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FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 9/22/2026

PARSONS BEHLE & LATIMER

50 West Liberty Street, Suite 750
Reno, Nevada 89501
Main 775.323.1601
Fax 775.348.7250

A Professional
Law Corporation

Justina A. Caviglia
Attorney at Law
Direct 775.789.6559
JCaviglia@parsonsbehle.com

September 22, 2026

Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 East William Street
Carson City, Nevada 89701-3109

Re: Docket No. 26-05007 – Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2027-2046 Triennial Integrated Resource Plan and 2027-2029 Energy Supply Plan..

Dear Ms. Osborne:

Please accept the attached Direct Testimony and Exhibits of Edward Burgess to be filed in the above-referenced dockets on behalf of our client Google Inc.

If you have any questions or concerns, please do not hesitate to contact me directly.

Sincerely,

PARSONS BEHLE & LATIMER

/s/ Justina A. Caviglia

Justina A. Caviglia

JAC:sb
Enclosure

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and

Sierra Pacific Power Company d/b/a NV Energy

2026 Joint Triennial Integrated Resource Plan (2027-2046)

Docket No. 26-05007

Prepared Direct Testimony of

Edward Burgess

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1. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Edward Burgess. I am a Founding Partner of Current Energy Group, LLC (CEG). My business address is 4764 E Sunrise Drive #508, Tucson, Arizona 85718.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Google, LLC ("Google") and its subsidiary Callisto Enterprises, LLC, as well as Advanced Energy United ("AEU") and Southwest Energy Efficiency Project ("SWEEP").

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have spent over 14 years working as a consultant in the energy and utilities industry. I specialize in electric utility issues including utility resource planning, transmission planning, fuel and power purchase costs, rate design, revenue requirements, distributed energy resource programs, and electric vehicle programs. Prior to co-founding CEG in 2024, I was a Consulting Partner at Strategen Consulting (Strategen), where I worked for over 8 years. While at Strategen, I directed the company's grid planning practice area. I also helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council and grew the organization to over 40 member companies. Prior to joining Strategen, I worked as an independent consultant, providing technical support to clients before state utility commissions and legislatures. During that time, I also worked for

Arizona State University where I helped launch their Utility of the Future Initiative as well as the Energy Policy Innovation Council.

Regarding my education, I have a bachelor's degree in Chemistry (A.B.) from Princeton University. I also have master's degrees in Solar Energy Engineering and Commercialization (P.S.M.) and in Sustainability (M.S.) both from Arizona State University. My resume is attached as Burgess Direct Exhibit 1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I have testified regarding NV Energy's Integrated Resource Plan in Docket No. 20-5 07023, Docket No. 22-09006, and Docket No. 24-05041. I also testified regarding SPPC's general rate case in Docket No. 24-02026.

2. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide additional detail and evidentiary support for the Large Customer Offsite Demand Side Management (DSM) Pilot Program, which was described by NV Energy in the Direct Testimony supporting its 2026 Integrated Resource Plan[1] and Demand Side Plan.[2] My testimony provides additional detail on the program's background, its goals, the collaborative process used to develop it, and the specifics of its

[1] PUCN Docket No. 26-05007, NV Energy 2026 Joint Integrated Resource Plan ("2026 Joint IRP"), Vol. 3, Direct Testimony of Patricia Rodriguez ("Rodriguez Direct") at 10-11.
[2] 2026 Joint IRP, Vol 33, Demand Side Management at 4-6;

proposed implementation, evaluation, and crediting framework. I recommend that the Commission approve the pilot program as a valuable and innovative addition to NV Energy's DSM portfolio.

Q. CAN YOU EXPLAIN WHY GOOGLE HAS RETAINED YOU TO PROVIDE THIS TESTIMONY?

A. Google retained my firm, Current Energy Group, to provide independent, expert analysis and support on the design of this pilot program, drawing upon our firm's expertise with DSM programs and IRPs nationally and specifically within Nevada. I am providing this testimony on Google's behalf to present the results of that work and offer an expert opinion on the pilot program's design and merits.

Q. ARE THERE OTHER PARTIES IN THIS CASE THAT YOUR TESTIMONY REPRESENTS?

A. Yes. While Google is the primary sponsor, Advanced Energy United and SWEEP have joined Google in supporting my testimony in this case. I am presenting this testimony on behalf of all three entities who jointly support the approval of the Large Customer Offsite DSM Pilot Program.

Q. **PLEASE SUMMARIZE THE REMAINDER OF YOUR TESTIMONY.**

A. The remainder of my testimony is organized into four sections.

1. First, I will describe background on the development of the Large Customer Offsite DSM Pilot Program, including the collaborative development process. I will introduce and discuss the results of a study evaluating demand reduction potential performed by the Brattle Group which informed the design of the program.

2. Second, I explain the pilot program's specific goals, framework, evaluation metrics, and the process for finalizing the necessary details for a successful pilot and permanent program.
3. Third, I propose cost recovery and bill crediting mechanisms appropriate for the pilot program.
4. Finally, I briefly discuss the importance of large customer electric service agreements ("ESAs") in supporting options for large customer supply options, like the Large Customer Offsite DSM Program.

Ultimately, my testimony will demonstrate that the pilot proposal is sufficiently detailed, well-designed, innovative, and in public interest, and for these reasons, I respectfully recommend that the Commission approve it.

Q. CAN YOU PROVIDE MORE SPECIFIC RECOMMENDATIONS FOR THE COMMISSION'S APPROVAL?

A. Yes. My specific recommendations for Commission action are as follows:

1. *Recommendation 1*: Approve the Large Customer Offsite DSM Pilot Program as discussed herein such that it can begin implementation as soon as 2027.
2. *Recommendation 2*: Establish a date certain within the next 6 months for NV Energy to finalize key components of the pilot program, including the bill crediting mechanism.
3. *Recommendation 3*: Require NV Energy to consider making the pilot program permanent in the next IRP cycle or as part of any consideration of a Large Load Tariff (whichever comes first)

3. LARGE CUSTOMER OFFSITE DSM PROGRAM BACKGROUND

A. PROCEDURAL HISTORY

Q. WAS THE LARGE CUSTOMER OFFSITE DSM PROGRAM PREVIOUSLY PROPOSED IN NV ENERGY'S INTEGRATED RESOURCE PLAN?

A. The concept of a Large Customer Offsite DSM Program was initially proposed by Google during the 2025-2044 Integrated Resource Plan (IRP) proceeding (Docket No. 24-05041). In its resulting Order, the Commission did not approve the program. At the time, the Commission cited a lack of detail and evidentiary support in the record.[3] However, it did provide clear encouragement for Google, NV Energy, and other stakeholders to continue developing the proposal for a future IRP.[4]

Q. SINCE THE 2024 IRP ORDER, HAVE GOOGLE AND NV ENERGY COLLABORATED TO FURTHER DEVELOP THIS PROGRAM CONCEPT?

A. Yes. Over the past 18 months, informed by valuable stakeholder input, Google and NV Energy have collaborated to advance the concept. This work has resulted in broad agreement on the core pilot design and many details of the proposed pilot program. The purpose of this pilot is to demonstrate the general structure on a limited basis, while

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[3] PUCN 24-05041, Order, December 20, 2024 at 139.

[4] NV Energy stated that the Commission had established three threshold requirements for a future proposal; however, this language is not present in the Commission's order in 24-05041. NV Energy stated the requirements as "specificity around eligibility, duration, budget, credit mechanics, and measurement;" "evidentiary support that the program will not harm other ratepayers;" and "a clear endpoint or review." See, 2026 Joint IRP, Vol. 33, Demand Side Management Plan at 5.

providing a clear path to expand the pilot into a full program in the future if successful. The ultimate goal is to make this offering available to all interested Large Customers, while achieving broader benefits for all customers.

Q. HAVE OTHER STAKEHOLDERS BEEN INVOLVED IN COLLABORATION?

A. Yes. In addition to direct conversations, NV Energy and Google have discussed the proposed program at three DSM Collaborative meetings and sought feedback on program design and development directly from stakeholders. In addition, Google staff have met directly with many DSM Collaborative members to solicit feedback and identify areas that need further development.

Q. HAVE STAKEHOLDERS GENERALLY SUPPORTED DEVELOPMENT OF THIS PILOT PROGRAM?

A. Yes. Stakeholder responses have been consistently positive. Throughout both the collaborative meetings and direct conversations, members of the DSM Collaborative have expressed strong support for the program's development, and no party has voiced opposition; instead, many parties are interested in learning more about the proposed crediting mechanism.

Q. WHAT ADDITIONAL WORK HAVE NV ENERGY AND GOOGLE CONDUCTED TO PROVIDE THE REQUESTED SUPPORT?

A. In addition to ongoing stakeholder collaboration, Google engaged The Brattle Group for technical analysis on load reduction potential and engaged my firm, Current Energy Group, for program design support, drawing upon our expertise in DSM and resource planning both with NV Energy's programs and more generally.

B. Opportunities to Expand NV Energy's Existing DSM Portfolio

Q. BRIEFLY DESCRIBE THE PRIMARY PURPOSE OF NV ENERGY'S EXISTING DEMAND SIDE MANAGEMENT (DSM) PROGRAMS.

A. The primary purpose of NV Energy's existing DSM programs is to deliver meaningful energy savings and manage peak demand, directly bolstering system reliability and supporting energy affordability for all ratepayers. These programs improve the efficiency of the electric grid, avoid energy costs during critical peak demand periods, and can defer the need for constructing new transmission and generation capacity. In 2025 alone, NV Energy's DSM Portfolio achieved over 213 MW of peak reduction and $298 million in net benefits.[5]

Q. DO THESE PROGRAMS PROVIDE ADDITIONAL BENEFITS BEYOND DIRECT ENERGY AND CAPACITY SAVINGS?

A. Yes. In addition to grid benefits, DSM programs deliver valuable non-energy benefits. They lower energy burdens, foster local economic development, reduce environmental externalities such as greenhouse gas emissions, and provide targeted support to low-income and historically underserved communities.

Q. AT A HIGH LEVEL, WHAT IS THE LARGE CUSTOMER OFFSITE DSM PILOT PROGRAM?

[5] 2026 Joint IRP, Vol. 33, Demand Side Management at 17 and 24. Tables DSM-8 and DSM 13.

A. The Large Customer Offsite DSM Pilot Program would allow a Large Customer, such as Google, to make a supplemental financial contribution—in addition to its standard payments under existing riders—to deploy "offsite" energy-saving and demand-reducing measures like residential HVAC upgrades and distributed battery storage. The term "offsite" refers to implementing the measures throughout the community rather than at the Large Customer's own facilities. In exchange for this voluntary funding, the Large Customer receives an appropriate amount of energy and capacity credit (somewhat analogous to a green tariff program, such as NV Energy's GreenEnergy Rider). The core purpose is to create incremental grid capacity, enhance reliability, and deliver direct benefits to existing ratepayers, especially low-to-moderate income households, without any cost impact on non-participating ratepayers. This aligns well with the goals of the existing DSM programs.

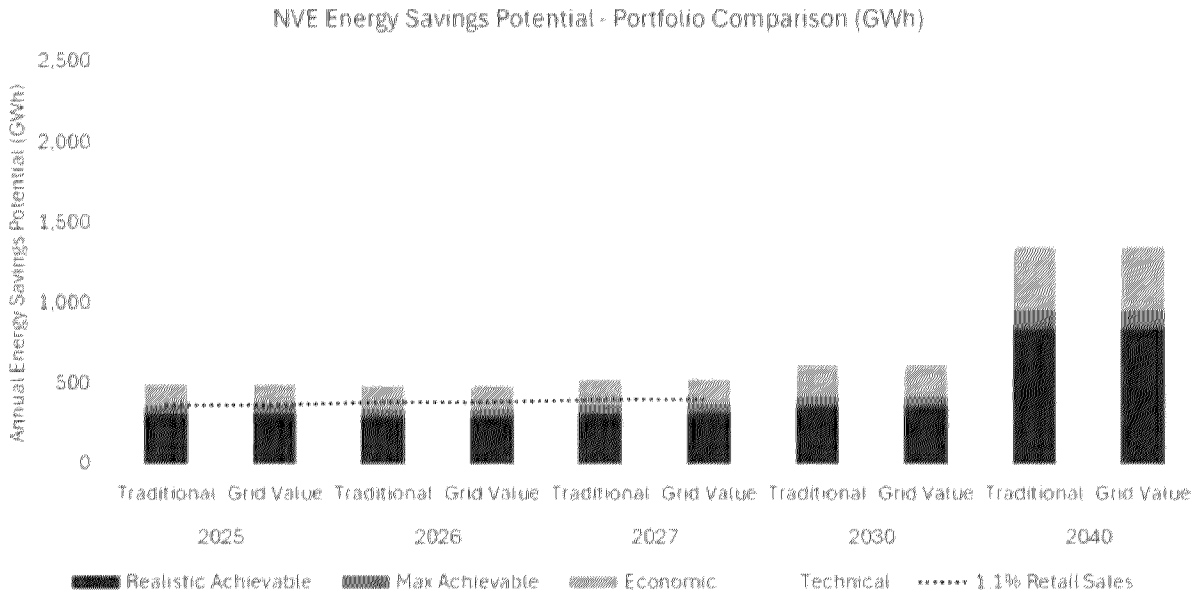
i. NV Energy's Potential Study

Q. IS THERE POTENTIAL FOR DEMAND SAVINGS BEYOND NV ENERGY'S CURRENT DSM PORTFOLIO?

A. Yes. NV Energy periodically conducts a market potential study to forecast the available energy and capacity savings from continued DSM efforts. The market potential study also assesses the potential for new DSM measures, identifying the technical, economic, and achievable savings potential. When broken down by DSM measure or program, this study helps identify available opportunities for cost-effective energy and capacity savings through the DSM programs.

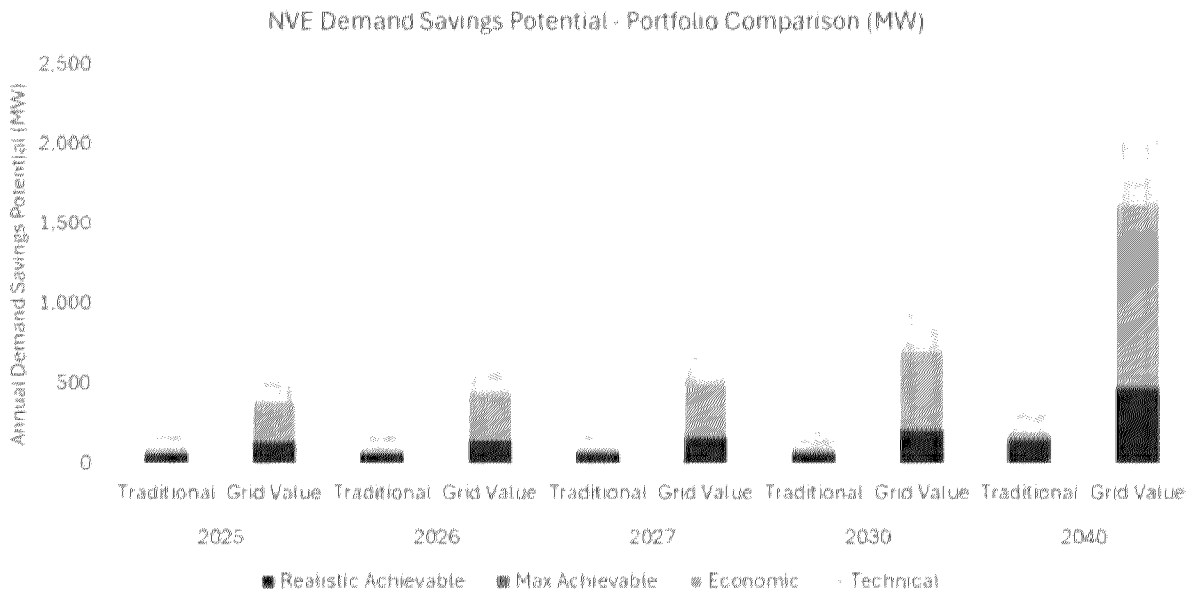
For the 2026 IRP, NV Energy relies upon its 2024 Market Potential Study, which was completed in the last IRP cycle. The 2024 Market Potential Study forecasted substantial energy and capacity savings beyond NV Energy's current performance level that are both economic and achievable through 2030.[6] Figure 1, reproduced below from the 2024 Market Potential Study, shows that the technical and economic potential for DSM savings far exceeds the historic incremental target for energy savings at 1.1% of annual energy sales annually (i.e., in kWh). Figure 2 similarly shows significant potential to grow capacity or demand savings (i.e., in MW) through focused development of demand response resources.

Figure 1: 2024 DSM Market Potential Study - Comparison of Energy Savings Potentials



[6] PUCN 24-05041, NV Energy Joint 2024 Integrated Resource Plan, Vol. 18, DSM-26 ("2024 Market Potential Study").

Figure 2: 2024 DSM Market Potential Study - Comparison of Demand Savings Potential



Q. DO YOU THINK NV ENERGY'S DSM PORTFOLIO IS LIMITED TO THE "REALISTIC ACHIEVABLE" LEVELS?

A. No. As NV Energy explained in the last IRP proceeding, the "realistic achievable" level of performance is capped based on incentive and budget levels tied to what the Commission approved in previous DSM plans.[7] NV Energy could likely achieve materially more economic potential for EE and DR resources if it were able to meaningfully supplement its portfolio budgets and incentive levels.

[7] 2024 IRP, Market Potential Study (DSM-26), page 75 of 179

ii. Brattle Study

Q. HAS ANY ANALYSIS BEEN PERFORMED ON THE POTENTIAL TO EXPAND NV ENERGY'S DSM PORTFOLIO THROUGH SUPPLEMENTAL FUNDING (E.G., THROUGH A LARGE CUSTOMER OFFSITE DSM PROGRAM)?

A. Yes. Google engaged The Brattle Group to perform a demand reduction potential study supporting the opportunity to achieve additional capacity savings through the Large Customer Offsite DSM Program. This study ("Brattle Study") is included as Exhibit 2 to my testimony.

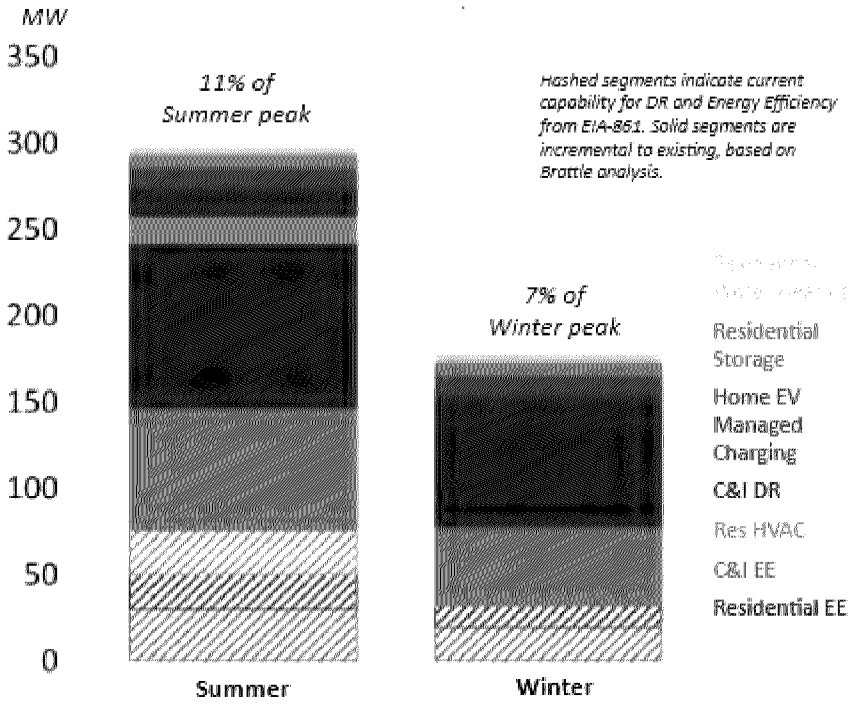
Q. CAN YOU PROVIDE AN OVERVIEW OF THE BRATTLE STUDY AND SOME OF ITS KEY FINDINGS?

A. Yes. This study looks specifically at the SPPC region of NV Energy's territory, where Google's Storey County facility is located. The study also focuses on capacity savings as a means to offset large load capacity additions while maintaining overall resource adequacy. The study confirms that although the "maximum achievable" savings estimated by NV Energy's market potential study have not been achieved in recent years, additional funding could unlock these savings.[8] More specifically, the Brattle Study estimated that 221 MW of incremental DSM potential is available by 2030 in the base scenario, increasing to 404 MW in the high enrollment scenario.[9] This forecast is based on a robust behavioral and technical feasibility analysis that considers customer participation rates, enrollment rates, and

[8] Exhibit 2 at 18.
[9] Accounting for 75.5 MW of existing DSM load reduction. See, Exhibit 2 at 5 and 33.

technology adoption limitations to determine an achievable peak load reduction potential across many DSM technology measures. Figure 3 illustrates the resulting base scenario achievable capacity savings potential, reproduced from the Brattle study.[10]

Figure 3. DR & EE Achievable Peak Reduction Potential - NV Energy SPPC, 2030



Q. HOW DO THESE RESULTS COMPARE TO NV ENERGY'S 2024 POTENTIAL STUDY RESULTS?

A. The Brattle study finds a significant increase in the available peak load reduction potential, compared to the 2024 NV Energy study. NV Energy's study projects a DR & EE realistic achievable potential in 2030 of just 48 MW in SPPC under the Grid Value Portfolio.[11] The

[10] Exhibit 2 at 21.
[11] 2024 Market Potential Study, at 123 and 128.

Brattle study finds more than four times the savings potential, exceeding even NV Energy's estimate for total economic potential of 204 MW.

Q. DO THESE RESULTS SUGGEST GREATER POTENTIAL FOR SAVINGS STATE-WIDE?

A. Yes. SPPC is the smaller of NV Energy's two utilities and constitutes a minority of NV Energy's DSM program savings. Nevada Power Company (NPC) has 2.5 times the peak load of SPPC.[12] In terms of DSM programs, NPC's portfolio has approximately 5 times as much peak load reduction as SPPC. By extrapolating the findings of Brattle's analysis to the larger customer base of NPC, the statewide potential for Large-Customer funded demand savings could exceed 1,000 MW.[13]

Q. WHICH DSM MEASURES DOES THE BRATTLE STUDY INDICATE ARE THE GREATEST OPPORTUNITY FOR INCREMENTAL SAVINGS IN SPPC'S SERVICE TERRITORY?

A. Based on the findings of the Brattle study, the measures with the greatest unmet potential are EE measures for both residential and commercial customers. Other measures with significant potential include residential programs specifically for HVAC equipment, EV managed charging, energy storage, and water heating, which together contribute more than 50 MW of potential summer peak load reduction by 2030.

Q. ARE THESE DSM MEASURES ECONOMICALLY COST-EFFECTIVE?

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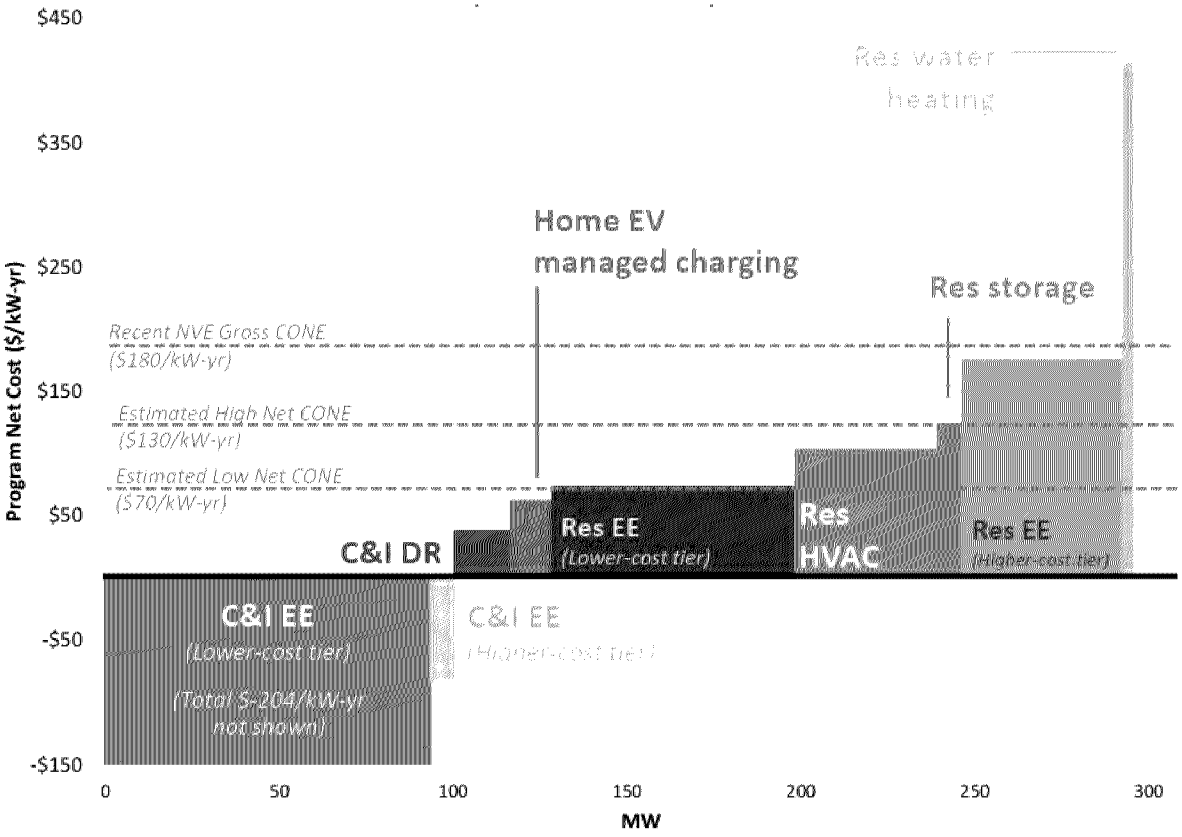
[12] 2026 Joint IRP, Vol. 33, Table DSM-30

[13] 1,000 MW is only 4 times greater than the incremental savings found in the Brattle study's base scenario (221 MW) for SPPC alone, and 2.5 times the high-enrollment scenario savings (404MW).

