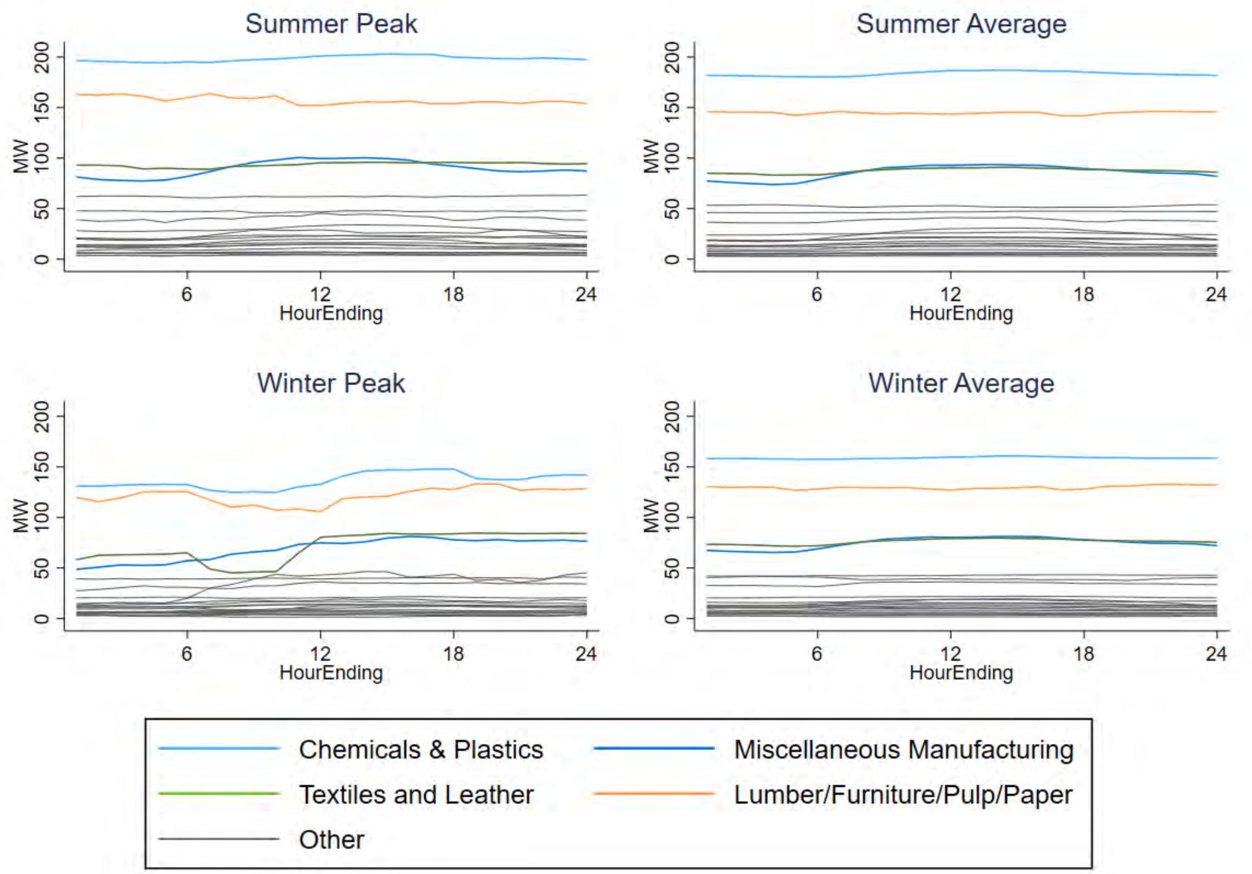


Figure 8-9: Aggregate Load Shapes for DEP Large C&I Customers



Appendix D Combined Heat and Power Potential

The CHP analysis created a series of unique distributed generation potential models for each primary market sector (commercial and industrial).

Only non-residential customer segments whose electric and thermal load profiles allow for the application of CHP were considered. The technical potential analysis followed a three-step process. First, minimum facilities size thresholds were determined for each non-residential customer segment. Next, the full population of non-residential customers were segmented and screened based on the size threshold established for that segment. Finally, the facilities that were of sufficient size were matched with the appropriately sized CHP technology.

