**BEFORE THE**

**NEW MEXICO PUBLIC REGULATION COMMISSION**

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| **IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF,** | ) | **CASE NO. 22-00058-UT** |
| **PUBLIC SERVICE COMPANY OF NEW MEXICO,** | ) | |
| **APPLICANT.** | ) | |

**SUPPLEMENTAL TESTIMONY**

**OF**

**COURTNEY LANE**

**ON BEHALF OF**
**THE OFFICE OF ATTORNEY GENERAL**

**March 8, 2023**

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Exhibits:

1. New Mexico Attorney General's Responses to Second Bench Request Order Issued November 16, 2022. Docket No. 22-00089-UT. January 17, 2023.

2. Case No. 21-00178-UT. Direct Testimony of Chas S. Nickell

3. Liburd, S., Sinclair, E., Woolf, T., and Roberto, C. 2021. *Hosting Capacity Analysis and Distribution Grid Security*. Prepared by Synapse Energy Economics for the Minnesota Department of Commerce.

4. Minnesota Public Utilities Commission. Docket No. E002/GR-19-564. Direct Testimony of Ravikrishna Duggirala. November 1, 2019.

5. Massachusetts Department of Public Utilities. November 5, 2014 Order in the Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid. DPU 12-76-C.

6. Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval by the Department of Public Utilities of its Grid Modernization Plan. DPU 15-121. August 19, 2015.

7. The Narragansett Electric Company d/b/a Rhode Island Energy, Grid Modernization Plan, Docket 22-56-EL. Schedule KC/RC/WR-1.

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, title, and employer.**

A. My name is Courtney Lane. I am a Principal Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

**Q. Did you previously file testimony in this case?**

A. Yes, on January 27, 2023, I filed Direct Testimony on behalf of the New Mexico Office of the Attorney General ("NMAG"), addressing the Grid Modernization Application ("Application") filed on October 3, 2022 by Public Service Company of New Mexico ("PNM" or "Company").

**Q. Please summarize the conclusions and recommendations outlined in your Direct Testimony.**

A. The following are the primary conclusions and recommendations contained in my Direct Testimony:

1. PNM's Application goes well beyond the New Mexico Public Regulation Commission's ("NMPRC" or "Commission") request for the Company to file a proposal for smart meters with automatic meter reading and remote fault detection modernization components and does not sufficiently justify many of the additional grid modernization technologies proposed in its filing.

2. The Company does not provide sufficient information to allow a determination of reasonableness. The Company fails to provide a BCA and does not quantify the expected impacts from its proposed investments, including increased distributed

energy resources ("DER"), reduction in greenhouse gases ("GHG"), or reliability improvements.

3. The Company fails to sufficiently link the desired outcome of an investment to the ability of the investment to meet that outcome. For example, the Company does not justify how its grid modernization investments will address the current interconnection backlog of solar applications or how the reliability of the distribution system will incrementally improve due to these investments.

4. The Company's Application brings into question the accuracy of cost projections in the later years of its proposal and whether Commission approval is needed today for these future investments.

5. It is unclear how the Company's proposed Environmental Justice Screening Tool ("EJ Screening Tool") will bring incremental benefits to disadvantaged communities in its current form.

6. The Company does not provide a robust annual reporting process with a full set of evaluation metrics.

7. The Commission should approve, with conditions, Advanced Metering Infrastructure ("AMI") related investments including meters, Neighborhood Area Network ("NAN"), Head End System, and Meter Data Management System ("MDMS"); the Customer Energy Management Platform and applications like Green Button Connect; supporting services including, Wide Area Network ("WAN"), Cybersecurity, Data

and Network Management, and the Data Warehouse; Home Area Network ("HAN"); Customer Analytics; and the EJ Screening Tool.

8. The conditions for approval of this suite of investments should include the requirement that the Company files a BCA within six months of an order being issued in this case; includes additional detail in its annual review filing related to progress toward the deployment of customer-facing programs and rate designs; includes the reporting metrics as listed in Attachment B of my Direct Testimony related to AMI within its annual review filing; and files an updated proposal for an EJ Screening Tool as part of its first annual review filing.

9. The Commission should reject the remaining grid modernization proposals in the Application and direct the Company to consider these projects for inclusion in a future grid modernization filing.

10. The Commission should require that any future filings include a BCA for the proposed grid modernization projects, quantify the expected outcomes, and provide more details related to program design.

11. The Commission should also adopt the recommendations discussed in the testimony of Andrea Crane.

**Q. What is the purpose of your Supplemental Testimony.**

A. On February 24, 2023, Hearing Examiner Christopher Ryan issued a Bench Request directing various parties to file Supplemental Testimony to address certain issues that were raised in the rebuttal testimonies filed by various parties on February 8, 2023. I am filing this Supplemental Testimony to respond to certain questions in the Bench Request that were directed at the NMAG.

**Q. To which sections of the Bench Request are you responding to in your Supplemental Testimony?**

A. Paragraphs 44 through 53 were addressed to the NMAG but no specific witness was identified for these questions. I am responding to Paragraphs 48, 51, and 52 and NMAG witness Andrea Crane is responding to Paragraphs 44-47, 49-50, and 53. I am also responding to Paragraphs 54-60, which were specifically directed to me by the Hearing Examiner.

As directed by the Hearing Examiner, the remainder of my Supplemental Testimony reproduces and responds to the questions contained in the Bench Request. The corresponding paragraph number from the Bench Request is provided at the end of each question.

## II. QUESTIONS DIRECTED AT NMAG

**Q. At page 14 lines 7 to 15 of PNM witness Warner's rebuttal testimony, he points to the Burns & McDonnell analysis (OBW-2) as sufficient justification for the programs PNM has proposed here and as a sufficient substitute for the BCA analysis NMAG witness Lane says was necessary. Does the NMAG agree that this analysis is a sufficient alternative? Please explain your answer. (Paragraph 48)**

A. No. I do not find the Burns & McDonnell analysis (OBW-2) to be a sufficient alternative for a BCA analysis.

First, OBW-2 only provides costs for some of PNM's proposed grid modernization investments and does not seek to monetize any of the purported benefits. OBW-2 does not discuss the benefits resulting directly from AMI and ADMS modules. There is also no discussion of an examination of potential alternatives to the proposed investments.

Second, while OBW-2 includes a discussion of benefits for a subset of grid modernization equipment, it does not provide any context for the magnitude of the incremental benefits compared to PNM's current system and whether those benefits outweigh the costs. For example, pages 30 and 31 of OBW-2 describe the benefits of communicated fault current indicator (FCI), stating that this equipment will minimize outage duration. However, this does not provide the reader with any information regarding the level of expected improvement compared to business as usual. There is also no discussion of the costs of business-as-usual compared to FCI within this section. Lastly, the report concludes that FCI is a medium priority. There is no information as to whether PNM chose to move forward with investment, and if it did, why it is investing in something with a medium level of priority.

One of the key benefits of a BCA is that it improves transparency by articulating the expected benefits and costs of proposed utility investments. A BCA provides utilities, stakeholders, and regulators the information necessary to determine if a utility investment will provide net benefits to customers. Without such information, it is difficult to determine whether a utility investment will be in the public interest.[1]

[1] New Mexico Public Regulation Commission. Docket No. 22-00089-UT. New Mexico Attorney General's Responses to Second Bench Request Order Issued November 16, 2022.

**Q. Do the statements PNM witness Warner makes at page 29 line 17 to page 30 line 4 answer (from the NMAG's perspective) the criticisms offered about PNM not adequately explaining what investments in volt-var management and ADMS will achieve? (Paragraph 51)**

A. No, they do not. My Direct Testimony indicates that PNM did not explain how investments in volt-var management and ADMS will directly address the system upgrade issues causing the interconnection backlog and did not estimate the increase in DERs from these investments.

Witness Warner's response further justifies my criticism. Based on witness Warner's response on pages 29 and 30, it appears that PNM's proposed investments in volt-var management and ADMS will not contribute to the existing interconnection backlog. Instead, witness Warner indicates that PNM is proposing additional infrastructure-related investments in its current rate case including the installation of battery storage on constrained feeders and rebuilding feeders. If separate investments in the current rate case will address PNM's distribution feeders with the highest constraints, the Company should provide justification for why volt-var management and ADMS are needed beyond these traditional utility investments. It is also unclear whether volt-var management and ADMS will avoid the need for future feeder upgrades.

Witness Warner also fails to address the second concern noted above, which is PNM's failure to estimate the increase in DERs resulting from these investments. Stating that "transformative changes" are required to achieve a carbon-free future is not sufficient. Any grid modernization proposal should provide quantitative data on the purported increase in DERs, especially if that is a key objective of PNM's application. At a minimum, a grid modernization proposal should articulate how the proposed investments will facilitate the implementation of DERs and provide estimates of how much energy and capacity would be saved or generated by those DERs.

**Q. Same question as immediately above but with respect to Warner rebuttal page 33 lines 2 to 8 and FLISR. (Paragraph 52)**

A. No. Witness Warner does not adequately address the criticism of the NMAG related to FLISR. Within my Direct Testimony I recommend that PNM should target FLISR to only the worst-performing feeders or those that are most susceptible to outages from storm-related events, to result in more cost-effective reliability improvements. This recommendation stems from the recent grid modernization filing of Southwestern Public Service Company (SPS) in Case No. 21-00178-UT. In its filing, SPS indicated that based on cost-benefit analysis, reliability benefits decline as the level of FLISR investments increases. The Company maximized benefits by only proposing to install automated equipment on areas of the system that have lower reliability performance, approximately 8 percent of feeders in its system.[2] PNM does not conduct a similar cost/benefit analysis.

While I appreciate that PNM will target feeders with poorer reliability first, it still does not justify why these investments are needed on feeders without reliability issues. Witness Warner states that the cost to integrate other feeders with functional intelligent switches is minimal, yet does not provide any cost details to support this statement. Furthermore, PNM did not provide any quantitative information on the improvements

[2] Case No. 21-00178-UT. Direct Testimony of Chad S. Nickell, pgs. 40-41.

expected from FLISR. For example, the Company did not provide information on the typical time to restore a typical feeder-level fault or how FLISR will improve those times.

**Q. At PNM witness Warner's rebuttal at page 25 line 5 to page 26 line 2, he appears to be arguing that Ms. Lane's company published literature that supports the investments PNM asks for authorization for here. According to witness Warner, that literature indicates that AMI with distribution automation will increase hosting capacity analysis which will speed up resolution of the interconnection backlog. Does Ms. Lane agree with this claim, or does she take issue with this statement? Please explain. (Paragraph 54)**

A. I do not agree with witness Warner's statement in regards to PNM's existing interconnection backlog. As stated by witness Warner on pages 27 and 28 of his Rebuttal Testimony, PNM is proposing a Distribution Battery Expansion Project as well as feeder and substation upgrades to address existing interconnection backlog issues in its current rate case.[3] The benefits of hosting capacity analysis and external-facing hosting capacity maps as noted in the Synapse study prepared for the Minnesota Department of Commerce apply to future DER interconnection applications and do not address existing constrained feeders that are in need of upgrades.

Witness Warner also takes the Synapse study out of context. This study was submitted to provide recommendations on improving Minnesota utilities' hosting capacity analyses by providing more transparent third-party access to hosting capacity maps and system information. As noted in the Synapse study, hosting capacity maps can help third party project developers identify optimal locations for interconnecting DERs on the distribution

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[3] Rebuttal Testimony of Omni B. Warner, pgs. 27-28.

system to minimize project costs by providing visibility into which feeders are constrained and may require system upgrades.[4]

**Q. Can you please provide an illustrative example where a utility provided a BCA for the types of grid mod proposals PNM offers here. A concrete example will help very much to make clear the kind of analysis you believe PNM should have done but did not. (Paragraph 55)**

A. Yes. As indicated on pages 14 and 15 of my Direct Testimony, other utilities have conducted BCAs for grid modernization projects similar to those proposed by PNM.

In Minnesota, Excel Energy conducted BCAs for many of the same grid modernization technologies proposed by PNM including AMI (with a time-of-use pilot), FLISR, Integrated Volt-Var Optimization, (IVVO), and associated components of the Field Area Network (“FAN”). Xcel provided individual BCAs for each technology individually and for its total Advanced Grid Intelligence and Security (AGIS) initiative plan.[5] Table 1 below provides a copy of the resulting benefit-cost ratios (BCRs) resulting from its BCA of each program and its overall AGIS, including sensitivities related to IVVO.

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[4] Liburd, S., Sinclair, E., Woolf, T., and Roberto, C. 2021. *Hosting Capacity Analysis and Distribution Grid Security*. Prepared by Synapse Energy Economics for the Minnesota Department of Commerce. Pg. 5. Available at https://www.synapse-energy.com/hosting-capacity-analysis-and-distribution-grid-security-minnesota.

[5] Minnesota Public Utilities Commission. Docket No. E002/GR-19-564. Direct Testimony of Ravikrishna Duggirala. November 1, 2019.

**Table 1. Xcel Energy BCA Example**

| | Low Sensitivity *IVVO 1.0% Energy Savings, With Contingency* | Baseline *IVVO 1.25% Energy Savings, With Contingency* | High Sensitivity *IVVO 1.5% Energy Savings, No Contingency* |
|---|---|---|---|
| AMI | 0.83 | 0.81 | 0.99 |
| FLISR | 1.31 | 1.31 | 1.53 |
| IVVO | 0.46 | 0.57 | 0.72 |
| Overall AGIS | 0.86 | 0.87 | 1.03 |

In Massachusetts, utilities are required to file BCAs to justify grid modernization investments. Specifically, utilities are required to evaluate the full suite of costs and benefits, including an itemization and analysis of all quantifiable costs and benefits, and an assessment of difficult to quantify or unquantifiable benefits.[6] In response to this requirement, Unitil conducted BCAs for a broad suite of grid modernization technologies as part of its Grid Modernization Plan in Docket 15-121. Unitil quantified the costs and benefits for similar projects to PNM including voltage regulation, AMI and OMS Integration, and ADMS. The utility also monetized the costs and benefits associated with DER enablement, grid reliability, distribution automation, customer engagement, and workforce development.[7] The Excel version of the workbook can be downloaded from the Massachusetts Department of Public Utilities webpage link for Docket 15-121: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9220913. I have also included this BCA as Exhibit 5.

[6] Massachusetts Department of Public Utilities. November 5, 2014 Order in the Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid. DPU 12-76-C.

[7] Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval by the Department of Public Utilities of its Grid Modernization Plan. DPU 15-121. August 19, 2015. pg. 77.

In Rhode Island, Rhode Island Energy (formerly National Grid) filed a BCA with its Grid Modernization Plan in Docket No. 22-56-EL. Within its BCA the utility grouped grid modernization project costs and benefits into the categories of avoided infrastructure costs, reduced DER curtailment, Volt/Var Optimization-Conservation Voltage Reduction, reduced outage frequency from ADMS and FLISR, whole house TOU and CPP, EV TVR, and O&M savings.[8]

**Q. At PNM witness Warner's rebuttal page 26 lines 15 to 19, he says that part of the reason PNM did not provide the quantitative data you think essential is because PNM lacks the necessary technologies to obtain that data. Witness Warner makes a similar claim at page 27 lines 4 to 8 where he says that PNM requires components requested in its grid mod app to be able to see how to best integrate DER at scale. Are these claims credible? Why or why not? Please explain. (Paragraph 56)**

A. I do not find these claims credible. First, utilities should use monetary values of costs and benefits to the fullest extent possible. As noted on pages 15 and 16 of my Direct Testimony, a recent study prepared for the U.S. DOE Grid Modernization Laboratory Consortium in 2021 found it is possible to monetize many of the common benefits of grid modernization investments related to reliability, DER integration, distribution operation and maintenance, energy, capacity, GHG emissions, power quality, and resilience.

Second, even in the absence of monetary values, utilities should use quantitative and qualitative information to provide as much information as possible to describe and justify the potential benefits of grid modernization investments.

[8] The Narragansett Electric Company d/b/a Rhode Island Energy, Grid Modernization Plan, Docket 22-56-EL. Schedule KC/RC/WR-1.

Even with data challenges, PNM should demonstrate how its proposed grid modernization investments are going to increase the quantity of DERs by using its existing DER interconnection queue or DER forecast to represent the business-as-usual scenario and compare that to the expected change from its proposed grid modernization investments. If PNM's claim is that an investment will reduce interconnection backlog, then PNM should forecast how many more DERs could be interconnected per year as a result of that investment. The incremental MW of DER per year from these two cases could be used as quantitative support for a grid modernization investment.

**Q. At PNM witness Warner's rebuttal testimony at page 28, he cites to testimony filed in PNM's rate case relating to infrastructure investments that PNM seeks to have approved in the rate case. Were you aware of this, and does the existence of this testimony change your views at all? (Paragraph 57)**

A. No, I was not aware of this testimony. PNM did not present this information in Direct Testimony within Case No. 22-00058-UT. However, knowledge of this fact does not change the views contained in my Direct Testimony. In fact, this knowledge raises additional concerns.

PNM is proposing multiple investments to address interconnection backlog across multiple proceedings. This further exacerbates the lack of transparency related to the overall costs and benefits of PNM's investments. The Company's long-term grid mod plan filed as PNM Exhibit LES-2 as part of its application should include information regarding what is being proposed in other dockets to support DER enablement.. In addition, PNM has not sufficiently addressed whether benefits of grid modernization investments are decreased if investments in the rate case are already addressing feeder usage.

**Q. At PNM witness Warner's rebuttal testimony at page 31 lines 15 to 17, he contends that investment in Volt-Var management is prudent because it will enable additional interconnections without the need for infrastructure upgrades. Do you agree with this or have any comments about the point? Please explain your answer. (Paragraph 58)**

A. I do not disagree that voltage management can support DER integration. The issue with PNM's proposal for volt-var management is the lack of quantitative data to support the purported benefits. On page 31 of witness Warner's Rebuttal Testimony, he states that the level of interconnections that can be supported on a circuit will be lower without voltage management yet provides no supporting quantitative information on the expected changes to the level of interconnections.

The Company should seek to provide additional context such as the typical or average number of additional interconnections enabled by volt-var management before infrastructure upgrades are instituted based on industry reports or from other utilities that have implemented this technology. Understanding the additional number of DERs that can be added to a feeder would also provides necessary, though not necessarily sufficient support for the Company's argument that these investments will enable and support DERs.

**Q. At PNM witness Warner's rebuttal at page 32 line 19 through page 33 line 7, witness Warner offers arguments to rebut your recommendations about FLISR. Please respond to Warner's testimony. (Paragraph 59)**

A. My response is the same as that included in the answer to Paragraph 52 above. Witness Warner does not adequately rebut my recommendation about FLISR. As indicated above, PNM (a) does not seek to maximize benefits by only proposing to install automated equipment on areas of the system that have lower reliability performance, and (b) does not conduct a similar cost/benefit analysis as was done by SPS.

The Company also fails to explain why ratepayers should pay for this technology on feeders that do not suffer from reliability issues. Witness Warner states that the cost to integrate other feeders with functional intelligent switches is minimal yet does not provide any cost details to support this statement. Furthermore, PNM did not provide any quantitative information on the improvements expected from FLISR. For example, the Company did not provide information on the typical time to restore a typical feeder-level fault or how FLISR will improve those times.

**Q. In PNM witness Warner's rebuttal testimony at page 7 lines 5 to 11, he points to a misalignment of PNM's infrastructure readiness and PNM's customer's DER adoption rate as justification for an aggressive grid mod program. At page 8 lines 3 to 8 of his rebuttal testimony, witness Warner explains that an AMI-alone grid-mod plan does not even address the DER adoption that already exists and needs to be met. Please respond to these claims and state whether you accept this argument and why. (Paragraph 60)**

A. First it is clear that AMI-alone does not support the level of DER adoption that already exists in New Mexico as PNM is proposing investments unrelated to grid modernization in its current rate case to support interconnection backlog by increasing feeder constraints through feeder and substation upgrades.[9]

I do not disagree that there is a high level of DER adoption in New Mexico. But, as indicated in my Direct Testimony, I find that PNM did not sufficiently justify many of the additional grid modernization investments beyond those pertaining to AMI. High levels of DER adoption alone do not justify investment in grid modernization. The Company should quantify the expected impacts to DERs from its proposed investments. Without any quantitative assessment or BCA, it is difficult to assess the reasonableness of the Company's application. For example, is it more cost-effective for the Company to continue upgrading feeders through the types of investments currently proposed in its rate case, or will more DERs be enabled through investments in hosting capacity analysis and volt-var management? Without this context it is unclear whether PNM's proposed investments are in the best interest of ratepayers.

**Q. Does this conclude your testimony?**

A. Yes, it does.

[9] Rebuttal Testimony of Omni B. Warner, pgs. 27-28.

# [EXTERNAL] 22-00089 - NMAG's Responses to 2nd Bench Request Order

Keven Gedko <kgedko@nmag.gov>

Tue 1/17/2023 4:55 PM

To: Records, PRC, PRC <PRC.Records@prc.nm.gov>



Good afternoon.

Attached, please find New Mexico Office of the Attorney General's Responses to Second Bench Request Order.

Thank you.

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Exhibit 1

**<u>BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION</u>**

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|---|---|---|
| **IN THE MATTER OF A COMMISSION** | **)** | |
| **INQUIRY INTO A RULEMAKING TO IMPLEMENT** | **)** | |
| **THE GRID MODERNIZATION** | **)** | |
| **ACT, NMSA 1978, SECTION 62-8-13 (2019)** | **)** | |
| | **)** | **Docket No. 22-00089-UT** |

**<u>NEW MEXICO ATTORNEY GENERAL'S RESPONSES TO SECOND BENCH REQUEST ORDER ISSED NOVEMBER 16, 2022</u>**

The New Mexico Office of the Attorney General ("NMAG"), Raúl Torrez, by and through counsel, submits these responses to the New Mexico Public Regulation Commission's ("Commission") Second Bench Request issued in the above-referenced docket on November 16, 2022. The Attorney General is statutorily charged with representing residential and small business consumers in matters before the Commission, and appreciates the opportunity to provide these responses.