A. Yes. The study also estimated the net costs of each DSM measure and compared them with the estimated cost of new capacity resource alternatives. The net cost of the DSM measure is reported as the total costs of program administration and incentives minus the inherent value of energy savings provided by the measure, providing a comparable metric to a generation resource's capacity cost. Commercial EE and DR programs' energy savings benefits alone outweigh their costs, so their net costs are negative. Moreover, every DSM resource considered in the study, except water heating, has a cost below NV Energy's recent Gross Cost of New Entry (CONE), which is the expected full cost of procuring new generation capacity (e.g. a new combustion turbine). Therefore, nearly all DSM resources discussed are cost-effective when compared with the cost of new supply-side generating capacity, as illustrated in Figure 4, reproduced from the Brattle Study.[14]

Figure 4. Net Cost of Capacity from the DR & EE Portfolio - Summer 2030

[14] Exhibit 2 at 6.



Q. HOW DOES THE LARGE CUSTOMER OFFSITE DSM PROGRAM ADDRESS BARRIERS TO MEETING THE DSM SAVINGS POTENTIAL?

A. NV Energy's DSM programs, and most other utility-led programs are limited in their scope by the need to meet specific economic cost tests. New technologies, such as battery storage, can be especially incompatible with traditional DSM programs because program administration and scalability can be uncertain and expensive early in development. This is, in part, why economic and achievable potential estimates can fall short of the technical potential for savings. A Large Customer Offsite DSM program can address both the cost-effectiveness and technology maturation barriers to achieve greater DSM savings. Further, leveraging funds not required to meet cost-effectiveness thresholds to support new

technologies can help towards the maturation of technologies that will become cost-effective in the future.

Q. HOW DOES THE LARGE CUSTOMER OFFSITE DSM PROGRAM ADDRESS THE COST-EFFECTIVENESS BARRIER FOR DSM PROGRAMS?

A. Supplemental funding through the Large Customer Offsite DSM Program can pay for additional incentives or DSM measures that drive program participation. Voluntary funding contributed through the Large Customer Offsite DSM Program would not be charged to other customers and therefore should be excluded from traditional DSM cost-effectiveness screening tests. In many cases, EE and DR measures with significant potential could contribute to overall savings levels, but these measures would be excluded if the ratepayer funded program costs are too high. However, supplemental funding from large customers could add to or supplement the ratepayer funded costs for programs that are marginally cost-effective, thereby enabling their potential savings to be included.

Q. CAN YOU GIVE AN EXAMPLE OF PROGRAMS THAT ARE MARGINALLY COST-EFFECTIVE?

A. Yes. Heating, ventilation, and air conditioning (HVAC) systems are one of the largest sources of energy use in residential homes, and increasing the efficiency of those units—through system upgrades and tune-ups—has the potential to save considerable energy and capacity. However, residential HVAC programs are often marginally cost-effective because of the labor, marketing, and administrative burden of working with many individual residential customers. In SPPC specifically, these savings cannot be recognized because the HVAC tune-up program did not pass the net Total Resource Cost test (nTRC) and therefore

is not included in the potential study's economic or achievable potential.[15] However, in NV Energy's NPC territory, the HVAC tune-up program did pass the cost test, adding approximately 6% to NV Energy's total energy savings potential. This cost-effectiveness barrier has led NV Energy to limit deployment of HVAC programs in SPPC, despite proven technical potential in southern Nevada. The Large Customer Offsite DSM Program could offset or supplement the costs of these HVAC programs to ensure NV Energy's investment is cost-effective and captures the full potential of HVAC programs.

Q. ARE NV ENERGY'S CURRENT RESIDENTIAL HVAC PROGRAMS LIMITED BY COST-EFFECTIVENESS AND PARTICIPATION?

A. Yes. NV Energy's 2025 program results found that residential HVAC and heat pump programs in SPPC underspent their budgets by 40% and achieved less than one-third of the targeted energy savings.[16] NV Energy attributed the lower-than-expected participation rates to the high unit cost of an air conditioning unit. As a result, most participation in this program was for HVAC tune-ups, which have lower savings per participant versus unit upgrades that have a high cost-effectiveness barrier.

Q. CAN A LARGE CUSTOMER OFFSITE DSM PROGRAM FUND OTHER MEASURES THAT FACILITATE COST-EFFECTIVE UTILITY INVESTMENTS?

A. Yes. Such a program could also fund repair, remediation, and maintenance items, so-called "pre-weatherization upgrades," that are necessary before participating in existing programs.

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[15] 2024 DSM Potential Study at 116 and 125.
[16] 2026 Joint IRP, Vol. 33, Demand Side Management Plan at 124, Table DSM-57.

Water intrusion, hazardous electrical systems, or asbestos are common pre-weatherization issues that often disqualify low- and moderate-income customers from participating in weatherization programs. Funding these pre-weatherization measures expands the potential pool of DSM program participants, particularly low- and moderate-income customers.

Q. HOW DOES THE LARGE CUSTOMER OFFSITE DSM PROGRAM ADDRESS THE TECHNOLOGY MATURITY BARRIER FOR DSM PROGRAMS?

A. The Large Customer Offsite DSM Program can also target DSM measures that are still nascent and may not have a mature market. Such measures may be less suitable or more risky for inclusion in a utility DSM program, as their effectiveness and scale are uncertain. This is true of new technologies, like home energy storage, which has almost no penetration in the current SPPC market. The Brattle study finds that across five scenarios, the available residential energy storage capacity could vary from 3 MW to 85 MW by 2030. Higher participation incentives and greater customer engagement are likely to increase the potential outcome of a battery storage program. The Large Customer Offsite DSM Program is well suited to fund this type of nascent program as the additional funding can help to overcome early-stage barriers and establish this technology as a DSM resource, while protecting existing utility customers from the risks associated with early program development.

Q. IS NV ENERGY'S CURRENT RESIDENTIAL BATTERY DR PROGRAM LIMITED BY MARKET MATURITY?

A. Yes. In 2025, only 15 customers with battery storage in SPPC participated in NV Energy's residential DR program.[17] Participation was limited by vendor access for different battery technologies/manufacturers. Further, because residential DR participants are compensated with performance credits under the Schedule GSR-C and GSR-E tariff and no upfront incentive, participation has been limited. The Large Customer Offsite DSM Program presents an opportunity to supplement these incentives to increase participation.

C. NV ENERGY'S IRP PROPOSAL

Q. DID NV ENERGY ADDRESS THE LARGE CUSTOMER OFFSITE DSM PROGRAM IN ITS INITIAL IRP FILING?

A. Yes. NV Energy's IRP identifies a Large Customer Offsite DSM Pilot Program under development. NV Energy states in its Demand Side Management Plan that it "is addressing the concept in this filing" in response to the Commission's directive in Docket No. 24-05041.[18] It goes on to say that there has been "a collaborative effort [resulting] in general alignment on the core structure and key design elements of a potential pilot program."[19]

Q. DOES NV ENERGY'S DSM PLAN PROVIDE ANY ADDITIONAL DETAILS OF THE PROGRAM?

A. Yes. The Company provides limited additional details while explaining that aspects of the program need further development.

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[17] 2026 Joint IRP, Vol. 33, Demand Side Management Plan at 212.
[18] 2026 Joint IRP, Vol. 33, Demand Side Management Plan at 5.
[19] 2026 Joint IRP, Vol. 3, Rodriguez Direct at 10:1-7.

Q. DOES NV ENERGY REQUEST COMMISSION APPROVAL OF A FULL LARGE CUSTOMER OFFSITE DSM PROGRAM?

A. No. NV Energy does not recommend the approval of a fully-fledged new program but suggests that it is appropriate to "continue developing a pilot program." The Company further states that "The Collaborative work to date has advanced the concept, but the threshold requirements identified by the Commission in the 2024 IRP Order have not yet been fully satisfied."[20]

Q. DID THE COMMISSION IDENTIFY SPECIFIC THRESHOLD REQUIREMENTS FOR PROGRAM APPROVAL IN THE 2024 IRP ORDER?

A. No, the Commission did not identify any specific threshold requirements for program approval. However, NV Energy's DSM Plan suggests that the Company interpreted the Commission's Order to include three threshold requirements. NV Energy's response to DR Google 07 confirms that these three threshold requirements were not specifically identified in the Commission's 2024 Order but were based on "the Companies' understanding of the areas requiring additional detail and evidentiary support, based on the program elements the Commission considered."[21] The three specific criteria NV Energy believed should be met for a program or pilot to be approved are described in the Company's DSM Narrative as follows:

- Specificity around eligibility, duration, budget, credit mechanics, and measurement

[20] 2026 Joint IRP, Vol. 33, Demand Side Management Plan at 5.
[21] NV Energy response to Data Request Google 07, attached as Exhibit 3

- Evidentiary support that the program will not harm other ratepayers
- A clear endpoint or review mechanism

Q. DOES YOUR TESTIMONY ADDRESS THESE THREE CRITERIA?

A. Yes. The following table summarizes how each of these criteria has been addressed herein.

NV Energy's Suggested Criteria	Response
1. Specificity around eligibility, duration, budget, credit mechanics, and measurement.	Section 4 provides additional details regarding eligibility (4b), duration (4b), budget (4c), and measurement (4d). Section 4e and 5b discuss bill credit mechanics with the recognition that this detail should be finalized within 6 months.
2. Evidentiary support that the program will not harm other ratepayers	Section 5 discusses financial details (e.g., program cost recovery and bill credits) intended to ensure the large customer fully funds the program costs and is credited only for the savings created by their contribution. Section 5d addresses specific recent concerns about Cost Shifting associated with large load programs.
3. Clear Endpoint or review mechanism	Section 4 discusses the duration and evaluation process.

Many of these items were discussed within the DSM Collaborative and other stakeholder meetings.[22]

Q. DO YOU AGREE THAT THE LARGE CUSTOMER OFFSITE DSM PROGRAM IS NOT READY FOR COMMISSION APPROVAL?

A. No. With the additional details provided in my testimony, I believe a fully-fledged program could be ready for approval in the near future. However, even if that does not occur, the pilot should still move forward. Significant progress has been made in building a framework

[22] A presentation from the January 2026 DSM Collaborative meeting is attached as Exhibit 4.

for the Large Customer Offsite DSM program. While a few details for a permanent program remain to be finalized, there is sufficient structure for a pilot program to be approved now. In the following sections of my testimony, I address NV Energy's suggested three areas requiring additional detail and evidentiary support, as outlined in the table above.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED PILOT PROGRAMS THAT INVOLVED A STAKEHOLDER PROCESS FOR FINALIZING DETAILS?

A. Yes. The Commission has established a clear precedent for this type of structured, collaborative approach. For example, in its Order in the Distributed Resource Planning (DRP) proceeding (Docket No. 17-09021), the Commission approved a framework for DRP pilots. That framework explicitly directed NV Energy to work with stakeholders in a collaborative process to develop and finalize specific goals, metrics, and implementation details for those pilots. The process I will propose here for the Large Customer Offsite DSM Pilot mirrors that Commission-approved precedent.

4. PILOT PROGRAM GOALS AND FRAMEWORK

A. OVERALL GOALS AND OBJECTIVES

Q. PLEASE DESCRIBE THE OVERALL GOALS AND OBJECTIVES OF THE LARGE CUSTOMER OFFSITE DSM PILOT PROGRAM.

A. The pilot program is built upon four key objectives:

1. *Increase Incremental Clean Grid Capacity*: Provide a scalable option for Large Customers seeking access to incremental clean grid capacity. This could also expand the solutions available under the Clean Transition Tariff (CTT) framework and free up capacity new customers seeking to connect to NV Energy's system.
2. *Facilitate Distributed Solutions*: Introduce a pathway to rapidly deploy capacity resources through distributed solutions, bypassing current supply chain constraints for supply-side generation and transmission. Additional funding support from large customers also increases distributed resources' (sometimes referred to as Virtual Power Plants) ability to scale more quickly.
3. *Provide Direct Customer Benefits*: Support a form of grid capacity that has direct benefits to NV Energy ratepayers. This includes expanding the reach of NV Energy's customer programs that provide bill relief, including for low-to-moderate income (LMI) customers and customers in historically underserved communities, by seeking to expand funding beyond the minimum requirements in N.R.S 704.741(3)(b).
4. *Support Nevada Policy Goals*: Assist with Nevada's overall policy goals for advancing clean energy, enhancing grid reliability, and supporting customer affordability.

Q. WHAT IS THE RATIONALE FOR A LARGE CUSTOMER, SUCH AS GOOGLE, TO BE INTERESTED IN DEVELOPING THIS TYPE OF PROGRAM?

A. The interest from a Large Customer like Google stems from several key strategic drivers:

1. Pathway for Community Investment: The program offers a direct mechanism to invest in the local communities where large customers operate, providing tangible benefits to local residents.
2. Access to a Readily Available Grid Resource: Energy efficiency is a form of clean grid capacity that can be deployed quickly. Coordinated DERs, operated as a Virtual Power Plant (VPP), also provide rapidly scalable capacity, helping to expand the resource pool today. Expanding rapid-deployment DSM and VPP capacity alleviates near-term peak constraints on the broader system, enhancing grid reliability for the entire region. Further, providing funding to support incremental clean grid capacity also aligns with the key attributes of a Clean Transition Tariff that Google has pioneered in Nevada.
3. Alignment with State and Corporate Goals: This program helps a Large Customer support Nevada's clean energy goals while also aligning with corporate sustainability objectives.

Q. HOW WILL THE LARGE CUSTOMER OFFSITE DSM PROGRAM FUNCTION IN PRACTICE?

A. The general program framework allows a qualifying Large Customer to make a voluntary, monetary contribution to expand SPPC's DSM portfolio, over and above its standard contributions under the Energy Efficiency Program Rate (EEPR) Schedule. NV Energy must leverage these supplemental funds to enhance and/or expand existing DSM programs, or implement new measures and programs.

Q. HOW DOES THIS SUPPLEMENTAL FUNDING ALLOW FOR AN EXPANSION OF DSM EFFORTS?

A. This supplemental funding provides critical flexibility, allowing the Company to innovate and expand its DSM efforts in ways not typically possible with standard ratepayer funds. Primarily, it enables the pursuit of new measures and refreshed approaches to engaging customer segments. For instance, the funding could allow for:

- Addressing foundational barriers to efficiency, such as paying for pre-weatherization work needed before major upgrades can occur.
- Piloting new incentive strategies, like offering graduated, income-based incentives to provide greater support to customers who need it most.

The funding may also allow the Company to amplify its existing portfolio. By allowing NV Energy to exceed historic budget caps, overcome cost-effectiveness hurdles, increase up-front incentives for proven programs, or expand the portfolio to include new technologies, NV Energy could recognize increased savings for existing DSM programs.

B. ELIGIBILITY & DURATION

Q. WHO WOULD BE ELIGIBLE TO PARTICIPATE IN THE LARGE LOAD OFFSITE DSM PROGRAM?

A. For clarity's sake, participation is divided into two categories: 1) participation by large load customers as funders to the Large Load DSM program, and 2) participation by residential

and commercial customers as recipients of program services (including incentives and rebates). For the large load participants, Google proposes that eligibility eventually be extended to all Commercial and Industrial customers with loads above 1 MW who wish to participate. For recipients of program services, the eligibility should be consistent with the underlying DSM program offerings. For the initial pilot phase, Google also proposes that eligibility for both be limited to the SPPC service area.

Q. WHAT DURATION DOES GOOGLE RECOMMEND FOR THE OFFSITE DSM PROGRAM?

A. Google ultimately recommends that this effort be made into a permanent program. However, in the interest of delivering near-term benefits, Google supports an initial pilot program with a 3 year duration (2027-2029). This should be evaluated for permanent program status prior to the pilot's conclusion (i.e., in the 2029 timeframe or sooner).

C. PILOT PROGRAM MEASURES AND BUDGET

Q. IS YOUR PILOT PROPOSAL INFORMED BY ANY STUDY OF DSM POTENTIALS AND COSTS?

A. Yes. The Brattle Group study discussed in Section 3.b about the technical potential analysis assessed the incremental DSM potential and costs in the SPPC service area. The study identified a set of candidate DSM measures for the Offsite DSM program and evaluated total potential, net costs, and peak load reduction capability.

Q. WHAT TYPES OF PROGRAMS AND MEASURES DO YOU PROPOSE THE PILOT TARGET?

A. I recommend that the initial pilot focus on two primary categories of DSM measures: 1) residential HVAC, specifically targeting low-to-moderate (LMI) customers, and 2) residential distributed battery storage.

Q. WHY DO YOU RECOMMEND THESE SPECIFIC CATEGORIES?

A. Residential HVAC and customer-sited batteries were selected for a few reasons. Both opportunities face cost-effectiveness or technology-maturity barriers that the Large Customer Offsite DSM Program is well suited to address. As discussed in Section 3.b, residential HVAC programs face cost-effectiveness and participation barriers that supplemental funding could address. Residential battery storage was selected as a novel technology measure to pilot adding flexible grid capacity. This type of program has limited precedent, and NV Energy's current battery program has only 15 customers participating in SPPC. The Brattle study identified significant upside potential for storage capacity in its high-enrollment scenarios. Supplemental funding for a battery storage program could help scale up additional deployment beyond NV Energy's current program.

Q. WHAT IS THE POTENTIAL SCALE OF SAVINGS FOR THE LARGE CUSTOMER OFFSITE DSM PILOT PROGRAM?

A. To demonstrate the potential scale, the pilot is initially targeting a savings level in the range of 5 to 15 MW per year. A definitive savings goal will be established based on the funding level committed by the participating Large Customer, which is subject to the approval of the bill credit mechanism. The Brattle study found that the achievable peak reduction savings to SPPC from HVAC upgrades range from 15 to 57 MW and from battery storage

range from 7 to 85 MW. The combined potential (22 to 142 MW) strongly suggests that a cumulative pilot target of 5 to 15 MW per year is achievable.[23]

Q. HOW CAN SUPPLEMENTAL PROGRAM FUNDING BE USED?

A. For residential HVAC, it is proposed that funding from the Large Customer Offsite DSM Pilot Program be used to increase support for the existing Residential AC and Heat Pumps Program. Specifically, the Large Customer funding will be used to offer enhanced incentives directly to customers who replace old, inefficient HVAC systems with higher-efficiency equipment. This could include support for pre-weatherization work as described above. This enhanced HVAC initiative is proposed to utilize the same delivery model as NV Energy's existing Residential HVAC program and provide additional rebates for low-income customers.

For residential battery storage, the pilot's funding will supplement and expand the existing NV Energy Battery Storage DR offering to increase participation. Specifically, it will provide an upfront incentive for residential customers who install a new battery, in addition to ongoing DR participation performance incentives, fully funded by the Large Customer. Ongoing participation incentives could be provided as part of the Grid Services Rider program subsequent to the pilot program's conclusion.

Q. WHAT IS THE PROPOSED BUDGET FOR THIS PILOT PROGRAM?

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[23] Exhibit 2 at 2 shows DR & EE Achievable Peak Reduction Potential. Note that the HVAC potential value excludes existing HVAC demand savings of approximately 25 MW.

A. The proposal envisions an initial pilot budget of $5 million per year for two to three years, reflecting an initial target funding level proposed by Google. However, this figure is illustrative. The final funding amount would be determined by the participating Large Customers in consultation with NV Energy only after the final bill credit mechanism is approved. As the pilot would be fully funded by voluntary contributions, there would be no cost increase for non-participating customers as a result of this program.

Q. WILL ALL OF THE LARGE CUSTOMER FUNDING BE USED FOR CUSTOMER INCENTIVES?

A. No. Large Customer funding will include an administrative adder, but most of the funding will be directed to customer incentives. Allocating a portion of funding specifically for administrative costs ensures that existing DSM programs are not financially impacted by the addition of this pilot.

Q. WILL LARGE CUSTOMER FUNDING BE SUBJECT TO COST-EFFECTIVENESS REQUIREMENTS?

A. No. Because all incremental program capital is voluntarily contributed rather than collected from the general rate base, traditional cost-effectiveness screening tests, as set out in NAC § 704.934, designed to protect ratepayer funds from capital loss do not apply to the private funding component.

Q. WILL NV ENERGY RECEIVE ANY PERFORMANCE INCENTIVE OR LOST-REVENUES RECOVERY FROM SAVINGS GENERATED THROUGH THIS PROGRAM?

A. No. Any energy and capacity savings generated by this program will be excluded from NV Energy's calculation of its overall DSM energy and capacity savings, as well as from the calculation of its DSM performance incentive and lost-revenue adjustment mechanism. The program is intended to be additive rather than replacing existing opportunities. The energy and capacity savings from this pilot will be credited to the large customer that funds them, in accordance with the final bill credit mechanism, which will be developed with input from the DSM Collaborative and then filed for Commission approval.

Q. WILL CONTRIBUTING LARGE CUSTOMERS BE INVOLVED IN THE PROGRAM IMPLEMENTATION PROCESS?

A. Yes. While NV Energy will ultimately contract for services from DSM providers, contributing large customers that fund the Large Customer Offsite DSM Pilot will have an opportunity for oversight. Supporting Large Customers will work closely with NV Energy to review and select service vendors for program implementation. This approach is appropriate since the large customer is taking on the financial and performance risk of supporting these supplemental measures.

Q. FOR MEASURES INSTALLED UNDER THIS PILOT PROGRAM, HOW WILL ONGOING OPERATIONS AND MAINTENANCE COSTS BE HANDLED?

A. In the majority of NV Energy's DSM programs, customers bear all O&M expenses (e.g., normal HVAC repairs) after a measure is installed. The exception is the Company's DR program, where NV Energy handles thermostat installations and provides replacements specifically for failures caused by manufacturing defects. Generally, new devices supported by NV Energy subsidies include manufacturers' warranties that address most early-stage

failures. A portion of the overall budget may be set aside to cover any failures not covered by warranty, but this is anticipated to be *de minimis*. Beyond this, customers are responsible for routine maintenance costs, similar to any other household appliance.

D. MEASUREMENT AND EVALUATION

Q. HOW WILL THE PILOT PROGRAM BE EVALUATED AND MONITORED?

A. The pilot will be evaluated and monitored through a comprehensive, three-part process to ensure transparency and accountability:

1. Quantitative Evaluation: First, savings levels will be quantified using the established Evaluation, Measurement, and Verification (EM&V) framework applied to all NV Energy DSM programs.
2. Qualitative Assessment: Second, the pilot will be assessed against a set of five success criteria designed for this program, which I detail later in my testimony.
3. Stakeholder Oversight: Finally, as mentioned previously, there will be ongoing stakeholder review. Regular updates on program performance, spending, and savings will be provided to the DSM Collaborative.

Q. HOW DOES NV ENERGY GENERALLY MEASURE AND QUANTIFY THE SAVINGS FROM ITS DSM PROGRAMS?

A. NV Energy employs a combination of established EM&V techniques to determine energy and capacity savings for its DSM initiatives. To assess energy savings from HVAC installations, the Company has relied on engineering calculations that compare the efficiency of old and new equipment in accordance with its DSM Measurement and

Valuation Technical Appendix.[24] The Company validates these estimates by metering a subset of the hardware to ensure precision. For residential demand response programs and residential battery storage, NV Energy utilizes recorded meter and device-level data to determine savings based on actual performance during demand response events.

Q. HOW WILL EM&V BE CONDUCTED AND USED FOR CREDITING IN THE PROPOSED PILOT PROGRAM?

A. The pilot's savings will be quantified annually through NV Energy's existing EM&V contractor and framework. The results of this EM&V process—the verified energy and capacity savings—will then form the basis for the credits provided to the participating customer. These credits will be limited to the fraction of each program's savings directly attributable to the participating customer (e.g., based on percentage of funding contributed).

The precise methodology for attributing and crediting these savings will be a central component of the final bill credit mechanism developed for the pilot. For example, where the Large Customer's funds supplement an existing, ratepayer-funded program, one proposed approach is to attribute savings based on the percentage of total funding from each source. This approach will be fully detailed in the final mechanism submitted for Commission approval.

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[24] See 2026 Joint IRP, Vol. 35, DSM-8 ("M&V Technical Appendix 1: Calculation Methodology for Critical Peak Demand (kW) Savings and Monthly Energy (kWh) Savings per Rate Class").

Q. BEYOND THE FORMAL EM&V RESULTS, WHAT OTHER SUCCESS METRICS WILL BE USED TO EVALUATE THE PILOT PROGRAM?

A. In addition to the verified savings, the pilot's success will be assessed against five key performance metrics:

1. Scalability: The program will be assessed on its ability to deliver meaningful savings in its first year while demonstrating a model that can be substantially scaled in the future.
2. Cost: While not subject to a strict cost-effectiveness test, the program should demonstrate that it is a cost-competitive resource on a $/kW basis compared to other supply-side options.
3. Speed: The pilot must demonstrate its ability to leverage existing DSM frameworks to deploy capacity savings within the first 1-3 years, showcasing its value as a near-term resource.
4. Carbon Reduction: The program should lead to a verifiable, overall reduction in emissions compared to the status quo.
5. Community Benefits: The program must provide direct and tangible benefits to local communities, such as LMI customers and other historically underserved groups.