To determine the minimum threshold for CHP suitability, a thermal factor was applied to potential candidate customer loads to reflect thermal load considerations in CHP sizing. In most cases, on-site thermal energy demand is smaller than electrical demand. Thus, CHP size is usually dictated by the thermal load in order to achieve improved efficiencies.

The study collected electric and thermal intensity data from other recent CHP studies. For industrial customers, Nexant assumed that the thermal load would primarily be used for process operations and was not modified from the secondary data for climate conditions. For commercial customers, the thermal load is more commonly made up of water heating, space heating, and space cooling (through the use of an absorption chiller). Table 8-3, on the following page, present the values for thermal factors used to estimate technical potential.

Table 8-3: CHP Thermal Factors by Segment and Prime Mover

Application	Microturbines 250-500 kW	Fuel Cells 250-500 kW	Reciprocating IC Engines 0.5 - 1 MW	Reciprocating IC Engines 1 - 5 MW	Gas Turbines 5 - 20 MW	Gas Turbines >= 20 MW
Assembly	0.83	0.86	0.92	1.05	1.05	1.28
College and University	0.52	0.54	0.57	0.66	0.66	0.80
Data Center	0.55	0.57	0.61	0.69	0.69	0.85
Grocery	0.12	0.13	0.14	0.15	0.15	0.19
Healthcare	0.38	0.39	0.42	0.48	0.48	0.59
Hospitals	0.70	0.72	0.76	0.87	0.87	1.07
Institutional	0.51	0.53	0.56	0.64	0.64	0.79
Lodging/Hospitality	0.35	0.36	0.39	0.44	0.44	0.54
Miscellaneous	0.33	0.34	0.36	0.42	0.42	0.51
Office	0.37	0.38	0.41	0.46	0.46	0.57
Restaurants	0.33	0.34	0.37	0.42	0.42	0.51
Retail	0.40	0.41	0.43	0.50	0.50	0.61
Schools K-12	0.57	0.58	0.62	0.71	0.71	0.87
Warehouse	0.33	0.33	0.36	0.41	0.41	0.50
Agriculture and Assembly	1.20	1.24	1.32	1.51	1.51	1.85
Chemicals and Plastics	0.74	0.76	0.81	0.93	0.93	1.14
Construction	1.48	1.52	1.63	1.85	1.85	2.27
Electrical and Electronic Equip.	0.29	0.29	0.31	0.36	0.36	0.44
Lumber/Furniture/Pulp/Paper	1.09	1.12	1.19	1.36	1.36	1.67
Metal Products and Machinery	0.29	0.29	0.31	0.36	0.36	0.44
Miscellaneous Manufacturing	1.48	1.52	1.63	1.85	1.85	2.27
Primary Resources Industries	0.38	0.39	0.42	0.48	0.48	0.59
Stone/Clay/Glass/Concrete	2.45	2.52	2.69	3.07	3.07	3.76
Textiles and Leather	0.85	0.87	0.93	1.06	1.06	1.30
Transportation Equipment	0.48	0.49	0.53	0.60	0.60	0.74
Water and Wastewater	0.33	0.34	0.36	0.42	0.42	0.51

After determination of minimum kWh thresholds by segment, Nexant used the utility-provided customer data with NAICS or SIC codes as well as annual consumption data, and categorized all non-residential customers by segment and size. Customers with annual loads below the kWh thresholds are not expected to have the consistent thermal loads necessary to support CHP and were eliminated from consideration.

In general, internal combustion engines are the prime mover for systems under 500kW with gas turbines becoming progressively more popular as system size increases above that. Based on the available load by customer, adjusted by the estimated thermal factor for each segment, CHP technologies were assigned to utility customers in a top-down fashion (*i.e.* starting with the largest CHP generators).

D.1 Interaction of Technical Potential Impacts

As described above, the technical potential was estimated using separate models for EE, DSM, and CHP systems. However, there is interaction between these technologies; for example, a more efficient HVAC system would result in a reduced peak demand available for DSM curtailment. Therefore, after development of the independent models, the interaction between EE, DSM, and CHP was incorporated as follows:

- The EE technical potential was assumed to be implemented first.
- For CHP systems, the EE technical potential was incorporated in a similar fashion, adjusting the baseline load used to estimate DSRE potential.