**Paragraph 12**

a. ***Please provide your opinion and/or analysis of the goals and/or principles, articulated above in Paragraphs 11 and 12, to guide the Commission in promulgating a grid modernization rule.***

We generally support the goals and principles articulated by Gridworks and the Commission in paragraphs 11 and 12. However, we recommend another element be added to the description of Gridworks' goal (a) "invest in the future", which is to reduce system vulnerability. The electric system is increasingly exposed to natural disasters and cyber-attacks. The promulgation of a grid modernization rule should direct utilities to address these factors within their proposals.

In addition to the goals in Paragraphs 11 and 12, we recommend adding a fifth goal and principle:

**Maximize consumer benefits and protection –** maximize cost savings to ratepayers by enabling technologies and establishing programs that empower customers to achieve cost savings and maintain or improve data privacy and security.

This goal is needed to ensure that customers paying for grid modernization have access to the direct economic benefits of the technology. Given the large expense associated with most grid modernization investments, it is critical to maximize the net benefits from those investments.

Utilities can achieve this through utilizing grid modernization investments to create new demand response, energy efficiency, and pricing options, and by enabling customer access to real-time usage to share securely with third parties. While utilities frequently tout such customer offerings as benefits of grid modernization, concrete proposals and implementation plans are normally lacking in utilities' filings. In addition, the two-way flow of customer data raises privacy and security concerns for all parties involved. A grid modernization rule must therefore have the intention of preserving or enhancing data privacy as new data-driven capabilities are added to the system.

***b. Do the goals and principles, articulated above in Paragraphs 11 and 12, adequately align with the goals and objectives of House Bill 233, otherwise known as the Energy Grid Modernization Roadmap Act, and the New Mexico Grid Modernization Roadmap, published by EMNRD?***

The three sets of goals and objectives articulated by the New Mexico Energy, Minerals, and Natural Resources Department (EMNRD) Grid Modernization Roadmap (Roadmap), the goals and principles outlined in paragraphs 11 and 12 above, and House Bill 233 are generally in alignment, but the number of goals and their specificity differs. The Roadmap is primarily framed around two goals: reliability and affordability. Paragraphs 11 and 12 above expand the number of goals, and mention both affordability and reliability. However, these paragraphs also added elements such as coordinating action, predictability, and flexibility to facilitate grid modernization from the perspective of utilities.

The goals and principles described in House Bill 233 are the most comprehensive and capture the additions we recommend to paragraphs 11 and 12 above. For example, House Bill 233 specifically notes that in approving grid modernization grants, consideration shall be given to "the extent to which the project […] lowers operations and maintenance costs."[1] The need to "enhance […] grid security" and demand response capability is also explicit in House Bill 233's definition of grid modernization.[2] An additional element of House Bill 233 that is not reflected in paragraphs 11 and 12 is an evaluation of grid modernization projects on the basis of the "extent to which the project stimulates in-state economic development, including the creation of jobs and apprenticeships."[3] The Commission should consider whether this criterion should be included in the Grid Modernization Rulemaking.

House Bill 233 also includes seven factors that the Commission shall review when considering the reasonableness of a proposed grid modernization project. As noted by the Commission in paragraph 15 below, these factors provide a "what" analysis. Within its rulemaking, the Commission should detail the filing requirements for grid modernization proposals and specific evaluation criteria so that it can adequately assess these factors. We expand upon these factors and recommend evaluation criteria further below in response to paragraph 15.

[1] House Bill 233 from the 2020 Legislative session. Available at: https://www.nmlegis.gov/Sessions/20%20Regular/final/HB0233.pdf

[2] *Ibid*.

[3] *Ibid*.

c. ***To what extent, if any, are these two sets of ideals contradictory, mutually exclusive, or redundant?***

We do not have comments at this time.

d. ***Please explain which goals and/or principles you believe should guide the Commission in promulgating a grid modernization rule.***

Please see our responses above to paragraph 12.

**Paragraph 14**

a. ***Please describe the Commission's authority to require the periodic filing of grid modernization plans.***

NMSA § 62-8-13 (A) establishes that the Commission may require the periodic filing of grid modernization plans. It states that "A public utility may file an application with the commission to approve grid modernization projects that are needed by the utility, **or upon request of the commission.**" (emphasis added). NMSA § 62-8-13 (A) goes on to state what an application may or shall include and makes no differentiation between an application that is filed by the utility under its own initiative versus an application that the utility files upon request of the commission. It follows that the commission has the authority to determine which elements from the "may" category, as established in this statute, the utility should include in a filing done upon request of the commission. The statute also defines a "shall" category, and the elements in that category must be included in all filings, regardless of whether they are initiated by the utility or initiated by the commission.

***b. Please provide and explain your opinion on whether it is prudent to require the periodic filing of grid modernization plans.***

We recommend each utility file a short-term grid modernization plan every three years for near-term investments. Frequently updated plans will help to ensure better accuracy of the projected costs and benefits of the grid modernization investments and increase regulatory oversight and transparency. This periodic filing can also serve as an opportunity to review and evaluate performance of the previously installed grid modernization technologies through review of tracking metrics, utility spending, and customer engagement. Annual reports should also be used to increase visibility into how the grid modernization plan is progressing. In addition, we recommend that utilities be required to notify the Commission, the Commission's Utility Division Staff, and the intervening parties in this case regarding any material changes to the proposed grid modernization components and timeline. This would be triggered by a need to change the type of meter technology or meter capabilities, delays of more than a year in the implementation timeline, and if costs are expected to exceed planned contingency amounts. This would also trigger the need to update the plan during the three-year period.

In addition, the periodic grid modernization filings should be coordinated with a long-term strategic grid modernization plan that follows the utility's distribution planning timeframe. For example, if a utility distribution plan covers 11 years, then so should the grid modernization plan. This alignment becomes increasingly important with the ability of grid modernization investments to provide more data and transparency to improve load forecasts, enable hosting capacity maps, and increase visibility of the grid to third-party non-wires alternative developers, all of which will impact investment decisions in long-term distribution planning.

*c.* ***Should a grid modernization plan be incorporated into a utility's integrated resource plan ("IRP") planning process, or a utility's general rate case filing, or should a utility propose a grid modernization plan in a stand-alone proceeding?***

Thus far, the Public Service Company of New Mexico (PNM), Southwestern Public Service Company (SPS), and El Paso Electric (EPE) have filed grid modernization proposals separately from their IRP planning processes in stand-alone proceedings. We support the continuation of this practice and believe a grid modernization plan should not be incorporated into the IRP planning process; however, we emphasize how interconnected grid modernization, rate case filings, and IRP processes must be if the grid modernization proceeding is separate.

A stand-alone grid modernization proceeding must closely coordinate with the IRP process. If the processes of grid modernization and the IRP are not sufficiently coordinated, there is a risk that, due to poor sequencing, the assumptions used for the IRP (such as system status, load forecasts, and demand response) will turn out to be inaccurate as a result of grid modernization. Likewise, although the Commission does not require utilities to submit distribution system plans, grid modernization must be closely integrated with distribution system planning to ensure that assumptions, goals, and outcomes align.[4]

Investments proposed in the grid modernization proceeding and general rate case filing must also be consistent. If a utility requests cost recovery for an item related to grid modernization in its rate

[4] New Mexico Energy, Minerals, and Natural Resources Department. 2021. Grid Modernization Advisory Group Whitepaper #6: Require Distributed Resource Planning. Available at https://www.emnrd.nm.gov/ecmd/wp-content/uploads/sites/3/RequireDistributionResourcePlan_1.29.21.pdf

case, that utility should be able to reference the specific place in the grid modernization proceeding where it justifies that item as part of its plan.

In the context of this necessary coordination and integration between grid modernization, the IRP, and rate cases, we support a stand-alone grid modernization proceeding for the following reasons:

- Combining the IRP with a grid modernization filing would create a significant burden to intervenors and stakeholders. A separate proceeding for grid modernization will allow a more in-depth review of proposed investments.

- Separate filings allow for differentiated planning horizons. The IRP process has a planning horizon of 20 years.[5] The grid modernization proposals filed so far focus more on near term steps for technological implementation and cost recovery. PNM is the only utility to-date that has filed a comprehensive, long-term grid modernization plan, which spans 11 years.[6] While we support longer term grid modernization plans, it is likely that IRP plans will continue to cover longer time periods.

- Grid modernization and the IRP have interactive effects that may make it difficult to perform both simultaneously. For example, the impact of advanced metering infrastructure (AMI) and demand response programs enabled by grid modernization must feed into the load forecasts used in IRP planning. Solidifying

[5] 17.7.3.1 NMAC, "Integrated Resource Plans for Electric Utilities," available at https://www.srca.nm.gov/parts/title17/17.007.0003.html#:~:text=(1)%20integrated%20resource%20plan%20(,rule%20and%20applicable%20state%20policies.

[6] NM PUC Case No. 22-00058-UT, "PNM's Application for Authorization to Implement Grid Modernization Components," accessed 1/11/2023. available at https://www.pnmforwardtogether.com/assets/uploads/22-00058-UT-2022-10-03-PNM-Grid-Modernization-Application-1-of-2.pdf

grid modernization plans is an important prerequisite to certainty in IRP planning and modeling.

- Creating a separate proceeding for grid modernization as opposed to routine grid maintenance allows utilities to optimize whether grid upgrades fall into one category or the other, subject to Commission approval and stakeholder intervention, to ensure timely completion.

***d. If a periodic grid modernization plan filing procedure is not adopted, how should the Commission track utility investments in grid modernization projects?***

We recommend adoption of a grid modernization plan filing procedure. However, even if a periodic formal grid modernization plan filing procedure is not adopted, it will still be necessary for the Commission to examine the progress made, and actual costs incurred, by those utilities that have approved Grid Modernization Plans. EPE's plan has already been approved and the SPS and PNM plans are currently being litigated. Assuming that some Grid Modernization Plan is approved for all three utilities, and that each utility is using a rate rider to collect at least some of the Grid Modernization costs, then it will be necessary for the Commission to periodically review both the progress made by the utilities and the actual costs relative to the costs estimated in the approved plan. It is likely that this review will be on an annual basis. In addition to these annual reviews, the Grid Modernization efforts and associated costs may also be examined as part of each base rate case filed by the utilities.

*e.* ***Aside from the statutory power to "request" a utility application for a specific grid modernization project, how could the Commission best direct grid modernization investments to meet state policy objectives?***

The grid modernization rulemaking can make clear to utilities that they must demonstrate proposed investments will contribute to state policy objectives. See our response to paragraph 15(a) and (b) below where we recommend specific evaluation criteria related to achievement of policy goals.

*f.* ***If a utility files a grid modernization plan and follows that plan, what is the implication for cost recovery?***

The statute provides that costs approved by the Commission for a Grid Modernization Plan are presumed to be reasonable and that a utility may recover these reasonable costs. In approving a Grid Modernization Plan, the Commission is authorizing a specific program at a specific cost. Therefore, in order to meet the presumption of reasonableness, the utility must not only be at or below the authorized cost, but the utility should have provided the services outlined in the approved plan. For example, if a utility estimates that it will replace 50,000 meters at a cost of $15 million in year 1, then both variables should be met in order for the presumption of reasonableness to apply. If the utility spends $15 million but only replaces 25,000 meters, the burden should shift to the utility to justify why the level of services was not provided. An examination of the actual costs must be coupled with an examination of the services provided.

In addition, in establishing an initial rate rider for Grid Modernization Plans, the NMAG recommends that such riders be limited to capital costs. Operating and Maintenance costs and other expenses should be flowed through base rates. In addition, the base rate case process should continue to be the primary ratemaking tool used by the Commission to charge ratepayers for utility service, so Grid Modernization Plan costs should be rolled into base rates with each base rate case. Finally, with regard to legacy meters that become obsolete as a result of Grid Modernization Plans, the NMAG recommends that the Commission authorize recovery of the undepreciated investment without carrying charges. This proposal provides a proper balance between the interests of shareholders and ratepayers with regard to legacy meter costs.

**Paragraph 15**

While NMSA 1978, Section 62-8-13 (2021) details seven factors that the Commission shall take into consideration when reviewing utility applications, these factors provide a "what" analysis but not a "how" analysis to evaluate projects qualitatively. The Commission proposes that it also takes into consideration proposals that: a) promote a holistic approach, rather than one-off projects; b) maximize benefits from programs for ratepayers and communities; c) ensure fair cost allocation and mediation of rate impacts; and d) measure and evaluate effectiveness to inform future investments.

***a. Please provide your opinion and/or analysis of the factors, articulated in Paragraph 15 above, to guide the Commission in analyzing grid modernization applications.***

We support the additional factors proposed by the Commission in Paragraph 15 and summarize our opinion of each below.

a) <u>Promote a holistic approach</u>. We support this factor as it is important to provide transparency regarding the interdependencies of proposed grid modernization investments. Also, promoting a holistic approach supports regulatory efficiency. Any grid modernization application should be tied to a comprehensive grid modernization plan that details the utility's grid modernization objectives, the solutions considered, and an overarching strategy for the timing and sequencing of known future investments. Proposals should clearly indicate the objective of each grid modernization component and describe whether its performance is dependent on other components. This approach would help to answer the questions of "how" to modernize the grid, "when" to make investments, and "how much" investment to make over time. Lastly, if a utility already has grid modernization components installed, any new filing should detail how the new investment will work with those components and explain the additional benefits and costs of the new investment.

b) Maximize benefits from programs for ratepayers and communities. We support this factor and find it to be a critical component of assessing a grid modernization application. Grid modernization components without customer-facing programs will not maximize benefits or fully leverage the capabilities of the investment. A significant portion of the direct economic benefits to ratepayers from grid modernization investments come from energy efficiency, and reductions in peak demand. This is often through new rate structures that take advantage of interval data such as time-varying rates or new demand response and energy efficiency programs. However, as of 2019 only 3 percent of US households were billed on time-varying rates even though 60 percent have AMI metering in place[7]. In addition, a recent study by the American Council for an Energy-Efficient Economy (ACEEE) found that only one of the 52 utilities surveyed was optimizing its AMI to create energy savings opportunities for customers.[8] It is therefore important that the Commission

[7] Alvarez, P., Stephens, D. 2019. Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. GridLab.

[8] Gold, R., Waters, C., York, D. 2020. *Leveraging Advanced Metering Infrastructure to Save Energy*. American Council for an Energy-Efficiency Economy (ACEEE).

hold utilities accountable for following through with the development of customer-facing programs that leverage grid modernization investments. In order to maximize benefits, customers need access to education, prices signals, applications, and programs that fully leverage the new information and advanced capabilities of the technology.

c) Ensure fair cost allocation and mediation of rate impacts. We support this factor as it is important to ensure that the cost of grid modernization investments are properly allocated and that rate impacts are reasonable. The statute provides that "Costs for a grid modernization program that only benefits customers of an electric distribution system shall not be recovered from customers served at a level of one hundred ten thousand volts or higher from an electric transmission system in New Mexico." Except for this prohibition, the Commission has the flexibility to adopt allocation methodologies that it believes results in the most reasonable allocation, considering all factors including overall benefits associated with system reliability and security. In addition to ensuring fair cost allocation, it is important for the Commission to consider the level and timing of grid modernization investments so that the cost to ratepayers is manageable. For example, some grid modernization investments can be phased in over many years to allow for the costs to be phased into rates more slowly.

d) Measure and evaluate effectiveness to inform future investments. We support this factor to help ensure that the purported benefits of grid modernization investments are realized. Utilities should include tracking metrics in grid modernization proposals to track spending and progress towards the anticipated outcomes of investments over time. Metrics can be established to track both the monetized and non-monetized benefits of grid modernization investments. For example, utilities can track changes to customer satisfaction, reliability, hosting capacity, job creation, and power quality. Utilities can also track the number of AMI meters installed each year, the number of customers enrolled in time-varying rates (i.e., time-of-use, critical peak pricing), and the percentage of customers accessing energy data or utilizing an online portal. Additionally, we recommend that the Commission adopt an annual grid modernization report structure to provide consistency across utilities. We recommend a format similar to the Smart Grid Advanced Metering Annual Implementation Progress Report as filed by Commonwealth Edison in Illinois.[9] This report provides a wide array of tracking metrics with baselines and includes updates on the deployment of customer-facing programs and rate structures and planned activities for the following year.

We also recommend that the Commission include three additional factors when considering grid modernization proposals.

1. Support secure and transparent information sharing and data access. This is one of the principles within the Interstate Renewable Energy Council (IREC) and GridLab's Playbook for Modernizing the Distribution Grid[10] and pertains to factor number five within NMSA 1978, Section 62-8-13 (2021), which relates to the need for grid modernization projects to allow for private capital investments and skilled jobs in related services, and providing customer projection, information, and education. In order to achieve these principles, proposals should enable customers to obtain real time energy data and share that information with third parties. There should also be information related to data privacy and

[9] Commonwealth Edison Company. April 2021. Smart Grid Advanced Metering Annual Implementation Progress Report. Available at: https://www.icc.illinois.gov/industry-reports/comed-advanced-metering-infrastructure.

[10] Baldwin, S., O'Connell, R., Volkmann, C. 2020. *A Playbook for Modernizing the Distribution Grid; Volume I: Grid Modernization Goals, Principles and Plan Evaluation Checklist*, IREC and GridLab, https://irecusa.org/publications/ and https://gridlab.org/publications/.

security standards and how the utility plans to increase transparency to distributed energy resource (DER) developers regarding beneficial grid locations for technology deployment.

2. Demonstrate cost-effectiveness or cost reasonableness. While the grid modernization statute does not explicitly require that grid modernization investments be cost-effective, it is important that any utility grid modernization proposal include a benefit-cost analysis (BCA) to demonstrate that costs are reasonable. First, a BCA requires the articulation of grid modernization benefits, either in monetary, quantitative, or qualitative terms. Identifying benefits of a grid modernization investment is necessary to determine whether the costs are reasonable. Second, a BCA provides increased transparency of the projected costs and benefits, allowing for those costs and benefits to be tracked over time using metrics to support the measurement and verification of the effectiveness of the grid modernization investments. Lastly, a BCA can encourage the examination of alternatives. For example, if a proposed investment is not cost-effective it may be possible to find another technology or solution that creates the same desired outcome at a lower cost.

3. Contribute to state regulatory and policy goals. NMSA 1978, Section 62-8-13 (2021) states that the Commission should consider whether a utility grid modernization application is reasonably expected to achieve certain policy goals such as increased access to and use of clean and renewable energy, better access to low-income users in underserved communities, and reduction of greenhouse gas (GHG) emissions. Therefore, we recommend that the Commission add an additional factor that makes it clear to utilities that any grid modernization proposal should clearly articulate how it contributes to the achievement of New Mexico's regulatory and policy goals. The utility should detail how each investment supports these outcomes and quantify those impacts to the extent possible.

b. ***How may the Commission translate these qualities of a proposal into a uniform set of criteria for evaluation?***

We recommend the following set of evaluation criteria for each of the qualities:

a. Promote a holistic approach, rather than one-off projects.

  - Is the proposal tied to a short-term or long-term grid modernization plan?
  - Does the proposal describe the ultimate objectives and goals of the proposed grid modernization investments?[11]
  - Does the proposal describe the interdependencies between grid modernization components?
  - Does the proposal include disclosure of all planned grid modernization investments including those beyond the initial period of the request?
  - Does the proposal consider a reasonable range of alternatives to achieving the objectives of the proposed grid modernization investments?
  - Does the proposal show coordination with other filings including DER plans, distribution planning, transmission planning, and IRPs?

b. Maximize benefits from programs for ratepayers and communities.

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[11] U.S. Department of Energy. 2019. *Modern Distribution Grid: Volume I: Objective Driven Functionality*. Version 2.0. Prepared by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, Office of Energy Policy and Systems Analysis, and the Pacific Northwest National Laboratory. This guidebook includes a taxonomy framework to connect the objectives of grid modernization to the proposed investment. This includes four items: objectives, capabilities, functionalities, and technologies.

- Does the proposal articulate the type of benefits that the proposal plans to achieve for customers (e.g., increased DERs, increased reliability)?
- Does the proposal quantify these benefits? For example, if a utility states a goal of its proposed grid modernization plan is to increase DERs, does it indicate how many DERs and what type of DERs will be adopted?
- Does the proposal include customer-facing programs that utilize the proposed grid modernization technology?
- Does the proposal include an implementation plan and timeline for the commitment to development and deployment of customer-facing programs?
- Does the proposal include an implementation plan and timeline for the development of new rate designs that incorporate the use of the grid modernization investments?
- Does the proposal include a plan to track and report on the development and implementation of customer-facing programs and rate designs?

c. Ensure fair cost allocation and mediation of rate impacts.

- Has the company articulated customer benefit from the proposal and how those benefits will impact each customer class?
- Does the proposal allocate costs in a reasonable manner consistent with the statute?
- Does the proposal mitigate rate impacts by phasing in grid modernization over time? And to what extent?

- How do the costs of the proposal affect low-income customers and customers in underserved communities?

d. Measure and evaluate effectiveness to inform future investments.

- Does the proposal include a robust set of metrics that track the costs, benefits, and attainment of the goals detailed in the grid modernization application?
- Does the utility include sufficient detail for how each metric will be measured and reported within its proposal and the rationale for any target or benchmark?
- Does the utility propose to track metrics against targets that correspond to the level of performance assumed in the grid modernization proposal and BCA?
- Do the metrics and targets reflect the same time periods specified in the grid modernization BCA?
- Does the proposal include a description of an annual implementation report structure and content?

e. Support secure and transparent information sharing and data access.

- Does the proposal include data access and privacy standards?
- Does the utility demonstrate that it will provide all customer classes with access to real-time energy usage data?