Furthermore, additional metrics may be reported on as the program is implemented, based on input and advice from the DSM Collaborative.

E. STAKEHOLDER PROCESS FOR FINALIZATION

Q. IS GOOGLE RECOMMENDING THAT THE COMMISSION APPROVE A COMPREHENSIVE LARGE CUSTOMER OFFSITE DSM PROGRAM?

A. No, Google recommends that the Commission approve a pilot program that will continue to advance the development of the Large Customer Offsite DSM Pilot Program. While stakeholders broadly agree on the program design, a few elements still require finalization for a permanent DSM program. Rather than waiting for the next IRP to establish a program, the Commission should direct NV Energy to initiate a pilot to include in SPPC's DSM portfolio. This approach allows the initiative's benefits to be unlocked for customers in the near-term while the remaining details are finalized and approved.

Q. WHAT IS GOOGLE'S RECOMMENDED PROCESS FOR FINALIZING THE PILOT'S DETAILS AND ENSURING ONGOING STAKEHOLDER COLLABORATION?

A. Google proposes that a structured process be used to finalize the bill credit mechanism. Following an approval order, an initial proposal will be developed and presented to the DSM Collaborative for its review within three months. Based on that input, a final bill credit mechanism will be filed with the Commission for its approval within a total of six months.

In addition, NV Energy and Google will provide regular updates to the DSM Collaborative throughout the pilot's implementation. The Collaborative will be a key forum for discussing program performance, spending, and savings, ensuring a transparent and collaborative partnership for the duration of the pilot.

5. PROGRAM COST RECOVERY AND BILL CREDITING MECHANISMS

A. PROGRAM COST RECOVERY

Q. HOW WILL THE COSTS OF THE LARGE CUSTOMER OFFSITE DSM PILOT PROGRAM BE RECOVERED?

A. The total costs of the pilot program would be paid by the contributing large customer. The supplemental, voluntary funds are intended to augment existing resources through enhanced incentives and new measures. Funding is envisioned to be collected through the large customer's Energy Efficiency Program Rate (EEPR) over the program year. Currently, all customers, including large customers, contribute financially towards NV Energy's DSM Portfolio through the EEPR, which is collected on customer bills. For large customers who opt into the Offsite DSM Pilot Program, a modified or supplemental EEPR would be calculated and added to that customer's bill to account for their contributions.

Q. CAN YOU PROVIDE AN ILLUSTRATIVE EXAMPLE OF HOW THIS MIGHT WORK IN PRACTICE?

A. Yes. As a hypothetical example, assume a large customer commits $5 million annually to fund a distributed battery storage deployment program over 3 years. Also assume the large customer has monthly sales of approximately 73 million kWh. Under this scenario, a supplemental increase in the EEPR from its current value of $0.001/kWh to $0.006/kWh should be sufficient to collect program costs of approximately $415,000 per month, or $5M per year.

Q. WILL THE LARGE CUSTOMER CONTRIBUTION COVER BOTH UPFRONT AND PERFORMANCE INCENTIVES?

A. Yes. The annual large customer contribution funds upfront incentives to participants who enroll in the program. For EE measures, these funds can support standard rebate programs that produce permanent load reductions without any need for ongoing program support. For DR measures, the contributions can support upfront incentives analogous to NV Energy's DR-Build program. For DR measures with ongoing performance incentives, the annual contribution can also prefund a set period (e.g., three years) of expected performance incentives for the newly enrolled customers consistent with the duration of the pilot program. If the pilot program is made permanent, a large customer could then continue funding performance incentives beyond the initial pilot period. These ongoing contributions would function similar to NV Energy's DR-manage program and could even directly support DR-manage. If the large customer ends its contributions to the Large Customer Offsite DSM program, those participants originally enrolled under the program would be moved into NV Energy's DR-Manage program.

Q. WILL THESE VOLUNTARY CONTRIBUTIONS COVER ADMINISTRATIVE AND OTHER NON-INCENTIVE COSTS OF THE PROGRAM?

A. Yes, the funding model is based on an expected cost of DSM resources per unit of peak load reduction, plus a 10% Administrative Adder designed to cover Evaluation, Measurement, and Verification (EM&V) and incremental administrative costs.

B. PARTICIPANT BILL CREDIT

Q. DOES THE PROPOSED PILOT INCLUDE A DIRECT FINANCIAL BENEFIT FOR THE CONTRIBUTING LARGE CUSTOMER?

A. Yes. A central feature of the pilot program is that the contributing customer will receive a bill credit corresponding to the value of the incremental energy and capacity savings their financial contribution generates. The proposed framework is intended to align with the existing bill credit framework for NV Energy's GreenEnergy Rider program and Clean Transition Tariff (CTT). [25] It may also align with the emerging compensation structure for DERs through the Grid Services Rider (GSR). [26]

Q. WHAT IS YOUR PROPOSED FRAMEWORK FOR THE LARGE CUSTOMER OFFSITE DSM PROGRAM CREDITING MECHANISM?

A. The proposed crediting framework is modeled after the principles in the CTT. At a high level, it would function as follows:

- Capacity Credit: The customer would receive a bill credit for the verified kW capacity savings (and potentially kWh energy savings). The value of these credits would be based on the cost of generation capacity as set forth in the Base Tariff General Rate ("BTGR") (and potentially the cost of energy in the Base Tariff Energy Rate ("BTER")).

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[25] See 2026 Joint IRP, Vol. 33, Section 9. See also PUCN Docket No. 25-10012, Order, August 11, 2026. Available at https://puc-onbase.nv.gov/api/Document/AR1%C3%89de7wz%C3%89pQ0ktZAMu45MTCZ1SlWFabe3uZeyqLaW24JqjPw5%C3%899go%C3%89h%C3%89rQT%C3%89xTZmht8OuzVM2lsNlVNnAk7hWo%3D.

[26] See PUCN Docket No. 24-05022, NV Energy Compliance Filing, June 11, 2025. Available at https://puc-onbase.nv.gov/api/Document/ARSAzL2PccMMQm%C3%81zw5IWTdkiEZCoTky5nh1pdVKjS0Ob4DxfynNzSg6kVf8MiKDiP%C3%89xTLJJLM7%C3%89Aj9rZco1LB5Q%3D.

- Proportionality: The customer is credited for incremental savings from the measures funded by its contribution. For example, if a large customer funds 50% of the participants in NV Energy's residential battery storage program that achieved a total 20 MW of peak reduction, and NV Energy funded the remainder, the large customer would receive credit only for their 50% contribution (i.e., 10 MW).
- Timing: Crediting would begin after the savings from a given measure are verified through the formal EM&V process and would continue for the life of the measure based on continued performance evaluation.

The full details of the final crediting mechanism should be developed with input from the DSM Collaborative and then filed for Commission approval, along with other finalized program details, within six months following the Commission order in this proceeding.

Q. PLEASE EXPLAIN HOW THIS ALIGNS WITH THE APPROACH USED UNDER THE CTT.

A. The CTT states that a customer on that tariff pays "the BTGR of the otherwise applicable rate schedule of the Customer, with the cost of generation capacity and energy supply removed through bill credits" for the portion of their demand and energy supplied by another source. [27] The proposed pilot program would use an similar method where the large customer pays their standard retail rate (inclusive of the BTGR) corresponding to their

[27] NV Energy, Schedule No. CTT. Available at https://puc-onbase.nv.gov/api/Document/AblQGcH02pl2Ic1jiE2r%C3%812WhxYTPb6dVa45O3BTTsL%C3%81CpqKVHjtM7YWjyYifCZrLRaBTzOCHbuJNXOXrLN07KFU%3D/?OverlayMode=View

overall demand as normal, but they would then receive a bill credit for the portion of their demand that is "supplied" by the incremental DSM resources.

Q. HOW DOES THE CTT ALIGN WITH THE LARGE LOAD CUSTOMER OFFSITE DSM PROGRAM?

A. The CTT framework provides a fair pathway for large customers to procure preferred resources (i.e. CTT Facilities) while paying for any incremental costs of those facilities. In theory, this framework should also accommodate DSM resources such as those procured through the Offsite DSM program.

Q. DO YOU HAVE ANY CONCERNS ABOUT DOUBLE COUNTING BETWEEN LARGE CUSTOMER BILL CREDITS AND PARTICIPANT SAVINGS?

A. No. The Offsite DSM Pilot will reduce residential customer's energy consumption who will capture some of the value of these bill savings; however, since residential rates are largely based on volumetric energy charges, they are unlikely to fully capture the marginal *capacity* value of incremental DSM resources. Therefore, it is still appropriate for Offsite DSM Pilot contributors to receive bill credits corresponding to the BTGR component of rates which is reflective of fixed generation capacity costs (but not reflective of volumetric energy costs).

Q. WHAT IS THE PURPOSE OF THE TIMING THAT DELAYS THE CUSTOMER'S CREDITS?

A. The scheduled delay to the second year is intended to allow sufficient time for the formal EM&V process to conclude. Withholding credits to the participating customer during installation of program measures, followed by a measurement period in year one, ensures

that compensation accurately reflects the capacity and energy benefits derived from the DSM program.

Q. CAN YOU PROVIDE AN ILLUSTRATIVE EXAMPLE OF HOW THE CREDIT WOULD BE CALCULATED?

A. Yes. As a hypothetical example, let's assume a Large Customer agrees to fund an Offsite 5 MW residential battery program with an estimated gross cost (including administration), of $2 million. The batteries installed through this program are expected to have a 10-year measure life. The $2 million is used to increase the budget of a hypothetical new battery program implemented by NV Energy from $2 million to $4 million, and expand the deployment from 5 MW to 10 MW, supporting customer incentives and administrative costs. Once the program savings are verified through the EM&V process, the contributing Large Customer would receive a bill credit for the 5 MW portion that reflects their contribution to the total. For calculation's sake, assume that NV Energy's BTGR value is found to be $70/kW-yr, which is close in proximity to recent estimates for marginal cost of new generation (e.g., the Cost of New Entry for a recently built or proposed gas peaker plants). This would provide a total annual credit of $350,000 during the years of the measure's life.

C. Alignment with GSR

Q. WHAT ARE THE GRID SERVICE RIDERS?

A. The Energy Grid Services Rider ("Schedule GSR-E") and Capacity Grid Services Rider ("Schedule GSR-C") are new tariff riders that establish a standardized, performance-based framework for compensating customers who participate in a Load Flexibility Program.[28] These two riders modify the compensation under the Optional Load Management and Automation Services Rider ("OLM-AS") for customers participating in residential and small commercial demand response programs. Schedule GSR-E compensates the energy (kWh) avoided or provided during called load reduction events, while Schedule GSR-C compensates the capacity (kW) reduction capability demonstrated. The grid services riders provide a technology-agnostic, harmonized approach to accommodate diverse DER types and avoid double compensation and inconsistent fixed incentives.

Q. CAN YOU DESCRIBE THE COMPENSATION MECHANISMS DEFINED IN THE GRID SERVICES RIDERS?

A. Each rider calculates a participant's compensation based on their performance against a "customer specific baseline," a counterfactual hourly load curve estimating what the customer would have consumed absent the event. Interval data from the event is subtracted from the baseline to determine the expected energy or capacity provided by the participant during the event. The GSR-E tariff, credits each kwh provided against the baseline at a rate set by the wholesale market price, modified by an energy resource rate reflecting administrative program costs (90%) and a distribution node adder (8%). The GSR-C

[28] PUCN Docket No. 25-10012, NV Energy Exhibit 101, October 14, 2025. Available at https://puc-onbase.nv.gov/api/Document/ARIV%C3%81n5%C3%81eNwG%C3%814%C3%892nBfj63rGaIltCgJKILVcHQZ4qm9KtDsed2X65G4ZkJonQq6T2b2uztt8c9rvZSH%C3%81B%C3%81ISZ7g%3D.

measures performance across multiple events to determine the participant's seasonal performance. This seasonal performance is compensated at an avoided cost of capacity that reflects generation and transmission infrastructure, with a standard value of $120/kW-yr. An adder of $25/kW-yr accounts for distribution infrastructure, while the total is multiplied by a capacity resource rate (30%) reflecting administrative program costs.

Q. HOW DOES THE GSR TARIFF ALIGN WITH THE LARGE LOAD CUSTOMER OFFSITE DSM PROGRAM?

A. The Offsite DSM program primarily offers a means of providing supplemental funding for DSM resources. As initially conceived, this funding would target traditional DSM programs from service providers that are contracted directly with NV Energy. Customers in the Residential Battery Storage DR program will receive participation incentives through the GSR tariffs.[29] The funding could also support third-party implementers that aggregate participation in the GSR program. This could provide a promising pathway to increase the number of offsite DSM resource options available to large load customers and scale the GSR program.

However, combining the Offsite DSM and GSR efforts may require some additional consideration for how and whether incentives should be shared between the contributing large load customers and the participating aggregator/site host. One potential option would be for the Offsite DSM bill credits for large load customers to correspond to initial deployment in earlier years (akin to DR Build programs) while GSR incentives

[29] 2026 Joint IRP, Vol. 33, Demand Side Management Plan at 218.

would compensate aggregators for performance in later years (akin to DR Manage programs). To avoid confusion during this initial pilot stage it is recommended that dual participation not be permitted for the first 3 years of the pilot.

Q. DOES THE APPROACH OF PROVIDING PARTICIPANT BILL CREDITS THROUGH THE GSR TARIFF CREATE A BARRIER TO AGGREGATOR PARTICIPATION?

A. Yes. Compensation through the GSR tariffs is delivered directly to the electric customer who hosts the DER behind their electric meter. However, the electric customer that is host to a participating DER is not necessarily the owner of that DER. One structure for aggregated grid services is for the aggregator to own the DER installed in the participants' homes to provide grid services. For battery storage, this structure can be beneficial since it would allow the aggregator to collect a 30% tax incentive for the installed battery.[30] However, compensation from the GSR tariff would accrue to the participant as a bill credit rather than to the aggregator. This disparity between the owner and beneficiary of the DER's performance would require additional information sharing and billing requirements to adjudicate compensation based on the DER performance between the DER owner and electric customer. This creates additional overhead and uncertainty for aggregators administering this program structure. If the GSR compensation could be assigned to the

[30] Federal tax credits for battery storage remain in place through 2032 for commercially-owned batteries, while residential tax credits for battery storage were sunset in 2025 by the One Big Beautiful Bill.

DER owner, rather than the customer hosting the DER, this would streamline the operations and billing for aggregators. To facilitate this use case, the Commission should consider allowing GSR participants to assign credit to a third-party DER owner.

D. ADDRESSING CONCERNS ABOUT A POTENTIAL COST SHIFT

Q. HAVE ANY RECENT PUCN DECISIONS RAISED CONCERNS ABOUT LARGE LOAD CUSTOMERS SEEKING ALTERNATIVE RESOURCE OPTIONS?

A. Yes. In Docket No. 24-06012, the PUCN dismissed a proposed ESA between LVCVA and NV Energy due to concerns about its alignment with the public interest. As part of its evaluation, the PUCN considered two criteria to determine whether the ESA was aligned the public interest:

- Criterion 1: Whether there is value in retaining LVCVA as a bundled customer versus the risk of them seeking a competitive alternative supplier.
- Criterion 2: Whether there is the potential for the shifting costs to non-participating customers

Q. DO YOU BELIEVE THE SAME CONCERNS ARE PRESENT IN THE CASE OF THE LARGE LOAD OFF-SITE DSM PROGRAM?

A. No. The Large-Customer Off-site DSM Proposal is distinct from the LVCVA case and the same concerns would not apply here.

Q. CAN YOU ELABORATE WHY THE PUCN'S CRITERION 1 CONCERNS ARE NOT APPLICABLE FOR THE LARGE LOAD DSM PROGRAM?

A. Yes. In the LVCVA case, the PUCN found that retention was not a justifiable reason for approval since NV's generation resources are highly restricted, meaning the customer lacks access to a truly competitive supplier. The Commission also determined that LVCVA did not need the ESA to reach its corporate objectives, as NV Energy's GreenEnergy Rider already provides a sufficient path. In contrast, the Large-Customer Off-Site DSM Program addresses these concerns as follows:

- Unlike supply-side resources, demand-side management (DSM) in NV is not similarly restricted, leaving substantial room for further growth.
- While DSM resources may technically be available, there is currently no viable route for a large customer to seek a competitive "demand-side resource supplier." Consequently, this program focuses on providing sufficient choice and optionality for customers through NV Energy.
- Providing flexible, clean energy options ensures Nevada remains a competitive, attractive destination for long-term advanced technology investment and innovation aligned with the State's clean energy objectives.
- Current offerings, such as the GreenEnergy Rider, do not meet Google's requirements for 24/7 Carbon Free Energy and local community impact.

Q. CAN YOU ELABORATE WHY THE PUCN'S CRITERION 2 CONCERNS ARE NOT APPLICABLE FOR THE LARGE LOAD DSM PROGRAM?

A. Yes. The PUCN argued that LVCVA's ESA would result in a cost shift because it locked in rates for 25 years, lacked a realistic market alternative, and shifted risks from the participant

to other customers without the participant providing their own resource. In contrast, the Large-Customer Off-Site DSM Program addresses these concerns as follows:

- The proposal defines a three-year pilot program rather than a long-term 25-year commitment.
- Access to similar opportunities remains open to other customers; in fact the program is explicitly designed to permit additional participants to opt in.
- Unlike the LVCVA case, Google expects to pay an initial premium for the incremental DSM resources it contributes.
- The DSM resources in this program are intended to be incremental to NV Energy's "status quo" portfolio. Thus, the large customer would be "providing its own resource" in contrast with the LVCVA case.
- The primary goal is expanding system capacity and community benefit, even if participation results in a net cost to Google. While a fair crediting mechanism is being requested to account for avoided costs, the level of this credit is not the overriding or determining factor in Google's interest in the program. If a net benefit occurs, it likely indicates current underinvestment in cost-effective DSM by NV Energy rather than a cost shift. Any potential impact from BTGR bill credits would be matched by avoided generation capacity costs for non-participants.
- This program addresses a specific gap where no "market alternative" currently exists for customers wanting to invest in higher DSM levels, as NV Energy offers no equivalent to a "green energy rider" for DSM.

- Because these DSM resources are incremental, they do not deplete the portfolio available to other customers or shift risk to non-participants. Instead, the program reduces risk by funding more costly DSM measures that lower peak demand without using ratepayer funds, thus bypassing existing PUCN budget limitations.

6. LARGE LOAD ELECTRIC SERVICE AGREEMENT

Q. DID NV ENERGY FILE A LARGE LOAD ELECTRIC SERVICE AGREEMENT IN THIS PROCEEDING?

A. Yes, NV Energy requests approval of a standard Large Load Electric Service Agreement ("LLESA") in this proceeding.[31] The Company states that the LLESA provides clear rules for serving very large customers, while protecting existing customers through cost-causation provisions.[32]

Q. ARE YOU COMMENTING ON THE LLESA TERMS IN YOUR TESTIMONY?

A. At this time, I am not providing any testimony regarding the LLESA terms and conditions or other provisions in the LLESE proposed by NV Energy. Instead, I offer observations of specific provisions that may be missing and should be addressed by NV Energy in its Rebuttal testimony.

Q. ARE THERE ADDITIONAL PROVISIONS THAT THE LLESA SHOULD ADDRESS?

---

[31] 2026 Joint IRP, Vol. 2, Wells Direct at 2
[32] 2026 Joint IRP, Vol. 2, Wells Direct at 17:15-22

A. The LLESA, as proposed by the Company, does not specifically address how a Clean Transition Tariff or Offsite Demand Side Management program would be addressed in the future. Because these provisions may be part of the ESA for large load customers in the future, the LLESA should address their treatment at a high level. This will prevent unnecessary delays in approving CTT or Offsite DSM programs in the future.

Q. ARE THERE OTHER PROVISIONS THAT THE LLESA FAILS TO ADDRESS?

A. The LLESA also does not address the ability for flexible connections.

Q. WHAT IS A FLEXIBLE CONNECTION?

A. Flexible connection, also called non-firm capacity service, refers to a connection to the grid that can be flexibly interrupted as needed by the grid operator. This is typically done because of grid congestion or capacity constraints.

Q. WHY ARE FLEXIBLE CONNECTIONS RELEVANT TO THE DISCUSSION OF NEW LARGE CUSTOMER LOAD GROWTH AND THE LLESA?

A. The risk and costs of serving new large loads can be further mitigated by connecting these large loads flexibly. Flexible connections allow loads to connect with a mixture of firm and non-firm capacity. The firm capacity delivers uninterrupted grid power under normal operating conditions to serve a portion of the customer's load, while the non-firm capacity is served when power is available. Large load can utilize on-site generation or demand flexibility to reduce demand during times where non-firm load is unmet by the utility. This non-firm load is integrated into the utility's operations and planning models.

Q. CAN YOU DISTINGUISH FLEXIBLE OR NON-FIRM LOAD FROM INTERRUPTIBLE LOAD OR DEMAND RESPONSE?

A. Flexible connections differ from interruptible load or demand response programs in both technical and program design elements.

Traditional demand response programs include commercial and industrial customers that negotiate flexibility after interconnection. These customers enroll voluntarily or through negotiated tariff agreements in exchange for incentive payments and can curtail or shift load after receiving a signal from the utility. Flexible connections consider a broader range of customers (e.g. aggregated smart devices, EV chargers, and large loads) and more holistically incorporate flexibility into resource planning and dispatch decisions.

On a technical level, flexible connections rely on more advanced monitoring and control approaches than traditional interruptible tariffs and provide system operators more confidence in relying on these resources. Additionally, flexible connections have different dispatch requirements than traditional interruptible customers, including but not limited to economic dispatch considerations. Flexible connections can also incorporate behind-the-meter resources, which may introduce further additional technical requirements. While the customer may bear the majority of this complexity, the design of flexibility options should consider how behind-the-meter resources could or will be used.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE LLESA TREATMENT OF CTTS, OFFSITE DSM PROGRAMS, AND FLEXIBILITY CONNECTIONS?

A. I recommend that NV Energy address how each of these provisions will interact with the LLESA under its proposal as part of its Rebuttal testimony.

7. CONCLUSION AND RECOMMENDATIONS

Q. CAN YOU SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. Yes. My testimony has demonstrated that the Large Customer Offsite DSM Pilot Program is an innovative, collaborative proposal, developed with extensive stakeholder input and in direct response to the Commission's encouragement in the last IRP proceeding.

I have explained that this pilot offers a unique framework where a large customer can voluntarily provide supplemental funding to expand DSM benefits throughout the community, with no cost impact on other ratepayers. The proposal includes a transparent, time-bound process for finalizing the remaining details, such as the bill credit mechanism, and ensures ongoing stakeholder oversight through the DSM Collaborative.

Based on these points, I believe the record shows this is a well-designed and valuable pilot. Therefore, I respectfully recommend that the Commission approve the Large Customer Offsite DSM Pilot Program as a component of NV Energy's IRP application. My specific recommendations for Commission action are as follows:

Recommendation 1: Approve the Large Customer Offsite DSM Pilot Program as discussed herein such that it can begin implementation as soon as 2027.

Recommendation 2: Establish a date certain within the next 6 months for NV Energy to finalize key components of the pilot program, including the bill crediting mechanism.

Recommendation 3: Require NV Energy to consider making the pilot program permanent in the next IRP cycle or as part of any consideration of a Large Load Tariff (whichever comes first).

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT 1

EXHIBIT 1

CURRENT
ENERGY GROUP

Edward Burgess

Founding Partner, eburgess@currentenergy.group

Professional Summary

Ed has over 13 years of experience working as a consultant in the energy and utilities industry. He specializes in various grid planning issues including the integration of renewable energy, energy storage, electric vehicles, and distributed energy resources. He has provided expert testimony on over 30 occasions before 13 state utility commissions on issues including utility resource planning, transmission planning, fuel and power purchase costs, rate design, and electric vehicle programs.

Prior to co-founding Current Energy Group in 2024, Ed was a Consulting Partner at Strategen Consulting. While at Strategen, he directed the company's grid planning practice area, where he provided technical consulting services to a variety of public and private sector clients including state and federal government agencies, Fortune 500 companies, trade associations, and public interest organizations. Ed also helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council growing the organization to over 40 member companies. Additionally, he worked for Arizona State University where he helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council.

Education

Professional Science Masters, Solar Energy Engineering and Commercialization
Arizona State University – Tempe, AZ (2012)

Master of Science, Sustainability
Arizona State University – Tempe, AZ (2011)

Bachelor of Arts, Chemistry
Princeton University – Princeton, NJ (2007)

Work Experience

Founder, Current Energy Group (March 2024 – Present)

Consulting Partner, Strategen Consulting (August 2015 – March 2024)

- Joined in 2015 and helped grow the company's consulting practice team by more than 3 times.

- Directed the company's grid planning practice area, where he provided technical consulting services to a variety of public and private sector clients including state and federal government agencies, Fortune 500 companies, trade associations, and public interest organizations.
- Helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council and grew the organization to over 40 member companies.

Independent Consultant (2012 – 2015)
- Worked as a technical consultant supporting various clients for attorney Kris Mayes (former Arizona Corporation Commission Chair and current Arizona Attorney General).
- Technical consultant for Schlegel & Associates, working with a coalition of Fortune 500 companies on energy efficiency and demand-side management policies across the US.