For CHP systems, the reduced baseline load from EE resulted in a reduction in the number of facilities that met the annual energy threshold needed for CHP installations. Installed DSM capacity was assumed to not impact CHP potential as the CHP system feasibility was determined based on energy and thermal consumption at the facility. It should be noted that CHP systems not connected to the grid could impact the amount of load available for curtailment with utility-sponsored DSM. Therefore, CHP technical potential should not be combined with DSM potential but used as independent estimates. Table 8-4 presents technical potential for CHP in the DEC jurisdiction.

Table 8-4: DEC Technical Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potential	MWh Potential
Commercial	Assembly	6	2	5,688
Commercial	College and University	12	18	104,287
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	14	5	28,069
Commercial	Hospitals	26	27	145,593
Commercial	Institutional	0	0	0
Commercial	Lodging/Hospitality	11	4	24,011
Commercial	Miscellaneous	7	4	22,184
Commercial	Office	56	35	213,665
Commercial	Restaurants	0	0	0
Commercial	Retail	46	25	88,772
Commercial	Schools K-12	16	7	25,007
Commercial	Warehouse	8	4	16,632
Industrial	Agriculture and Assembly	1	0	1,481
Industrial	Chemicals and Plastics	11	42	228,530
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	0	0	0
Industrial	Lumber/Furniture/Pulp/Paper	9	26	152,477
Industrial	Metal Products and Machinery	1	1	6,862
Industrial	Miscellaneous Manufacturing	62	57	284,178
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	1	2	10,424
Industrial	Water and Wastewater	0	0	0
Total		**287**	**259**	**1,357,859**

The CHP technical potential for DEPNC is presented below in Table 8-5.

Table 8-5: DEP Technical Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	1	0	1,047
Commercial	College and University	1	0	1,552
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	3	2	11,170
Commercial	Hospitals	11	7	36,311
Commercial	Institutional	0	0	0
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	0	0	0
Commercial	Office	11	4	24,248
Commercial	Restaurants	1	0	1,085
Commercial	Retail	20	8	28,745
Commercial	Schools K-12	15	15	54,270
Commercial	Warehouse	4	2	6,089
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	1	1	6,212
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	0	0	0
Industrial	Lumber/Furniture/Pulp/Paper	1	2	12,532
Industrial	Metal Products and Machinery	1	1	4,674
Industrial	Miscellaneous Manufacturing	24	21	105,545
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	0	0	0
Industrial	Water and Wastewater	0	0	0
Total		**94**	**63**	**293,480**

D.2 CHP Economic Potential

Nexant conducted cost research for CHP prime movers and used research on the technology type to identify the appropriate technologies for each segment. CHP costs and utility avoided energy costs are used to estimates TRC ratios for CHP technologies of a given size at each eligible Duke Energy account. These estimates are based on 2018 billing data provided by Duke Energy to Nexant. Economic Potential for DEC is presented below in Table 8-6.

Table 8-6: DEC Economic Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	6	2	7,158
Commercial	College and University	9	17	112,577
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	0	0	0
Commercial	Hospitals	19	24	153,435
Commercial	Institutional	0	0	0
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	0	0	0
Commercial	Office	7	12	80,084
Commercial	Restaurants	0	0	0
Commercial	Retail	3	5	22,376
Commercial	Schools K-12	0	0	0
Commercial	Warehouse	0	0	0
Industrial	Agriculture and Assembly	1	0	1,595
Industrial	Chemicals and Plastics	11	42	244,889
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	0	0	0
Industrial	Lumber/Furniture/Pulp/Paper	9	26	158,843
Industrial	Metal Products and Machinery	1	1	7,563
Industrial	Miscellaneous Manufacturing	62	57	328,617
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	1	2	11,552
Industrial	Water and Wastewater	0	0	0
Total		**129**	**189**	**1,128,689**

Economic potential for CHP in the DEP service territory is presented below in Table 8-7.