- Does the proposal indicate that the utility will enable automatic data transfers from customers to third parties?

f. Demonstrate cost-effectiveness or cost reasonableness

- Does the proposal articulate all costs and benefits of each component separately and combined with inter-dependent components, including interactions with grid modernization investments already in service? Does this include quantitative, qualitative, and monetized costs and benefits to the extent possible?

- Does the proposal include a BCA to demonstrate cost-effectiveness or cost reasonableness of the grid modernization investments?

- Has the utility defined and justified the type of cost-effectiveness test and choice of discount rate in its BCA calculations?

- Has the utility provided a sensitivity analysis on key assumptions, such as different levels of customer engagements with technology?

e. Contribute to state regulatory and policy goals.

a. Does the proposal explain how it will achieve reductions in air pollution and GHG emissions?

b. Does the proposal explain how it will provide access to the benefits of the grid modernization investments to low-income customers and underserved communities?

c. Does the proposal quantify, by type, the increase in DERs resulting from the grid modernization investments?

d. Does the proposal explain how it will improve reliability, resilience, and security?

e. Does the proposal explain how it will increase system efficiency?

f. Does the proposal explain how it will contribute to state regulatory and policy goals?

***c. Are there other considerations that should fall into this category of analysis?***

We do not have any additional considerations at this time

**Paragraph 16**

***a. Does Section 62-8-13 establish a standard of review for grid modernization project/application costs other than simply whether costs are reasonable?***

Section 62-8-13 states: "Applications for grid modernization projects shall be filed pursuant to Sections 62-9-1 and 62-9-3 NMSA 1978, as applicable." Section 62-9-1 states: "No public utility shall begin the construction or operation of any public utility plant or system or of any extension of any plant or system without first obtaining from the commission a certificate that public convenience and necessity require or will require such construction or operation."

This requirement in 62-9-1, with respect to a Certificate of Convenience and Necessity ("CCN"), appears to establish a standard of review other than simply whether costs are reasonable. The Commission should consider the manner in which the Commission defines whether a grid modernization Project is considered to be required for public convenience and necessity, and should also clarify the interaction between a grid modernization filing and a CCN filing. The lack of clarity in this matter was highlighted by the hearing examiner in Case No. 21-00269-UT.[12]

Of particular difficulty is that Section 62-8-13 states that "grid modernization projects shall be filed pursuant to Sections 62-9-1 and 62-9-3 NMSA 1978, **as applicable**." (emphasis added) Clarity is needed to understand how Sections 62-9-1 and 62-9-3 are applicable to Grid Modernization Project filings.

***b. May the Commission establish a more specific standard of review for grid modernization project/application costs, such as "lowest reasonable cost" or "most cost-effective" or something else? Please explain.***

Yes. NMSA § 62-19-9 A establishes: "The commission shall administer and enforce the laws with which it is charged and has every power conferred by law." Next, NMSA §62-19-9 B (10) establishes: "The commission may: (10) adopt such reasonable administrative, regulatory, and procedural rules as may be necessary or appropriate to carry out its powers and duties." Hence, if the statutory standard of review is determined to be "reasonableness," the Commission has the statutory authority to define, through a rulemaking, a more specific definition of what is deemed to be "reasonable" for a Grid Modernization Project filing.

[12] Case No. 21-00269-UT, June 10, 2022 Bench Request, item 2a. "Parties should identify all legal authority, including authority under the Public Utility Act, that pertains to EPE's requested actions from the Commission in this case, including those that would allow advance ratemaking approval treatment for plant (advanced meters, communications networking tools, etc.) used to provide electric service, and whether the Commission is required to consider EPE's requests under the requirements of the CCN statute."

For example, if the Commission standard is determined to be whether "costs are reasonable," the Commission could require that the grid modernization application be at the "lowest reasonable cost for the desired objectives." Further, the Commission could, and we recommend that it do so, require utilities to conduct a BCA to indicate whether the standard is met. The benefits in the BCA would be based on the desired objectives. As part of that requirement, the Commission could define the cost-effectiveness test or tests to be used, the types of benefits that should be quantified and monetized within those tests, and whether the BCA should be applied to each investment or the proposal as a whole.

***c. Is LRC the appropriate cost/benefit analysis framework the PRC should consider for grid modernization projects?***

No, it is not. We recommend that a BCA should be the primary method for assessing grid modernization projects. The lowest reasonable cost (LRC) or least-cost, best-fit approach should not be the primary means of evaluating these projects, even if the project is deemed necessary or the benefits cannot be fully monetized.

The LRC approach has been historically used by utilities to inform decisions related to traditional distribution investments. This approach works well for traditional investments as they are typically driven by a clear need to meet safety and reliability requirements. However, grid modernization investments are more challenging because it is less clear whether a particular grid modernization component is needed for safety, reliability, or other policy goals.[13] A BCA will provide additional information regarding how the proposed investments will affect customers and aid the

[13] Woolf, T., L. Schwartz, B. Havumaki, D. Bhandari, M. Whited. 2021. *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*. Prepared by Lawrence Berkeley National Laboratory and Synapse Energy Economics for the Grid Modernization Laboratory Consortium of the U.S. Department of Energy, pp. 13-14.

Commission in its assessment of reasonableness. In addition, the BCA places the burden on the utility to demonstrate the merits of the proposed investment whereas the LRC approach begins with an assumption that the investment is necessary.

A BCA is also important if the Commission seeks to maximize net benefits to ratepayers. The BCA approach provides a comparison of the full range of costs and benefits and is more comprehensive than the LRC method, which focuses on costs.

It is increasingly common for utilities to file BCAs for grid modernization plans. A recent survey by the Brattle Group found that regulators often require utilities to provide a BCA.[14] In addition, it is possible to monetize many of the common benefits of grid modernization investments. For example, a recent study prepared for the U.S. DOE Grid Modernization Laboratory Consortium found that some grid modernization plans monetized benefits related to reliability, DER integration, Distribution operation and maintenance, energy, capacity, GHG emissions, power quality, and resilience.[15]

It is also important to note that the requirement for a utility to conduct a BCA to justify its grid modernization investments does not need to indicate a requirement that monetary benefits exceed monetary costs. In the case where benefits are more difficult to monetize, a resulting benefit-cost ratio less than 1.0 could still lead to a determination that the investment is reasonable and is

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[14] Sergici, S., Li, M., and Carroll, R. 2018. *Reviewing the Business Case and Cost Recovery for Grid Modernization Investments: Summary of Recent Methods and Projects*. Prepared by The Brattle Group for the National Electrical Manufacturers Association, p. 5.

[15] Woolf, T., L. Schwartz, B. Havumaki, D. Bhandari, M. Whited. 2021. *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*. Prepared by Lawrence Berkeley National Laboratory and Synapse Energy Economics for the Grid Modernization Laboratory Consortium of the U.S. Department of Energy, p. 21.

expected to provide net-benefits to customers based on consideration of both monetized and unmonetized benefits.

### *d. How may the Commission value non-monetary benefits of a specific proposal against costs and expenditures?*

The Commission should examine the significance of non-monetary benefits.

To aid in the determination of significance, we recommend that the Commission require the utilities to quantify as many of the non-monetary benefits as possible. For example, a utility could calculate job-years to quantify economic development benefits, determine the number and capacity of incremental DERs expected from grid modernization, and use the number of customers enrolled in Green Button Connect or accessing a data portal to quantify customer access.

The U.S. DOE Grid Modernization report also recommends the use of quantitative techniques to facilitate the assessment of unmonetized impacts. Suggested approaches include the use of a point system to assign values to unmonetized benefits, a weighting system, the assignment of proxy values, and the use of a multi-attribute decision-making technique.[16]

In addition, we recommend that if the utility uses non-monetized benefits to justify its grid modernization proposal, the Commission should require the utility to track progress towards achieving those benefits through the use of metrics. For example, if the utility states its proposal will increase reliability and resilience but does not quantify or monetize those benefits, it could track metrics related to cumulative customer energy demand not served, cumulative critical

[16] *Id.*, at p. 29.

customer-hours of outages, time to recovery, or cost to recovery.[17] The inclusion of metrics for non-monetized benefits will help to evaluate whether the purported benefits are realized and can also help to accumulate data to enable monetization of impacts in future grid modernization proposals.

e. ***Please compare the merits of a utility performing the cost/benefit analysis versus a Commission-prescribed method for determining costs and benefits, such as the use of an independent expert.***

We recommend that the Commission prescribe a BCA framework and method for determining costs and benefits prior to the utility submitting requests for approval of grid modernization investments. A Commission-prescribed framework will encourage consistency with Commission objectives and consistency across utility grid modernization proposals, which will make for a more efficient review of such proposals.

In general, we recommend utilities prepare their own BCAs, based on the Commission-prescribed framework. This is because utilities have the necessary information to populate the BCA and its results should be instrumental to utility decision-making. The Commission might decide, however, to use an independent expert to review the utility BCA.

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[17] Pacific Northwest National Laboratory. 2017. *Grid Modernization: Metrics Analysis*. Version 2.1. 2017. Prepared for the Grid Modernization Laboratory Consortium of the U.S. Department of Energy, p. iv.

*f. Alternatively, should the Commission consider using scenarios and sensitivities within cost-benefit analyses? Scenarios may represent the inclusion of various cost tests, each representing costs and benefits from different perspectives.*

We recommend that the Commission direct utilities to conduct BCAs with sensitivities to provide additional information with low, medium, and high cases for realized benefits from grid modernization investments. This is particularly important for benefits associated with customer-facing offerings such as levels of participation in time-of-use rates and demand response programs. National Grid's 2022–2025 Grid Modernization Plan in Massachusetts provides an example of the use of BCA sensitivities: the company analyzed sensitivities related to an opt-out versus opt-in structure for time-varying rates, the use of a lower societal discount rate, and the impact of removing all benefits that depend on customer response to rates and energy usage information.[18]

We do not have a specific recommendation on which secondary tests to use. However, secondary cost-effectiveness tests can help to enhance the overall understanding of the impacts of a grid modernization proposal by providing different information and perspectives about cost-effectiveness. Secondary tests can be useful in the prioritization of grid modernization investments. For example, if the primary test is the utility cost test (UCT) and the results of a proposal show that all investments are cost-effective, a secondary test that includes the social cost of carbon could be used to help prioritize grid modernization investments based on the achievement of GHG emissions reductions.

[18] Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid. D.P.U. 21-81. *2022-2025 Grid Modernization Plan*. Exhibit NG-AMI-2, pp. 41-43.

If the Commission chooses to require secondary cost-effectiveness tests, we recommend it specify the primary cost-effectiveness test so that utilities understand how proposals will be vetted. It is also important that any secondary test does not undermine the primary cost-effectiveness test or confuse and burden the decision-making process.[19]

***g. In conducting such analyses, should stakeholders and parties be able to have access to information for independent analysis, like how the IRP process is structured?***

Yes. Transparency and access to information is a key BCA principle found across recent cost-effectiveness frameworks including, the *National Standard Practice Manual* (NSPM), DOE's *Modern Distribution Grid*, and the New York Public Service Commission's *Order Establishing the Benefit Cost Analysis Framework*.[20] We recommend that the utilities file BCAs with their grid modernization proposals and include all documentation of relevant assumptions, methodologies, and presentation of results that are clearly documented and available for stakeholder review and input.

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[19] National Energy Screening Project (NESP). 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM for DERs), pp. 3-16. Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-04-2020_Final.pdf.

[20] Woolf, T., L. Schwartz, B. Havumaki, D. Bhandari, M. Whited. 2021. *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*. Prepared by Lawrence Berkeley National Laboratory and Synapse Energy Economics for the Grid Modernization Laboratory Consortium of the U.S. Department of Energy, p. 10.

**Paragraph 19**

a. ***Please provide and explain your opinion on whether a utility's grid modernization plan should be required to contain a report on the reliability of its distribution system using SAIDI, CAIDI, SAIFI, and MAIFI metrics.***

We recommend that a utility's grid modernization plan include a report on the reliability of its distribution system and a defined set of reliability metrics that it will track in annual reports to show changes to reliability.

The most commonly cited reason utilities provide to justify investment in grid modernization technologies is improvement to reliability. A recent survey of 21 grid modernization plans found that close to 90 percent claimed reliability as a benefit.[21] If grid modernization investments are justified on the basis that they will increase reliability, it is important that changes to reliability are tracked and evaluated in a transparent matter.

While it may be difficult to isolate what changes to reliability are directly due to any one grid modernization investment, if a utility indicates that an investment will increase reliability over time, then overall reliability of the system should improve over time and this should be tracked.

Regarding the types of reliability tracking metrics, we recommend utilities use SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) to track the average duration and frequency of outages. We also recommend that a more customer-focused reliability metric be adopted. This could include CEMSM (Customers Experiencing Multiple Sustained and Momentary Interruptions), Customers Experiencing Long Interruption

[21] *Id.*, p. 20.

Durations (CELID), or number of critical customers experiencing power outages. In addition, since grid modernization investments will allow for increased visibility of the distribution grid and provide more granular information, we recommend that utilities report on locational reliability. This can include tracking changes to SAIDI and SAIFI by zip code, in underserved communities, and on the circuits with historically poor reliability performance.

**Paragraph 20**

***The filing of periodic grid modernization plans and reliability reports could align with the IRP cycle, and funding requests could be considered in the general rate case. What other state policies are implicated in this approach and how should they be reconciled?***

Grid modernization plans could also align with triennial energy efficiency and load management plans. While these plans and associated cost-recovery should be kept separate, alignment of timing may be beneficial to ensure coordination and allow for utilities to develop energy efficiency and demand response programs in coordination with grid modernization investments. Between base rate case filings, the Commission could approve the use of rate riders to accelerate cost recovery as an additional incentive to the utilities. Alternatively, the Commission could review, and approve, a specific plan but delay rate recovery until a subsequent base rate case. In either scenario, grid modernization plan costs are integral to the underlying reliability and integrity of the utility system and should be rolled into base rates with each base rate case. Grid modernization plans will provide the foundation for continued operation of the grid, and therefore the associated costs should ultimately be recovered through the normal ratemaking process.

**Paragraph 21**

a. ***Should each iteration of a grid modernization plan include consideration of refinements to the grid modernization rule (assuming a rule is promulgated)? Or should the Commission establish a set timetable for revisiting the rule (assuming a rule is promulgated)?***

No. We do not recommend refinements to the grid modernization rule each time a plan is filed because this would create unnecessary regulatory burden. We also do not find a prescribed cycle or term to be necessary, but the Commission can open an investigation to update the rule on an as-needed basis.

b. ***If the latter, what should be the update cycle or term?***

See response to a.

**Paragraph 22**

***What are the best methods to promote and/or encourage customer engagement with grid modernization projects and/or programs?***

Customers will have different needs and different comfort levels with grid modernization, and it is therefore important that utilities deploy a variety of outreach techniques as well as a diverse set of offerings.

Most direct customer engagement with grid modernization will result from access to more granular time-differentiated energy data, which, when paired with innovative tools and programs can help customers better manage their energy usage and reduce costs. The ability to take advantage of this information, through well designed rate structures and other offerings to customers, is therefore just as important as the promotion of those programs. Said differently, a successful program or offering will to some degree promote itself through word of mouth, so well designed rates and offerings are just as important as the promotion of those rates and offerings.

Below we summarize commonly successful customer-facing programs enabled by grid modernization and methods to promote engagement.

**Time-varying rate structures**: By varying electricity prices according to system peak, utilities can financially incentivize customers to voluntarily change their energy usage patterns to achieve bill savings and reduce system costs. It can be challenging to educate customers on the benefits of time-of-use rates even if they are well-designed and easy to understand. An approach that can increase customer enrollment in these rates is the use of a shadow bill. Shadow billing is a method in which a utility uses actual household consumption to create personalized bill comparisons between different rate options. The customer would receive their normal bill based on the current rate and a second "shadow" part of the bill that shows what they would have paid for the same electricity usage under a time-varying-rate or other form of peak pricing. The use of a shadow bill along with varied forms of outreach including emails, text messages, mail inserts, and webpages can help to increase engagement. It is also important that the utility continue engaging with customers after they enroll in time-of-use (TOU) rates so that they feel supported in best ways to shift energy usage. An additional approach that has improved participation in time-varying pricing in tandem with AMI deployment is making participation opt-out as opposed to opt-in.[22]

[22] Gold et al. (2020), "Leveraging Advanced Metering Infrastructure to Save Energy," Available at https://www.aceee.org/sites/default/files/publications/researchreports/u2001.pdf

**Customer energy usage platforms**: A customer energy platform, hosted online or through a smart phone app, enhances customer access to information by providing a convenient and easy-to-access source of information generated by AMI. Such a platform could include energy price information, energy use information, opportunities to sign up for high-bill alerts, and load disaggregation data. One way to engage customers with the platform is to create personalized insights and tips for reducing energy consumption. In addition, personalized energy savings tips that are delivered to the customer within 24 hours of a peak event can more effectively motivate customers to save energy than impersonal or delayed information.[23]

**Smart technologies**: AMI is well suited to integrate with a range of technologies that enable demand response, such as smart thermostats, heat pumps, heat pump water heaters, and electric vehicle chargers, to name a few. Utilities can increase customer engagement with these technologies by providing rebates in conjunction with online information. Creating an online tool that offers a one-stop-shop for technologies themselves and enrollment in demand response programs is one way to improve participation.[24]

**Pay-for-performance:** This model encourages customers to participate in energy efficiency and demand response by providing them with performance payments based on savings quantified using meter data. AMI provides more granular usage data which enables shorter-term performance and rewards. Utilities can set performance payments that scale based on the value they offer to the grid,

[23] *Ibid*.

[24] See, for example, the Mass Save Marketplace https://www.poweredbyefi.org/masssave

the greenhouse gas emissions reductions achieved, and the timing and duration of energy savings.[25]

**Low-Income Offerings**: It is important that grid modernization proposals include specific consideration for how to engage low-income customers and develop program offerings specific to their unique needs. Utilities should work with local community groups to determine optimal communication methods. For example, studies have found that low-income customers may prefer direct communications with utility representatives, and many may not have access to the internet.[26] Engagement with local community organizations can also be a helpful means to disseminate information to customers. Lastly, programs such as high-bill alerts and other mid-billing cycle communications with personalized energy-saving tips to keep bills on track, and pre-pay options can be enabled with AMI technology are also an important option for low-income customers, especially those that may be unable to change usage patterns to benefit from time-varying rates or demand response programs.

**Paragraph 23**

***What else should the Commission take into account as it considers a grid modernization rule and/or planning program?***

As indicated in our response to paragraph 15, we recommend the Commission include requirements for the development and tracking of performance metrics within its grid

[25] Gold et al. (2020), "Leveraging Advanced Metering Infrastructure to Save Energy," Available at https://www.aceee.org/sites/default/files/publications/researchreports/u2001.pdf

[26] Uplight. 2019. Engaging Low-Income Customers in the 21st Century. Available at: https://uplight.com/wp-content/uploads/2019/10/U_eBook_EngagingLowIncomeCustomers.pdf.

modernization rule. A robust set of metrics is needed to evaluate the success of grid modernization investments in meeting stated objectives and to inform future proposals. Metrics are also an important mechanism to hold the utility accountable for taking actions and achieving goals set forth within proposals and adhering to proposed budgets.

While the type of metrics will ultimately be driven by the nature of the grid modernization technology proposed, we recommend the Commission establish a uniform set of minimum reporting criteria and evaluation metrics where feasible. To-date EPE, SPS, and PNM have all filed for similar types of grid modernization components including AMI, FLISR, the Neighborhood or Field Area Networks (NAN) or (FAN), and customer-facing energy management platforms. These proposals also point to a similar set of expected benefits such as increased DER deployment and integration, reductions in operation and maintenance (O&M) costs, customer control of energy usage, enhanced electric system efficiency, reliability, and resiliency.[27] While not an exhaustive list, the below table details examples of potential metrics that can be tied to these outcomes.

| **Sample Outcome** | **Sample Metrics** |
|---|---|
| Increased DER Deployment | • Average number of days to interconnect DER system<br>• Number of DERs interconnected<br>• MW DER installed as a percentage of load, by class<br>• MW DER installed by type, by circuit<br>• Percent of load served by DERs, by type |

[27] See the following dockets: Case No. 21-00269-UT (EPE), Case No. 21-00178-UT (SPS), Case No. 22-00089-UT (PNM).

| | |
|---|---|
| O&M Cost Savings | • O&M cost savings from avoided field visits<br>• Number of avoided truck rolls and field visits<br>• Greenhouse gas reductions from avoided truck rolls and field visits |
| Reliability | • SAIDI<br>• SAIFI<br>• CEMSM<br>• CELID<br>• Cumulative customer-hours of outages<br>• Cumulative customer energy demand not served |
| System Efficiency | • System load factor and load factor by customer class |
| Resiliency | • Cumulative critical customer-hours of outages<br>• Critical customer energy demand not served<br>• Average number (or percentage) of critical loads that experience an outage<br>• Time to recovery<br>• Cost of recovery<br>• Cost of grid damages (e.g., repair or replace lines, transformers)<br>• Avoided outage cost |
| Customer Control of Energy Usage | • Number of monthly, unique customer visits to the web portal<br>• Number and percent of customers with access to real-time data |

| | |
|---|---|
| | • Number and percentage of customers by customer class using Green Button Connect my Data<br>• Number and percent of customers with Home Area Network (HAN) functionality<br>• Number and percentage of customers, by class, on a time-varying rate<br>• Number and percentage of customers, by class, enrolled in an AMI-enabled demand management program<br>• Peak MW reduction from demand response |

We recommend that the Commission establish reporting criteria for annual grid modernization reports. Annual reports should include current spending compared to budgets, technology implementation status, and an explanation of any variances to planned timeline. The utilities should also include updates on the development and implementation of customer-facing programs, time-varying and dynamic pricing options, marketing and communications activities, and stakeholder engagement. Utilities should also discuss the development of the third-party marketplace offerings being enabled by grid modernization investments, such as in-home energy monitoring devices or energy management applications. Utilities should also discuss actions taken to upgrade the transmission and distribution system to improve hosting capacity, reduce the interconnection backlog, and enable DER deployment. If a utility has a waitlist for solar interconnection requests, then it should report on changes to waitlists if its grid modernization investments have the goal of increasing DERs. This type of information will provide visibility into grid modernization deployment and create accountability to the utilities for following through with actions and outcomes included in their proposals.