Research Associate, Arizona State University (2012-2015)
- Worked across disciplines as a researcher and program administrator for various efforts related to energy and sustainability.
- Assisted in launching the University's Utility of the Future initiative as well as the Energy Policy Innovation Council.
- Conducted a technical study in partnership with Arizona Department of Environmental Quality on the compliance pathways and impacts of the EPA's Clean Power Plan.

Research Fellow, Environmental Defense Fund (2007 – 2009)

Expert Testimony

Duke Energy Carolinas 2026 General Rate Case (DKT: E-7, Sub 1329) on Behalf of the North Carolina Attorney General's Office
Cost of Service, Revenue Requirement

PacifiCorp 2026 Inter-jurisdictional Cost Allocation Protocol (DKT: 25-035-47) on Behalf of Sierra Club
Inter-Jurisdictional Cost Allocation, Net Power Costs

Duke Energy's 2025 Carbon Plan and Integrated Resource Plan Proceeding (DKT: E-100, Subs 207) on Behalf of the North Carolina Attorney General's Office
Integrated Resource Planning, Carbon Plan

Xcel Energy Colorado's 2025 Distribution System Plan and Aggregated Virtual Power Plant Program (DKT: 24A-0547E & 25A-0061E) on Behalf of Advanced Energy United
Distribution System Planning, Virtual Power Plants

Duke Energy Business Combination Proceeding (DKT: E-2, Sub 1393 and E-7, Sub 1332) on Behalf of the North Carolina Attorney General's Office
Business Combination, Ratepayer Impacts

Wisconsin Electric Certificate of Public Convenience and Necessity (DKT: 6630-CE-316) on Behalf of the Wisconsin Citizen's Utility Board
Generation Resource Need, Load Forecasting

Wisconsin Electric Certificate of Public Convenience and Necessity (DKT: 6630-CE-317) on Behalf of the Wisconsin Citizen's Utility Board
Generation Resource Need, Load Forecasting

Wisconsin Electric Certificate of Authority (DKT: 6630-CG-140) on Behalf of the Wisconsin Citizen's Utility Board
Gas Infrastructure Need, Load Forecasting

NV Energy's Integrated Resource Plan (DKT: 24-05041) on Behalf of Advanced Energy United
Integrated Resource Planning, Demand-Side Management

Duke Energy's 2023 Carbon Plan and Integrated Resource Plan Proceeding (DKT: E-100, Sub 190) on Behalf of the North Carolina Attorney General's Office
Integrated Resource Planning, Carbon Plan

Tri-State Generation and Transmission 2023 Electric Resource Plan (DKT: 23A-0585E) on Behalf of Interest Energy Alliance
Electric Resource Plan, Capacity Expansion Modeling

Duke Energy Progress' 2023 General Rate Case (DKT: E-2, Sub 1300) on Behalf of the North Carolina Attorney General's Office
Cost of Service, Revenue Requirement

Duke Energy Carolinas' 2023 General Rate Case (DKT: E-7, Sub 1276) on Behalf of the North Carolina Attorney General's Office
Cost of Service, Revenue Requirement

Dominion Energy 2023 Integrated Resource Plan (DKT: PUR-2023-00066) on Behalf of Advanced Energy United
Integrated Resource Planning

Duke Energy's 2022 Carbon Plan (DKT: E-100, Sub 179) on Behalf of the North Carolina Attorney General's Office
Carbon Plan, Capacity Expansion Modeling

Pacific Power 2022 Energy Cost Adjustment Clause (DKT: A.21-08-004) on Behalf of Sierra Club
Power Cost Recovery, Unit Commitment and Dispatch

Pacific Power 2022 Transition Adjustment Mechanism (DKT: UE-390) on Behalf of Sierra Club

Power Cost Recovery

Northwest Natural 2022 General Rate Case (DKT: UG-435) on Behalf of Earth Justice
Cost of Service, Gas Distribution Planning

Avista Utilities 2022 General Rate Case (DKT: UE-220053/UG-220054) on Behalf of Sierra Club
Cost of Service, Revenue Requirement

Puget Sound Energy 2022 General Rate Case (DKT: UE-220066/UG-220067) on Behalf of Sierra Club
Cost of Service, Revenue Requirement

NV Energy's Integrated Resource Plan (DKT: 22-09006) on Behalf of Western Resource Advocates
Integrated Resource Planning

Tri-State Generation and Transmission Application for a CPCN (DKT: 22A-0085E) on Behalf of Interest Energy Alliance
Generation Resource Need, Alternatives Analysis

Duke Energy Fuel Adjustment Clause –Sub-docket Investigation (DKT: 38707 FAC 123 S1) on Behalf of the Citizens Action Coalition
Fuel Cost Recovery, Unit Commitment and Dispatch

Consumers Energy 2021 Integrated Resource Plan (DKT: U-21090) on Behalf of Earth Justice
Integrated Resource Planning, Capacity Expansion Modeling

Pacific Power 2021 Energy Cost Adjustment Clause (DKT: A.20-08-002) on Behalf of Sierra Club
Power Cost Recovery, Unit Commitment and Dispatch

Pacific Power 2021 Transition Adjustment Mechanism (DKT: UE-375) on Behalf of Sierra Club
Power Cost Recovery

Dominion Energy South Carolina 2021 Avoided Cost Methodologies (DKT: 2021-88-E) on Behalf of the South Carolina Solar Business Association
Avoided Cost Methodology, Distributed Solar

Pacific Gas and Electric's Electric Vehicle Charge 2 Application (DKT: A.21-10-010) on Behalf of the Vehicle Grid Integration Council
Transportation Electrification, Electric Vehicle Programs

Duke Energy Fuel Adjustment Clause (DKT: 38707 FAC 125) on Behalf of the Citizens Action Coalition

Fuel Cost Recovery, Unit Commitment and Dispatch

Entergy Certification to Deploy Natural Gas Distributed Generation (DKT: U-36105) on Behalf of the Alliance for Affordable Energy
Generation Resource Need, Alternatives Analysis

Pacific Power 2020 Energy Cost Adjustment Clause (DKT: A.19-08-002) on Behalf of Sierra Club
Power Cost Recovery, Unit Commitment and Dispatch

Avista Utilities 2020 General Rate Case (DKT: UE-200900) on Behalf of Sierra Club
Cost of Service, Revenue Requirement

NV Energy's Integrated Resource Plan (DKT: 20-07023) on Behalf of Western Resource Advocates
Integrated Resource Planning

Pacific Gas and Electric's Day-Ahead Real Time Rate and Pilot (DKT: A.20-10-011) on Behalf of the Vehicle Grid Integration Council
Rate Design, Transportation Electrification

CPUC Rulemaking on Emergency Summer Reliability (DKT: R.20-11-003) on Behalf of the Vehicle Grid Integration Council
Resource Adequacy, Distributed Energy Resources

Dominion Energy South Carolina 2019 Avoided Cost Methodologies (DKT: 2019-184-E) on Behalf of the South Carolina Solar Business Association
Avoided Cost Methodology, Distributed Solar

Duke Energy Carolinas 2019 Avoided Cost Methodologies (DKT: 2019-185-E) on Behalf of the South Carolina Solar Business Association
Avoided Cost Methodology, Distributed Solar

Dominion Energy Progress 2019 Avoided Cost Methodologies (DKT: 2019-186-E) on Behalf of the South Carolina Solar Business Association
Avoided Cost Methodology, Distributed Solar

National Grid General Rate Case (DKT: D.P.U. 18-150) on Behalf of the Massachusetts Attorney General's Office
Cost of Service, Rate Design

Eversource, National Grid, and Until SMART Tariff (DKT: D.P.U. 17-140) on Behalf of the Massachusetts Attorney General's Office
Distributed Solar, Incentive Program Design

Selection of Relevant Experience

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 -2019

- Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003).
- Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General

SMART Program / 2016 -2017

- Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years.
- Served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

Southwest Energy Efficiency Project

IRP Technical Analysis and Modeling / 2018 -2020

- Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
- Provided analysis on Salt River Project's resource plan as part of its 2035 planning process.
- Evaluated different levels of renewable energy and energy efficiency and identify any changes to the resources needed to meet these requirements and ensure reliability.
- Worked with Strategen technical team on utilizing a capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRPs.

California Energy Storage Alliance

California Hybridization Assessment / 2018 -2019

- Managed a special initiative of this leading industry trade group to conduct technical analysis and stakeholder outreach on the value of hybridizing existing gas peaker plants with energy storage,

Portland General Electric

Energy Storage Strategy / 2016

- Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
- Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.

- Supported development of a competitive solicitation process for storage technology solution providers.

Arizona Residential Utility Consumer Office (RUCO)
IRP Analysis and Impact Assessment / 2015 -2018
- Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
- Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
- Lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Sierra Club
PacifiCorp 2021 IRP Technical Support / 2020 -2021
- Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp's IRP stakeholder input process.
- Prepared analysis, technical comments, discovery requests in advance of drafting formal comments to be submitted before the Oregon Public Utility Commission.

North Carolina, Office of the Attorney General
Duke Energy 2020 IRP Technical Support / 2020 -2021
- Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.
- Presented original analysis at multiple IRP-related technical workshops hosted by the NCUC

University of Minnesota
Energy Storage Stakeholder Workshops / 2016 -2017
- Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
- Conducted study on the use of storage as an alternative to natural gas peaker.
- Presented workshop and study findings before the Minnesota Public Utilities Commission.

New Hampshire Office of Consumer Advocate
NEM Successor Tariff Design / 2016
- Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Xcel Energy
Time-of-use Rates / 2017 -2018
- Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

Publications

- New York BEST, 2020. Long Island Fossil Peaker Replacement Study.
- Ceres, 2020. Arizona Renewable Energy Standard and Tariff: 2020 Progress Report.
- Virginia Department of Mines and Minerals, 2020. Commonwealth of Virginia Energy Storage Study.
- Sierra Club, 2019. Arizona Coal Plant Valuation Study.
- Strategen, 2018. Evolving the RPS: Implementing a Clean Peak Standard."
- SunSpecAlliance for California Energy Commission.,2018.Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California.

EXHIBIT 2

EXHIBIT 2

Creating Capacity by Reducing Demand:
NV Energy Sierra Pacific Power Case Study

PREPARED BY

Ryan Hledik
Kate Peters
Carly McAdam

PREPARED FOR

Google

SEPTEMBER 2026



Brattle

Notice

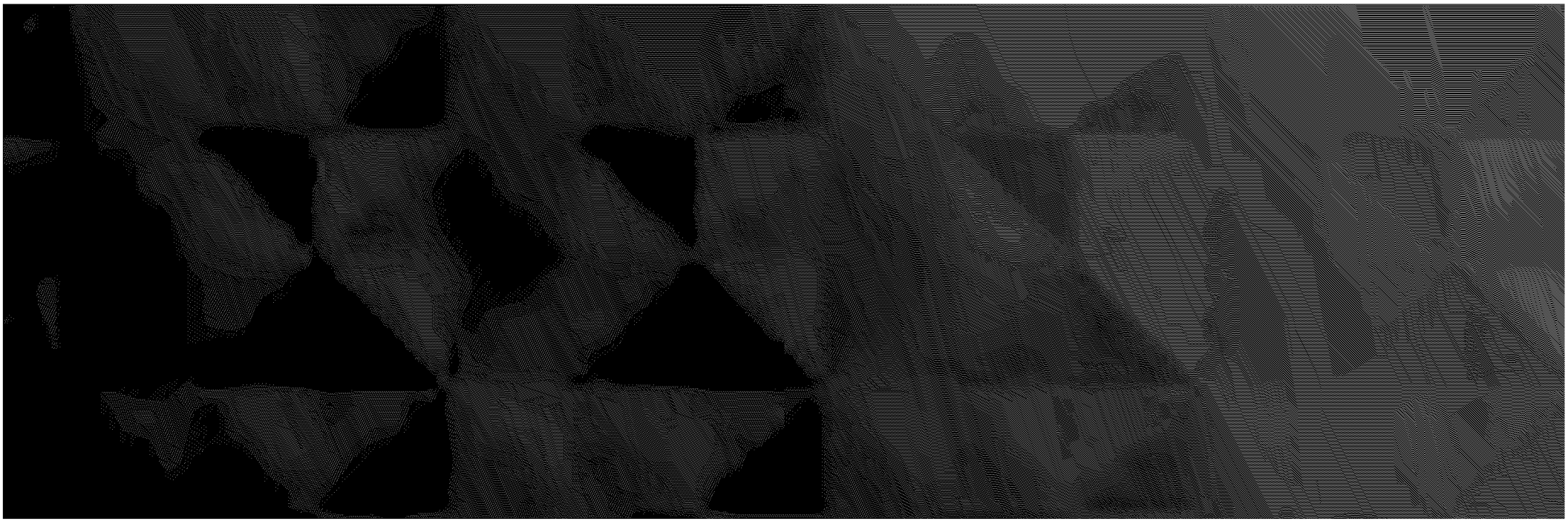
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2. Introduction
3. Behavioral Feasibility
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5. Economic Feasibility
6. Operational Feasibility
7. Scenario Analysis
8. Conclusion

Appendix



1. Summary

Study overview

Context: Load growth, supply chain constraints, and technology cost uncertainty are driving the need for novel approaches to developing new capacity on the power system. Peak load reductions through expanded demand response (DR) and energy efficiency (EE) offerings could be an affordable and environmentally beneficial approach to achieve that outcome. An emerging business model where hyperscalers finance the expansion of utility DR and EE portfolios could deliver new capacity online quickly and at low cost.

Purpose of this study: Google retained The Brattle Group to analyze the extent to which selected DR and EE offerings could provide new, reliable resource adequacy in NV Energy's Sierra Pacific Power Company (SPPC) system.

Our approach: We assess DR and EE potential in four steps to ensure the results are achievable from four perspectives:

1. **Behavioral feasibility** ensures assumed program participation rates are consistent with those achieved in other U.S. jurisdictions.
2. **Technical feasibility** builds on the behavioral assessment by considering achievable technology adoption rates and performance.
3. **Economic feasibility** evaluates costs from the administrator's perspective to benchmark against alternative resource options.
4. **Operational feasibility** demonstrates the portfolio's ability to reduce load during all hours of the year necessary to achieve annual system peak demand reduction.

We combine all perspectives to provide an overall indication of the peak reduction that could be achieved in NVE's SPPC system.

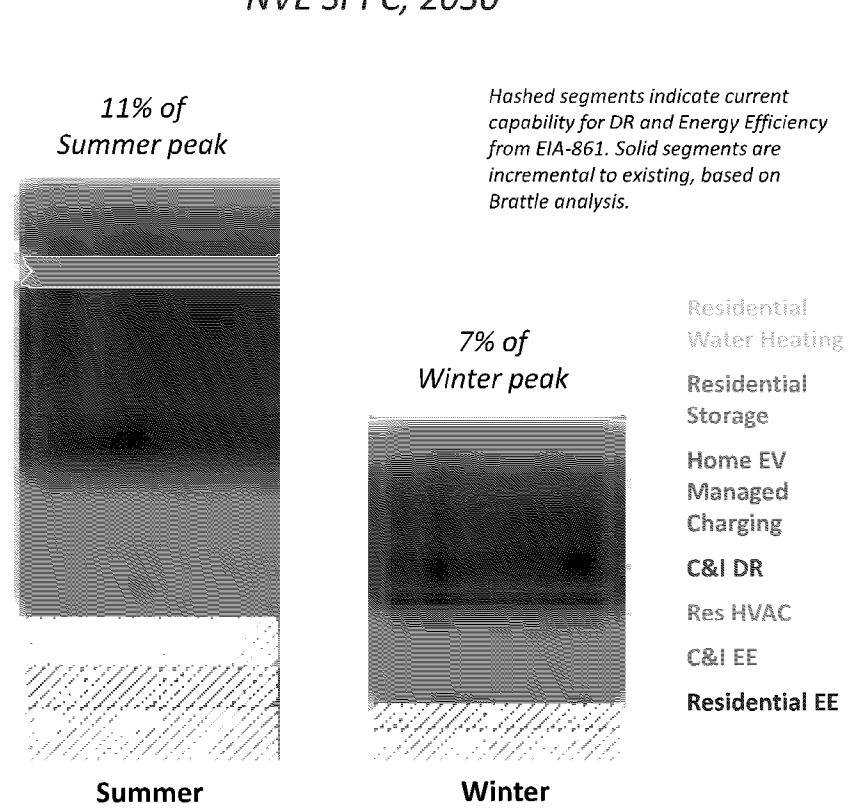
Behavioral and technical feasibility

NVE SPPC's cumulative market potential for selected DR and EE measures in 2030 is 296 MW, or 11% of the summer peak, representing 221 MW of incremental potential relative to current DR and EE capability.

- **Residential & Commercial EE** are the largest portfolio contributors, mostly including HVAC, appliance and lighting measures. We report cumulative savings from 2026 through 2030.
- **Residential Cooling** is the largest near-term DR opportunity for the mass market, with the existing program providing a foundation to build upon.
- **Commercial DR** assumes both automated and manual load control. Large C&I customers have been the target market segment for aggregators historically.
- **EV managed charging** makes a significant contribution despite using NVE's low EV adoption scenario from its DER potential study (to reflect the impact of recent federal policy changes).
- **BTM battery potential** for residential customers is modest but with significant upside potential depending on the battery adoption outlook for NV Energy customers.
- **Electric water heating** load control remains limited due to low adoption levels.
- **Current peak DR and EE capability:** 25.5 MW of DR primarily from residential smart thermostat programs (sourced from EIA-861 2024) and 50 MW of EE from residential and commercial programs (assumes cumulative 5-year growth of average annual values from EIA-861 2020-2024).

DR & EE Achievable Peak Reduction Potential

NVE SPPC, 2030



Note: Capacity reported at system peak hour. Current DR capability is sourced from EIA-861 (2024) reported data. Current EE savings shown as estimates of cumulative 2026 – 2030 savings assuming annual values from average 2020-2024 savings from EIA 861. Current winter capability estimated from summer savings.

Economic feasibility

The majority of modeled demand reduction potential has a net cost that is lower than recently observed capacity estimates.

Commercial EE measures have negative net costs, with energy value alone more than offsetting the full costs of the measures. Residential EE measures have higher customer acquisition costs.

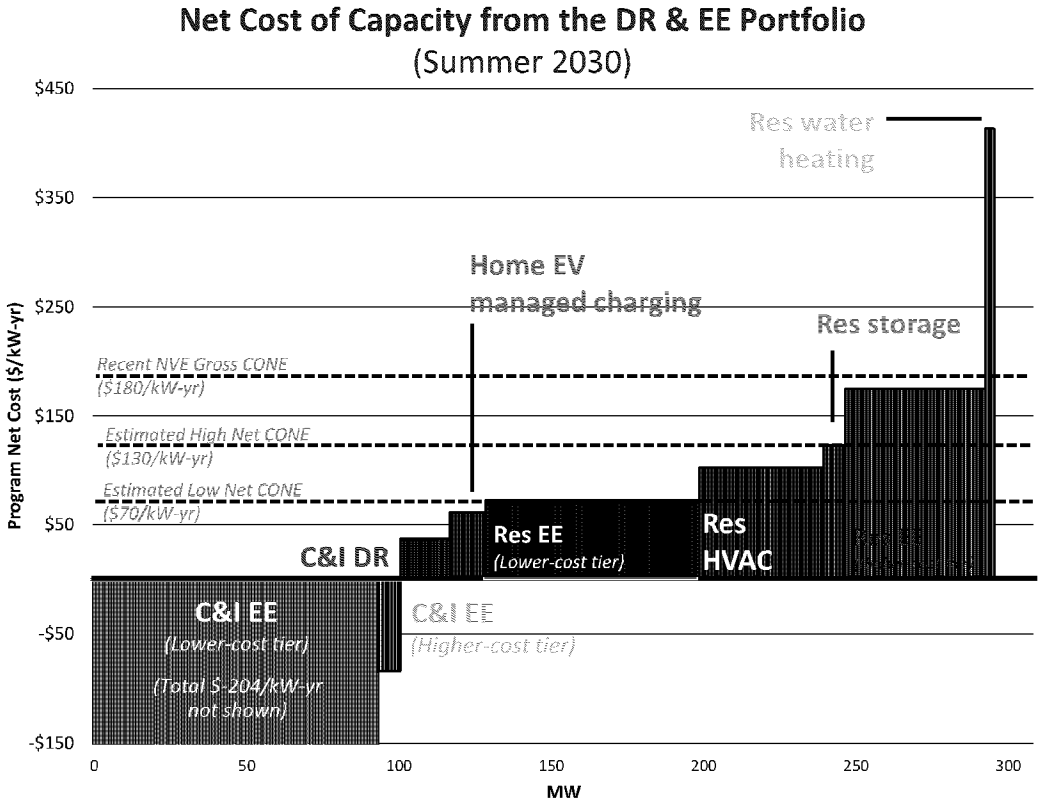
Commercial DR represents an opportunity to tap into a customer segment with relatively low acquisition costs.

Residential storage can deliver notable savings at low net cost with customer adoption.

By 2030, electric vehicle penetration could reach significant scale and can be controlled through DR at relatively low costs.

Residential HVAC can be cost effective depending on the avoided cost of new capacity.

All programs except residential water heating have a net cost that is below recently observed cost of new entry (CONE) estimates, which will likely remain high, if not grow, due to supply chain constraints in the near-term.



Notes: Program net costs are reported as program administration and incentive costs less energy benefits. MWs are reported as maximum reduction in a single hour. CONE estimates serve as illustrative capacity cost benchmarks. Gross CONE estimates are consistent with NVE's recent $1,433/kW and $1,287/kW capital costs from NVE IRP Vol. 8 (PDF pages 14, 19) levelized at NREL ATB financing assumptions for gas CT plants. Net CONE estimates assume $50/kW-yr and $110/kW-yr in E&AS revenues, consistent with ranges estimated in Brattle analysis of comparable markets (e.g. PJM's CONE analysis). Capacity reported at system peak hour.

Operational Feasibility

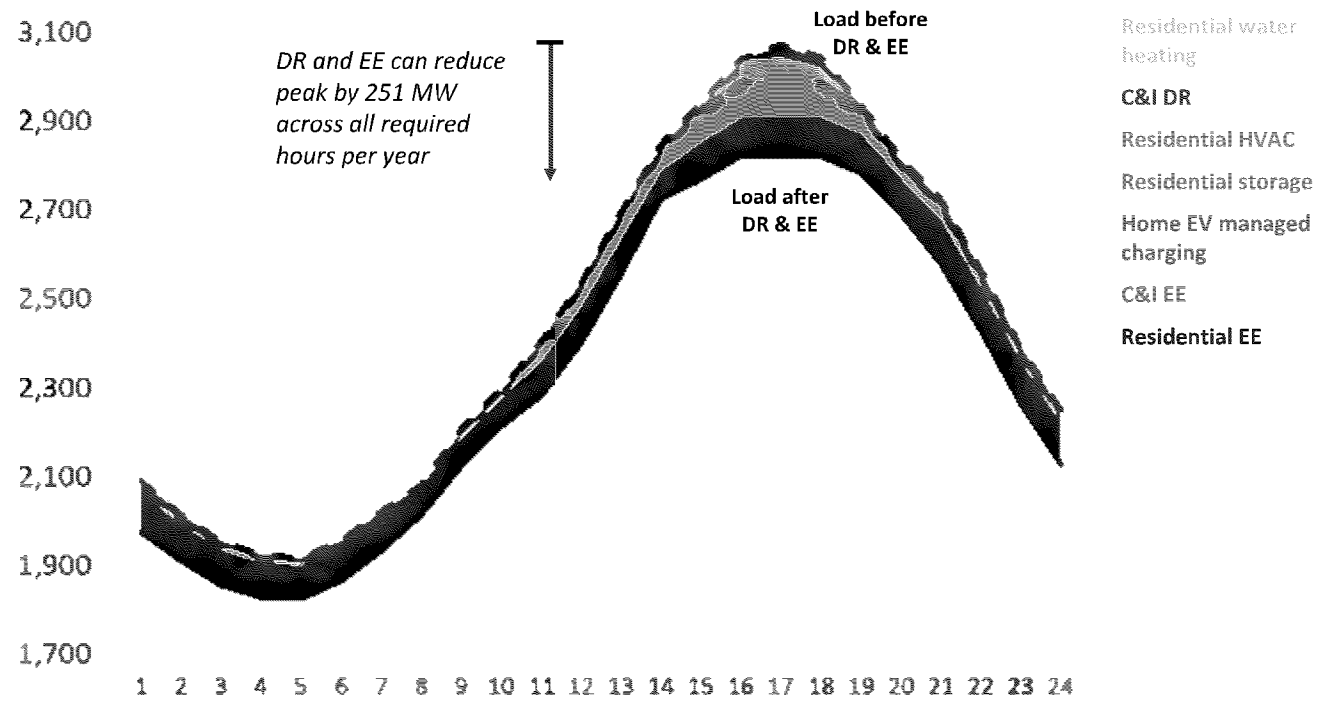
DR and EE can deliver demand reductions during the hours when needed most.

The figure at right illustrates how the modeled portfolio could be operated to achieve a 251 MW reduction across all hours on NVE's peak load day.

DR program dispatch is constrained by event frequency and duration limitations, and accounts for pre- and post-event load-building. These operational constraints are consistent with the parameters of existing programs and pilots.

Reducing annual system peak load by 251 MW would require DR load reductions on 8 days of the year. Achieving this level of reduction is feasible within the program constraints.

Illustration of Portfolio Demand Reduction on Peak Demand Day



Note: For simplicity, load building associated with DR programs has been netted out of EE savings in the figure. Y axis is cropped to highlight program dispatch detail.