Table 8-7: DEP Economic Potential for CHP

Sector	Segment	Total		
		# of Sites	MW Potentials	MWh Potentials
Commercial	Assembly	0	0	0
Commercial	College and University	0	0	0
Commercial	Data Center	0	0	0
Commercial	Grocery	0	0	0
Commercial	Healthcare	1	1	8,761
Commercial	Hospitals	10	6	40,490
Commercial	Institutional	0	0	0
Commercial	Lodging/Hospitality	0	0	0
Commercial	Miscellaneous	0	0	0
Commercial	Office	0	0	0
Commercial	Restaurants	0	0	0
Commercial	Retail	0	0	0
Commercial	Schools K-12	0	0	0
Commercial	Warehouse	0	0	0
Industrial	Agriculture and Assembly	0	0	0
Industrial	Chemicals and Plastics	1	1	6,657
Industrial	Construction	0	0	0
Industrial	Electrical and Electronic Equip.	0	0	0
Industrial	Lumber/Furniture/Pulp/Paper	1	2	13,055
Industrial	Metal Products and Machinery	1	1	5,151
Industrial	Miscellaneous Manufacturing	24	21	122,050
Industrial	Primary Resources Industries	0	0	0
Industrial	Stone/Clay/Glass/Concrete	0	0	0
Industrial	Textiles and Leather	0	0	0
Industrial	Transportation Equipment	0	0	0
Industrial	Water and Wastewater	0	0	0
Total		**38**	**33**	**196,163**

D.3 CHP Achievable Potential

This analysis describes the physical and economic factors that may contribute to facilities' energy savings through the installation of CHP technologies. The data available for characterizing CHP opportunities are limited to representative values for each commercial and industrial segment. These value represent general segment characteristics, and describe the order of magnitude for likely drivers of CHP potential in each segment.

The question of which specific facilities are more or less likely to adopt CHP potential bears further research. CHP installations are large projects that are inherently site-specific. Assuming CHP is technical feasible and economic at a given location, there are other important considerations for whether CHP should actually go forward. Nexant's understanding is that Duke Energy is currently working through a variety of channels to gauge customer interest in CHP technology. Without further research on the topic, we identified project payback period as a potential criterion for screening eligible. Based on our estimates of cost for CHP prime movers and technical feasibility, we find that payback periods range from 4.5 to 35 years among Duke Energy customers.

Similar studies of CHP potential recently performed by Nexant have used jurisdictional rules for screening achievable potential: a payback period of 2 years or less for larger commercial and industrial customers. Based on this information, Nexant finds that CHP achievable potential is likely to be relatively low without additional research on key drivers that can be used to target facilities, or without outreach to potential facilities.

Appendix E Qualitative Analysis of Duke Energy Programs

E.1 Residential

Smart$aver

In 2019, Smart $aver program costs exceeded Duke Energy's avoided costs for the associated savings generated by the program. The program offers tiered incentive rates for higher efficiency HVAC units. The Smart $aver program generates high participant satisfaction, especially with contractors. Trade ally participants report that Smart $aver influenced them to recommend and implement qualified measures, and to increased their knowledge of EE technologies. Trade allies are the program's most successful marketing channel. That said, Smart $aver does not appear to serve as a strong gateway program; while many participants indicated purchasing other products or services to save energy in the home, they did not assign influence to the Smart $aver program for those subsequent energy upgrades.

Trade allies reported interest in additional sales training. The program now has an online portal for trade allies, and 71% of trade allies reported problems such as data entry and upload problems. Trade allies are looking for additional information on why rebates requests are rejected; they indicate the application process is time-consuming, as is resolving application issues. That said, 75% of Trade Allies reported the portal issues have improved with time.

Overall EM&V findings suggest looking for improvements to the trade ally experience, as they are the primary drivers of the program. Key areas for improvement include the application process and portal, program training, and the quality installation process and requirements. Other suggestions include cooperative marketing with trade allies, which Duke Energy is currently doing with the "Find it Duke," contractor referral. The program is also marketed through a variety of channels: TV, radio, social media, and email messaging. One other suggestions was to provide trade allies with some compensation for time spent on the rebate process, and project portal submissions. Lastly, nearly 60% of program data for the quality install measure had demonstrable issues such as mathematical errors, non-qualifying capacities, rule-of-thumb CFM estimates.

DEP Neighborhood Energy Saver (NES)

Nexant reviewed the EM&V report dated January 17, 2017. The Neighborhood Energy Saver program provides one-on-one energy education, onsite energy assessments, and packages of no-cost energy efficiency measures to customers in income-qualified neighborhoods. Neighborhoods are eligible if 50% of households in the community have incomes equal or less than 150% of the Federal poverty level. The program provides equipment and education at no cost, and when possible, works with community leaders to maximize the number of customers participating in each neighborhood.