**Paragraph 24**

***How may the Commission use a grid modernization rule to support utility applications for Federal funding opportunities under the Infrastructure Investment and Jobs Act or the Inflation Reduction Act of 2022?***

The Commission should use a grid modernization rule to charge utilities with the responsibility to investigate and periodically report back their progress in securing Federal funding through the *Inflation Reduction Act* (IRA) and the *Infrastructure Investment and Jobs Act* (IIJA). This includes the responsibility to participate, where applicable, in federal agency requests for comments on implementation of the Acts.[28]

Both laws incentivize decarbonization through financial "carrots" (mainly tax credits and funding opportunities) rather than "sticks" (mandates with repercussions for noncompliance). They are a set of tools to apply proactively as further instruction is issued by the federal government and they provide multiple ways for utilities to qualify for funding to support grid modernization and demand response programs. Since details about funding disbursement are in many cases still in development, there is also an opportunity for utilities to participate in the public process, which includes submitting public comments to proceedings that help determine how funds are disbursed and how tax credits are implemented.

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[28] In November of 2022, for example, the IRS has released six requests for comments on implementing new tax credits. See https://www.irs.gov/newsroom/irs-asks-for-comments-on-upcoming-energy-guidance

To ensure maximum impact and best use of Federal Funds, the Commission, utilities, and stakeholders will need to collaborate and share information openly to understand the myriad eligibility requirements and interaction dynamics attached to the bills' pools of available funding (e.g., some incentives can be stacked while others are mutually exclusive). This may be best accomplished by forming a working group that meets periodically to specifically discuss (1) what funding is available; (2) what work utilities are performing to secure funding; and (3) how utilities, the commission, and other stakeholders can be involved in shaping the rulemakings that allocate Federal funding.

In terms of direct funding available for grid modernization, the IIJA has allocated $3 billion to the existing Smart Grid Investment Matching Grants program for use between 2022 and 2026. This program funds up to 50 percent of eligible costs for qualified investments in the following areas relating to grid modernization:

- Smart meters, sensors, control devices
- Grid automation
- Data analytics
- Enabling demand flexibility and smart grid functions in end-use loads (including buildings)
- Ability to redirect and shut off power to minimize blackouts in natural disasters
- Advanced transmission technologies

Previous funding for the Smart Grid Investment Matching Grants program was through the *American Recovery and Reinvestment Act*, which provided $3.4 billion to 99 projects: primarily installation of AMI and adding smart grid capabilities to distribution and transmission systems.[29]

The IIJA also set aside $5 billion for electric grid reliability and resilience research, development, and demonstration projects, which may include storage as a grid-hardening technology. It is possible that some of this funding may be used for storage deployment to facilitate demand response in concert with grid modernization. States and public utility commissions are eligible to apply for funding and must contribute 20 percent of the cost of each project.[30]

Another broad pool of funding that may be used for active demand response deployment is the IRA's Greenhouse Gas Reduction Fund, to be run by the U.S. Environmental Protection Agency, which is equipped with $27 billion in competitive funding available through September 2023 for projects that reduce or avoid greenhouse gas emissions.[31,32] Of that quantity, $7 billion is set aside for competitive grants to enable low-income and disadvantaged communities to "deploy or benefit from zero-emission technologies, including distributed technologies on residential rooftops." It is likely that such funding can be used to expand the penetration of smart meters and

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[29] PotomacLaw.com. "The Infrastructure, Investment & Jobs Act of 2021: What's In It For You? (Part V: Grid Infrastructure and Resiliency)," accessed 1/1/2023. Available at https://www.potomaclaw.com/news-Infrastructure-Investment-Jobs-Act-of-2021-Whats-In-It-For-You-Part-V-Grid-Infrastructure-and-Resiliency.

[30] *Ibid.*

[31] U.S. Environmental Protection Agency. "Greenhouse Gas Reduction Fund," EPA.gov. Accessed 1/1/2023. Available at https://www.epa.gov/inflation-reduction-act/greenhouse-gas-reduction-fund.

[32] *Ibid*.

other grid-modernization-supporting technologies. Further details on the program are expected in the near term.[33]

Respectfully submitted,

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[33] *Ibid*.

## BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

| | | |
|---|---|---|
| **IN THE MATTER OF A COMMISSION** | **)** | |
| **INQUIRY INTO A RULEMAKING TO** | **)** | |
| **IMPLEMENT THE GRID MODERNIZATION** | **)** | |
| **ACT, NMSA 1978, SECTION 62-8-13 (2019)** | **)** | |
| | **)** | **Docket No. 22-00089-UT** |

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**DATED** this 17th day of January, 2023.

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**BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

| | | |
|---|---|---|
| **IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF,** | **)** | **Case No. 22-00**178**-UT** |
| **SOUTHWESTERN PUBLIC SERVICE COMPANY,** | **)** | |
| **APPLICANT.** | **)** | |

**DIRECT TESTIMONY**

***of***

**CHAD S. NICKELL**

***on behalf of***

**SOUTHWESTERN PUBLIC SERVICE COMPANY**

Exhibit 2

Case No. 22-00____-UT
Direct Testimony
of
Chad S. Nickell

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of
Chad S. Nickell

## GLOSSARY OF ACRONYMS AND DEFINED TERMS

| **Acronym/Defined Term** | **Meaning** |
|---|---|
| ADMS | Advanced Distribution Management System |
| AGIS | Advanced Grid Intelligence and Security |
| AMI | Advanced Metering Infrastructure |
| C&I | Commercial & Industrial |
| ComEd | Commonwealth Edison |
| Commission | New Mexico Public Regulation Commission |
| DER | Distributed Energy Resource |
| DI | distributed intelligence |
| FAN | Field Area Network |
| FLISR | Fault Location Isolation System Restoration |
| FLP | Fault Location Prediction |
| GBC | Green Button Connect |
| GIS | Geospatial Information Systems |
| GMR | Grid Modernization Rider |
| HAN | Home Area Network |
| IT | Information Technology |
| Itron | Itron, Inc. |
| kW | kilowatt |

| | |
|---|---|
| kWh | kilowatt hour |
| LBNL | Lawrence Berkeley National Laboratory |
| March 22, 2022 Order | March 22, 2022 Order Granting SPS's Motion to Dismiss Without Prejudice and Closing Docket and Order to Refile Updated Application |
| O&M | Operations and Maintenance |
| OMS | Outage Management System |
| Plan | Customer Education Plan |
| PSCo | Public Service Company of Colorado |
| RF | radio frequency |
| RFP | Request for Proposal |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SPS | Southwestern Public Service Company, a New Mexico corporation |
| SCADA | Supervisory Control and Data Acquisition |
| WiSUN | Wireless Smart Utility Network |
| Xcel Energy | Xcel Energy Inc. |
| XES | Xcel Energy Services Inc. |

Case No. 22-00____-UT
Direct Testimony
of
Chad S. Nickell

## LIST OF ATTACHMENTS

| **Attachment** | **Description** |
|---|---|
| CSN-1 | Planned Distribution Grid Modernization Capital Additions 2023-2026 |
| CSN-2 | Planned Distribution Grid Modernization O&M Expenses |
| CSN-3 | Planned Distribution Grid Modernization O&M Expenses by FERC Account |
| CSN-4 | Advanced Metering Infrastructure Summary of Request for Proposals |
| CSN-5 | Customer Communications Plan |

## I. WITNESS IDENTIFICATION AND QUALIFICATIONS

**Q. Please state your name and business address.**

A. My name is Chad S. Nickell. My business address is 1123 West 3rd Avenue, Denver, Colorado 80223.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS"), and wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy").

**Q. By whom are you employed and in what position?**

A. I am employed by Xcel Energy Services Inc. ("XES") Senior Director, Grid Transformation. XES is a wholly owned subsidiary of Xcel Energy and provides an array of support services to SPS and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

**Q. Please briefly outline your responsibilities as AGIS Delivery Lead for Distribution.**

A. As the Senior Director, Grid Transformation, I am responsible for managing the delivery of the AGIS projects for Distribution, which includes management of costs, schedule, and scope in partnership with Technology Services. This also includes supporting the AGIS governance structure for Project Management, Resource Management, and Financial Management. In addition, I am responsible for managing the delivery of the AGIS projects for Distribution which includes management of costs, schedule, and scope in partnership with Technology Services. This also includes supporting the AGIS governance structure for Project Management, Resource Management, and Financial Management.

**Q. Please describe your educational background.**

A. I graduated from the University of Colorado, Boulder in May 2004, where I earned a Bachelor of Science degree in Electrical Engineering.

**Q. Please describe your professional experience.**

A. I joined Public Service Company of Colorado ("PSCo") in 2008 and have over 13 years' experience in the utility industry and have held previous positions as a Advanced Grid Intelligence and Securuity ("AGIS") Delivery Lead for Distribution, Distribution System Planning Engineer and the Manager of Distribution System Planning and Strategy—South.

**Q. Have you testified before any regulatory authorities?**

A. Yes. I have testified before the Public Utilities Commission of Colorado regarding PSCo's AGIS initiative. I have also submitted direct testimony on behalf of SPS at the Public Utility Commission of Texas.

**Q. Are you sponsoring any attachments as part of your direct testimony?**

A. Yes, I am sponsoring Attachments CSN-1 through CSN-5, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment CSN-1: Planned Distribution Grid Modernization Capital Additions for 2023-2026;
- Attachment CSN-2: Planned Distribution Grid Modernization Operations and Maintenance ("O&M") Expenses by Cost Element for;
- Attachment CSN-3: Planned Distribution Grid Modernization O&M Expenses by FERC Account for;
- Attachment CSN-4: Summary of AMI Request for Proposals ("RFP") Results; and

- Attachment CSN-5: Customer Communications Plan.

## II. PURPOSE AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS

**Q. What is the purpose of your direct testimony?**

A. The purpose of my direct testimony is to support SPS's request for Distribution capital and O&M cost recovery for grid modernization components through SPS's proposed Grid Modernization Rider ("GMR"). To support this request, I provide an overview of the grid modernization components and the need for this initiative. I also explain and support SPS's proposed implementation of, and capital and O&M forecasts for, the Distribution grid modernization components.

Specifically, my testimony supports the prudence of Distribution's costs related to the Advanced Metering Infrastructure ("AMI"), Field Area Network ("FAN"), and Fault Location Isolation Service Restoration ("FLISR") grid modernization components that are planned at this time. Overall, my direct testimony supports SPS's request for cost recovery for these projects through the proposed GMR. I also discuss SPS's planned outreach efforts to help educate customers on what to expect from these grid modernization components and how the new functionality will benefit them. In addition, I provide responsive information to the New Mexico Public Regulation Commission's ("Commission") March 22, 2022 Order Granting SPS's Motion to Dismiss Without Prejudice and Closing Docket and Order to Refile Updated Application ("March 22, 2022 Order").

**Q. How is the technical discussion of the various grid modernization components divided between your Distribution testimony and Mr. Remington's Technology Services testimony?**

A. Since most of the benefits of the grid modernization initiative reside at the Distribution level and the initiative supports the distribution system, I will provide the project overview and discuss the expected benefits of each component. I also provide primary support for the costs and implementation related to the AMI equipment, procurement, and installation of FAN devices, and the procurement and installation of the intelligent field devices required for FLISR.

Mr. Remington will focus on the information technology ("IT") integration necessary to implement these components. While the grid modernization initiative is implemented in partnership with Technology Services, Technology Services has primary responsibility for implementing certain components. Where the Technology Services Business Area has primary responsibility for the component's implementation, I defer to Mr. Remington, as set forth in Table CSN-1 below.

**Table CSN-1: Grid Modernization Witness Support**

| Component | Project | Witness |
|---|---|---|
| AMI | Meters and deployment | Nickell Direct |
| | IT Integration and head end application | Remington Direct |
| FLISR | Advanced application and field devices | Nickell Direct |
| | System development | Remington Direct |
| FAN | Installation of pole-mounted devices | Nickell Direct |
| | IT Integration and deployment | Remington Direct |

## III. OVERVIEW OF SPS'S GRID MODERNIZATION ACTIVITIES

Q. **What is the purpose of this section of your testimony?**

A. I provide an overview of SPS's grid modernization activities, of which the proposal in this case is a subset, and describe its purpose and principle components.

**Q Please provide an overview of the grid modernization components.**

A. Below is a brief overview of the grid modernization components:

- *AMI*: AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," allowing for near real-time[1] monitoring of the distribution system. These meters provide information about customer usage and will enhance SPS's ability to send price signals to customers, allow for new rate structures that will enable customers to manage their energy usage with near real-time energy usage data available through a customer web portal, identify outages without customer reporting, respond efficiently to metering and usage issues, and allow remote service connects, disconnects, and reconnects. AMI meters will replace existing (or "legacy") meters with more advanced technology to improve service and reliability.
- *ADMS*: Advanced Distribution Management System ("ADMS") provides an integrated operating and decision software and hardware support system to assist control room, field personnel, and engineers with the monitoring, control, and optimization of the electric distribution system. As further technology is rolled out, it will manage the complex interaction of Distributed Energy Resources ("DER"), outage events, feeder switching operations, and the advanced applications utilizing intelligent field devices, such as FLISR, discussed below. ADMS gives access to real-time and near real-time data to provide all information on operator console(s) at the control center in an integrated manner, which means the different operating systems and technologies will communicate with and update each other in the ADMS platform. ADMS is the fundamental platform that will utilize the updated data that is being gathered as part of the Geospatial Information Systems ("GIS") project (described below) and manages each of the other components described below.
- *GIS*: GIS is a geospatial project that provides location information about all physical assets that make up SPS's electric distribution system. The records also

[1] The term "near real-time" refers to the fact that there is a slight delay (under ten seconds) between the time the data is pulled and when it is received by the customer.

include specifications regarding the physical assets, such as a distribution feeder's size. While SPS already has a GIS, SPS has been engaging in a data gathering effort to validate and update the information in GIS because the ADMS model needs enhanced data accuracy to operate effectively. ADMS uses the GIS location and specifications to maintain the as-operated electrical model and advanced applications.

- *FLISR*: FLISR allows for the use of software and automated switching devices to decrease the duration and number of customers affected by any individual outage. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary. FLISR reduces the frequency and duration of customer outages. A subset application of FLISR, FLP, leverages sensor data from field devices to locate a faulted section of a feeder line and reduce patrol times needed to physically locate the fault.

- *FAN*: The FAN is the communications network that will enable communications between the infrastructure that already exists at SPS's substations, the the AMI software systems, the new AMI meters, and the new intelligent field devices associated with advanced applications such as FLISR. The FAN provides benefits to all grid modernization components, but is designed and built according to the needs of various specific components, and each has different communication network requirements.

**Q. Is SPS seeking to recover costs associated with all of these components through the GMR in this proceeding?**

A. No. In this case, SPS is only seeking to recover costs associated with AMI, FAN, and FLISR. However, I will discuss the other components to the extent they will facilitate the operation of AMI, FLISR, and FAN. The other components have independent utility and merit and SPS is proceeding with them irrespective of Commission action on the application in this matter.

**Q. What is the overall timeline for implementation of AMI, FAN, and FLISR?**

A. Implementation of AMI, FAN, and FLISR will occur over several years and be substantially complete by 2024 for AMI and FAN and 2025 for FLISR. The implementation timeline is set forth in Table CSN-2.

**Table CSN-2**

| Program | Implementation Timeline |
|---|---|
| AMI | Meter roll-out October 2023-2024 |
| FAN | Deployment 2023-2024 with optimization and support of FLISR in 2025 |
| FLISR | Deployment, integration, and testing 2023-2025 |

That said, the grid modernization effort is ongoing by nature, and SPS will continue to maintain the system as well as leverage evolving technology, platforms and optionality as appropriate over time.

**Q. Did SPS consider alternatives to AMI, FAN, and FLISR?**

A. Yes. SPS has considered alternatives for the various components of the grid modernization initiative. By that, I mean that SPS has not only considered options as part of overall strategic planning, but also compared options within that plan for each component and device through information gathering, vendor discussions, Requests for Information, RFPs, and vendor contract negotiations. With respect to the component-based alternatives, SPS has considered not only whether to move forward with AMI vs. Automated Meter Reading (as discussed by SPS witness Steven D. Rohlwing) or a FAN versus a cellular network, but also different types of AMI meters and systems, different device options, different functionalities, and different support and security considerations.

## IV. SPS'S CURRENT DISTRIBUTION SYSTEM

**Q. What is the purpose of this section of your testimony?**

A. I will discuss the attributes of SPS's current distribution system as background for my discussion of AMI, FAN, and FLISR.

**Q. How was SPS's distribution system originally designed, and how does this design limit the capabilities and operation of the system?**

A. SPS's distribution system was originally designed to accommodate primarily a one-way flow of electricity and information from the utility to the customer with limited monitoring points. This design limits the amount of information and visibility that is available regarding the workings of the system and the customer experience beyond the distribution substation level. The system was also designed to operate through manual and local control configurations and lacks connectivity to easily share information between different portions and components of the system. These different system limitations can be categorized as:

- limited visibility;
- manual control; and
- limited connectivity.

### A. Limited Visibility

**Q. How does limited visibility beyond the substation impact operation of the system and the customer experience?**

A. Since the existing distribution system only measures limited data on a small number of points on the system (primarily at substations), SPS is unable to view the flow of power, voltages, and the operation of equipment on the system beyond the substation. Thus, SPS is not able to specifically monitor the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable. To obtain information regarding the numerous distribution system components beyond the substation, such as meter readings, current flow, or voltage levels, SPS must send workers out into the field to gather this information.

**Q. How does this limited visibility beyond the substation level impact SPS's ability to identify outages?**

A. Since SPS has limited visibility into the system beyond the substation level, it relies on customers to initially notify SPS of outages via phone or website/app. SPS's Outage Management System ("OMS") then aggregates the outage call information and determines which portion(s) of the distribution system lost power. Once SPS identifies the portion of the system affected by the outage, SPS field personnel must patrol the lines to find the source of the problem. This increases the time and expenses associated with responding to outages and leaves customers without power for longer periods of time.

**Q. How does this limited visibility impact SPS's ability to monitor and control voltage levels on the system?**

A. Because SPS does not have visibility into the system beyond the substation level, it does not have insight into voltage issues on the system or the ability to efficiently manage the voltage level on the system. Similar to outage information, SPS relies on customers to report either high or low voltage issues. However, even after the issue is reported, it can take time to install monitoring equipment to help identify the source of the problem, which can be either on the utility side or the customer side of the meter. Similarly, this increases the time and expenses associated with responding to power quality complaints and the issues can persist for longer periods of time.

**Q. How does the limited visibility impact the distribution system's ability to accommodate distributed generation?**

A. SPS currently has limited visibility to measure the amount of distributed generation that is flowing onto or leaving the system. Rather, SPS relies on conservative estimates to quantify the amount of distributed generation entering and leaving the grid. Because SPS must ensure adequate voltage and protection at all times, conservative estimates, coupled with the inability to modify voltages or system configuration, can limit the accommodation of DER. This limited accommodation occurs because the output of distributed generation sources is highly variable and can lead to operational complexities, such as protection or voltage regulation concerns. For example, when high levels of distributed generation are on a feeder, protective equipment such as reclosers or substation breakers may not operate as intended because they are unable to differentiate between loads, distributed generation, and a system fault. The inability of protective equipment to operate as intended creates a risk that a faulted portion of the system would remain energized and present a hazard. It is important for the distribution system to have the capability to accommodate increasing levels of distributed generation as more distributed generation is added to the system.

**Q. How does the limited visibility and information impact the customer experience?**

A. The current meter reading system is limited to providing SPS with customer monthly energy usage information necessary to support customer billing. As a result, SPS cannot provide customers with timely power usage information to enable them to manage their electric usage more efficiently, nor can SPS provide customers with interval energy usage information over the course of the billing period. Additionally, the current meters do not have the capability to communicate information regarding outage or voltage issues to SPS. As a result, SPS relies on customers to report issues via phone or website/app.

## B. Manual Control

**Q. How does the limited number of remotely controlled devices beyond the substation impact operation of the system?**

A. Operation of the current distribution system relies primarily on manual and local control schemes that require human intervention to complete an operation. For example, field switches for nearly all feeders are manually operated. If there is a fault on any feeder segment, the circuit breaker will open at the substation. When this occurs, a field crew has to patrol the feeder to find the location of the fault. This process can be time consuming, especially if visibility is poor or if sections of the line are not adjacent to roads. After the crew locates the fault, they manually open switches to isolate the faulted feeder section. Then, after the faulted section of the feeder is repaired, the switches are manually closed to restore service to the feeder. AMI and FLISR enable the automation of a portion of this process, which will reduce customer outage durations, enable quicker responses to faults, and reduce crew field time.

## C. Limited Connectivity

**Q. How does SPS currently communicate with substations, field devices, and meters and how will SPS's proposals in this application improve the current system?**

A. For many years, SPS has communicated with its substations through leased telecommunications circuits with widely varying capabilities, especially in rural areas, or through expensive microwave installations. Connecting field devices (switches, etc.) and meters with communication networks has been limited to only a few very specific uses. Although SPS has been able to successfully operate the system for many years under these conditions, advancements in technology can now support communications between the intelligent devices deployed across the distribution system – up to and including meters at customers' homes and businesses. These improvements will allow SPS access to information to better manage the system and respond to outages, and to provide customers with access to near real-time data on their energy usage. Further, the continued increase of small-scale DER located on the grid edge (i.e., near or behind customer meters) has created a need for enhancements to accommodate these resources.