Key findings

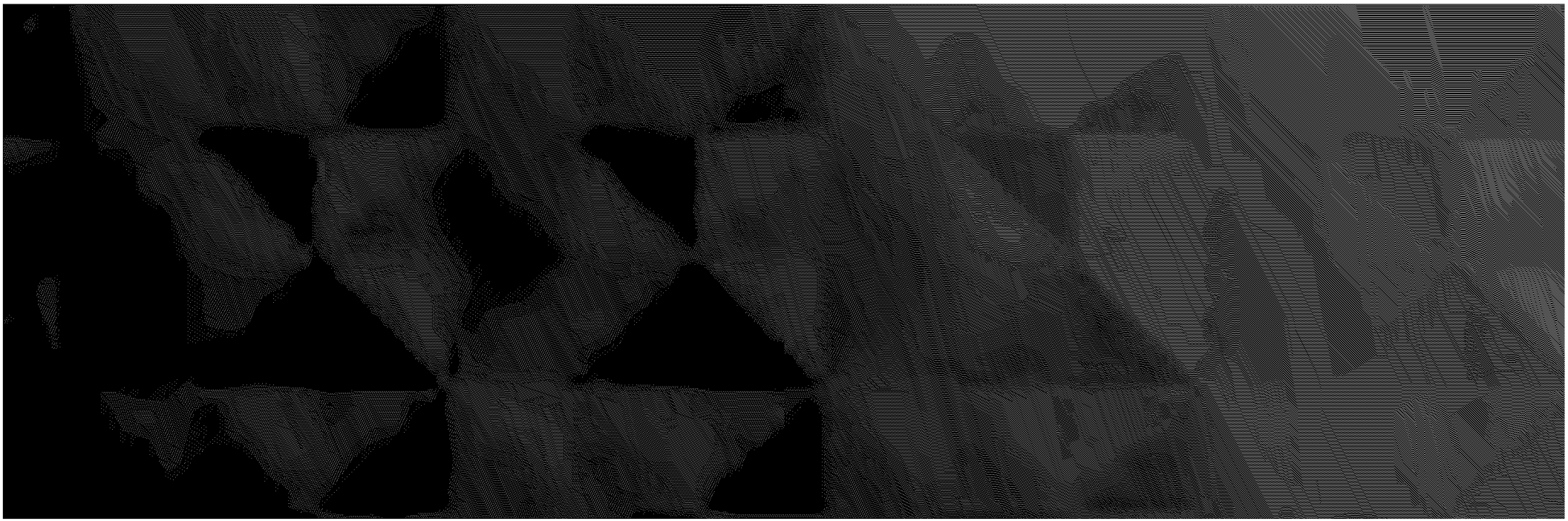
New, hyperscaler-enabled DR and EE can serve as a reliable resource for NVE, delivering significant peak demand reductions at competitive costs.

- Within the next five years, it is possible to scale demand-side initiatives to provide 296 MW of demand reduction capability during summer peak hours.
- Operationally, this portfolio of programs could provide 251 MW of annual demand reduction capability even under the most challenging load conditions observed over the past 10 years.
- The portfolio would create new headroom on NVE's system and reliably serve demand at a cost lower than the recently observed cost of competing conventional resources.
- The findings are relatively robust across varying enrollment and program cost assumptions, with cost-competitive peak reduction potential consistently at or above 250 MW.

Considerations for a Google-NVE Partnership

Important considerations for moving forward with the development of a Google-funded expansion of NVE's demand-side offerings include:

- **Incrementality:** Design programs and M&V methods to clearly demonstrate incrementality of the new initiatives relative to NVE's ongoing/planned activities. This could include a focus on funding attractive programs that do not currently pass cost-effectiveness screens.
- **Durability:** The initiative may require a multi-year contractual commitment with backstops, to ensure that the capacity aligns with the lifetime of new data center load and/or availability of new supply-side resources.
- **Delivery:** Further work is needed to determine the appropriate implementation model (e.g., funding utility-led initiatives, or engaging with third-party aggregators and ESCOs).



2. Introduction

Study overview

Purpose

- The purpose of this study is to analyze the achievable demand response (DR) and energy efficiency (EE) potential for select measures in NVE's SPPC service territory.
- The study illustrates potential opportunities to add resource adequacy capacity to NVE SPPC's system and accommodate data center load growth.

Study scope

- Quantify **realistic DR and EE potential in 2030** that could serve near-term resource adequacy needs
- Report **total potential,** inclusive of NVE SPPC's existing and planned capabilities
- Quantify **program net costs** from the administrator's perspective, subtracting out energy savings from operational, administrative, and incentive costs. Additional benefits such as distribution value and ancillary services are not quantified
- Evaluate **operational capability** of the portfolio to reduce system peak demand throughout the year
- Model **four additional scenarios** to test the impact of uncertain market drivers on DR and EE potential

Interpreting the findings

- DR and EE potential estimates in this study are not a forecast of what is most likely to happen. Rather, the estimates represent the realistic potential that could be achieved from select program offerings with additional funding.
- Barriers may need to be addressed to reach the levels of enrollment assumed in this study. While an assessment of existing barriers is not within the scope of the study, they may include technical, regulatory, market, or implementation barriers. For example, our study assumes that BTM battery programs can export energy back to the grid, but compensation mechanisms are still evolving.
- Our study assesses future potential but is not an evaluation of the cost-effectiveness or performance of specific programs currently being offered by NVE SPPC. Similarly, our study is not conducted at the level of granularity necessary to make detailed program design recommendations.

Approach overview

Our analysis accounts for behavioral, technical, economic, and operational considerations essential to developing dependable system capacity from demand-side resources.

Behavioral Feasibility

- Establish realistic DR and EE participation levels anchored in demonstrated experience from other jurisdictions.
- Given the near-term modeling horizon (2030), we consider the achievable trajectory with which the programs could be scaled, in addition to the overall achievable level of enrollment.

Technical Feasibility

- Quantify the amount of EE and DR that could be achieved given realistic constraints on customer adoption of new technologies and technical flex capabilities of each resource.
- Event-reduction estimates grounded in real program experience in Ameren and comparable jurisdictions.

Economic Feasibility

- Establish program-level costs from the administrator's perspective, and compare against other capacity resources (e.g., gas peaker plants). Costs include program administration, marketing, and incentives and net out energy benefits provided to the system.
- We do not evaluate cost-effectiveness and instead benchmark cost estimates against alternative resource options.

Operational Feasibility

- Evaluate portfolio performance across all 8,760 hours of the year to determine annual demand reduction capability while accounting for operational constraints.
- Most EE and DR studies only measure capability contributions to a single seasonal peak hour.
- Accounts for load building outside of event hours (e.g., due to pre-cooling or post-event load snapback).

Selected programs

We model seven DR and EE options. This portfolio was selected in coordination with Google based on the company's strategic priorities and an expectation that these programs could provide near-term incremental potential.

Program	Program	Program Description
Residential DR	**Cooling**	Customers with smart thermostats can enroll and be compensated for up to 10 cooling control events. Reduced A/C demand due to setpoint increases of ~2 degrees. Program exists today at SPPC.
	Smart water heating	Grid connected water heaters that can shift water heating demand to non-peak hours on a daily basis.
	EV managed charging	Residential electric vehicle (EV) charging is controlled by the utility to occur outside peak periods on a daily basis. Managed charging includes load shifting but does not allow for energy exports back to the grid.
	BTM battery	Customer-sited battery storage that can dispatch during peak periods, up to 100 events a year, while maintaining backup reserve. Assets can be compensated for exports to the grid when dispatch exceeds customer peak demand.
Commercial DR	**Large C&I DR**	Customers are compensated for manual or automated demand reductions during peak periods, up to 30 times per year. Program exists today at SPPC.
Energy Efficiency	**Residential portfolio**	Residential EE high- and low-cost tiers based on Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP) portfolios in 2024 DER Potential Study. RAP represents a lower-cost portfolio assuming historic incentive levels and current program awareness, and incremental MAP impact represents the higher-cost portfolio assuming more aggressive incentive levels and optimistic delivery conditions.
	Commercial portfolio	Commercial EE high- and low-cost tiers savings based on Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP) portfolios in 2024 DER Potential Study (same approach as for residential, as described above).

The FLEX model

We use Brattle's *FLEX* model to estimate NVE SPPC's achievable DR and EE potential in 2030.

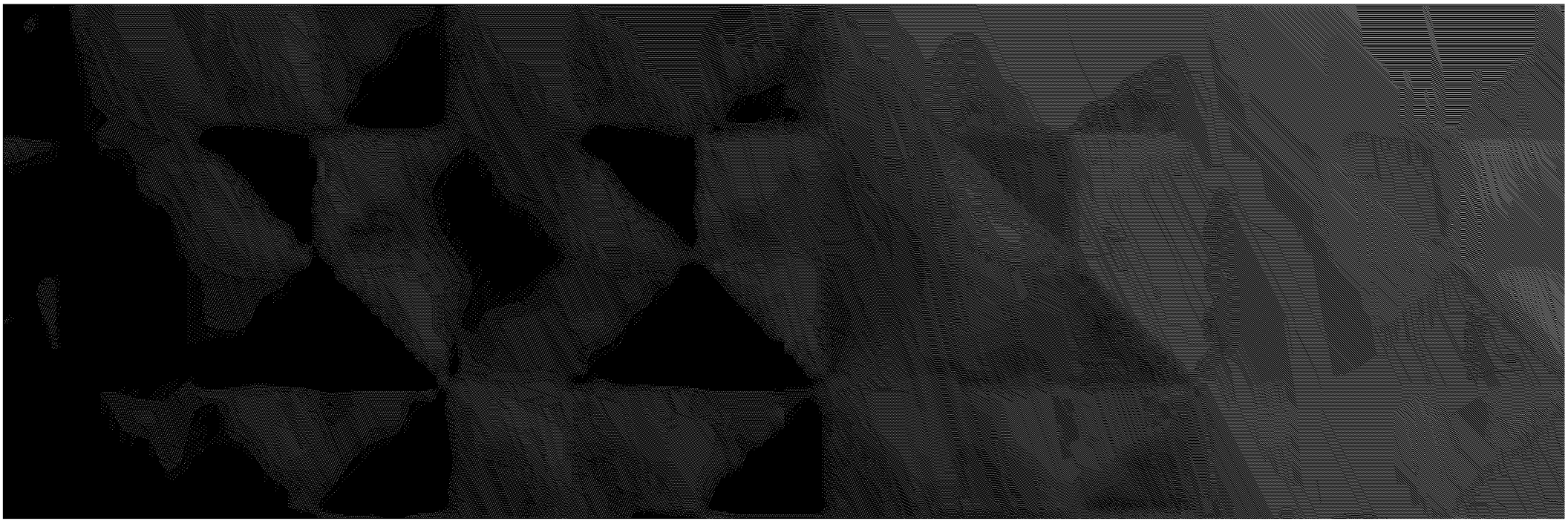
- Hourly modeling granularity captures opportunities associated with load shifting in all hours throughout the year.
- Participation rates and load impacts are based on ambitious but achievable assumptions, supported by actual industry experience.
- Simulated dispatch accounts for operational and behavioral constraints inherent in grid flexibility programs, such as availability of load, depth of reduction, and acceptable frequency of curtailment.
- Multi-scenario analysis accounts for uncertainty.
- Considers 1-in-10 challenging weather year conditions to demonstrate the portfolio's dependable peak demand reduction capability, accounting for operational constraints such as load building

See appendix for more detail on methodology, sources, and assumptions.

Recent Examples of *FLEX* Modeling

FLEX is the analytical engine behind a wide range of high-profile studies for utilities, government, research organizations, and technology companies. Examples include:

- Brattle's 2025 study, New York's Grid Flexibility Potential
- GridLab's 2024 report, California's Virtual Power Potential
- US DOE's 2023 VPP Commercial Liftoff Report
- Brattle's 2023 study, Real Reliability: The Value of Virtual Power
- Berkeley Lab's 2023 U.S. Building Sector Decarbonization Scenarios to 2050
- State of Maryland's 2023 GHG Abatement Study
- Xcel Energy Colorado's 2022 Demand Response Potential Study
- US DOE's 2021 A National Roadmap for Grid-Interactive Efficient Buildings
- Pepco's 2021 assessment of electrification impacts in Washington, DC



3. Behavioral Feasibility

Overview of behavioral feasibility analysis

To evaluate EE and DR potential that could provide reliable capacity value by 2030, we first establish realistic participation rates. Customer participation rates in demand-side programs can vary significantly due to incentive levels and enrollment hurdles, among other factors.

To ensure realistic potential estimates, we account for behavioral feasibility through several methods:

- Ground demand response participation rates in demonstrated experience from other jurisdictions to reflect realistic customer willingness for control across end uses.
- Inform DR participation rate ramping with observed program scaling experience in other markets. The most robust DR experience across utilities is from smart thermostat programs, which we extrapolate to other programs as needed.
- Evaluate forecasted EE savings relative to historical levels achieved by NVE SPPC.

EE and DR Capacity Feasibility Dimensions

Establish **behavioral feasibility** with participation rates that are grounded in successful levels of enrollment achieved in other U.S. jurisdictions

Estimate **technical feasibility** subject to realistic constraints on customer technology adoption, technical flex capabilities of each resource, and established customer behavior

Evaluate **economic feasibility** by comparing costs of EE and DR to other capacity options from an administrator cost perspective

Test **operational feasibility** across all 8,760 hours to demonstrate the portfolio's annual reduction capability, accounting for operational constraints such as load building

Support for five-year participation assumptions

Our participation assumptions align with successful participation rates achieved in other U.S. jurisdictions.

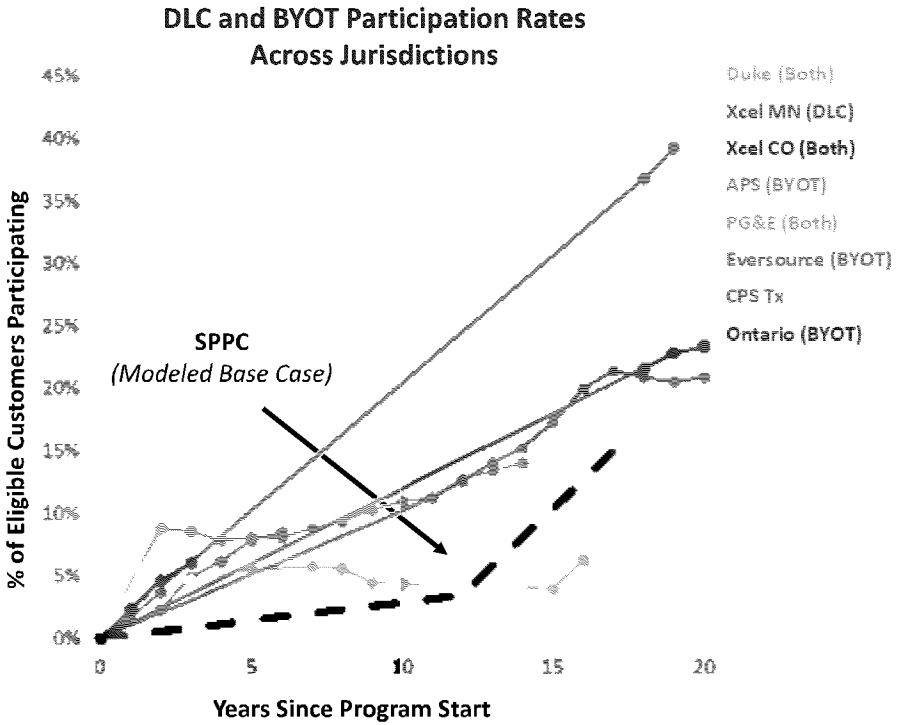
Program	Participation *(% of Eligible Cust. and # of Participants)*	Support from Other Jurisdictions
Cooling (residential)	15% (40k participants)	▪ In Minnesota, Xcel Energy has enrolled more than half of all eligible residential customers in A/C load control on a voluntary basis. ▪ In Ontario, Canada, EnergyHub enrolled 100,000 smart thermostat customers to build a 90 MW VPP in only six months and has grown to over 300,000 participants today.
Smart water heating (combined electric resistance and heat pump)	15% (14k participants)	▪ At many electric cooperative utilities across the Midwest, participation among eligible customers in water heating load control exceeds 25%. Otter Tail Power has enrolled 15% of residential customers in its water heating load control program.
EV managed charging (home)	25% (29k participants)	▪ Some utilities have exceeded 40% participation in voluntary EV TOU rates. ▪ Startup company ev.energy has partnered with 55+ utilities across the globe and connected over 200,000 drivers through smart charging, reducing peak charging load by over 90%.
BTM battery (residential)	0.25% (850 participants)	▪ California's Demand Side Resources (DSGS) program option 3 has scaled to over 700 MW in less than three years ▪ Green Mountain Power already has enrolled roughly 2% of its residential customer base in its battery program and forecasts that the program will reach between 4% and 7% participation by 2030. ▪ National Grid had over 2,000 residential customers (~24 MW and about 0.2% of customer base) enrolled in the Connected Solutions battery program in MA as of the end of 2023. ▪ Rocky Mountain Power's battery VPP program had 27 MW enrolled as of 2024.
Large C&I DR (auto and manual)	25% (11k participants)	▪ At least 12 states have enrolled over 20% of large C&I customers in interruptible tariffs. ▪ Voltus has over 13,000 sites enrolled across more than 60 demand flexibility programs to provide grid services, amounting to 7 GW of capacity.

Feasibility of scaling DR enrollment

Existing direct load control (DLC) and bring your own thermostat (BYOT) programs across the U.S. demonstrate that scaling to participation rates of 15% or greater is feasible.

NVE SPPC's smart thermostat DR program was introduced in 2012 and has grown to around 3% participation today. Reaching 15% enrollment by 2030 (as assumed in the Base case) would require a growth rate similar to periods of fastest growth in other observed programs. This could be feasible due to the following factors:

- NVE SPPC has over twelve years of prior experience and capability development through its existing A/C load control program
- Advancements in online marketplaces and digital marketing practices could boost enrollment rates relative to historical trends in legacy programs
- Organic adoption of smart thermostats (and higher internet saturation) creates an established eligible customer base that did not exist when the reviewed programs were being scaled
- Google funding could offer higher enrollment incentives

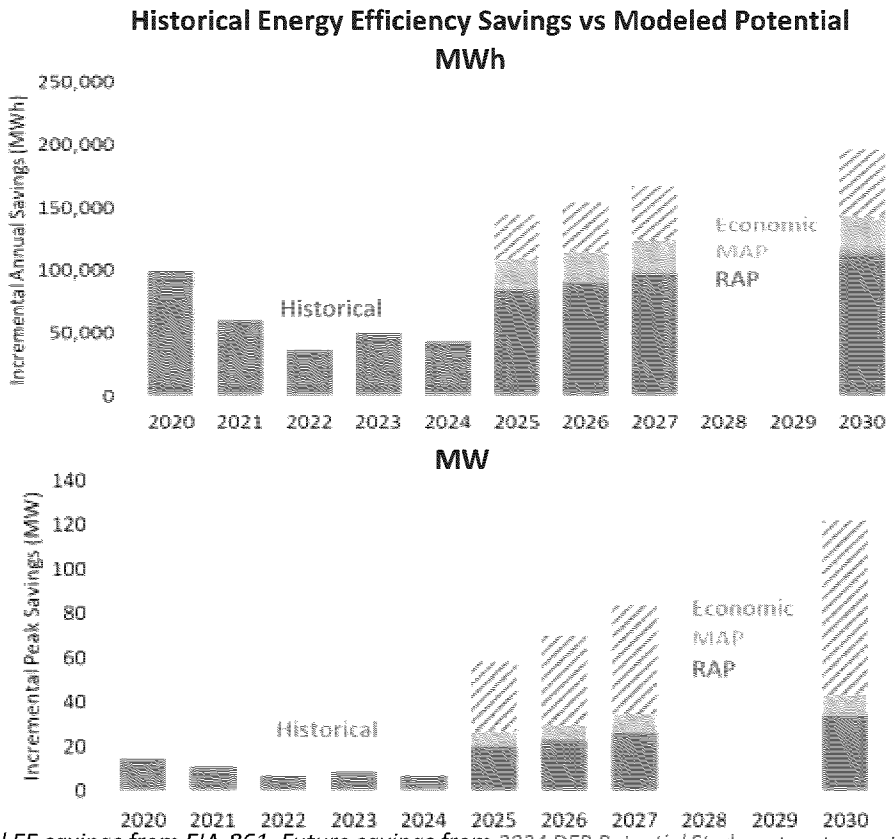


Notes: Program participation collected from utility program evaluation reports. Data points without markers indicate years where extrapolation was needed due to lack of available data.

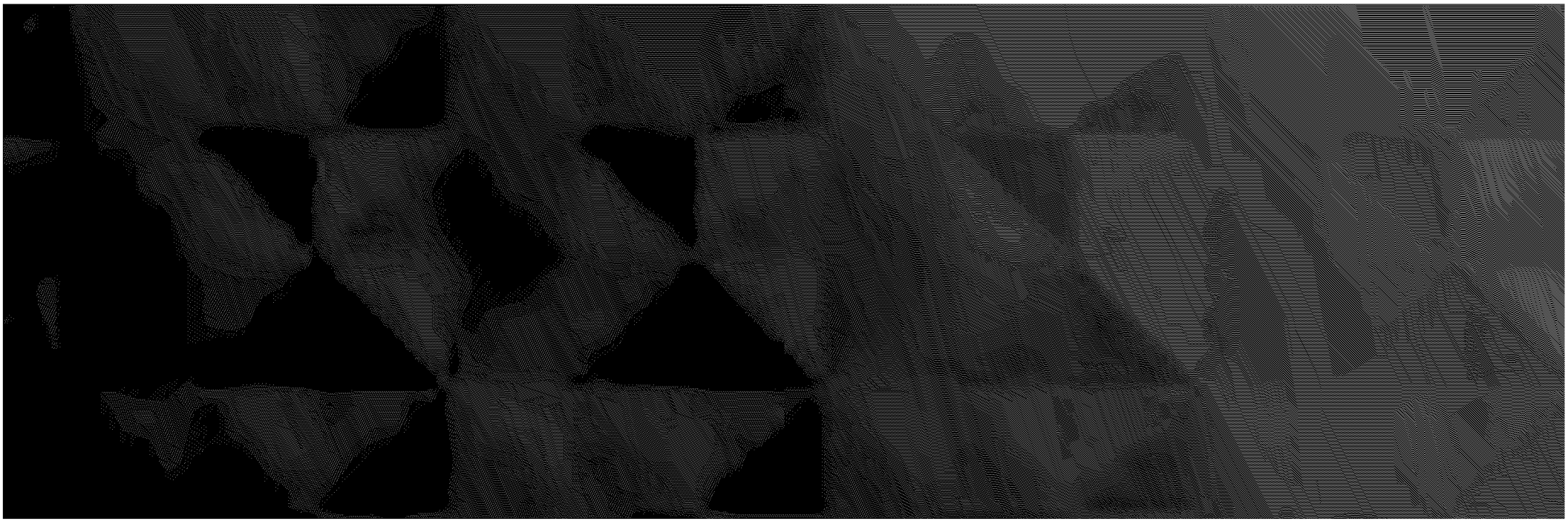
Achievability of energy efficiency savings

We model future EE savings consistent with historical performance to ensure realistic forecasts with achievable growth potential.

- Recent declines in NVE's annual EE savings have largely resulted from budget constraints. RAP EE potential estimates exceed the savings levels achieved since 2021.
- We model two tiers of EE savings, based on RAP and MAP forecasted savings from NVE's 2024 DER Potential Study.
- RAP estimates are achievable based on historical SPPC achievements.
- MAP levels have not been achieved in the past five years but are supported by historical precedent and could be unlocked with additional funding support.



Historical EE savings from EIA-861. Future savings from 2024 DER Potential Study.



4. Technical Feasibility

Overview of technical feasibility analysis

"Achievable potential" is the peak reduction capability of EE and DR that could be achieved given realistic constraints on customer adoption of electrification technologies and the technical load reduction capabilities of each modeled resource, in addition to the previously established participation rates.

Achievable potential accounts for:

- Bottom-up estimate of realistic capability, inclusive of existing capability
- Customer behavioral constraints discussed in the prior section, resulting in lower potential than technical potential

We report achievable potential as the contribution during system peak hour.