EM&V recommendations include expanding lighting offerings to specialty sockets, and evaluating the potential costs and savings of ENERGY STAR appliances. In terms of the program itself, EM&V

recommends adjusting the low-income threshold to 200% of the Federal poverty level. Duke Energy's 2019 year-end program summary indicates the 2019 program has already moved to this lower threshold for eligibility. Procedural EM&V findings include improving onsite data collection, which has been done by transitioning to a tablet-based onsite data collection system.

Currently the program activities are ongoing, having completed eight neighborhoods in 2019. The program's events included support from community groups and speakers such as elected officials, community leaders, and community action agency representatives. The program's marketing approach is grassroots, interacting with individual customers. Participation is driven through a neighborhood kick-off event that includes community leaders and officials.

Energy Efficiency Education Program

The Energy Efficiency Education program is available to students in K-12 enrolled in public and private schools in the DEC service territory. The program provides principals and teachers with an innovative curriculum around energy use and waste; the centerpiece of the program is a live theatrical production with professional actors. Teachers receive supporting education material for their classrooms, and students have take-home assignments. Students are encouraged to complete a request form for their families to receive an Energy Efficiency Starter Kit.

Nexant reviewed the program's 2017 – 2018 EM&V report. Conclusions in the report describe that teachers appreciate the theatrical performances from the standpoint of engaging students, but it is less clear whether the performances are linked to classroom learning, awareness of EE at home, or a change in behavior. Many parents surveyed were not aware the performance occurred; although roughly half of parents reported changes in their children's energy use behavior, those changes were limited. Another EM&V conclusion identified opportunities to increase parental awareness of the kits. Lastly, findings indicate nearly all respondents installed at least one kit measure, and about 20% indicated making additional energy saving improvements. Lastly, the education program could serve as a gateway program by referring customers with a demonstrated interest in energy efficiency to additional program offers.

My Home Energy Report

The My Home Energy Report is an opt-out program that delivers personalized energy reports to customers. The reports compare household consumption to other similar households and to an efficient household. The report also offers tips for saving energy and advertises other Duke Energy Program offerings. The program also includes an online portal that allows customers to learn more about their energy and use opportunities to lower it. The portal allows customers to set and track goals, and receive more targeted tips. Some customers are excluded from the program to serve as a control group for measuring program energy impacts.

The 2019 EM&V Report suggests continued commitment to simultaneous assignment of treatment and control groups. The report also suggests looking for ways to increase customer awareness of the Interactive Portal component of the program. This recommendation appears to have been implemented, according to Duke Energy's 2019 year-end program summary: an on-report marketing campaign in 2019 led to an increase in 56,900 Interactive Portal enrollments.

Home Energy House Call

The Residential Energy Assessment Program, also known as "Home Energy House Call," provides participants with a customized energy report that includes low- and no-cost recommendations for lowering energy bills. Customers receive an EE started kit with LEDs, low-flow showerhead, two faucet aerators, weather stripping, and outlet seals. These can be installed at no charge by the auditor. The auditors encourage behavioral changes to reduce consumption and recommends higher-cost energy-saving investments to customers.

Nexant reviewed the 2018 evaluation report for this program, which highlights the following recommendations: energy auditors should install all possible kit measures; educate customers on the benefits of early light bulb replacement; add tools for auditors to cross-market other Duke Energy programs, such as promotional materials or technology-assisted referrals that correspond to report recommendations.

According to Duke Energy's 2019 year-end program summary, the in-home audits are conducted by Building Performance Institute (BPI) certified energy specialists. The specialists conducts a 60 to 90 minute home walkthrough to assess the customers home and energy use to identify savings opportunities. This program is widely marketed through Duke Energy's website, online advertisements, paid search campaigns, Facebook, email, bill inserts, bill messages, direct mail, and customer segmentation to reach customers with a high propensity to participate. Program changes in 2019 focused on cross-promotion of other programs and integrated in-field referral for FindItDuke, thus responding to EM&V recommendations.