**Q. Please describe SPS's vision for the future of the distribution grid.**

A. SPS's vision for the future distribution grid is one that utilizes advances in technology to improve monitoring and operation of the grid for the benefit of customers. The implementation of AMI, FAN, and FLISR will provide SPS with timely and accurate information about what is happening on all portions of the grid, from substations down to each individual customer's meter. These investments will also provide the necessary information, automation, and intelligence to help SPS address problems more efficiently.

In some cases, these insights will alert SPS to situations likely to result in an outage (such as overloaded equipment) before an outage occurs. The increased number of field sensors and devices will also provide SPS with the necessary information to continually monitor and make the necessary adjustments to the system to support increasing amounts of DER and other technologies such as electric vehicles.

Additionally, as discussed later in my testimony, the advanced grid investments will provide the foundation for new projects and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications for customers.

## V. AMI OVERVIEW, COMPONENTS, AND IMPLEMENTATION

**Q. What is the purpose of this section of your testimony?**

A. In this section of my testimony, I provide an overview of AMI and discuss SPS's plan to implement AMI.

### A. Overview of AMI

**Q. Please describe AMI.**

A. AMI is an integrated system of AMI meters, communications networks, and software systems that enables secure two-way communication between customer meters and utilities' business and operational systems that enable benefits for both the customer and the utility. AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a sensor, providing timely monitoring at the customer's point of service, which has a variety of uses for customers and business operations. AMI is a key element of grid modernization because it provides a central source of information that interacts with many of the other components.

**Q. Please summarize the benefits of AMI.**

A. AMI has the potential to benefit customers in many ways, including enhancing SPS's ability to operate the distribution system, providing new information and insights to customers, enabling new rate options, and facilitating new capabilities to further enhance the customer experience.

First, AMI meters provide substantial near real-time data that can be used to improve SPS's ability to monitor, operate, and maintain the distribution grid. AMI meters will be used to verify power outages and service restoration. Improved reliability monitoring leads to improved outage response, proper protection system analysis, and ultimately can help reduce the number of outages. AMI meters also provide improved voltage monitoring and management, support better load studies and analysis resulting in improved planning and design, and are used to support additional systems, such as ADMS.

Second, AMI will provide SPS and its customers access to timely, accurate, consistent, and granular energy usage data that is necessary to develop personalized insights and that supports informed decision making, including data such as 15-minute interval energy usage information. With these insights and other data, customers will be empowered to make energy usage decisions based on their preferences that can reduce their bills and enhance their lives and businesses.

Third, AMI meters are also able to support new rate designs that cannot be supported by SPS's current or "legacy" meters. Last, as further discussed in my testimony below, there is also a potential for the new distributed intelligence ("DI") capability of these meters to further enhance the distribution grid capabilities as well as the customer experience.

## B. <u>AMI Meter Specifications and Components</u>

**Q. Has SPS selected a meter vendor and an AMI meter?**

A. Yes, SPS selected Itron, Inc. ("Itron") as the meter vendor and selected Itron's Riva Generation 4.2 AMI meter. The RFP process that was used to select this meter and vendor is described in greater detail below.

**Q. What are the components of AMI meters?**

A. The components of the AMI meter include: (1) the meter itself (responsible for measurements and storage of interval energy consumption and demand data); (2) an embedded two-way radio frequency communication module (responsible for transmitting measured data and event data available to backend applications and from meter to meter); (3) embedded DI capabilities (described below); and (4) an internal service switch (to support remote connection and disconnection).

**Q. What are the functions of the AMI meter itself?**

A. The primary purpose of the AMI meter is the same as SPS's legacy meters – to measure the amount of electricity used by SPS's customers for billing purposes. However, AMI meters have additional capabilities and can be remotely configured to measure bi-directional and/or time-of-use energy consumption in kilowatt hours ("kWh") and demand in kilowatts ("kW"). An AMI meter that is configured for bi-directional energy measurement measures energy provided by SPS to the customer and also measures net energy provided from customers (i.e., customers with solar panels) to SPS. Energy consumption data for billing purposes can be recorded by AMI meters in intervals as short as five minutes, or longer intervals if desired. The AMI meters also provide granular data regarding voltage and outages as explained further below.

**Q. How often will AMI meters collect and transmit data to SPS?**

A. The AMI meters will collect and transmit data to SPS a minimum of six times per day, or every four hours. However, there are several instances when the meters will communicate more often than every four hours. Some examples of this more frequent communication include:

- Individual meters can be read on an on-request basis. For example, a Customer Care call center employee may request and collect the meter data while on the phone assisting a customer.
- Through the customer portal, as described by Mr. Remington, a customer can access interval energy usage information and personalized insights that is developed from the granular energy usage data.
- Through the customer portal or smartphone application, as described by Mr. Remington, a customer can request an on-demand meter reading. This will provide a customer with near real-time energy information.
- AMI meters will transmit data when an event occurs such as a power outage, power restoration, power quality event, or a diagnostic event.
- AMI meters selected along the distribution feeders to provide data to ADMS will be configured for five-minute interval data and will transmit data to the head-end application every five minutes to make that information available to ADMS. The interrelation between AMI and ADMS is discussed further below.

**Q. What are the other capabilities of the AMI meters?**

A. In addition to the ability to measure, store, and transmit interval meter data, AMI meters also have the capability to:

- measure and transmit voltage, current, and power quality data;
- detect and transmit meter power outage and restoration events;
- detect and report meter tampering events;
- perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module;
- support electric vehicle interconnections;
- support customer-facing energy conservation technologies (i.e., smart thermostats);

- support DI; and
- support remote connect and disconnect functions[2] for customers taking single-phase service (generally, residential and some small business customers).[3]

**Q. What are the capabilities of the AMI meter's two-way radio frequency ("RF") communication module?**

A. The RF communication module will utilize SPS's communication network (i.e., the FAN) to provide two-way communication between the meter and the AMI head-end application. The AMI head-end application is the operating system that is used to send data requests and commands to an AMI meter and receive data from the meter. These communications include:

- transmitting the measurements, alarms, and events performed by the meter to the head-end application;
- receiving commands from the head-end application to send specific meter measurements, alarms, and events, configure the meter to measure specific sets of energy parameters or time-of-use intervals and data recording intervals;
- remotely perform meter firmware upgrades; and
- receiving commands from the head-end application to open or close the internal service switch and communicate its status.

**Q. Will the two-way radio module within the AMI meters have the ability to communicate with other devices?**

A. Yes. While the primary purpose of the two-way radio is to capture and transmit customer billing data and service quality data from the AMI meter to SPS, there is also a second

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[2] SPS will continue to abide by the Commission's rules as well as SPS's tariff regarding the steps that will be taken prior to disconnection.

[3] The only AMI meters available in the marketplace with remote connection/disconnection switches are single-phase meters.

radio within the meter that is Wi-Fi compatible and can be configured to communicate with a customer's Home Area Network ("HAN") and devices.

**Q. What is a HAN?**

A. The HAN is a network contained within a customer's home or business that connects a customer's HAN devices together as well as to the customer's AMI meter. HAN devices can include thermostats, home security systems, energy display devices, and smart appliances. When connected through the HAN, these devices can communicate with each other to support energy management functions.

**Q. How will customers be able to connect their HAN devices to the AMI meters?**

A. The current AMI meter communication protocol allows HAN devices that are IEEE 2030.5 compliant (which includes Smart Energy Profile 2.0) to connect to the meter. SPS is in the process of reviewing other options with Itron for connecting HAN devices to the AMI meters. For devices that are compliant with the meter communication protocol, there is a two-step process that will involve customers submitting an activation request for their HAN devices and SPS processing that request and activating the appropriate components within the AMI meter to communicate with the customer's HAN device.

**Q. What is Green Button Connect ("GBC")?**

A. GBC is a web portal that allows customers to access usage information and provide it to third parties that can provide recommendations on energy consumption. The AMI meters will enable SPS to implement GBC through the Xcel Energy website.

**Q. What is Distributed Intelligence?**

A. Distributed intelligence or "grid edge computing" refers to the distribution of computing power, analytics, decisions, and action away from a central control point and closer to localized devices or platforms where it is actually needed, such as AMI meters or other "smart" devices on the grid. Since data does not need to be continually transmitted over the FAN, it reduces the strain on the network (for other uses of AMI and FLISR for example) and improves the computational speed, efficiency, and capabilities derived from these platforms.

**Q. What portion of the HAN and DI costs are included in the costs that SPS is seeking to recover through the GMR?**

A. The components in the meter that will support HAN and DI, including the microprocessor, memory and Wi-Fi radio, are integral parts of the AMI meters and these costs are included in the GMR. The additional costs for HAN and DI, including software applications and backend systems, are not included in the GMR costs. SPS anticipates future filings that could include these costs or costs for future components that data shows are beneficial to SPS's customers.

**Q. What is the purpose of the internal service switch that is contained within the AMI meters?**

A. The internal service switch has the ability to remotely connect or disconnect power to the customer's electric service upon command from the head-end data application. SPS is not requesting any changes to its disconnection procedures as part of this proceeding.

**Q. How did SPS determine the expected service life for the AMI meters?**

A. SPS relied on information from an Ameren filing from June 2012 as a basis for determining the service life for the AMI meters, as this filing has been used as a standard for determining the service life for AMI meters by other utilities in subsequent years. With respect to meter depreciation, Ameren Illinois reviewed some of the largest AMI deployment plans in the United States, such as those by Duke Energy, Southern California Edison, DTE, and PG&E to as support for its estimated service life of 20 years for an AMI meter.[4] Other utilities following this approach include Consumers Energy Company in Michigan, ComEd Illinois, Nevada Power, and ConEd New York.[5] SPS witness Mark P. Moeller discusses the depreciation rate for the AMI meters in greater detail.

Based on this information, SPS expects that the average service life for the AMI meters will be 20 years. As with any complex system, individual components may fail early or last longer than the average useful life. The AMI meter's useful life does not depend on when the first component fails or how long the last meter-module functions. Instead, its life depends on the system, as a whole, operating correctly and reliably. As these new AMI meters are computer-oriented and are integrated with large software

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4 *See* Ameren Illinois Cost-Benefit Analysis filed in Illinois Commerce Commission Proceeding No. 12-0244 (approved by Commission order on Dec. 5, 2012).

5 *See* Michigan Utility Commission May 14, 2015 order in Proceeding No. U-1765 (Consumers Energy Company); Illinois Commerce Commission June 11, 2014 order in Proceeding No. 12-0298 (ComEd Illinois); Nevada Public Utilities Commission July 30, 2010 order in Proceeding No. 10-03023 (Nevada Power); and New York Utility Commission March 17, 2016 Order in Proceeding No. 15-E-0050 (ConEd New York). However, utilities in other jurisdictions have also applied a depreciation rate based on a 15-year expected useful life for AMI meters, including Xcel Energy operating company Northern States Power Minnesota.

systems, it is expected that these AMI meters will have a shorter service life than the current meters.

## C. AMI Deployment Timeline

**Q. Please describe the work that distribution will undertake to implement AMI.**

A. SPS plans to install approximately 120,000 AMI meters between 2023 and 2024. The Distribution Business Area is primarily responsible for the purchase, testing, and installation of these meters. Distribution will support the installation of the new AMI meters as well as removal, retirement, and disposal of the existing meters, but the installation and removal work will primarily be done by the meter vendor. Distribution will also test and configure all AMI hardware to ensure that it is working properly and is able to integrate with other products and applications.

**Q. What are the components of AMI deployment?**

A. The deployment of AMI has two components: (1) meter deployment and (2) software deployment. The software deployment is discussed by Mr. Remington.

**Q. When will SPS commence deployment of the AMI meters?**

A. SPS anticipates that full deployment will begin in the fourth quarter of 2023 with the first AMI meter installation.

**Q. Please provide an overview of the current AMI deployment timeline.**

A. SPS plans to install approximately 20,000 AMI meters in 2023 and 100,000 AMI meters in 2024.

**Q. With respect to AMI, what work will Distribution complete between the time of this filing and the start of the meter deployment schedule?**

A. As I described earlier SPS selected Itron's Riva Generation 4.2 AMI meter, which is the same meter that will deployed in other jurisdictions across Xcel Energy. Xcel Energy deployed the Riva 4.2 meters in Colorado first and began testing the Itron Riva Generation single-phase meter in 2020, focusing on the electric distribution and customer operational requirements. This meter testing included First Article Testing of the meter accuracy, and evaluation of the data sets from the meter through the meter reading and billing systems. First Article Testing is performed on meters containing the requirements and configurations, to ensure they meet all specifications as required by Xcel Energy. Integration Testing that examines business requirements and functionality across the products, applications, and platforms involved in the implementation of AMI, from meter to bill has been completed in Colorado and includes the assets that will be shared by SPS for the AMI deployment. The purpose of Integration Testing is to confirm that changes made within individual applications work correctly when tested together with changes made within individual applications. In addition and specific to SPS, as SPS configures rates within its billing system and any other requirements unique to SPS, SPS will follow a similar testing process prior to deploying meters. For commercial meters, two types of meters will generally be deployed, commercial meters with and without KYZ (wired connections from AMI meters that provide energy pulses to customer devices). Below is a timeline for commercial meters without KYZ. Commercial meters with KYZ will be available Q1 2023 for ordering and SPS will follow similar phases of testing for these meters.

**Table CSN-3**
**AMI Poly Phase Testing Timeline**

| **Scheduled Milestone** | **Timeframe** |
|---|---|
| First Article Testing Poly Phase | 4th Quarter 2021 to 1st Quarter 2022 |
| Integration Testing Poly Phase | 1st Quarter 2022 to 2nd Quarter 2022 |
| Production Sample Test Poly Phase | 3rd Quarter 2022 |
| Start of AMI Meter Deployment | October 2023 |

## VI. FLISR OVERVIEW, COMPONENTS, AND IMPLEMENTATION

**Q. What is the purpose of this section of your testimony?**

A. In this section of my direct testimony, I provide an overview of FLISR and the benefits associated with this application. I then discuss the implementation plan for FLISR.

### A. FLISR Overview

**Q. What is FLISR?**

A. FLISR is an integrated system that includes the advanced application within ADMS, a communication network, and automated field devices that enable automated switching devices to decrease the duration and number of customers affected by any individual outage. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to un-faulted sections by closing switches to adjacent feeders as necessary. FLISR reduces the frequency and duration of customer outages and improves utility performance metrics such as system average interruption duration index ("SAIDI") and the system average interruption frequency index ("SAIFI").

Fault Location Prediction ("FLP") is a subset application of FLISR that leverages data from field devices to predict a faulted section of a feeder line and reduce patrol times needed to physically locate a failure on the system.

**Q. What are faults on the distribution system?**

A. Faults are failures of the electrical system, which result in abnormal power flows. The distribution system is designed to detect such conditions and de-energize the affected portions of the system in order to limit damage and ensure safety. Faults can be either temporary or permanent. A permanent fault is one where permanent damage is done to the system and a sustained outage (greater than five minutes) is experienced by the customer. Permanent faults may be the result of insulator failures, broken wires, equipment failure (e.g., cable failure, transformer failure), and public damage (e.g., an automobile accident impacting a utility pole). Temporary faults are those where customers experience a momentary interruption (less than five minutes). Causes of temporary faults are transient in nature such as lightning, conductors moving in the wind, animal contact, and branches that fall across conductors and then fall or burn off.

**Q. How does SPS's system currently identify faults and restore power for customers?**

A. SPS has Supervisory Control and Data Acquisition ("SCADA") system capability at some of its substations that informs it of feeder and substation-level outages. When the outage does not impact a full feeder or where SCADA capability does not yet exist (common in rural systems), SPS must rely on calls from customers to inform SPS of an outage. SPS's outage management system then aggregates the outage call information and determines which portion(s) of the distribution system lost power. The Control Center Operator then uses information from all current outages, prioritizes, and dispatches field personnel to start patrolling an area. Prior to ADMS, SPS did not have fault location prediction capabilities, which required crew to patrol a distribution line to find the location of the fault. This process can be time consuming, especially if visibility is poor or if sections of the line are not adjacent to roads and can require field crews patrolling several miles of distribution line before visually identifying the failure.

When crews identify the cause of the failure, they proceed to manually open switches to isolate the fault. Next, they manually close other switches to restore service to as many customers as possible. Finally, they repair the failure and restore power to the remaining customers.

**Q. What is the outage time for a typical feeder-level fault?**

A. The five-year average time to restore a feeder-level fault in SPS has been 85 minutes (not storm-normalized). SPS feeders serve, on average, 626 customers. I discuss the expected benefits of FLISR in more detail below.

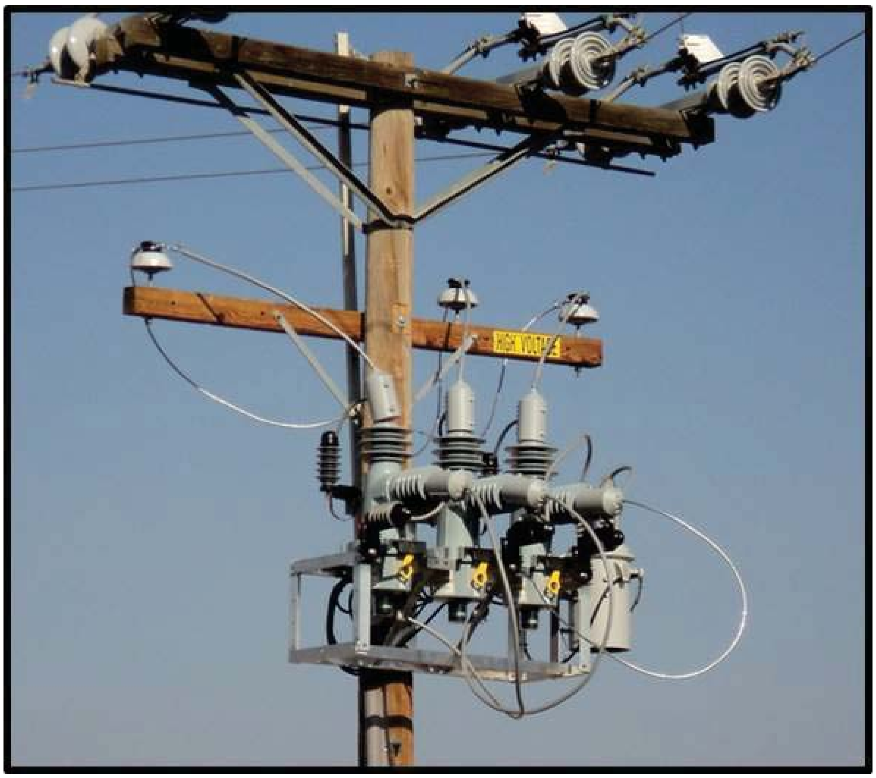
**Q. What are the components of FLISR?**

A. There are four principal components of FLISR: reclosers, automated overhead switches, automated switch cabinets, and substation relaying. The two main components to FLP are powerline sensors and substation relaying.

**Q. What are reclosers and how do they operate?**

A. Reclosers are pole-mounted reclosing and switching devices. SPS currently has reclosers on the distribution system, but only a few of these reclosers have communication abilities to enable remote operations capabilities. The new devices will perform the same functions of existing reclosers but have enhanced monitoring, communications, and control capabilities. The devices are able to identify and interrupt a fault event, then report the fault current to ADMS. ADMS can then use that information to execute FLP to determine the location of the fault. The reclosers will be able to "re-close" after a fault event to determine if a fault still exists. If the fault does not persist, the recloser will reclose and restore service. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will communicate the fault information to ADMS, which will inform SPS of the need to dispatch a crew to the fault location. In addition, the reclosers will be controlled by ADMS when there is a permanent fault to automatically restore service. Figure CSN-1 is a picture of a recloser on a distribution pole.

Figure CSN-1



**Recloser on Distribution Pole**

**Q. What is an automated overhead switch?**

A. These switches are overhead remote supervisory sectionalizing and motor operated switching devices. When a fault occurs, a feeder breaker senses the fault and opens.

Although the overhead switches do not communicate directly with the feeder breaker, local controllers on switches on both sides of the fault will sense the loss of voltage and open, isolating the fault. However, unlike a recloser, the overhead switches do not have the capability of reclosing to determine whether the fault is permanent in nature. Instead, overhead switches rely on the feeder breakers for the reclosing functionality. Although automated overhead switches lack the reclosing functionality, they are more compact and less expensive than reclosers, making them the preferred choice for space-constrained locations or where localized reclosing capability is not required.

**Q. What are automated switch cabinets?**

A. Automated switch cabinets are pad-mounted sectionalizing and switching devices. Each cabinet has motor-operated, remote-controlled devices that SPS will use for switching underground feeders. They will perform functions similar to the automated overhead switches for our underground feeders. Each cabinet has two or more switches inside, providing the safe and reliable switching capabilities required for FLISR.

**Q. What is the function of the powerline sensors?**

A. Powerline sensors are equipment placed on distribution lines to continuously monitor the grid and send information back to the utility for analysis and response. Sensors are available to measure such attributes as current, voltage, power factor, and faults. For FLISR specifically, this technology will allow SPS the ability to detect disturbances on the grid and use this information to identify fault locations, isolate faults, and analyze the unique patterns of these events to predict the likelihood of future outages. SPS hopes to leverage the equipment in the future to detect defective equipment before it fails.