EE and DR Capacity Feasibility Dimensions

Establish **behavioral feasibility** with participation rates that are grounded in successful levels of enrollment achieved in other U.S. jurisdictions

Estimate **technical feasibility** subject to realistic constraints on customer technology adoption, technical flex capabilities of each resource, and established customer behavior

Evaluate **economic feasibility** by comparing costs of EE and DR to other capacity options from an administrator cost perspective

Test **operational feasibility** across all 8,760 hours to demonstrate the portfolio's annual reduction capability, accounting for operational constraints such as load building

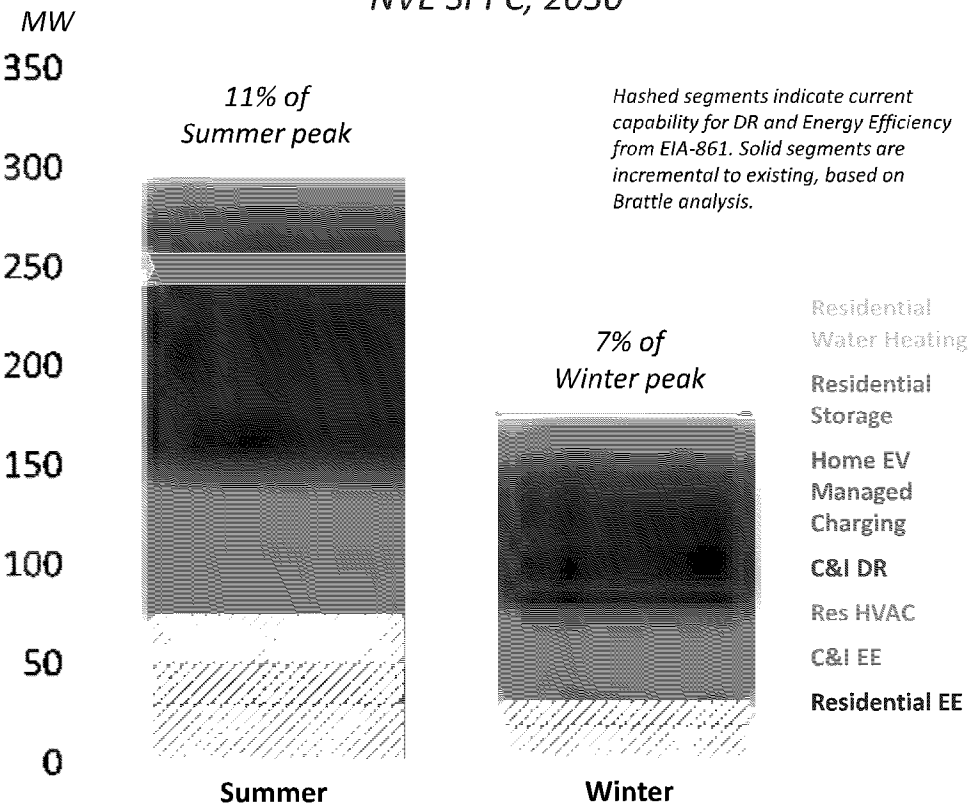
Behavioral and technical feasibility

NVE SPPC's cumulative market potential for selected DR and EE measures in 2030 is 296 MW, or 11% of the summer peak, representing 221 MW of incremental potential relative to current DR and EE capability.

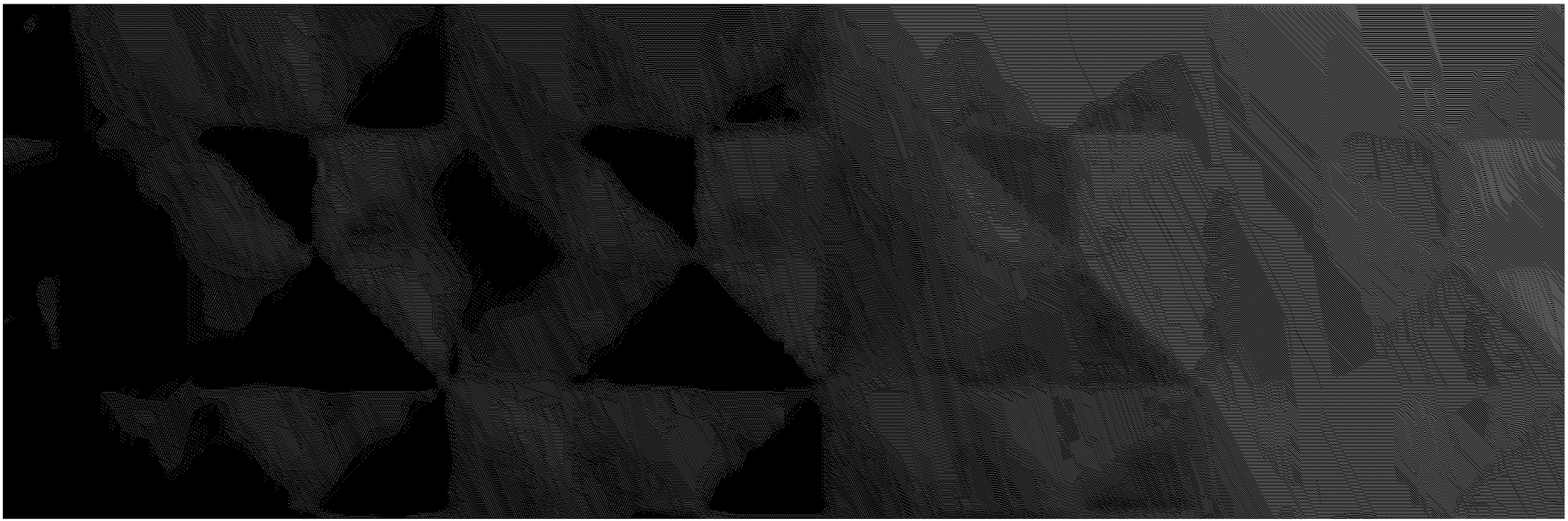
- **Residential & Commercial EE** is the largest portfolio contribution, mostly including HVAC, appliance and lighting measures. We report cumulative savings from 2026 through 2030.
- **Residential Cooling** is the largest near-term DR opportunity for the mass market, with the existing program providing a foundation to build upon.
- **Commercial DR** assumes both automated and manual load control. Large C&I customers have been the target market segment for aggregators historically.
- **EV managed charging** has significant contribution despite using NVE's low EV adoption scenario from its DER potential study (to reflect the impact of recent federal policy changes).
- **BTM battery potential** for residential customers is modest but with significant upside potential depending on the battery adoption outlook for NV Energy customers.
- **Electric water heating** load control remains limited due to low adoption levels.
- **Current peak DR and EE capability:** 25.5 MW of DR primarily from residential smart thermostat programs (sourced from EIA-861 2024) and 50 MW of EE from residential and commercial programs (assumes cumulative 5-year growth of average annual values from EIA-861 2020-2024).

DR & EE Achievable Peak Reduction Potential

NVE SPPC, 2030



Note: Capacity reported at system peak hour. Current DR capability is sourced from EIA-861 (2024) reported data. Current EE savings shown as estimates of cumulative 2026 – 2030 savings assuming annual values from average 2020-2024 savings from EIA 861. Current winter capability estimated from summer savings.



5. Economic Feasibility

Overview of economic feasibility analysis

We quantify the cost of each DR and EE measure from the administrator's perspective, establishing estimates that can be compared against alternative capacity options. We do not directly evaluate cost effectiveness but instead benchmark EE and DR costs against alternative measures of capacity cost.

Cost-effectiveness thresholds change based on the availability of alternate capacity investments. Today, tightening supply chains and growing demand are creating an expensive supply procurement landscape, with significant delays to develop and connect conventional resources.

We present the "net cost" of each DR and EE measure, which subtracts out the energy benefit from the program administration, incentive, and other marketing costs required to enroll and retain customers in the programs.

EE and DR Capacity Feasibility Dimensions

- Establish **behavioral feasibility** with participation rates that are grounded in successful levels of enrollment achieved in other U.S. jurisdictions
- Estimate **technical feasibility** subject to realistic constraints on customer technology adoption, technical flex capabilities of each resource, and established customer behavior
- Evaluate **economic feasibility** by comparing costs of EE and DR to other capacity options from an administrator cost perspective
- Test **operational feasibility** across all 8,760 hours to demonstrate the portfolio's annual reduction capability, accounting for operational constraints such as load building

The DR and EE Supply Curve

The majority of modeled demand reduction potential has a net cost that is lower than recently observed capacity estimates.

Commercial EE measures have negative net costs, with energy value alone more than offsetting the full costs of the measures. Residential EE measures have higher customer acquisition costs.

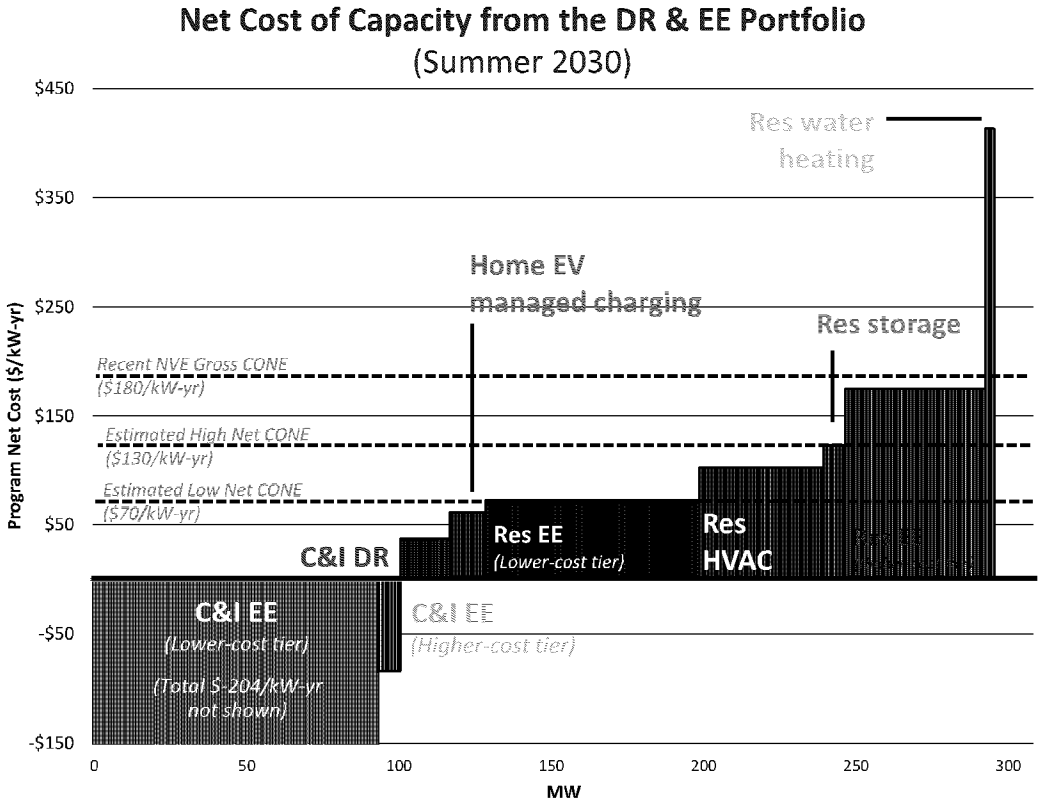
Commercial DR represents an opportunity to tap into a customer segment with relatively low acquisition costs.

Residential storage can deliver notable savings at low net cost with customer adoption.

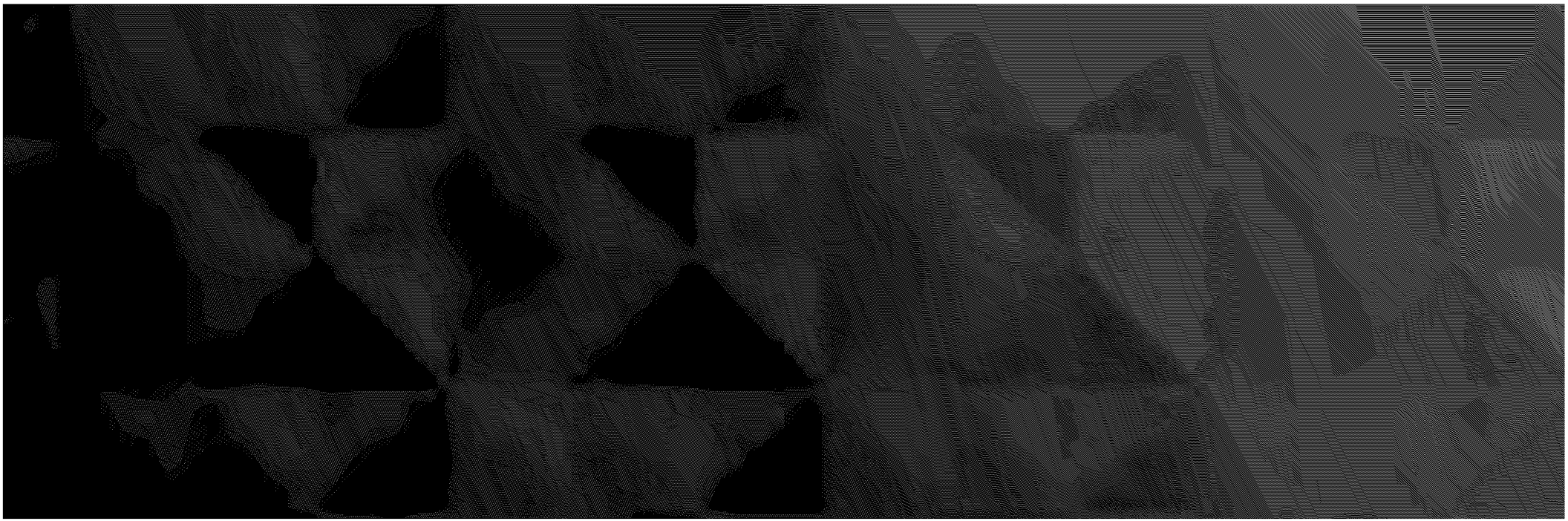
By 2030, electric vehicle penetration could reach significant scale and can be controlled through DR at relatively low costs.

Residential HVAC can be cost effective depending on the relative cost of new capacity.

All programs except residential water heating have a net cost that is below recently observed cost of new entry (CONE) estimates, which will likely remain high, if not grow due to supply chain shortages in the near-term.



Notes: Program net costs are reported as program administration and incentive costs less energy benefits. MWs are reported as maximum reduction in a single hour. CONE estimates serve as illustrative capacity cost benchmarks. Gross CONE estimates are consistent with NREL ATB financing assumptions for gas CT plants and NVE's recent $1,433/kW and $1,287/kW capital costs from NVE IRP Vol. 8 (PDF pages 14, 19). Net CONE estimates assume $50/kW-yr and $110/kW-yr in E&AS revenues, consistent with ranges estimated in Brattle analysis of comparable markets (e.g. PJM's CONE analysis). Capacity reported at system peak hour.



6. Operational Feasibility

Operational feasibility analysis overview

Many EE and DR studies focus only on theoretical potential. However, for a portfolio of demand-side resources to provide dependable, planning-grade capacity, the resources need to be able to provide load reductions throughout the year when needed.

Our estimate of operational feasibility evaluates portfolio performance in all hours of the year to measure annual system peak demand reduction capability.

We model each program with applicable load building characteristics (e.g., pre-cooling for smart thermostats) and dispatch the portfolio across all 8,760 hours of the year to measure the feasible annual system load reduction. We evaluate portfolio operations across a decade of weather/load conditions.

EE and DR Capacity Feasibility Dimensions

Establish **behavioral feasibility** with participation rates that are grounded in successful levels of enrollment achieved in other U.S. jurisdictions

Estimate **technical feasibility** subject to realistic constraints on customer technology adoption, technical flex capabilities of each resource, and established customer behavior

Evaluate **economic feasibility** by comparing costs of EE and DR to other capacity options from an administrator cost perspective

Test **operational feasibility** across all 8,760 hours to demonstrate the portfolio's annual reduction capability, accounting for operational constraints such as load building

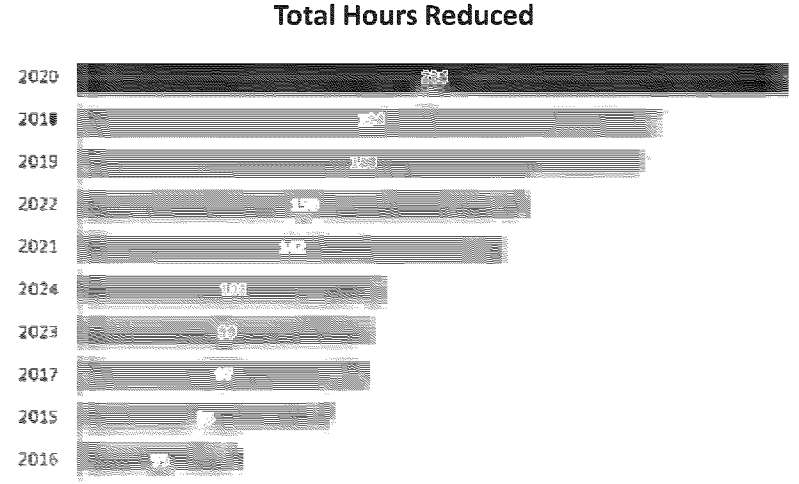
Defining annual performance requirements across weather years

Our analysis of operational feasibility is anchored on 1-in-10 weather conditions, to ensure that conclusions about the ability of the portfolio to reduce peak demand are robust across a range of performance requirements.

As the system peak is flattened after DR and EE operations, it becomes more challenging to further reduce the peak. Our analysis accounts for this effect by analyzing the hourly system load shape and the associated performance requirements at various levels of system peak demand reduction.

We selected the 2020 system load shape as the basis for our analysis, because it represents the most challenging conditions needed to achieve deep peak demand reductions over the past ten years. The figure at right shows that achieving a 10% (307 MW) peak reduction in 2020 would have required the most hours of demand reduction.

Performance Requirements for 10% System Peak Demand Reduction, by Base Weather Year



Notes: We compared the maximum consecutive hours and total hours of reduced load needed to achieve a 10% (307 MW) peak reduction across ten available weather years. We are just presenting total hours since most years had comparable consecutive hour requirements.

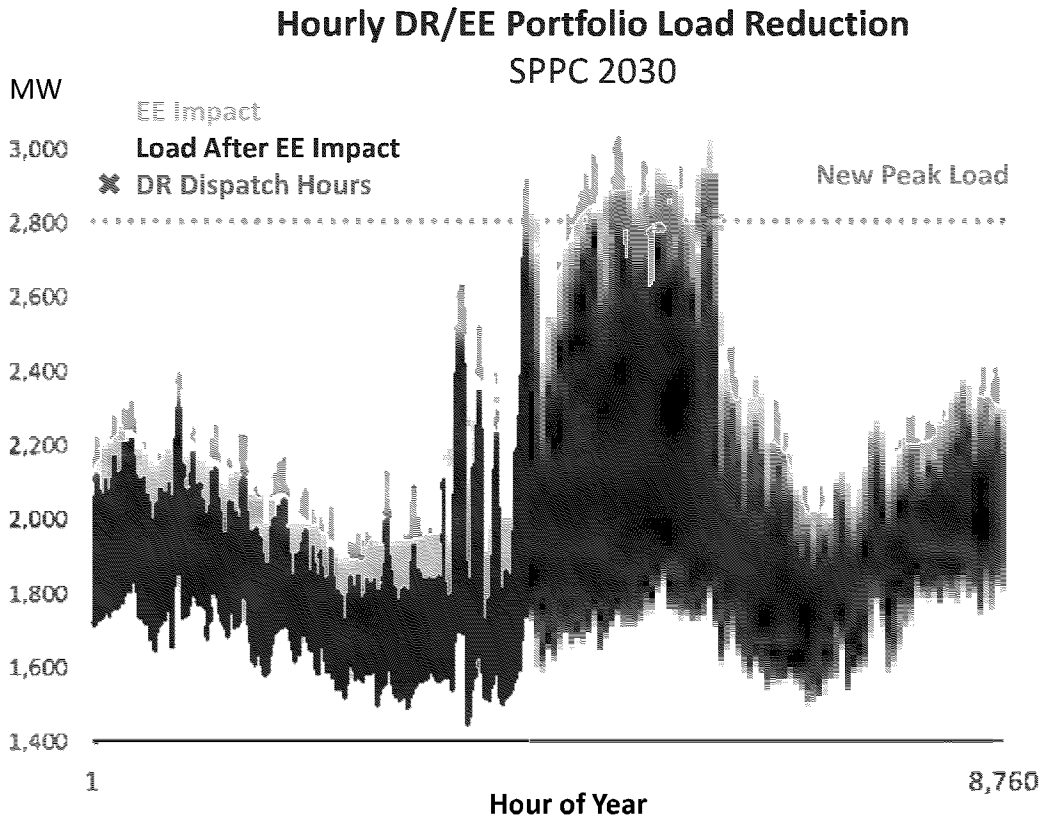
Annual performance requirements

Performance requirements throughout the year may limit the portfolio's overall capacity contribution to around 251 MW.

We illustrate the performance characteristics of the DR/EE portfolio that would be needed to achieve various target levels of system peak reduction.

Reducing the system peak by the full 296 MW portfolio would require load reductions that may exceed the realistic capability of the modeled portfolio, particularly given imperfect ability of the system operator to predict system conditions.

We test the portfolio's maximum ability to feasibly reduce NVE SPPC system peak, in this case by 251 MW. This requires 236 hours of load reduction. After accounting for hours with EE reductions, DR programs would need to reduce demand in 23 hours (up to 4 per day) over 8 days, which is within the operational capability of the modeled portfolio.



Operational Feasibility

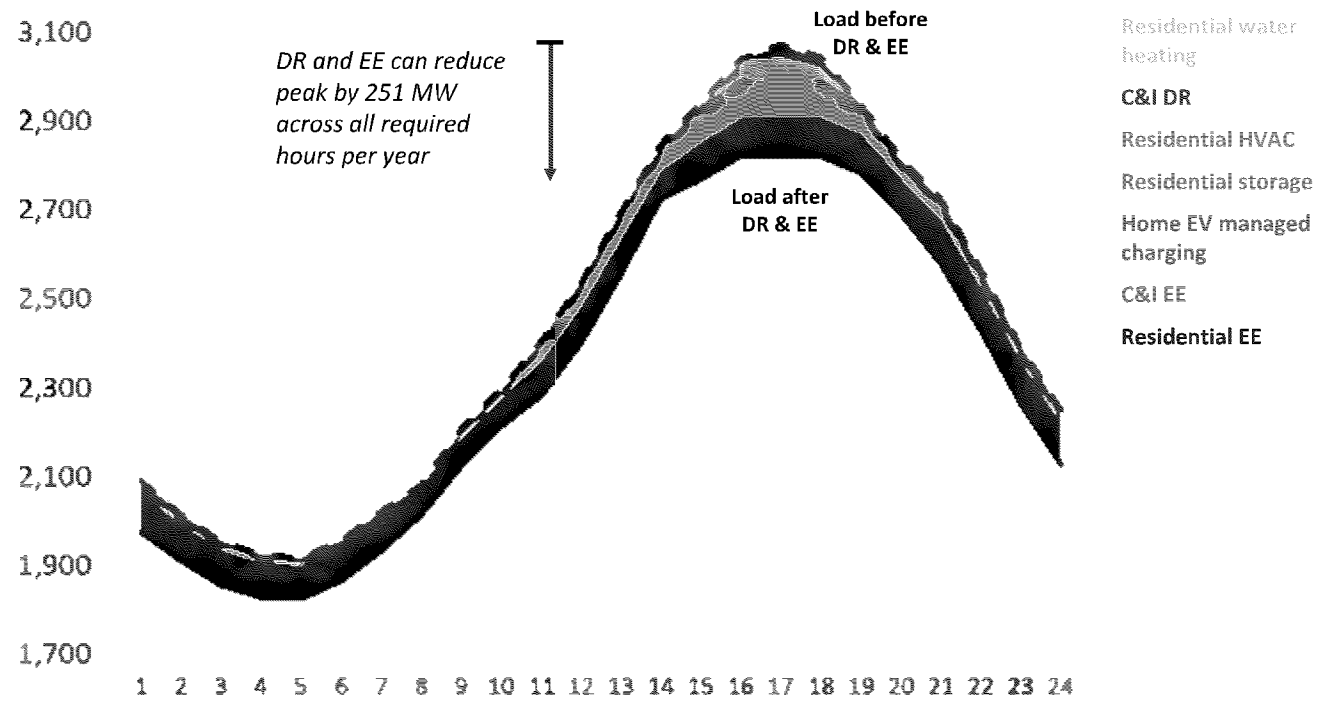
DR and EE can deliver demand reductions during the hours when needed most.

The figure at right illustrates how the modeled portfolio could be operated to achieve a 251 MW reduction across all hours on NVE's peak load day.

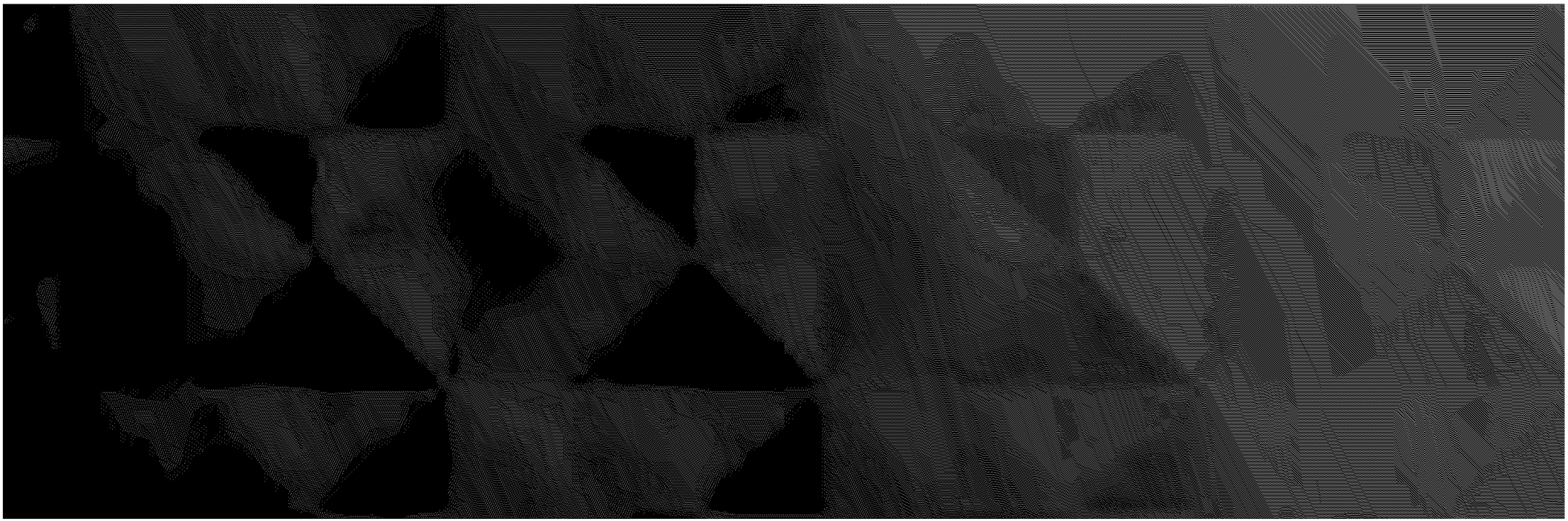
DR program dispatch is constrained by event frequency and duration limitations, and accounts for pre- and post-event load-building. These operational constraints are consistent with the parameters of existing programs and pilots.