Energy Efficient Appliances

The Energy Efficient Appliances and Devices program offers a variety of measures such as lighting, pool pumps, heat pump water heaters, and water measures. This program includes the Free LED program offer gives away 15 LEDs per account. Customers have multiple ways to track their order. The program also includes the Duke Energy Savings Store ("Store"), which offers specialty bulbs. The program added smart thermostats to the Store in 2018. Most recently, in 2019, the program added LED fixtures and small appliances such as dehumidifiers and air purifiers. The Store platform also provides educational information that can assist with purchase decisions.

The EEAD program includes a retail lighting component that reduces prices at retail locations, and the Save Energy and Water Kit Program. The SEWK markets to customers by business reply card and direct email. The kit offers a free aerator, insulating pipe tape, shower heads, and bathroom aerators.

The EEAD program also offers rebates on high efficiency pool pumps, which is marketed through Trade Allies. New swimming pools are eligible. High efficiency heat pump water heaters are also available and marketed through Trade Allies.

Nexant reviewed the 2018 EM&V report for the Online Savings Store, which recommends that Duke Energy adjust for the 2020 EISA standards in terms of lighting install rates. Overall, evaluators found the program was running smoothly and demonstrated high customer satisfaction. The EM&V also recommended adding additional non-lighting measures to the store, which Duke Energy has done.

Duke Energy will discontinue the Free LED program in 2020 due to EISA standards. Regarding specialty lighting included in the Store, Duke Energy is enhancing the website to provide additional information that raises customer awareness of specialty lighting offers.

The pool pump and water heater measures are marketed through trade allies; Duke Energy is investigating ways to implement point of sale rebates. Duke Energy is also work with major retailer to educate customers and create awareness, including the use of co-branding strategies with manufacturers and national retailers.

Multifamily Energy Efficiency

This program offers lighting and water measures to reduce consumption at multifamily properties. LED lighting measures include typical A-lines, as well as other specialty bulb types. The measure are professionally installed by a contractor and quality assurance is performed on 20% of properties each month. In 2019 the Duke Energy year-end program summary indicates the program completed installation at 45,422 multifamily units. Duke Energy is implementing technology solutions to support participation tracking and data accuracy. The third-party implementation contractor is responsible for marketing and outreach to property managers. This is done with outbound calling, and recruiting at industry trade events, and on-site visits.

E.2 Commercial

Small Business Energy Saver

The Small Business Energy Saver (SBES) program offers a performance-based incentive of up to 80% of total project caught, including materials and installation. The main focus of program measures is lighting, HVAC, and refrigeration equipment. The program is implemented by a third party that conducts marketing outreach, provides technical expertise, and performance incentives to reduce equipment and installation costs.

Nexant reviewed the 2018 EM&V report for the program, which recommends clear communication about the quality and depth of retrofit. The most common feedback from participants described post-installation equipment issue and a perceived lack of coordination between the parties involved in delivering the program. Some customers also appeared to be confused about what measures could be provided under the program, versus those desired by participants. The current eligibility criterion of 180 kW demand, may lead to larger projects being included in the SBES program when those projects might be better accommodated by other programs.

The EM&V also recommends tracking burnout lamps at customer locations during the initial audit, as burnouts may be ignored by customers and reduce the savings achievable for retrofits. The EM&V also notes the implementation contract might benefit from having more up-to-date and accurate customer billing data.

Duke Energy's 2019 year-end summary for the SBES program indicates customers receive a free audit and recommendations for energy efficiency upgrades. The program is administered as a pay-for-performance program where the implementation contractor is compensated on the basis of customer savings. In 2019 the program began offering a tiered incentive structure for deeper retrofits, which is designed to encourage the adoption of more non-lighting measures. This approach successfully reduce the share of lighting measure in the program from 80% to 53%.

The program is also contemplating changes that would lead to using energy savings to pay off the project cost and thereby reduce the financial impact on customers. The program is marketed directly through the implementer, direct mail, website, social media, email, and Business Energy Advisors, and community events.

Non-residential Smart $aver Prescriptive

The Duke Energy Smart $aver Prescriptive program provides incentives for electric commercial and industrial customer to purchase and install a variety of high-efficiency equipment, including lighting, HVAC, pumps and drives, qualifying process, food service, and information technology equipment. Incentives are paid for new construction, retrofits, and replacements. Incentives are limited to 75% or less of the customer cost. The program is primarily application-based and driven by trade allies. The program has two delivery channels: the Business Savings Story on Duke Energy's website ("Store"). The program also includes a midstream channel that lets distributors give instant discounts on eligible lighting equipment.