**Q. What is the function of the substation relays?**

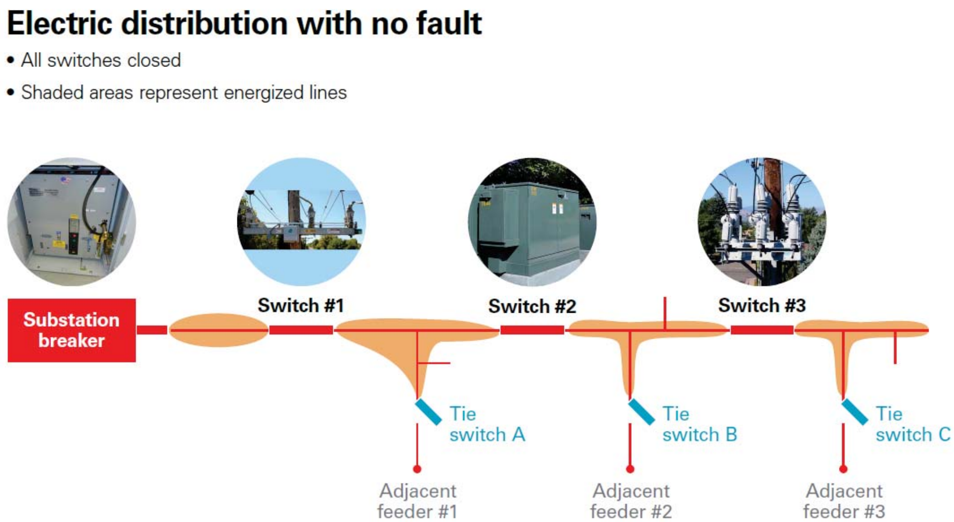
A. Substation-based relays, historically referred to as the feeder's overcurrent relays, provide the logic for when and why a breaker opens. The purpose of these relays is to monitor and, if warranted, to initiate commands to the feeder breaker to de-energize systems which have been compromised. This is to protect the public, utility personnel, and to minimize damage to public or private property or utility equipment. Modern relays are multi-functional and have multiple protection functions programmed into them. These relays can also capture important fault information which will be sent to ADMS for the fault location application.

**Q. Please describe in more detail how FLISR operates in conjunction with ADMS.**

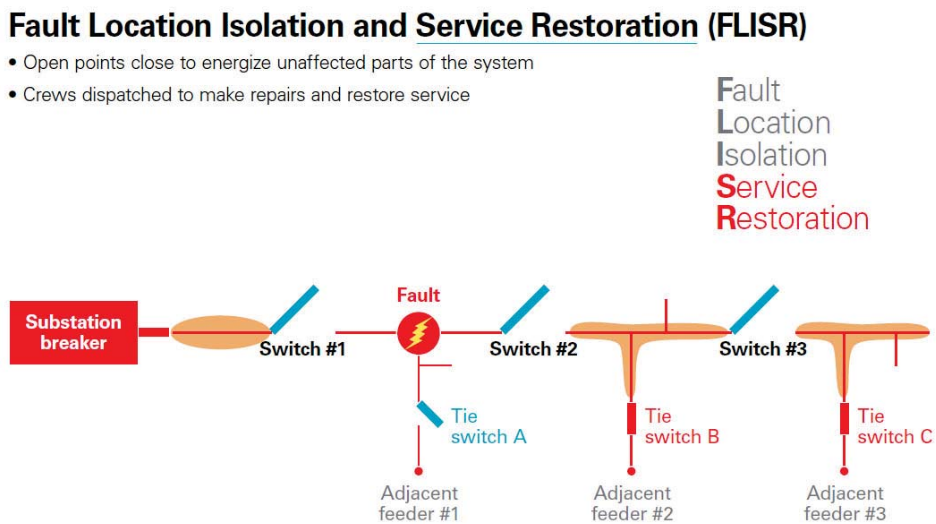
A. There are three basic steps to the operation of FLISR within ADMS. In the first step, when a fault occurs, the automated field devices will open, or sectionalize the feeder to isolate the fault. Depending on the devices and the situation, the device may attempt to reenergize (or "re-close") the affected area first, in case the fault was only temporary in nature. Once the fault is cleared (de-energized), data will be sent from those intelligent field devices to ADMS (over the FAN). ADMS will then run the FLISR application which will analyze the situation, select appropriate switching device near the fault, and generate a switching plan to restore service to other customers. In doing so, ADMS will consider not only device and feeder loading, but surrounding substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to manually investigate the fault event. This process takes less than five minutes from the occurrence of an outage to operator notification. ADMS will also be able to run the FLP algorithm and predict which segment within a FLISR section the fault exists, which will reduce expected patrol times by crews. Figure CSN-2 below shows how FLISR isolates that impacted feeder section to restore power to other sections of the line.

1 **Figure CSN-2**

**FLISR Feeder Configuration – Prior to Fault**




**FLISR Feeder Configuration – Service Restored**



**Q. How does FAN support the operation of FLISR?**

A. FLISR will leverage the FAN for communication between the field devices and the ADMS system. Without FAN, ADMS would not be able to gather readings from the FLISR field devices or be able to remotely control these devices.

**Q. How does AMI support the operation of FLISR?**

A. Indirectly, the FLP component of FLISR considers outage prediction results from a separate outage prediction application in situations where multiple possible fault locations are indicated. The outage prediction application utilizes data from AMI meters. In this way, FLISR and FLP indirectly use AMI data when determining the location of an outage.

**Q. Please describe in more detail how FLISR benefits customers.**

A. Electric power outages and blackouts cost the United States about $44 billion annually, according to a 2018 study by Lawrence Berkeley National Laboratory ("LBNL").[6] The 2018 study by LBNL provides economic impact data per event based on the customer class (i.e., medium and large Commercial & Industrial ("C&I"), Small C&I, Residential) and the length of the outage.[7]

In addition, customer reliance on electricity has increased due to the rise of

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[6] *Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers* (June 2018), available at: http://eta-publications.lbl.gov/sites/default/files/copi_26sept2018.pdf.

[7] *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, available at https://emp.lbl.gov/sites/all/files/value-of-service-reliability-final.pdf.pdf. For instance, a one-hour outage would have an economic impact of $17,804 on a medium or large C&I customer, $647 on a small C&I customer, and $5.10 on a residential customer.

electrification, increasing customer service expectations imposed on the businesses and employees that use our electric service, and increasing overall expectations regarding power quality, number of outages, and outage length. Whether or not customers understand metrics like SAIDI, they expect reliable electric service from their electric utility.

For commercial and industrial customers, the impacts from reliability tend to more readily apparent as outages result in loss of production and loss of revenue. For example, for many of the larger energy requests, such as oil and gas customers, electric reliability is typically one of the main considerations that is emphasized as essential to their operations. Being able to demonstrate a history and commitment to reliability make it easier to attract these types of customers, which in turn can bring jobs and economic development to New Mexico

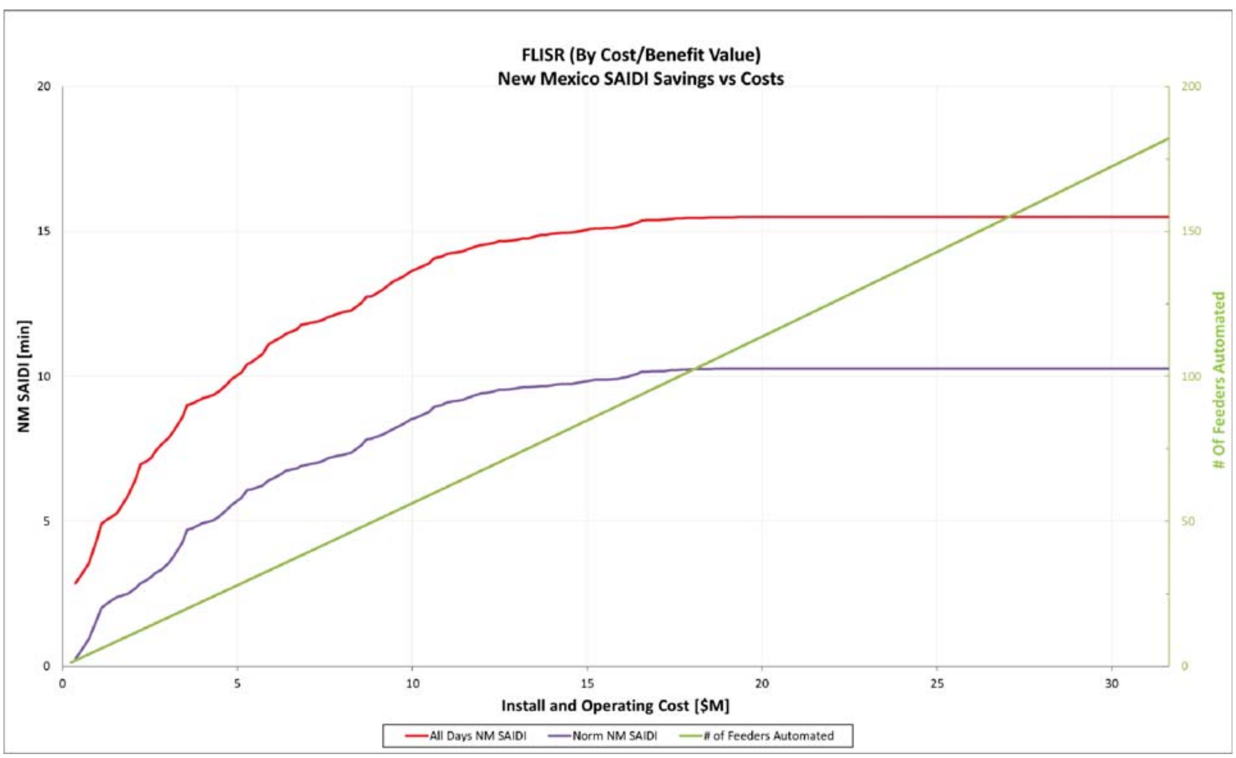
**Q. How does SPS's reliability compare with that of peer utilities?**

A. On an annual basis over the past five years, SPS has been in the first and second quartile when compared to its peer utiltities and, on average, customers have electric service more than 99.9 percent of the time. However, as reliability standards increase over-time and as other utilities implement more advanced technologies, SPS anticipates it may not maintain its position amongst its peers if it does not enhance its reliability performance through investments in FLISR.

**Q. Does SPS intend to deploy FLISR on all of its distribution feeders?**

A. No. SPS plans to install automated equipment on approximately 55 feeders, or approximately 8 percent of the feeders on SPS's distribution system. The deployment is based on the cost/benefit analysis summarized in Figure CSN-3 and is targeted towards areas that have lower reliability performance. As Figure CSN-3 illustrates, the reliability benefits decline as the level of FLISR investment increases. The highest level of benefits is provided by deploying FLISR on feeders with the greatest number of outages and customers. In addition, the deployment will include feeders that will have full FLISR capabilities enabled and feeders that have a subset of FLISR functionality or fault location prediction capabilities enabled. Fault location prediction capabilities will be enabled in areas where it is not possible or practical to enable full FLISR capabilities.

**Figure CSN-3**



**Q. Please describe in more detail why it may not be cost effective to deploy FLISR on all feeders.**

A. Some of the areas of SPS's system already have extremely high reliability and, in some cases, it may be many years between outages, where others may be more susceptible to outages and storm-related events such that FLISR will offer reliability improvements. For instance, approximately 34 percent of SPS's feeders have not had any mainline outages from 2015-2019, and around 73 percent of SPS's feeders have averaged less than one mainline outage per year from 2015-2019. The remaining feeders on SPS's distribution system have had a higher number of outages. With respect to those feeders, FLISR can reduce the number of customers impacted by a fault and the time to restore power for customers as I described previously. In addition, as with all the investments SPS makes, SPS evaluates the costs and benefits of enhancing the experience for customers. FLISR is one of the most cost-effective ways for improving reliability for customers.

**Q. Will SPS deploy FLISR to only those circuits with lower reliability performance?**

A. No. While the deployment will target areas that have historically had lower reliability performance, SPS will also consider opportunities to utilize existing compatible substation and field devices that can enable FLISR and FLP capabilities, which avoids the cost of deploying a new substation or field device. In addition, the deployment of devices and enablement of feeders will be grouped in geographic areas to gain operational and reliability benefits which will include some feeders that have had historically higher reliability performance.

## B. FLISR Deployment Timeline

**Q. What work will the Distribution Business Area undertake to implement FLISR and FLP?**

A. The FLISR and FLP devices are on a three-year deployment schedule that will begin in 2023. The deployment priority will be based on the historical reliability performance of the feeders. Deployment of devices and enablement of feeders will be grouped in geographic areas to gain operational and reliability benefits. Distribution will be responsible for managing the engineering, procurement, and installation of the physical devices that will enable the FLISR and FLP advanced applications. This work will be done in combination with internal labor and third-party contractors.

Distribution will also be responsible for the system analysis to determine the appropriate placement of the field devices described above. It will also be necessary to complete make-ready work to install these devices, such as reconfiguring the location of a pole to allow a device to be placed on that pole or reconfiguring an underground cable so that a pad-mounted piece of equipment can interconnect with it.

**Q. Please describe the different steps involved in enabling FLISR.**

A. SPS is taking a multi-step approach to FLISR in New Mexico. The first step involves deployment of protective equipment that can be leveraged with local programming to reduce outage exposure for customers. Second, this equipment will be enabled with FAN communications and those devices will report information about faults to the ADMS. That information will be leveraged to dispatch field crews directly to a fault as opposed to manually patrolling a distribution line, thereby reducing outage durations for affected customers ('Fault Location Prediction'). Third, ADMS will provide Control Center Operators information about a fault and possible restoration scenarios. Control Center Operators will use this information to remotely operate the automated field devices ('Open Loop FLISR'). Finally, the ADMS will automate execute those restore service after a fault without requiring action from a Control Center Operator ('Closed Loop FLISR').

**Q. Are different steps required for feeders that do not have FLISR capabilities?**

A. No. As I described earlier, in areas where it is not possible or practical to enable full FLISR capabilities, a subset of FLISR functionality or fault location prediction capabilities will be enabled. Enabling FLP capabilities requires the first two steps I describe above.

**Q. What work will SPS perform between now and 2025 to implement FLISR?**

A. SPS plans to deploy FLISR field devices at a relatively steady rate through 2025, which as I described above includes multiple steps for implementing FLISR, including enabling FAN communcations and integrating the field devices with ADMS. The field device installation rate is shown in Table CSN-4 below. By the end of 2025, FLISR devices will be installed on approximately 55 feeders, benefiting nearly 34,000 customers. As I described above, SPS currently does not have plans to deploy FLISR on all feeders as some feeders already have extremely high reliability and SPS's cost/benefit analysis showed diminishing benefits to customers beyond the proposed funding level for the FLISR project.

**Table CSN-4**
**FLISR Field Device Installation**

| **FLISR Field Devices** | 2023 | 2024 | 2025 |
|---|---|---|---|
| SPS Field Devices | 53 | 69 | 44 |
| SPS No. of Feeders | 17 | 23 | 15 |
| NM Field Devices | 0 | 25 | 29 |
| NM No. of Feeders | 0 | 8 | 10 |

## VII. FAN OVERVIEW, COMPONENTS, AND IMPLEMENTATION

**Q. What is the purpose of this section of your testimony?**

A. In this section of my testimony, I provide an overview of FAN and discuss SPS's plan to implement FAN. The implementation of FAN is a joint effort with Technology Services. Mr. Remington discusses the IT aspects of FAN in his direct testimony.

### A. Overview of FAN

**Q. What is the FAN?**

A. SPS's FAN will be a resilient wireless communications network that will provide connectivity and enable two-way communications between the existing infrastructure and new and planned field devices up-to and including the customer meter.

**Q. What are the components of the FAN?**

A. The FAN will consist of two separate wireless technologies: (a) a lower-speed private WiSUN mesh network, and (b) a high-speed network to connect the WiSUN mesh network to the WAN. This network will primarily consist of public Long Term Evolution ("LTE") cellular service, supplemented by alternatives such as microwave or fiber where public LTE service is unavailable.

**Q. How will the FAN operate?**

A. The FAN will be a single, general-purpose, wide area wireless networking resource that will be capable of simultaneously accessing diverse types of endpoints, each with its own performance requirements on SPS's electric system. These endpoints will include a variety of field devices, including reclosers, feeders, electric meters, capacitor banks, and virtually any other field device capable of communications. These endpoint devices also participate in the FAN mesh network by providing connectivity and act as repeaters. Going forward, FAN will be able to communicate with other endpoints as new devices are installed or existing devices are upgraded with communications modules.

**Q. What are the components of the FAN network?**

A. As noted, the FAN is a highly secure, wireless network. The equipment consists of cellular modems, access points, and repeaters. Access points link the endpoint devices to the communications network and extend the reach of the communications network. Repeaters are range extenders and are used to fill in coverage gaps where devices would be otherwise unable to communicate. These devices will be deployed in strategic locations to pick up signals from field sensors that are then fed to cellular.

**Q. Why is the FAN necessary?**

A. A communications network is required to support the deployment of AMI meters and FLISR field devices and will facilitate the operation of advanced grid applications in the future. Deploying devices that can improve distribution system operations without the FAN would be considerably more expensive to install and operate and would limit SPS's ability to gain full value from their capabilities.

Implementation of the FAN will also provide reliable communication capabilities to all participating field devices, regardless of the device's use. Therefore, the FAN will provide the same, reliable communication to multiple business application and devices.

## B. FAN Deployment Timeline

**Q. What work is Distribution undertaking to support the installation of the FAN?**

A. The implementation of FAN will be a joint effort between Technology Services and Distribution. Distribution will be responsible for installing the FAN devices (primarily access points and repeaters) that will be located on distribution poles. Technology Services will be responsible for the design of the network systems for WiSUN, the security of these networks, and configuring the software and hardware components of FAN.

**Q. How will Distribution install the FAN devices?**

A. The access points and repeaters will be mounted primarily on distribution poles to provide adequate height for the radio signal to propagate. In certain instances, the distribution pole will need to be modified or replaced to support a particular device and Distribution will be responsible for completing this modification or replacement. In areas where SPS has underground service, arrangements will be made to mount the devices on street lights or other structures with appropriate height.

**Q. Please explain how FAN will be deployed.**

A. As discussed by Mr. Remington, the WISUN portion of the FAN is being implemented in a phased approach. Xcel Energy engaged in comprehensive planning for implementation of the FAN beginning in 2016.

The first phase of the implementation of the WiSUN portion of the FAN was the design phase to select the WiSUN device vendor and a preliminary design on the number of FAN devices. This phase was completed in 2018.

Phase II of the WiSUN FAN implementation involves a detailed network design, site surveys to inspect each location identified in the design phase to evaluate its suitability for an access point andWiSUN device. These inspections confirm that SPS can receive the appropriate signal anticipated in the design phase at the height and location on the pole where the device will be located.

In Phase III, Distribution field crews will install the devices at locations identified in Phase II. Once devices are installed, they will be tested, and thereafter monitored by Xcel Energy's Integrated Network Operations Center to ensure they are operating as expected. Public LTE devices will be installed concurrently with the WiSUN components. The FAN implementation activity will begin in 2023 and primarily continue into 2024, driven by the need to build out the FAN approximately six months in advance of the deployment of AMI meters. In addition, SPS has capital expenses beyond 2023 as part of optimizing the mesh network and adding additional FAN devices once AMI is fully deployed and as part of supporting FLISR field devices. Further details regarding the implementation of FAN are discussed by Mr. Remington.

## VIII. THE IMPLEMENTATION OF AMI, FAN, AND FLISR PROMOTES GRID MODERNIZATION, PROVIDES BENEFITS TO SPS AND ITS CUSTOMERS, AND IS IN THE PUBLIC INTEREST

**Q. What is the purpose of this section of your testimony?**

A. In this section of my testimony, I will describe how the implementation of AMI, FAN, and FLISR benefits customers, is in the public interest, and provides a net public benefit because it will: promote grid modernization, improve the efficiency, reliability, resilience, and security of SPS's system; allow SPS to maintain reasonable operations, maintenance, and customer costs; improve SPS's ability to develop programs that promote clean and renewable energy; support a flexible, diversified, and distributed energy portfolio; and improve SPS's abilty to provide product and program offerings to customers.

In the sections below, I separately discuss the benefits of AMI and FLISR. I do not discuss FAN directly since it is not a standalone program and does not provide benefits on its own. Rather, FAN enables AMI and FLISR functionality by providing secure and efficient two-way communication of information and data between the AMI meters and FLISR field devices to the supporting software systems.

### A. The Benefits of AMI

**Q. Please summarize how AMI will improve electrical system efficiency, reliability, and operations.**

A. As discussed previously in my testimony, SPS currently has limited visibility into the distribution grid and relies on customers to notify it of issues that include outages. When responding to incidents, SPS must send workers out into the field to locate the source of the problem. This increases the time and expenses associated with responding and leaves customers without power for longer periods of time.

AMI will benefit the operation of the grid and customers in many ways, including improved system efficiency, reliability, and operations. I will specifically describe the following benefits:

- improved distribution system management efficiency;
- improved outage management efficiency;
- improved outage management during storms;
- reduction in field and meter services; and
- improved efficiency in distribution maintenance.

**Q. Do the improvements described in more detail below address the Commission's request in their March 22, 2022 Order for information regarding how SPS's updated Application proposes smart meters (or AMI meters) uses beyond automatic meter reading and remote fault detection?**

A. Yes. The AMI meter uses and improvements described in more detail below are beyond automatic meter reading and remote fault detection capabilities.

**Q. Do the improvements described in more detail below address the Commission's request in their March 22, 2022 Order for SPS to identify demand response and grid management programs being considered for implementation using smart meter capabilities?**

A. Yes. The AMI meter capabilities and identification of demand response and grid management programs are described in more detail below. Mr. Luth discusses how proposed programs work in conjunction with rate design principles in his Direct Testimony.

**Q. What distribution system management efficiencies will be gained as a result of AMI?**

A. AMI will provide a wealth of information about the workings of the distribution system. This AMI data can be aggregated at various levels of the distribution system, including tap, transformer, and service lines amongst other distribution system equipment. SPS will use this data to prioritize distribution grid improvements and more efficiently plan and design the system. Through the aggregated AMI data, SPS will have greater insights into the nature of the load - specifically load profiles, which will help SPS evaluate risk. The voltage insights will help SPS prioritize areas for investments in tap, transformer, and secondary wire replacement. For instance, the AMI data can be aggregated at the transformer level to identify overloaded transformers and determine the optimal transformer for replacement transformers.