Reducing annual system peak load by 251 MW would require DR load reductions on 8 days of the year. Achieving this level of reduction is feasible within the program constraints.

Illustration of Portfolio Demand Reduction on Peak Demand Day



Note: For simplicity, load building associated with DR programs has been netted out of EE savings in the figure. Y axis is cropped to highlight program dispatch detail.



7. Scenario Analysis

Scenario analysis overview

We test the sensitivity of the results to key assumptions in the analysis.

Enrollment rates and program costs (including customer incentives) are key drivers of the magnitude and cost-competitiveness of the portfolio. Both assumptions have some uncertainty.

Enrollment is influenced by factors like program design and engagement strategies, the effectiveness of which will vary across utilities and service providers. Participation rates could exceed assumed base case levels through the implementation of new approaches to engaging customers, or lag behind assumed levels if barriers to enrollment create significant friction in uptake.

Higher **program costs** may be required to achieve base case participation levels, such as higher incentive payments and more expensive marketing campaigns. Further, there is uncertainty in the future cost of original equipment manufacturer (OEM) fees and Distributed Energy Resource Systems (DERMS) expenses.

To assess the robustness of our conclusions, we created alternative scenarios based on plausible ranges of these assumptions.

Modeled scenarios

We vary participation and cost inputs across four additional scenarios relative to the base case, as described below.

Input Assumption	Scenario 1: Higher Enrollment	Scenario 2: Higher Costs	Scenario 3: Lower Enrollment w/Higher Costs	Scenario 4: Higher Enrollment w/Higher Costs
Enrollment	Participation rates exceed base case levels through new approaches to engaging customers and other innovative marketing strategies. Primary market research (e.g., customer surveys) could refine estimates of NVE customer willingness to engage in DR and EE.	No change relative to base case.	Enrollment lags behind best-practice participation rates achieved in other jurisdictions, reflecting low customer engagement success. Could be driven by barriers preventing enrollment not explored in this study (e.g., onerous enrollment process, lack of customer trust).	Participation rates exceed base case levels through effective customer engagement strategies and more lucrative incentives. Primary market research (e.g., customer surveys) could refine estimates of NVE customer willingness to engage in DR and EE. Higher incentives alone may not lead to increased participation.
Implementation Cost *(incl. marketing, incentive)*	No change relative to base case.	Higher incentive payments and more expensive marketing campaigns are required to achieve base case participation levels. Also includes additional original equipment manufacturer (OEM) fees as well as Distributed Energy Resource Management Systems (DERMS) contract and per-participant expenses.	Increased program expenses to cover higher incentives and marketing costs. Higher costs also include incremental OEM fees and DERMS contract and per-participant expenses.	Higher incentive payments and more expensive marketing campaigns are required to achieve high participation levels. Also includes additional original equipment manufacturer (OEM) fees as well as Distributed Energy Resource Management Systems (DERMS) contract and per-participant expenses.

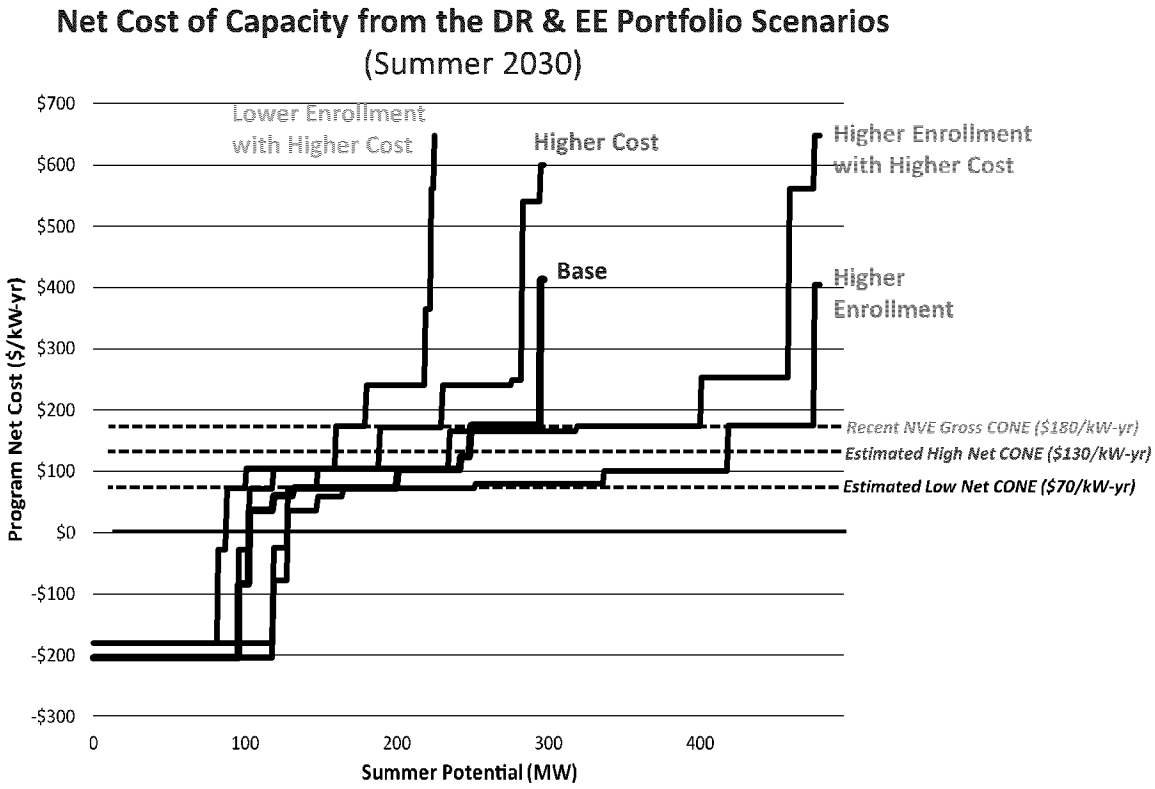
Scenario analysis results

Under a range of scenarios, the majority of demand reduction potential has a net cost lower than recent CONE estimates.

Relative to the Base scenario that has 296 MW of DR and EE, improving customer enrollment strategies (Higher Enrollment scenario) could increase potential by 62% (+183 MW).

If higher incentive and operational costs are required to attract participants, combined with low enrollment, potential decreases by 25% (-75 MW).

Battery storage and Large C&I DR continue to be cost-competitive opportunities. Significant portions of residential and commercial EE programs remain below recent net CONE estimates.



Notes: Program net costs are reported as total cost, including incentives, less energy benefits. MWs are reported as program contribution to the system peak hour. Certain programs could provide additional grid benefits not quantified here such as distribution or ancillary services.

See appendix for program level information.

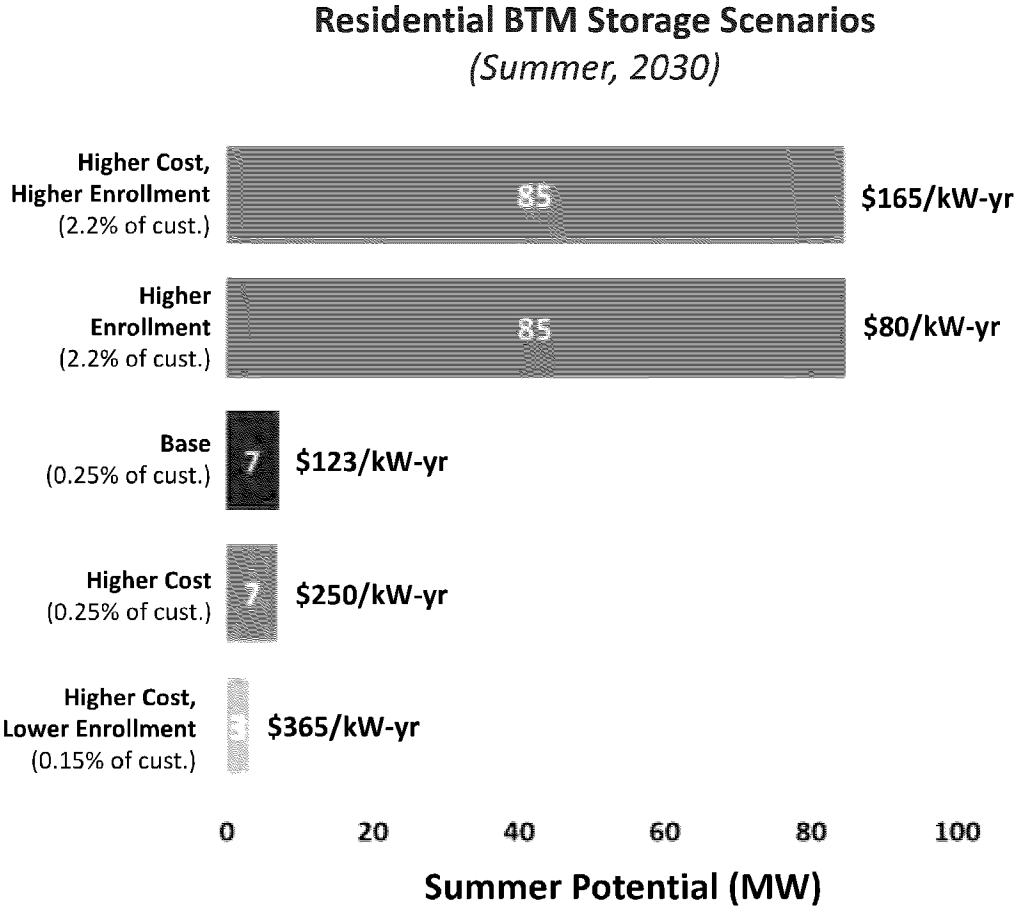
Battery storage deep dive

There is significant upside in the potential for behind-the-meter batteries.

Across the five enrollment and cost scenarios, NVE SPPC could control between 3 and 85 MW of battery DR capability by 2030 at a cost ranging from $80/kW-yr to $365/kW-yr.

We model participants with existing batteries as having 5.8 kW capacity and three-hour duration based on NVE data, while all new battery adoption is assumed to follow recent industry trends and have capacity of 11.5 kW with one hour duration, comparable to Tesla's Powerwall 3. The difference in customer battery size dimensions contributes to variation in average program cost across enrollment scenarios, since incentives are paid on a $/kWh basis of battery capacity.

We assume customers are compensated for exports to the grid (i.e., battery dispatch exceeding customer demand), which would require addressing existing barriers.



Notes: Program net costs are reported as total cost, including incentives, less energy benefits. MWs are reported as the program contribution to the system peak hour.

Battery storage incentives

Participation incentives are benchmarked against existing programs in other jurisdictions for all modeled programs. Battery storage benchmarking is shown here as an example due to NVE and Google's interest in the program.

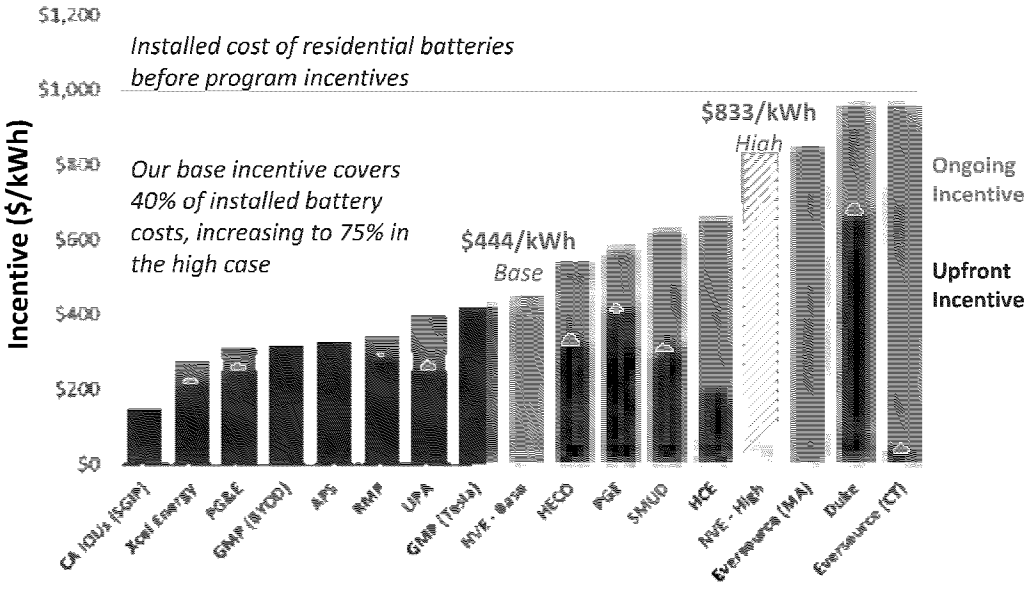
Base case estimates cover 40% of the installed cost of a new Tesla Powerwall over a 10-year enrollment period based a survey of participation incentives offered in existing programs across the U.S.

High case estimates reflect higher-end participation incentives offered in existing programs across the U.S. and cover 75% of the installed cost of a new Tesla Powerwall. While there are multiple factors, beyond customer incentives, that contribute to high enrollment, the Eversource programs through Connected Solutions have achieved high levels of program participation and offer incentives at the upper end of the benchmarking.

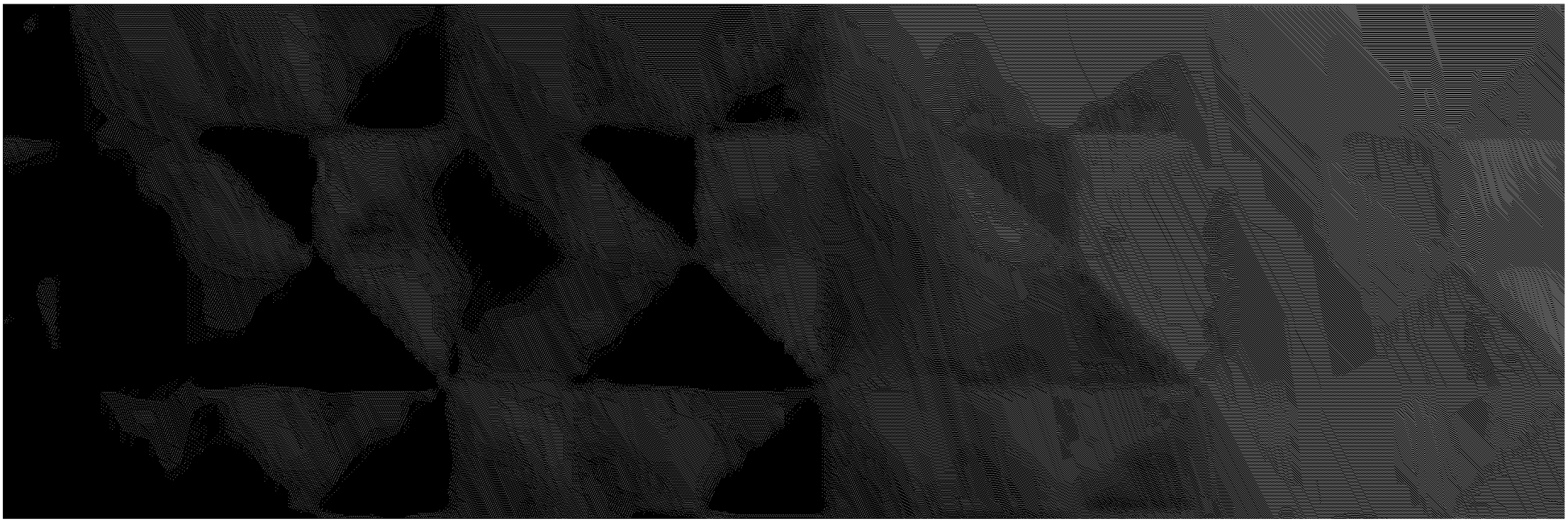
Higher incentives that cover nearly the full cost of the battery could increase enrollment beyond modeled levels. Additional primary research would be necessary to determine customer willingness to participate at higher incentive levels and other program design factors that contribute to enrollment levels.

All-in Participant Incentives in Battery Storage Programs

Present value over assumed 10 years of participation



Notes: Incentives include both up-front and ongoing incentives. Ongoing incentives reflect 10 years of program participation expressed per kWh of storage capacity. Our modeling applies annualized $/kWh-yr incentives and does assume a split between ongoing and upfront incentives. See appendix for more detail on the existing program data. The range of installed costs of residential batteries reflects Tesla Powerwall 2 and Tesla Powerwall 3 assets based on existing and new installations.



8. Conclusion

Key findings

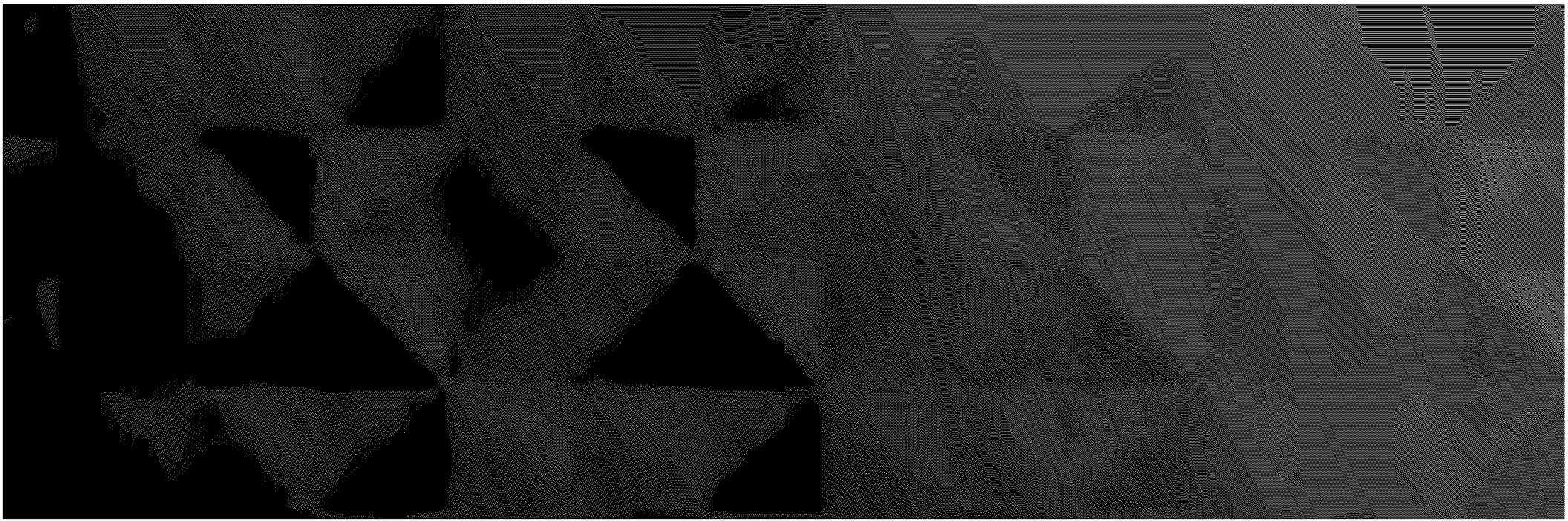
New, hyperscaler-enabled DR and EE can serve as a reliable resource for NVE, delivering significant peak demand reductions at competitive costs.

- Within the next five years, it is possible to scale demand-side initiatives to provide 296 MW of demand reduction capability during summer peak hours.
- Operationally, this portfolio of programs could provide 251 MW of annual demand reduction capability even under the most challenging load conditions observed over the past 10 years.
- The portfolio would create new headroom on NVE's system and reliably serve demand at a cost lower than the recently observed cost of competing conventional resources.
- The findings are relatively robust across varying enrollment and program cost assumptions, with cost-competitive peak reduction potential consistently at or above 250 MW.

Considerations for a Google-NVE Partnership

Important considerations for moving forward with the development of a Google-funded expansion of NVE's demand-side offerings include:

- **Incrementality:** Design programs and M&V methods to clearly demonstrate incrementality of the new initiatives relative to NVE's ongoing/planned activities. This could include a focus on funding attractive programs that do not currently pass cost-effectiveness screens.
- **Durability:** The initiative may require a multi-year contractual commitment with backstops, to ensure that the capacity aligns with the lifetime of new data center load and/or availability of new supply-side resources.
- **Delivery:** Further work is needed to determine the appropriate implementation model (e.g., funding utility-led initiatives, or engaging with third-party aggregators and ESCOs).



Appendix

Summary of key base case modeling assumptions

Program parameters are calibrated to NVE sources (e.g. 2024 DER Potential Study, 2024 M&V Study) when available and otherwise supplemented with a review of existing programs and pilots operating in other jurisdictions. Key program assumptions for the base case are summarized below.

Program	Eligibility and Participation Criteria	Per-Participant Peak Impact	Event Frequency and Duration	Load Building Assumptions	Program Costs*
Cooling (residential)	78% have central A/C with 15% participation	Residential: 1.03 kW	10 events per year, 4-hour events	40% of reduced load (2 hours of pre-cooling and 2-hour post-event snapback period)	$70/part-yr annual incentive. $75/part upfront incentive. $25/part-yr DERMS/OEM costs.
Smart water heating (combined electric resistance and heat pump)	27% have electric water heating with 15% participation	Customer impact varies by hour, based on water heating load available to curtail; 95% curtailment during event hours reflects 5% event opt-out rate.	Daily shifting of water heating load, 4-hour events	100% of reduced load	$30/part-yr annual incentive. $315/part variable equip cost. $8/part-yr DERMS/OEM costs.
EV managed charging (home)	34% of residential customers with electric LDVs (Implied from Low Scenario Sales in DER Potential Study) with 25% participation	Customer impact varies by hour, based on average LDV fleet charging load available to curtail at home; 90% of EV charging load curtailment during event hours reflects 10% event opt-out rate.	Daily shifting of load, 4-hour events	100% of reduced load	$50/part-yr annual incentive. $20/part-yr DERMS/OEM costs.
BTM battery (residential)	0.25% customer participation. Adoption forecasted based on DER Potential Study solar attachment rates and grossed up to account for DR program uplift; includes paired assets and standalone installations	8.3 kW based on a weighed average of customers with batteries today (5.8 kW|17.4 kWh) and new customers that will install a larger capacity battery following industry trends and incentivized through hyperscalar funding, comparable to Tesla Powerwall 3 specifications (11.5 kW | 13.5 kWh).	100 events per year, up to 3-hour events	118% of discharged energy (85% round-trip efficiency)	$110/part-yr annual incentive. $139/part-yr DERMS/OEM costs.
Large C&I DR (auto and manual)	All load eligible (except data centers), with 25% participation	20% of hourly load can be reduced during event. Class load shape developed from NVE provided data scaled to class-wide IRP forecasted demand after removing data center demand.	30 events per year, 4-hour events	50% of reduced load	$50/kW-yr annual incentive.
Residential EE	Established in DER Potential study	Hourly efficiency savings based on ResStock load shapes scaled to MWh and MW MAP Grid Value savings from DER Potential Study. End-use level shapes would need to be distorted to align savings with the Grid Value MW and MWh savings.	Daily load reductions based on ResStock load shapes and DER Potential Study	None	Cost data not available from DER Potential Study. Portfolio-wide $111/MWh based on Demand Side Plan (2025-2027) Grid Value estimates and applied to forecasted potential.
Commercial EE	Established in DER Potential study	Hourly efficiency savings based on ComStock load shapes by end use (e.g. HVAC, lighting, etc.) scaled to MWh and MW MAP Grid Value savings from DER Potential Study.	Daily load reductions based on ComStock load shapes and DER Potential Study	None	Cost data not available from DER Potential Study. Portfolio-wide $16/MWh based on Demand Side Plan (2025-2027) Grid Value estimates and applied to forecasted potential.

Note (*): All DR programs have a $75,000 set up cost, initial per participant marketing costs ($50/kW for both Res and C&I), and a share of administrative costs equivalent to 3 full-time employees at $100,000/yr. The incentive and DERMS costs summarized in the table above vary by program.

Portfolio results – Base Scenario

We report program level potential and associated net costs for each studied program.

Capacity reflects total potential, inclusive of current capability available at seasonal system peak hour.

Program net costs are reported as program administration and incentive costs less energy benefits on a per-kW basis. Gross costs reflect total costs without energy savings reductions.

DR & EE Achievable Peak Reduction Potential

Program	Summer (MW)	Winter (MW)	Program Gross Costs ($/kW-yr)	Program Net Costs ($/kW-yr)
Cooling (residential)	41	0	$111	$102
Smart water heating (combined electric resistance and heat pump)	3	3	$464	$414
EV managed charging (home)	12	12	$183	$61
BTM battery (residential)	7	7	$140	$123
Large C&I DR (auto and manual)	16	15	$55	$37
Residential EE (low and high cost)	116	74	$130, $263	$73, $175
Commercial EE (low and high cost)	101	82	$96, $224	-$204, -$84
Total Portfolio	**296**	**194**	**$141/kW-yr** *(Weighted average)*	**-$2.65/kW-yr** *(Weighted average)*

Note: Values shown are inclusive of existing DR capability. Net costs are after energy savings reductions.

Portfolio results across scenarios

We vary participation and cost inputs across four additional scenarios relative to the base case. Potential estimates are reported below.