Nexant review the 2018 EM&V report for this program, and primary recommendations include promoting lesser-known program components. For example, business energy advisors have an opportunity to promote the online store. Likewise, trade allies had a relatively low level of knowledge about, and attendance at trade ally training events. The EM&V also suggests introducing a mandatory, introductory training seminar to educate trade allies on program processes and requirements. Additional feedback included improvements to program tracking around trade ally performance, and adding customer identifiers for tracking participation. Data entry and data quality in the program tracking database could be improved, and well as ensuring complete program application data is entered into the participation database.

The 2019 year-end program summary prepared by Duke Energy indicates the midstream delivery channel garnered the most participants, followed by the online store; both of these deliver channels offer instant rebates and avoid the application process. The program also offers a pre-qualification procedure that allows customers to ensure their selected equipment qualifies for a rebate prior to purchase. Duke Energy's trade ally management strategy for the program includes a search tool allowing customers to find participating trade allies, QC inspections, co-marketing, online application portal, year-end awards for trade allies, a quarterly newsletter, training, discussion groups, and an online collateral toolkit.

Duke Energy plans to look for ways to bolster non-lighting measures and projects. This involves continual reassessment to look for additional measures that can be added to the program. Duke Energy is also looking for ways to reach out to customer segments with lower participations rates. The program is marketed through direct marketing such as mail and email, online marketing, print marketing, and supporting partnerships. The program is also marketed by Large Business Account Managers and Business Energy Advisors at Duke Energy.

Non-residential Smart Saver Custom

The Non-residential Smart $aver Customer program looks for ways to incentivize energy efficiency projects that do not qualify for Smart $aver Prescriptive. Typically these projects are more complex and would not be completed without technical or financial assistance from Duke Energy. Nexant reviewed the 2018 program EM&V findings, which suggest using T8 lighting as a baseline for linear fluorescent lamp types. Other recommendations include continuing to focus on trade allies and contractors as the main conduit for bringing customers into the program. Similarly, tools and calculators made available to contractors should remain up-to-date with program baselines and non-lighting measures. EM&V also recommends looking for ways to reduce application preapprovals to a period of less than six weeks.

Duke Energy's 2019 year-end program summary describes the pre-approval process, which uses the Classic Custom and Smart $aver Tools. These processes have slightly different documentation requirements, depending on the expect size of project savings. The program uses a flat incentive rate for energy and demand savings. There is also a fast-track option where customers can pay a fee to speed up the application process. In 2019 Duke Energy launched the Smart $aver tools, which allows customers to submit a single application to cover lighting measures incentivized by the Prescriptive and Customer programs. Following recommendations from EM&V, Duke Energy has reduced application processing time to an average of 19 days.

The program is marketed through a variety of channels to create customer awareness of the program. In some cases this involves targeted marketing such as to trade allies, to ensure they are aware of the program incentive offers. Larger accounts are targeted primarily through business account managers. Unassigned medium and small accounts are targeted through Business Energy Advisors. In 2017 Duke Energy began a new marketing channel focused on energy efficiency design assistance.

Non-residential Smart $aver Customer Assessment

This program is a recruitment channel for Smart $aver Custom. It offers incentives to fund a detailed energy assessment and retro-commissioning design that can take advantage of Smart $aver Customer incentives. In 2019 this program was enhanced with a virtual auditing tool that can use data collected remotely to shorten the audit period to 2-3 weeks. Typical recruitment channels include Business Account Managers, electronic postcards, emails, and information obtained through the Duke Energy website and direct customer inquiries. Anticipated future marketing may tie more directly to the virtual audit tool as it becomes more applicable.

Non-residential Smart $aver Performance Incentive

This program provides incentive payments to offset a portion of the higher cost of energy efficiency installations that are not eligible for Smart $aver Customer or Prescriptive. Typically these types of measures include projects with some combination of unknown building conditions or system constraints or uncertainty operating, occupancy, or production schedules. The performance incentive program pays incentives on the basis of observed performance, not modeled, expected, or pre-approved savings determined via the Customer or Prescriptive programs. M&V may include individual equipment sub-metering or billing analysis. This program is also marketed in a wide array of channels.

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