**Q. Please explain how the installation of AMI meters will improve efficiency in outage management.**

A. AMI will enable increased outage management efficiencies by transmitting automated outage notification and restoration confirmation to SPS, providing SPS with an expeditious and more accurate scope of an outage. This automated outage information will assist SPS in restoring power more quickly by providing more detailed outage location information that will reduce the time and expense in locating the outage. Overall, because of these increased outage management efficiencies, AMI enables quicker response and restoration to customer outages, which ultimately improves reliability.

**Q. How will AMI improve outage management during storms?**

A. AMI enables an automated outage information system that will allow SPS to deploy crews more efficiently to outage areas, especially during storm outages, ensuring that all customers in an area have been restored before dispatching the crew to the next location. This also will reduce outage impacts to customers and improve reliability.

**Q. What types of field and meter service will be reduced by implementing AMI?**

A. Since AMI meters will have the ability to provide billing, power, and voltage information to SPS on command, there will be a reduced need to send personnel to the field to gather this information. This will result in more efficient operations in several areas:

- *Reduction in Outage Trips due to Customer Equipment Damage*: SPS's current meter system requires crews to be dispatched to verify outages. Sometimes these outages are due to damaged customer equipment and not utility damaged equipment. Under the new AMI system, AMI meters will have two-way communications to the meter, and SPS can verify whether there is power at the meter thus pointing to a likely customer problem. This would help reduce field trips while also assisting customers in identifying the likely cause of the outage.
- *Cost Savings from Remote Connect Capability*: AMI enables remote connection and disconnection of residential type service without the need to dispatch crews. This will result in personnel and transportation cost savings due to the reduction in field visits.
- *Reduction in "Ok on Arrival" Outage Field Visits*: AMI will allow SPS to test for loss of voltage at the service point and detect both outage conditions and to know when restoration is complete. As a result, AMI implementation will help eliminate unnecessary field trips to customer premises that result in field personnel finding no electric service issues upon arrival.
- *Reduction in Field Visits for Voltage Investigations*: When notified of a potential voltage problem, SPS currently sends a technician to investigate. AMI enables the elimination of unnecessary trips when proper voltage can be verified remotely,

and helps SPS prioritize and dispatch the most appropriate crews if the voltage is outside of the appropriate range.

**Q. Will the benefits described above help SPS maintain reasonable operations, maintenance, and customer costs?**

A. Yes. In addition to improving system efficiency, reliability, and operations, the benefits described above will provide quantifiable benefits that are included in the cost benefit analysis discussed by Mr. Rohlwing.

**Q. Will other benefits of AMI help SPS maintain reasonable operations, maintenance, and customer costs?**

A. Yes. In addition to the benefits described, other quantifiable benefits include:

- avoided manual reading services;
- avoided meter purchases;
- remote connect and disconnect capability;
- reduced consumption on inactive meters;
- reduced uncollectible/bad debt expense; and
- reduced theft/meter tampering.

**Q. Please describe the avoided manual reading services benefit.**

A. SPS's current meters require it to send workers out into the field to manually read meters for billing purposes. This increases the time and expense for providing billing services to customers. AMI meters will have the ability to automate the billing process so there is no need to send workers to the field to gather this information. While automatic meter reading technologies do provide some efficiencies from SPS's current meters, drive-by automatic meter reading technologies would still require SPS to have workers driving in the field to support monthly meter reading.

**Q. Please describe the avoided meter purchase benefit that will result from deployment of the AMI meters.**

A. AMI meters will have a lower failure rate as compared to SPS's existing meters. As a result, there is a cost savings associated with not having to replace these failed meters. The benefit from avoided meter purchases, however, is partially offset by the cost of ongoing replacement of AMI meters due to normal failure rates.

**Q. Please describe the remote connect and disconnect capability benefit.**

A. AMI meters have remote connect and disconnect capabilities. The ability to remotely connect or disconnect service, when paired with customer protections, provides both cost and convenience benefits. When a customer wants to start service at a single-phase premise today, a field visit is necessary. This involves a fee for the customer and requires someone to be present at the location to meet an SPS representative. With remote connection capability, a customer would not need to be present and a lower fee could be charged.

Remote capabilities could also be beneficial for seasonal disconnections, where a customer may want electric service disconnected for a lengthy period of time because a home is unused. Instead of incurring the cost for two field visits to disconnect and reconnect service, a customer could schedule a remote disconnection and reconnection aligned with occupancy needs. This would save customers money through reduced fees and energy usage and would be more convenient.

There would also be benefits when changes in tenants occur. AMI remote disconnection will enable SPS to disconnect electric service between tenants if there was no landlord agreement in place. Today, it is typically cost prohibitive to disconnect the account given the expense to send employees into the field. Remote disconnection and reconnection can also help reduce the cost of an unoccupied retail location for a building owner who has a vacant property that is between tenants.

**Q. Please describe the reduced consumption on inactive meters benefit.**

A. This benefit is related to electric consumption during a gap between two separate user accounts and the process to disconnect and connect service between tenants or owners. With the remote connect/disconnect capability, usage on inactive meters should be reduced.

**Q. Please describe the reduced uncollectible/bad debt expense benefit.**

A. Due to the manual nature of the existing disconnect process for non-payment, SPS is not able to complete all the physical disconnections for non-payment orders issued in a given year. Utilizing the remote connect/disconnect capability of the AMI meters should result in more timely disconnection for nonpayment, which should reduce bad debt expense.

**Q. Please describe the reduced theft/meter tampering benefit.**

A. Improved data and analytics enabled by AMI technology will reduce energy theft through better detection and prevention capability, which can provide an overall cost benefit for customers. Today, customers who have been disconnected and try to reconnect their service illegally typically do so by removing the meter, removing the “boots” placed on the meter contacts, and then replacing the meter. This is an illegal and extremely unsafe practice. When AMI technology is in place, remotely disconnecting service will involve opening a disconnection switch on the meter to disconnect power to the customer. However, the meter still has power and can communicate over the network. If a customer removes the meter from the socket to bypass it, SPS would receive a notification flag over the network to indicate meter tampering. This will improve detection of instances where customers illegally bypass our meter to receive electricity without paying for it. These situations require time-intensive identification to detect today, but they can be detected automatically through AMI technology. For safety reasons, however, these situations will still require a physical visit to remedy.

**Q. Will the benefits described above help maintain reasonable operations, maintenance, and customer costs?**

A. Yes. In addition to improving system efficiency, reliability, and operations, the benefits described above will provide quantifiable benefits and are included in the cost benefit analysis as described in more detail by Mr. Rohlwing.

**Q. Does AMI provide any other benefits?**

A. Yes. AMI will provide several other benefits to the operation of the grid and to customers that include:

- providing customers the ability to better manager their energy costs;
- enabling or enhnacing new demand-side management programs; and
- enabling greater distributed generation integration.

**Q. Please describe how AMI will allow customers to better manage their energy costs.**

A. Customers are increasingly savvy when it comes to smartphone applications and sophisticated websites. They are accustomed to engaging electronically to manage their accounts, resources, and service needs across many industries. Without advanced meters that can provide regular usage data, it is not possible to bring the energy industry along that same curve by developing sophisticated energy management and conservation tools, such as TOU rates, nor the applications and web-based tools that allow the customer to observe and manage their consumption. The improved interactions and data that will be available with AMI will provide customers with more control over their energy usage and bills. This includes the ability to know how much energy they are using at a given period of time and alerts if their monthly usage or bill amount is higher than normal. These services require advanced metering and more timely usage data in order to provide these services and controls to our customers.

**Q. Please provide more detail on the data and information that AMI will provide to customers.**

A. AMI will provide customers access to timely, accurate, consistent, and granular energy usage data that is necessary to develop personalized insights and that supports informed decision making. This includes enhanced visualization of energy usage data, including views of daily, hourly, and 15-minute interval energy usage information, as well as enhanced insights surrounding the data, including personalized energy saving tips, high usage alerts, and a usage and spending breakdown associated with primary in-home and business appliances and devices accessible through the customer's MyAccount portal. With these insights and other data, customers will have more information to make energy usage decisions based on their preferences that can help reduce their bills and enhance their lives and businesses. In addition, SPS will make interval usage data available to authorized third-party providers via GBC, which will allow those providers to provide additional services to customers.

**Q. How will AMI enable or enhance new demand-side (or demand response) management programs?**

A. The more detailed and timely data that SPS's grid modernization investments provide can help enable or enhance programs in a number of ways. First, as SPS acquires more information regarding customer usage, it can update program designs and marketing tactics. SPS will have better insight into how and when customers use their energy which will allow it to better market and segment customers. This means that communications will be more relevant and SPS will be able to develop new products and services that support demand-side management goals. Second as described earlier, HAN capabilities enable the ability to connect with customer HAN devices such as thermostats which can be used to support support energy and demand response management functions. These capabilities can enable new ways to support energy and demand response management.

**Q. How will AMI enable greater distributed generation integration?**

A. AMI will provide more timely and more granular data on the flow of energy to and from customers. As I described earlier in my testimony, SPS relies on conservative estimates to quantify the amount of distributed generation entering and leaving the grid. Because SPS must ensure adequate voltage and protection at all times, such conservative estimates, coupled with the inability to modify voltages or system configuration, can limit the accommodation of DER. With this additional data and information, SPS will be able to facilitate the integration of greater amounts of distributed generation on to the system. In addition, in certain instances the bi-directional capabilities of the AMI meters will allow the ability to perform net metering for our DER customers without the need to change out the existing meter.

Additionally, the AMI system will capture voltage and usage data which can be compared with nameplate or operational limits of SPS's equipment. Using this data, SPS will be able to identify problems such as solar causing high secondary voltage, or transformer overload due to either a strong presence of electric vehicles (load) or high reverse flows (such as solar generation). It is SPS's intention to leverage AMI data for this purpose, which will allow SPS to enable DER while at the same time maintaining reliability and power quality for customers.

**Q. Overall, will the implementation of AMI provide benefits to SPS's New Mexico retail customers?**

A. Yes. For the reasons discussed above, the implementation of AMI will benefit SPS's New Mexico retail customers, and is in the public interest.

## B. The Benefits of FLISR

**Q. Please summarize how FLISR will improve electrical system efficiency, reliability, and operations.**

A. As discussed previously in my testimony, SPS's field switches on the distribution grid are nearly all manually operated switches and when an issue occurs, field crews must patrol a distribution line to find the location of the fault. This process can be time consuming.

FLISR has the potential to benefit the operation of the distribution grid and customers by providing information about the location of faults and automatically restoring power for customers. This will help improve the system efficiency, reliability, and operations. More specifically I will describe the following benefits:

- customer benefits from improved reliability;
- outage patrol time savings; and
- enhanced visibility and control of the distribution grid.

**Q. How will FLISR provide reliability benefits?**

A. Overall, implementing FLISR will allow SPS to more efficiently restore power to customers with the use of fewer resources and will improve customer's outage experience. Specifically, if there is a fault on a feeder that is automated with FLISR, SPS will be able reduce the number of customers who experience a sustained outage and will shorten the duration of certain sustained outages that affect a substantial portion of our customers.

**Q. How will FLISR reduce the number of customers who experience sustained outages?**

A. FLISR will allow SPS to restore service to customers affected by an outage within minutes of a fault. In the event of a fault, the FLISR protective devices will reclose, or sectionalize the feeder, and send data to ADMS. ADMS will then step through the FLISR sequence. The first step is fault location, identifying the location of the fault to, at minimum, between two automated field devices. Next, FLISR will proceed to isolation, in which ADMS will send open commands to automated field devices necessary to isolate the faulted section of feeder. Last, FLISR will execute service restoration, which will restore power to all possible customers.

This process is expected to take from 15-45 seconds from start to finish and by design, restore power to a portion of the customers on that feeder. After the service restoration step, system operators will send a crew to the isolated section to investigate the fault event, make repairs, and restore service to the remaining customers. As I described earlier, a feeder level fault will impact on average 626 customers for 85 minutes. FLISR will reduce the number of customers who experience a sustained outage and reduce restoration times for the remaining customers that do experience a sustained outage.

**Q. How will FLISR provide outage patrol savings?**

A. A primary benefit of FLISR is fault location prediction capabilities that will allow SPS to dispatch field cerws directly to the location of the fault, as opposed to having field crews patrol a distribution line to find the location of the fault or issue which can be time consuming.

**Q. How will FLISR enhance visibility and control of the distribution grid?**

A. As I described earlier, SPS has very limited visibility of the distribution grid beyond the substation level. FLISR provides key data at critical points along the system, which when integrated with ADMS provides additional insights into the operation and planning of the distribution grid. The increased system visibility will also improve reliability management efforts by increasing the quality and amount of the information SPS is able to analyze. In addition, these FLISR devices can capture momentary or transient fault and disturbance information, providing the ability to proactively identify potential issues on the distribution system.

**Q. Will FLISR enable greater distributed generation integration?**

A. Yes. Similar to AMI, FLISR will provide more timely and granular data on the flow of energy at several points along the distribution grid. This data can be used to enhance the operation and planning for distributed generation resources.

**Q. Will the implementation of AMI, FAN, and FLISR allow for capital investment and skilled jobs in related services?**

A. Yes. As discussed below, SPS plans to implement approximately $34 million in capital investment to implement AMI, FAN, and FLISR between 2023 and 2025. Skilled labor will be necessary to implement and maintain this investment.

**Q. How are changing customer needs and preferences driving the need for grid modernization?**

A. The needs and preferences of customers continue to evolve in the digital age, with increasing dependence on information and the connectivity of digital devices. While incremental modernization efforts have taken place on the distribution system over many years, and we have used these investments to provide reliable power for decades, we (along with the broader industry) believe now is the right time to begin a more significant advancement of the grid. Technological advances now make it possible to meet growing customer expectations for a more robust, reliable, and resilient system, as well as customer desire for more insight and visibility into the energy choices they are making.

## IX. DISTRIBUTION COSTS ASSOCIATED WITH AMI, FAN, AND FLISR

**Q. What Distribution costs does SPS propose to recover through the GMR?**

A. The Distribution costs that SPS proposes to recover through the GMR include material and equipment, labor, and vendor services associated with the implementation of AMI, FAN, and FLISR.

**Q. What Distribution capital costs are you supporting for the grid modernization components?**

A. Distribution's grid modernization capital additions that I am supporting for rider recovery are shown in Table CSN-5 below. These costs are forecasts intended to illustrate the scope of projected costs, subject to annual forecasts and true-ups through the GMR as described by SPS witness Ian C. Fetters.

**Table CSN-5**
**Grid Modernization Distribution - Capital Additions**
**(New Mexico Retail)**
**(Dollars in Millions)**

| Component | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|
| AMI | $5.21 | $16.13 | $0.51 | $0.00 |
| FLISR | $0.49 | $1.96 | $2.53 | $0.00 |
| FAN | $4.78 | $2.17 | $0.17 | $0.00 |
| **Total** | **$10.48** | **$20.26** | **$3.21** | **$0.00** |

*There may be differences between the sum of the individual project amounts and total amounts due to rounding.

Total Distribution capital additions for AMI, FAN, and FLISR are also set forth in Attachment CSN-1 to my direct testimony. I provide additional details and support for Distribution's capital costs below.

**Q. What types of O&M costs is Distribution incurring to implement AMI, FAN, and FLISR?**

A. Distribution's O&M costs include outside vendor contracts, employee expenses, and contract labor. All internal labor costs have been excluded as they are reflected in base rates.

**Q. What are Distribution's forecasted O&M costs for the implementation of AMI, FAN, and FLISR?**

A. The forecasted grid modernization O&M expenses for Distribution are shown in Table CSN-6. As with capital costs, these O&M costs are forecasts intended to illustrate the scope of projected costs, subject to annual forecasts and true-ups through the GMR as described by Mr. Fetters.

**Table CSN-6**
**Grid Modernization Distribution - O&M Expenses**
**(New Mexico Retail)**
**(Dollars in Millions)**

| Component | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|
| AMI | $0.27 | $0.25 | $0.15 | $0.14 |
| FLISR | $0.06 | $0.09 | $0.10 | $0.02 |
| FAN | $0.05 | $0.03 | $0.01 | $0.00 |
| **Total** | **$0.38** | **$0.37** | **$0.26** | **$0.16** |

Total Grid Modernization O&M costs are provided in Attachment CSN-2 to my direct testimony by cost element and in Attachment CSN-3 by FERC account. I provide additional details and support for the Distribution O&M costs below, organized by component.

## A. Distribution Costs for AMI

### 1. Distribution Capital Costs of AMI

Q. **Was Distribution primarily responsible for the forecasted capital costs for AMI?**

A. Distribution is responsible for the costs associated with acquiring and installing the AMI meters. I describe how we developed our forecast for these costs in more detail below. Technology Services is responsible for developing the costs and forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies, and Mr. Remington will address the development of those costs.

**Q. What are the projected capital additions for AMI from 2023-2026**

A. Table CSN-7 provides a breakdown of Distribution's capital additions forecasts for AMI for 2023 through 2026.

**Table CSN-7**
**AMI Distribution - Capital Additions**
**(New Mexico Retail)**
**(Dollars in Millions)**

| | 2023 | 2024 | 2025 | 2026 | Total |
|---|---|---|---|---|---|
| **AMI** | $5.21 | $16.13 | $0.51 | $0.00 | $21.85 |

**Q. What are the primary components of Distribution's AMI capital forecast?**

A. Distribution's AMI capital forecast has five key components: (1) AMI meter purchase; (2) AMI meter installation; (3) vendor project management; (4) AMI operations (external and internal); and (5) testing equipment.

**Q. How did Distribution develop its capital forecast for the AMI meter and installation costs?**

A. The costs for the AMI meters and installation are based on the meter contract with the AMI meter vendor, Itron. Additional overheads such as taxes are also included in these estimates.

**Q. Describe the process used to select the AMI meter vendor.**

A. Xcel Energy issued an RFP in March 2018 to select an electric AMI meter vendor that could provide an AMI meter, project management, and installation services. As part of the RFP process, potential vendors were asked to review Xcel Energy's priorities and vision for its AMI solution including the capabilities desired for this technology. The vendors were then asked to provide precise and detailed responses to numerous technical questions regarding their AMI meter offerings related to the following:

- technical standards of their meter;
- capabilities of their meter;
- compatibility of their AMI meter with other grid modernization components;
- data and cybersecurity safeguards;
- plan and schedule for technology development, integration, and AMI deployment; and
- itemized pricing information for their AMI meter and installation.

**Q. How many companies responded to the RFP?**

A. Four different companies responded to the RFP.

**Q. How did Xcel Energy evaluate these RFP responses?**

A. Xcel Energy evaluated these responses based on a number of factors including: (1) total cost; (2) schedule requirements; (3) core metrology; (4) customer benefits and capabilities; (5) integration with the selected Network Integration Card from Silver Springs (which was purchased by Itron); (6) future proofing/new technology; (7) commercial terms and conditions; and (8) security.

**Q. Were there other capabilities that Xcel Energy desired for the new AMI meters?**

A. Yes. Xcel Energy was also interested in making sure that the selected AMI meter could support distributed intelligence capabilities. These capabilities were an important consideration as Xcel Energy understood the customer-facing, operational, and future-proofing benefits that these capabilities could provide.

**Q. Did Xcel Energy select an AMI meter and installation vendor from these RFP responses?**

A. Yes. Based on an assessment and comparison of the capabilities, price, and schedule commitments provided in the RFP responses from these four different meter vendors, Xcel Energy selected a meter vendor and issued a Limited Notice to Proceed to that vendor in December 2018. However, in late March 2019, Xcel Energy learned that the meter vendor that was initially selected would not be able to integrate certain capabilities while also meeting the meter deployment schedule set forth in the Limited Notice to Proceed. As a result, in April 2019, Xcel Energy solicited and received a comprehensive proposal from another meter vendor that responded to the initial RFP. This meter vendor was able to meet the requested deployment schedule with the necessary integration, offered the necessary meter capabilities, and offered favorable price and contractual terms. As a result, in May 2019, Xcel Energy selected Itron as its meter vendor to serve all jurisdictions, including SPS, and a contract was executed on September 1, 2019 (the "Meter Contract").

**Q. Why did Xcel Energy select Itron as its meter vendor?**

A. The primary factors in the decision were:

- lowest cost/best overall value for an offering that included distributed intelligence and grid edge technology;
- lowest risk solution / least complexity;
- the vendor met Xcel Energy's deployment schedule;
- single vendor solution (Itron is already under contract for the mesh network and the head-end software);
- met or exceeded Xcel Energy's core metrology requirements, including distributed intelligence capabilities; and
- most favorable overall commercial terms and conditions, including for edge technology/distributed intelligence.

A summary of the analysis supporting the selection of Itron is provided as Attachment CSN-4.

**Q. How did Distribution develop its capital foreast for the AMI vendor project management costs?**

A. The forecast for AMI vendor project management is set forth in the Meter Contract. SPS's estimates also include internal overheads.

**Q. How did Distribution develop its capital forecast for AMI operations related to internal and external personnel?**

A. Cost estimates for internal and external personnel were developed based on the role and number of required personnel required to perform necessary tasks to enable installation and deployment of the AMI meters. The necessary positions include analysts, projects and project managers, engineers, and electricians. The cost estimates were determined using average pay scales for the needed positions combined with an estimate the amount of work required by each of these roles during the AMI installation and deployment. SPS then determined the appropriate allocation between capital and O&M for these costs based on the type of work being performed.

**Q. How did Distribution develop its capital forecast for testing equipment**

A. These cost estimates were based on quotes obtained and purchases that were made from vendors for this testing equipment. This testing equipment is standard off-the-shelf equipment and Xcel Energy leveraged relationships with existing vendors to obtain the best cost for this equipment.

### 2. Distribution's O&M Costs for AMI

**Q. What are Distribution's O&M costs associated with AMI?**

A. The primary components of Distribution's AMI O&M expense include outside vendor contracts, employee expenses, and contract labor. All internal labor costs have been excluded as they are reflected in base rates. These expenses relate to the following categories of work that I describe in more detail below: (1) support of the capital deployment, (2) business readiness, and (3) change management. Table CSN-8 below provides a summary of Distribution's O&M expense forecast for AMI for 2023 through 2026.