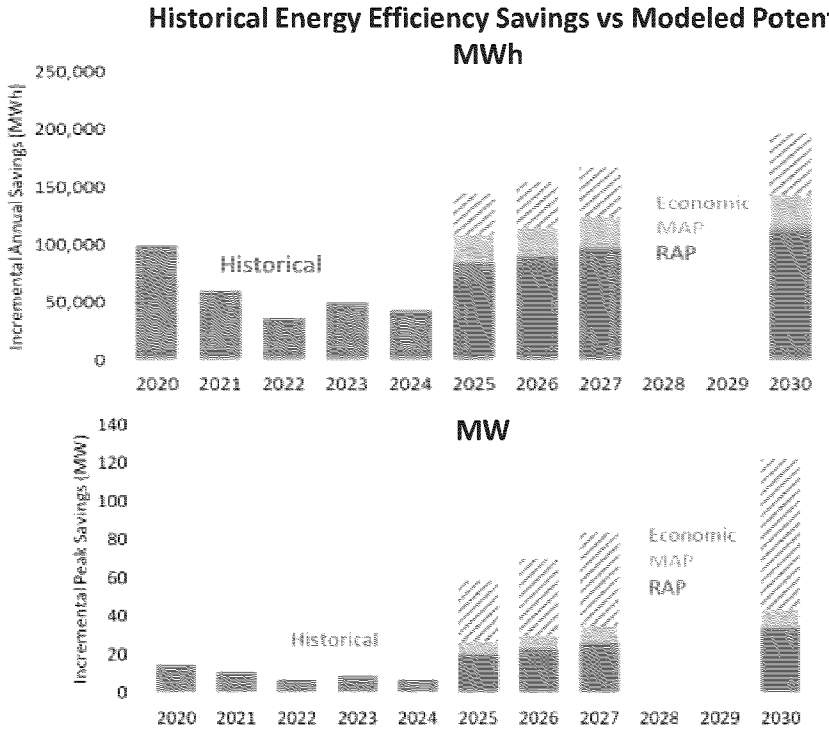
DR & EE Achievable Peak Reduction Potential Across Scenarios

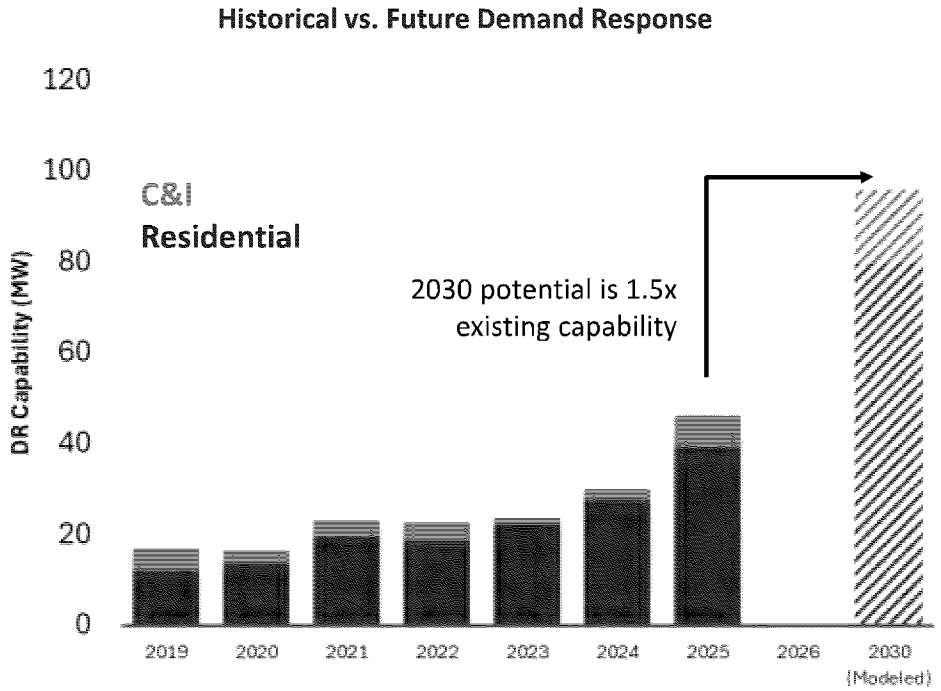
	Summer Program Potential (MW)					Net Cost ($/kW-yr)					Gross Cost ($/kW-yr)				
Program	Base	High Enrollment	High Cost	High Cost, Low Enrollment	High Cost, High Enrollment	Base	High Enrollment	High Cost	High Cost, Low Enrollment	High Cost, High Enrollment	Base	High Enrollment	High Cost	High Cost, Low Enrollment	High Cost, High Enrollment
Commercial EE (RAP)	94	118	94	80	118	-$204	-$204	-$180	-$153	-$180	$96	$96	$120	$102	$120
Commercial EE (Incremental MAP)	85	107	101	86	9	-$84	-$84	-$28	-$28	$28	$224	$224	$281	$281	$281
BTM battery (residential)	7	85	7	3	85	$123	$80	$250	$365	$165	$140	$91	$267	$389	$176
Large C&I DR	16	20	16	13	20	$37	$36	$72	$73	$71	$55	$54	$90	$91	$89
EV managed charging (residential)	12	17	12	2	17	$61	$60	$541	$561	$539	$183	$181	$663	$683	$661
Residential EE (RAP)	70	87	70	59	87	$73	$73	$105	$89	$105	$130	$130	$163	$138	$163
Cooling (residential)	41	82	43	20	82	$102	$102	$173	$174	$172	$111	$110	$181	$183	$181
Residential EE (Incremental MAP)	116	145	116	98	57	$175	$175	$241	$241	$241	$263	$263	$329	$329	$329
Smart water heating (residential)	3	4	3	1	4	$414	$405	$601	$649	$592	$464	$455	$652	$699	$642

Note: Values shown are inclusive of existing DR capability. Net costs represent per-kW cost less energy benefits.

Existing and future EE and DR capability

EE savings have declined in recent years and RAP EE potential estimates are higher than average historical levels. MAP EE potential exceeds maximum historical achievements in the last 5 years. Modeled 2030 EE potential is 1.5x greater than existing capability.





Historical EE and DR savings/potential from EIA-861. Future savings from NVE, 2024 DER Potential Study (for EE) and FLEX results (for DR).

Composition of the EE bundles (MW Savings)

Estimates of achievable EE potential are based on a review of NVE's most recent 2024 DER Potential Study. Measure level results are not provided, but the top contributors were summarized in the DER Potential Study. We rely on those select contributing categories to characterize residential and commercial EE savings.

Top Subsectors for Cumulative Programmatic EE

Residential	
End Use	% of Annual Savings (MWh)
Central AC	95%
Room AC	3%
Clothes Washing	1%
Refrigeration	1%
Total 2030 Energy Savings (GWh)	188.7
2030 Peak Savings (MW)	115.6

C&I	
End Use	% of Annual Savings (MWh)
Space Heating	55%
Linear Lighting	17%
Ventilation	13%
AC	9%
General Service Lighting	6%
Total 2030 Energy Savings (GWh)	579.9
2030 Peak Savings (MW)	101.3

Note: Savings shapes are developed from NREL ResStock and ComStock hourly data and scaled to MW and MWh values from the Grid Value case. We note that ResStock end-use savings shapes would need to be distorted to align savings with the Grid Value peak, so we instead scale Residential total class shapes. Additional measure data from NVE would allow for a better representation of the Residential measures that comprise Grid Value. For Commercial savings, the applicable end uses scale to MW and MWh Grid Value savings.

Scenario analysis cost input overview

We vary program costs across scenarios to test the impact on DR and EE potential if increased incentives are available or program administration costs vary.

Cost Input		Base Costs *(Base and Higher Enrollment scenarios)*	Higher Costs *(Higher Cost, Lower Enrollment w/Higher Costs, Higher Enrollment w/Higher Costs scenarios)*
DR	Marketing costs	$50/kW for all programs	50% increase for all programs assuming increased staff-hours, more intensive marketing campaigns, etc.
	Original equipment manufacturer (OEM) fees and DERMS Contract Costs	No OEM Fees included. $50,000 DERMS contract cost. $24/kW-yr for smart heating/cooling, water heating, EV managed charging, and storage based on expert interviews.	$10/device for ST and GIWH based on National Grid pilot programs and $150/device for storage and EVs based on 2024 SEPA State of Charging report. Increased DERMS contract costs and DERMS per-participant costs by 30% to account for contracting uncertainty.
	Technology incentives	• Smart thermostats: $70/participant-yr based on the current NVE incentives • EV Managed Charging: $50/participant-yr based on Dominion incentives • Storage: $444/kWh of enrolled capacity (levelized over 10 years of program enrollment to $63/kWh-yr) based on survey of existing programs • Grid-interactive water heating: $30/participant-yr based on MAP incentive value • C&I DR: $50/kW-yr based on PEPCO incentives	• Smart thermostats: $125/participant-yr based on incentives seen in SCE/PEPCO and Consumers territories • EV Managed Charging: $100/participant-yr based on Eversource incentives • Storage: $833/kWh of enrolled capacity (levelized over 10 years of program enrollment to $120/kWh-yr) based on survey of existing programs • Grid-interactive water heating: $54/participant-yr informed by smart thermostat program experience • C&I DR: $80/kW-yr informed by a survey of existing programs
EE	Gross Cost	Residential: $56/MWh for RAP and $111/MAP based on DSM Study Commercial: $5/MWh for RAP and $16/MWh for MAP based on DSM Study	25% increase from Base scenario

Scenario analysis participation input overview

We vary participation rates across scenarios to test the impact of customer behavior on DR and EE potential. Additional primary market research through customer surveys could improve data availability specific to NVE customers.

Program	Base *(Base and Higher Cost scenarios)*	High Participation *(Higher Enrollment and Higher Enrollment w/Higher Costs scenarios)*	Low Participation *(Lower Enrollment with Higher Costs scenarios)*
Cooling and heating (residential)	15%	30%, informed by review of other jurisdiction experience (slide 16).	7.5%, assuming delayed adoption.
Smart water heating (combined electric resistance and heat pump)	15%	25%, informed by review of other jurisdiction experience (slide 16).	5%, assuming delayed adoption.
EV managed charging	25%	35%, assuming accelerated adoption due to customer behavior.	5%, assuming delayed adoption.
BTM battery (residential)	0.25%	2.2%, based on adoption achieved by Green Mountain Power.	0.15%, based on National Grid MA ConnectedSolutions and Eversource participation.
Large C&I DR (auto and manual)	25%	30%, informed by DSM potential study MAP values.	20%, assuming delayed enrollment.
Energy efficiency measures	100% of MAP	125% of MAP	85%

Notes: Base participation assumptions are based on a review of the 2024 DER Potential Study, current experience, and benchmarking to achieved levels in other jurisdictions. See additional documentation in this report.

Notes on battery storage incentives benchmarking analysis

We made the following assumptions to establish comparable estimates of each of the utility program incentive payments presented in the incentives benchmarking section of this report.

Surveyed residential battery programs

- Surveyed 15 utility and statewide residential battery programs including offerings from Green Mountain Power, Duke Energy, Holy Cross Energy, Rocky Mountain Power, Portland General Electric, Liberty Utilities, Eversource, Arizona Public Service, Hawaiian Electric, SMUD, PG&E, Xcel Energy, and PSEG Long Island, as well as California's SGIP.
- The surveyed programs represent a range of approaches to customer compensation, including up-front rebates, recurring capacity payments, performance-based incentives, and utility-supported battery leasing.

Assumptions

- Assumed each participant has two Tesla Powerwall 2 batteries (10 kW / 27 kWh) unless otherwise specified in the program description.
- Assumed 10 years of participation where applicable.
- When retention incentives are a function of battery output, we assume the maximum amount of discharge available under program limits.
- Assumed discount rate for annualizing up-front program incentives is based on discount rate implied in Green Mountain Power lease (i.e., difference between up-front versus monthly payment plan offerings). It is approximately 1.8%/year.
- Estimates of battery cost savings to participants in leasing programs based on the pre-tax incentive battery cost without installation.

EXHIBIT 3

EXHIBIT 3

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	26-05007	**REQUEST DATE:**	08-25-2026
REQUEST NO:	Google 07	**KEYWORD:**	vol 33 narrative demand side plan p5 three threshold requirements; identify stat
REQUESTER:	Cook	**RESPONDER:**	Rodriguez, Patricia (NV Energy)

REQUEST:

Reference: Volume 33, Narrative Demand Side Plan at page 5

Question: Refer to Volume 33, Narrative Demand Side Plan at page 5, where the Company states "The Commission identified three threshold requirements for any future proposal: specificity around eligibility, duration, budget, credit mechanics, and measurement; evidentiary support that the program will not harm other ratepayers; and a clear endpoint or review mechanism." Please identify the specific reference for this statement.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: NOne

RESPONSE:

The referenced statement is based on the Commission's consideration of Google's proposed Large Customer Offsite DSM Program in the Companies' 2024 Joint IRP. See Docket No. 24-05041, December 27, 2024, Order at 136–139. The Commission did not approve the proposal, finding a lack of detail and evidentiary support in the record, and encouraged Google, NV Energy, and any interested stakeholder to continue discussions and refile any such proposal in a future IRP proceeding. Order at 139. The requirements described in the Narrative Demand Side Plan summarize the Companies' understanding of the areas requiring additional detail and evidentiary support, based on the program elements the Commission considered. Order at 136–139; see also Direct Testimony of Patricia Rodriguez at 10, n.7.

EXHIBIT 4

EXHIBIT 4

CURRENT
ENERGY GROUP



Large Customer Offsite DSM Program

January 2026

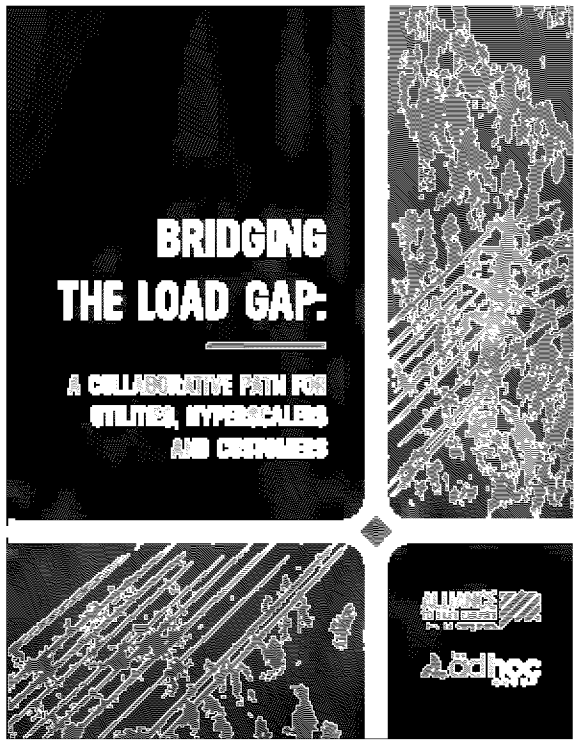
Background

- PUCN's December 2024 Order in NV Energy's 2025-2044 IRP (Docket No. 24-05041):
  - "However, the Commission encourages Google, NV Energy, and any interested stakeholder to continue discussions around the proposed Large Customer Offsite DSM Program and refile any proposal for such a program, with the Commission for consideration, with additional detail and evidentiary support, in a future IRP or IRP amendment proceeding."
- Throughout 2025, Google and NVE have held informal discussions on further development of a Large Customer Offsite DSM Program in SPPC territory.
- Google has also engaged:
  - Current Energy Group to provide technical support on program design
  - The Brattle Group to conduct additional analysis on technical potential

General Framework Gaining Traction

- "Bring Your Own Distributed Capacity" has emerged as a practical solution for addressing large load customer needs in a timely and cost-effective manner

- Alliance to Save Energy framework components:
  1. Geographically- and Technology-targeted Solution Portfolio
  2. Risk Transfer and Capital Commitment
  3. Targeted Deployment
  4. Capacity Accreditation
  5. System and Site Benefits



Alliance to Save Energy report (2026) (Google funded)

Similar Efforts in Other Jurisdictions

- **Kansas & Missouri** : The Kansas Corporation Commission and the Missouri Public Service Commission both adopted a new large load tariff that creates a Clean Energy Choice Rider, which enables customers to directly support the procurement of distributed energy resources, including demand-side management, energy efficiency, and battery storage in exchange for appropriate credit. These tariffs apply to large load customers of Evergy Kansas, Evergy Missouri, and Ameren Missouri.
- **Arizona:** Salt River Project also working with Google on a “Bring Your Own Distributed Capacity” program with aims to deploy in 2026
- Other programs in development and likely to be announced later in 2026

Offsite DSM Advantages:

- Low cost versus alternative capacity resource options
  - Assists with affordability goals
- Can provide “clean firm” contribution to assist with reliability as solar penetration increases
- Short deployment timeline versus other capacity resources (i.e., annual program cycle vs. multi-year development cycle)
- Investment can provide shared benefits for local communities where data centers are located

Objectives for a New NV Program

Clean Capacity

Large customers seek access to clean capacity beyond NVE's current plans

Distributed Solutions

Distributed solutions can address supply chain and transmission constraints

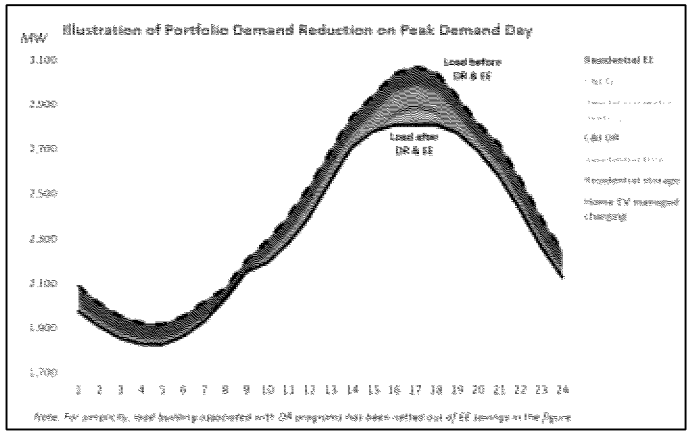
Customer Benefits

Increase reach of NVE customer programs to the benefit of NVE and large customers

Support Policy Goals

Expand set of solutions for CTT framework

Support Nevada policy goals around affordability and reliability



Source: The Brattle Group

Criteria for Success

Scalability:
Deliver 5+MW

Cost:
Competitive $/kw

Speed: Established path to deploy resources quickly

Carbon: Ideally carbon-free

Community Benefit:
E.g., Assist LMI community, schools, and nonprofits

Program Goals and Opportunity

- Brattle Study for SPPC estimates between 230-490 MW of incremental potential available by 2030
  - Significant opportunities in residential energy efficiency and behind-the-meter battery storage
- Large customer supplemental funding can expand deployment by stretching SPPC incentive budgets beyond traditional limits
  - Supplemental contributions can be used to exceed historic budget caps that limit program plans
  - Supplemental contributions can be used to overcome traditional cost-effectiveness barriers (while avoiding harm to non-participants).

Preliminary Proposed Program Framework for SPPC

- Large Customer contributes towards expansion of SPPC DSM portfolio
  - Monies supplement existing DSM program budget and will be used to offer enhanced incentives for existing measures and/or new measures/programs
  - Initial proposed focus on current programs gaps including in alignment with Brattle findings: 1) residential HVAC (targeting LMI customers) and 2) behind-the-meter battery storage.
- Proposing a pilot program of approximately $5 million/year for three years, with a goal of 5-15 MW of incremental savings each year (15-45 MW cumulative)
- Google receives capacity and energy benefit from its funding based on standard EM&V process.
  - Available for incremental capacity needs to serve new data centers or credited towards existing data center if system is short on capacity.
- If program braids funding, savings attributed based on percentage of total program funding from each entity.
- Large customer funding excluded from cost-benefit and other analysis

Next Steps

- Continued coordination with NV Energy on program framework development
- Seeking additional feedback from DSM Collaborative.
- Working towards full proposal for upcoming IRP proceeding (spring 2026)

AFFIRMATION

I, Edward Burgess, pursuant to NAC 703.710 hereby affirm that the foregoing prepared direct testimony was prepared by me or under my direction and is correct to the best of my knowledge.

Dated: September 22, 2026

/s/ ***Edward Burgess***
Edward Burgess

CERTIFICATE OF SERVICE

I hereby certify that on this 22nd day of September, 2026, I caused a true and correct copy of the foregoing document, PREPARED DIRECT TESTIMONY OF EDWARD BURGESS ON BEHALF OF GOOGLE, LLC to be served via e-mail to the following:

Roman Borisov
Trevor Dillard
NV Energy
Roman.Borisov@nvenergy.com
regulatory@nvenergy.com

Don Lomoljo
Public Utilities Commission of Nevada
dlomolojo@puc.nv.gov
pucn.sc@puc.nv.gov

Michelle Badorine
Michael Saunders
Bureau of Consumer Protection
mbadorine@ag.nv.gov
msaunders@ag.nv.gov
bcpserve@ag.nv.gov

Kirsten Stasio
Nevada Clean Energy
kirsten@nevadacef.org

Patrick Woolsey
Maddie Lipscomb
Sierra Club
patrick.woolsey@sierraclub.org
maddie.lipscomb@sierraclub.org

Brian Turner
Emma Hibbard
Advanced Energy United
bturner@advancedenergyunited.org
ehibbard@advancedenergyunited.org

Scott Dunbar
Keyes & Fox LLP
sdunbar@keyesfox.com

Jeffrey Ruskowitz
Caesars Enterprise Services LLC
jruskowitz@caesars.com

Carolyn Berry
Bates White LLC
carolyn.berry@bateswhite.com

Aisling Scott
Brittany Iles
Amazon
aiscot@amazon.com
beiles@amazon.com

Lucas Foletta
Amanda Sanchez
Kristine Roach
Laura Granier
Holland & Hart LLP
lmfoletta@hollandhart.com
alsanchez@hollandhart.com
karoach@hollandhart.com
lkgranier@hollandhart.com

Mike Fulkerson
Colovore LLC
fulkerson@colovore.com

Anna Fero
Chasity Hendren
Vidhya Prabhakaran
Davis Wright Tremaine LLP
annafero@dwt.com
chasityhendren@dwt.com
vidhyaprabhakaran@dwt.com

Curt Ledford
Dakota Councilman
Davison Van Cleve PC
crl@dvclaw.com
dlc@dvclaw.com

Shalini Sharma
Fleet Data Centers
Shalini.sharma@fleetdatacenters.com

Lucy Crow
Dietrich C. Hoefner
Michelle A. Gaeng
Womble Bond Dickinson LLP
lucy.crow@wbd-us.com
dietrich.hoefner@wbd.us.com
michelle.gaeng@wbd-us.com

Sydney Henry
Google LLC
sydneyhenry@google.com

Hunter Holman
Nina Peluso
Interwest Energy Alliance
hunter@interwest.org
npeluso@energyfuturesgroup.com

Henry Shields
MGM Resorts International
hshields@mgmresorts.com

Ann Pongracz
Sklar Williams PLLC
apongracz@sklar-law.com

Anna Congdon
Tyler Pepple
Pepple Moser PC
anna@pepplemoser.com
tyler@pepplemoser.com

Hiliary Wilson
Nevada Gold Mines LLC
hiliary.wilson@barrick.com

Virginia Valentine
Nevada Resort Association
valentine@nevadaresorts.org

Hunter Stern
Nevada Workers for Clean and AFF
hls5@ibew1245.com

Monique Rodriguez
Nathan Ring
Reese Ring Velto PLLC
monique@rrvlawyers.com
nathan@rrvlawyers.com

Robert Sweetin
Powerline Law
bob@powerline.law

George Cavros
Jeff Griffin
Nicolas Oliver
Zoe Harrold
Western Resource Advocates
george.cavros@westernresources.org
jeff.griffin@westernresources.org
Nicolas.oliver@westernresources.org
Zoe.harrold@westernresources.org

Alma Chao
Josh Gubkin
Redwood Materials, Inc.
alma@redwoodmaterials.com
joshgubkin@redwoodmaterials.com

Molly Watters
Tract Management Co
molly.watters@tractcapital.com

Kevin Lucas
Wil Gehl
Solar Energy Industries Association
klucas@seia.org
wgehl@seia.org

Shannon Anderson
Solar United Neighbors
sanderson@solarunitedneighbors.org

Courtney Feldman
Sweep
cfieldman@swenergy.org

Travis Madsen
Southwest Energy Efficient Project
tmadsen@swenergy.org

Danielle Hughes
Tahoe Spark
jointahoespark@gmail.com

Brad Heusink Veld
Vote Solar
bheusinkveld@votesolar.org

David Bender
Earth Justice
dbender@earthjustice.org

Jamie McGovern
Walmart Inc.
jamie.mcgovern@walmart.com

Joseph McClure
Hafsa Tout
Hallie Fox
McDermott Will & Schulte LLP
jmcclure@mcdermottlaw.com
htout@mcdermottlaw.com
hfox@mcdermottlaw.com

Danyale Howard
Qualus LLC
Danyale.howard@qualuscorp.com

Julia Hubbard
Solar United Neighbors
jhubbard@solarunitedneighbors.org

Terry Page
Terry Page Consulting
Terrypage0@me.com

Rachel McMahon
EDF Power Solutions
Rachel.mcmahon@edf-re.com

Lisa Tormoen Hickey
Tomoen Hickey LLC
lisahickey@newlawgroup.com

Randall H. Miller
David S. Jelsma
Arnold & Porter Kaye Scholer LLP
randy.miller@arnoldponer.com
david.jelsrna@amoldporter.com

/s/ Nancy A. Prout
Employee of Parsons Behle & Latimer