**Table CSN-8**
**AMI Distribution – O&M Expenses**
**(New Mexico Retail)**
**(Dollars in Millions)**

| | **2023** | **2024** | **2025** | **2026** | **Total** |
|---|---|---|---|---|---|
| AMI | $0.27 | $0.25 | $0.15 | $0.14 | $0.81 |

**Q. What O&M expenses are included in the Capital Deployment category?**

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. For instance, any repair activities that are necessary to perform the meter exchange would be deemed an O&M expense.

**Q. What is included in the Business Readiness cost category?**

A. This category includes the costs to support the business readiness activities that are necessary to ensure the business is prepared and processes are in place to support the AMI meter and applications.

**Q. What is included in the Change Management cost category?**

A. The change management costs consist of general change management activities such as training and communications, which I discuss in more detail below. This includes the O&M portion of costs for development and delivery of training needed to prepare SPS's employees and contractors for the AMI meters and data management systems being deployed to support AMI. It also includes costs in the development and delivery of internal communications in support of the change management plan necessary to engage and prepare the business for upcoming changes due to AMI.

### 3. Distribution Contingency for AMI

**Q. Does Distribution's AMI capital forecast include contingency amounts?**

A. Distribution's capital forecast in 2023 does include contingency amounts that may be necessary to address potential cost increases to support the AMI meter installations that currently are not known. This could include any upgrades necessary to complete the meter exchange, such as the upgrades to the wiring and meter socket that are not known until the meter exchange is done. These upgrades benefit customers by not requiring them to pay for upgrades to customer equipment during the AMI meter installation.

**Q. Can provide an example of potential cost increases?**

A. Yes. Based on inflationary pressure of material costs the Company has agreed to a 5% increase in material purchases from Itron in 2022. While this currently does not impact the AMI and FAN costs for New Mexico, it is possible that inflationary pressure could continue beyond 2022. This is example where contingency amounts would be utilized to support cost increases.

**Q. In summary, why are the Distribution AMI costs reasonable and necessary?**

A. AMI is a fundamental element of the grid modernization initiative because it provides a central source of information that interacts with many of the other components of the initiative. The system visibility and data delivered by AMI provides customer benefits in reliability and ability for remote connection, enables greater customer offerings for rates, projects, and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate and consistent data from the AMI system will provide insights for customers to make informed decisions about their energy sources and usage of reliable and sustainable energy. Distribution's capital investments described above that include the AMI meters are necessary to implement AMI and Distribution's capital and O&M forecast is reasonable.

## B. Distribution's Costs for FLISR

### 1. Distribution's capital costs for FLISR

**Q. Was Distribution primarily responsible for developing the forecast for FLISR?**

A. Yes. Distribution developed its forecast for FLISR by using data from actual installations of comparable devices, as well as pricing details from vendors and projects that require the same field device equipment.

**Q. What is the projected capital investment for FLISR and FLP for 2023 through 2026?**

A. Table CSN-9 below provides a breakdown of Distribution's capital additions forecasts for FLISR and FLP for 2023 through 2025.

**Table CSN-9**
**FLISR and FLP Distribution - Capital Additions**
**(New Mexico Retail)**
**(Dollars in Millions)**

| | 2023 | 2024 | 2025 | 2026 | **Total** |
|---|---|---|---|---|---|
| FLISR and FLP | $0.49 | $1.96 | $2.53 | $0.00 | $4.98 |

**Q. What are the primary components of the FLISR and FLP capital forecast?**

A. The primary components of the FLISR and FLP capital forecast, shown above, include: (1) device costs, which include device replacements, and (2) installation costs, which include project management, labor, and commissioning support.

**Q. How did Distribution derive the FLISR and FLP device costs?**

A. SPS was able to use actual costs to develop the capital forecast for the FLISR and FLP devices, such as the costs for previous, completed projects utilizing the same equipment that will be deployed for FLISR and FLP.

With respect to device replacement costs, Distribution experiences a roughly 0.6 percent equipment failure rate per year. This includes various factors such as product infancy failure rates and equipment failures due to public or environmental damage. This failure rate was applied to total equipment quantities to determine the number of devices that would need to be replaced and accurately reflect those costs in the FLISR and FLP deployments.

**Q. How did SPS estimate the installation costs for FLISR and FLP?**

A. The installation costs for FLISR include the capitalized costs for installing and commissioning FLISR devices (switches, reclosers, sensors, and relays). In addition, other Xcel Energy Operating Companies have installed FLISR devices, and Distribution was able to use historical installation and labor costs to develop the capital cost estimates.

### 2. Distribution's O&M Costs for FLISR and FLP

**Q. What are Distribution's O&M costs associated with the implementation of FLISR?**

A. The primary components of Distribution's AMI O&M expense include outside vendor contracts, employee expenses, and contract labor. All internal labor costs have been excluded as they are reflected in base rates. These Distribution's O&M costs for FLISR will include costs in the following categories: (1) capital support; (2) on-going asset/device support; (3) device replacement; (4) on-going communications network; and

(5) training. Table CSN-10 provides a breakdown of Distribution's O&M expense forecast for FLISR and FLP for 2023 through 2026.

**Table CSN-10**
**FLISR and FLP Distribution – O&M Expenses**
**(New Mexico Retail)**
**(Dollars in Millions)**

| | 2023 | 2024 | 2025 | 2026 | **Total** |
|---|---|---|---|---|---|
| FLISR and FLP | $0.06 | $0.09 | $0.10 | $0.02 | $0.27 |

**Q. What is included in the Capital Support cost category and how were these costs estimated?**

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching operations necessary to safely install new equipment. SPS used actual, average installation times to develop these cost estimates.

**Q. What is included in the On-Going Asset/Device Support cost category and how were these costs estimated?**

A. This category includes labor and repairs to maintain assets in good working order. SPS estimated the annual support costs by multiplying per-unit support cost estimates by the quantity of devices in service each year.

**Q. What is included in the Component Replacement cost category and how were these costs estimated?**

A. This category includes material and labor to replace batteries for certain devices on a five-year schedule. SPS estimated these costs by multiplying per-unit replacement cost by the quantity of devices expected to need battery replacement each year.

**Q. What is included in the On-Going Communications Network Cost Category and how were these costs estimated?**

A. This category includes costs to maintain communications to the field devices. SPS estimated these costs based on historical time to troubleshoot device communication issues and an estimate of the quantity of devices which typically have required such maintenance.

**Q. What is included in the Training Cost category and how were these costs estimated?**

A. This category includes training costs for the FLISR project. SPS estimated these costs based on the labor costs of the employees requiring FLISR training (control center, engineering, line crews, etc.) and the time required to train them.

### 3. Distribution's Contingency for FLISR

**Q. Does Distribution's capital forecast for FLISR include contingency?**

A. Distribution's FLISR capital forecast for the period 2023-2026 includes a contingency of five percent. This smaller contingency percentage is considered adequate because the cost projections for FLISR devices and installation were developed based on historical costs and should be a fairly accurate estimates of actual costs.

**Q. In summary, why are the Distribution Business Area's FLISR costs just and reasonable?**

A. Customers expect reliable power from their utility and the need for higher reliability has never been greater. The current pandemic has emphasized our increased dependency on high reliability throughout the service territory – even in remote areas as more people are working from home. Commercial and Industrial customers are more reliant on processes, equipment and cloud computing that require higher degree of electric reliability as well. The implementation of FLISR will enhance the reliability of SPS's system and target areas that historically have experienced a higher number of outages. Enhancing the reliability of SPS's system will not only improve reliability for existing customers but can be important for attracting industries that require higher reliability to New Mexico, which in turn can bring jobs and economic development.

## C. Distribution's Costs for FAN

### 1. Distribution's Capital Costs for FAN

**Q. Was the Distribution Business Area primarily responsible for developing the forecast for FAN?**

A. As discussed above, the work that Distribution will be performing to support the implementation of FAN is limited to the procurement and installation of pole-mounted FAN devices.

**Q. What is the projected capital investment for FAN?**

A. Table CSN-11below provides a breakdown of Distribution's capital additions forecasts for FAN for 2023 through 2026.

**Table CSN-11**
**FAN Distribution - Capital Additions**
**(New Mexico Retail)**
**(Dollars in Millions)**

| | 2023 | 2024 | 2025 | 2026 | **Total** |
|---|---|---|---|---|---|
| FAN | $4.78 | $2.17 | $0.17 | $0.00 | $7.12 |

**Q. What are the primary components of Distribution's capital forecast for the FAN?**

A. The primary components of the Distribution Business Area's capital forecast for the FAN are (1) make ready work (labor and hardware) and (2) FAN device hardware and installation (labor and hardware).

**Q. How did Distribution develop these capital cost estimates for FAN?**

A. The capital cost estimates are based on a detailed network design performed by Itron and reviewed and approved by SPS. The purpose of this is to determine the location and number of access points and repeaters that would be required to facilitate a reliable FAN communication network for the AMI meter and the distribution automation devices.

**Q. What was the next step in developing the capital cost estimates?**

A. After determining the number of devices, the price for each device was derived from prices included in contracts that resulted from several RFP processes as described by Mr. Remington. The labor costs to install each device are based on a combination of materials, contractor, and internal labor.

**Q. How did Distribution determine the labor costs for the installation of the FAN devices?**

A. Distribution based the labor estimates on prior experience with installing FAN devices in other Xcel Energy jurisdictions.

**Q. Have the capital costs for FAN been updated since SPS's initial GMR filing?**

A. Yes. The capital costs in the SPS's initial GMR filing were based on a preliminary network design or what was described earlier as Phase I and the current capital costs are based on a more detailed network design or what was described as Phase II.

### 2. Distribution's O&M Cost for FAN

**Q. What are the projected O&M costs for FAN?**

A. Table CSN-12 below provides a breakdown of Distribution's O&M expense forecast for FAN for 2023 through 2026.

**Table CSN-12**
**FAN Distribution – O&M Expenses**
**(New Mexico Retail)**
**(Totals in Millions)**

| | 2023 | 2024 | 2025 | 2026 | **Total** |
|---|---|---|---|---|---|
| FAN | $0.05 | $0.03 | $0.01 | $0.00 | $0.09 |

**Q. What are the primary components of Distribution's O&M costs for FAN?**

A. The FAN's O&M costs will include outside vendor contracts, employee expenses, and contract labor. All internal labor costs have been excluded as they are reflected in base rates. These expenses relate to costs for infrastructure and hardware, operations (including equipment and personnel), and preparation costs. These costs include the field level support for fixing broken and damaged equipment, additional personnel to monitor and manage the FAN, other preparation work that is designated as O&M, hardware and software maintenance, and training. Personnel will include both SPS employees and contractors, which will be used based on workload, location, and timing. Most incremental work will be performed by contractors.

**Q. How did Distribution determine the O&M costs for FAN?**

A. The projected costs associated with project employees are based on typical SPS wages, and contractor costs are costs of contractors at estimated wage scales. The costs to fix and replace broken and damaged equipment are based on expected failure and damage rates for these devices.

### 3. Distribution Contingency for FAN

**Q. Does Distribution's capital forecast for FAN include contingency?**

A. Yes there is a contingency amount included in Distribution's FAN costs due to the steps that need to be taken to ensure a reliable communication network from the current state, which is expected to vary as SPS deploys FAN across the New Mexico geographic terrain.

**Q. In summary, why are the Distribution FAN costs just and reasonable?**

A. The FAN enables the grid modernization devices and components to communicate with each other in a safe, secure, and reliable way. This communication is essential to harnessing the benefits of the grid modernization initiative in that it allows greater visibility into the customer experience at the edge of the grid. The Distribution components and their installation, as described above, are necessary to implement FAN and the Distribution forecast is reasonable.

## X. CUSTOMER EDUCATION AND OUTREACH

**Q. What is the purpose of this section of your testimony?**

A. In this section of my testimony, I will discuss SPS's plan to communicate with customers regarding the implementation and benefits of the Grid Modernization components.

**Q. Is SPS planning to educate customers regarding the ability to opt out of an advanced meter?**

A. Yes. SPS proposes to align its customer education regarding AMI opt-out with its overall Plan to educate customers regarding AMI.

**Q. Has SPS developed a Customer Education Plan?**

A. Yes. SPS has created a Customer Education Plan ("Plan") to educate customers on grid modernization and the associated products and services. A copy of the Plan is provided as Attachment CSN-5 to my direct testimony.

**Q. How does SPS plan to reach customers regarding the Plan?**

A. There are three phases to the Plan strategy included in Attachment CSN-5. The first phase includes raising awareness through an introductory and wide-reaching effort to inform customers about AMI meter installations and educate them on the overall benefits of grid modernization. The second phase will support successful AMI meter installations by sending notification materials to customers prior to the installation of their AMI meter. The third phase involves customer engagement, which will continue post-AMI meter installation so that customers can take full advantage of the AMI features and opportunities to save money. The strategies will be executed across multiple communications channels including, but not limited to, website updates, stakeholder outreach meetings, media outreach, social media, blogs, direct mail, e-mail, outbound calls, door hangers, community events, bill onserts, targeted advertising, fact sheets, video, and customer testimonials. It is important to use a diverse set of communications channels to reach customers in their preferred manner as SPS customers have different preferences for their preferred communication.

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**Q. Has SPS previously utilized these strategies?**

A. Yes, these strategies have been used in a variety of communications plans for introducing new programs or initiatives, including Energy Efficiency programs. Each communications strategy is different and based on the unique challenges and specifics of each plan's objectives.

**Q. Why are the strategies SPS is proposing effective for educating customers?**

A. These strategies are effective for educating customers because they provide information over a period of time, and each phase builds upon the previous one. Phases I through III gradually increase the complexity of information being provided to customers, and each will be adjusted based on customer feedback as time progresses. These strategies use almost every possible communications channel so that each customer can be reached through the channel that they prefer (e.g., email, direct mail, bill onserts, etc.).

**Q. What are the relative timelines for launching each customer education phase?**

A. The timelines for each phase are included in Table CSN-13 as follows: Phase I – Raising Awareness would take place from Q2 2023 to Q3 2024; Phase II – Supporting Meter Installation would happen from Q3 2023 to Q4 2024; Phase III – Customer Engagement would take place from Q1 2024 to Q4 2024. For example, customers receiving their meter in the fourth quarter of 2023 would see a bill onsert 90 days prior (July of 2023) to meter install, a postcard 60 days prior (August of 2023) to meter install, and a letter or e-mail 30 days (September of 2023) prior to meter install. There will also be mass communications supporting advanced meter installation. These communications will commence at the beginning of 2023.

**Table CSN-13: Customer Education Timeline**

| Phase | Event | Timing |
|---|---|---|
| I | Raise awareness | Q2 2023 – Q3 2024 |
| II | Informing meter installation | Q3 2023 – Q4 2024 |
| III | Customer engagement | Q1 2024 – Q4 2024 |

This is in conjunction with the planned timing for AMI meter installations commencing in the fourth quarter of 2023.

**Q. Can you describe in more detail the communication plan to customers prior to the installation of an AMI meter?**

A. Yes. The Plan includes a high-level 90-day communication with a bill onsert, a follow up with the 60-day postcard via mail, followed by a 30-day letter. The 30-day communication may be delivered as an email or a mailed letter, depending on the customer's communication preferences. Each customer will receive a pre-installation outbound call alerting them of a timeframe window when the installation of their AMI meter will take place. Two types of door hangers will be left upon meter installation : "Meter Installed" door hanger or "Sorry We Missed You" door hanger. If we were unable to install a meter, the door hanger will provide a reason and, information to re-schedule the installation. This approach, including the other tactics proposed as part of the Plan, is based on best practices from other utilities, such as Commonwealth Edison ("ComEd") in Chicago and Entergy located in multiple states. ComEd has successfully installed over four million advanced meters in the Chicago metro area, and Entergy is in the process of its advanced meter deployment in Arkansas. There are also several other communications tactics that will be used, which can be found in Attachment CSN-5.

**Q. Will SPS's communications plan aim to fully educate customers regarding AMI technology?**

A. Yes. When customers are about to receive an advanced meter, they will receive several types of communications over time leading up to the meter installation. They will also be informed as to the terms of advanced meter opt-out, described further in the next section of my testimony. There is a great deal of information for customers to process in the same time period, making clarity and simplicity critical.

## XI. OPT-OUT LOGISTICS AND COMMUNICATIONS

**Q. Please describe the extent to which customers will be able to opt-out of receiving an AMI meter.**

A. SPS will provide Residential and Small Commercial customers the opportunity to opt-out of receiving an AMI meter. These customers can also request to have their AMI meter removed after installation. I will describe the costs of customers opting out in more detail below.

**Q. Will customers who opt-out receive a new meter?**

A. Yes. The customers who opt-out will receive a non-communicating interval data meter, also referred to as an opt-out meter, instead of receiving an AMI meter. The non-communicating meter will have more limited capabilities in part since it will not be able to communicate; however, it will still provide interval data that supports billing functions, customer access to interval data through the customer portal, and will support more advanced rates such as time of use rates.

**Q. How will customers opt-out of an AMI Meter?**

A. Customers will have the opportunity to opt-out of an AMI meter by calling or emailing SPS's Customer Service department, in a similar process as shown at the bottom of Attachment CSN-5.

**Q. When can customers opt-out of an AMI Meter?**

A. Customers can opt-out of their AMI meter as soon as the opt-out policy is approved by the Commission and even after the AMI meter has been installed. If the opt-out is requested after the AMI meter has been installed, in addition to the one-time fee, a meter exchange cost will be charged to the customer.

**Q. Can customers opt-out of an AMI Meter when an installer is there to install the meter?**

A. No. Customers need to verify their opt-out choice in writing via email or on a recorded call with SPS's Customer Service department to accept the charges associated with opt out. If a customer asks a meter installer to opt-out when the meter installer is on-site to install the AMI meter, the meter installer will provide information to the customer on how to opt-out and the customer will have to directly contact SPS's Customer Service department by telephone or email. A meter installer does not have the ability to opt-out a customer on-site.

**Q. Please describe the frequency of communications informing customers directly of the option to opt-out?**

A. Customers will be directly informed of the option to opt-out on three separate occasions to meter installation: at 90-, 60-, and 30-day intervals prior to installation as described in the Plan.

**Q. How will customers be educated on AMI meter opt-out?**

A. Starting with the 90-day bill onsert, customers will have access to online information regarding opt-out costs and instructions on SPS's website. Both the 60-day and 30-day communications will direct customers to information sources, as well as provide the telephone number and email address to request an opt-out with SPS's Customer Service department. Attachment CSN-5 outlines this information in greater detail. FAQ's will be updated with opt-out costs and instructions, including examples for different scenarios for customer convenience (i.e. opting out before installation, opting out after installation, opting out and then moving, etc.).

**Q. What other communications channels will provide customer education concerning Advanced Meter opt-out?**

A. In addition to direct customer communications, opt-out information will be available primarily on SPS's website and in FAQ's. Overall information on opting out will also be included in information provided at stakeholder outreach and community meetings which are outlined in greater detail in Attachment CSN-5. Customer service agents will receive the requisite training to handle customer opt-outs.

**Q. Will SPS conduct any communications to mitigate the number of customers who opt-out?**

A. Yes. SPS has already developed preliminary materials to address these primary concerns including radio frequency (RF) and privacy concerns, including FAQ's[8]. These materials will continue to be built upon in 2023 leading up to direct communications to include additional web and video content.

In addition, messaging concerning the overall customer benefits of the AMI technology will be promoted to customers directly as well as through mass market communications channels as detailed in Attachment CSN-5. Call center agents will also be equipped with messaging to help customers understand the

[8] www.xcelenergy.com/SmartMeter

facts of RF if this is the reason the customer is opting out. This messaging will be shared when the customer calls to request an opt-out.

**Q. How many customers are expected to opt-out?**

A. Based on the experience of Xcel Energy and the experience of other utilities who have deployed AMI meters, the opt-out rate is expeted to be a very small number of customers. The opt-out rate costs are based on an estimated opt-out rate of 0.5 percent.

**Q. Can you describe the costs to customers who opt-out?**

A. Yes. The opt-out costs include a one-time fee and a recurring monthly fee. The one-time fee will recover the incremental costs for an opt-out program that include the IT costs to setup the opt-process and billing and the administrative costs to support the opt-out process. In addition, the one-time fee includes the costs for replacing the opt-out meter with an AMI meter once the customer vacates the premise in the future, which includes the cost for a trip charge for the meter exchange and the cost of the opt-out meter that was part of the initial installation.

For customers who opt-out prior to receving an AMI meter, the proposed one-time fee is approximately $200. For customers who opt-out after receiving an AMI meter, an additional trip charge will be included and the total one-time fee will be approximately $250.

In addition, the opt-out costs include a recurring monthly fee for manual reading services that will be needed to support billing for opt-out meters. The proposed recurring monthly fee for customers that opt-out is $21.14.

**Q. Does this conclude your pre-filed direct testimony?**

A. Yes.

**BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

| | | |
|---|---|---|
| **IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF,**<br><br>**SOUTHWESTERN PUBLIC SERVICE COMPANY,**<br><br>**APPLICANT.** | )<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>) | **Case No. 22-00 178 -UT** |

## VERIFICATION

On this day, July 1, 2022, I, Chad S. Nickell, swear and affirm under penalty of perjury under the law of the State of New Mexico, that my testimony contained in Direct Testimony of Chad S. Nickell is true and correct.

*/s/ Chad S. Nickell*
**Chad S. Nickell**

COMMERCE DEPARTMENT

September 30, 2021

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E999/CI-20-800, Docket No. E002/M-19-685

Dear Mr. Seuffert:

On April 30, 2021, the Minnesota Department of Commerce's (Department) consultant, Synapse Energy Economics, Inc. (Synapse), provided a report entitled *Hosting Capacity Analysis and Distribution Grid Data Security* (Report). The Report offers recommendations on Xcel's hosting capacity analysis and distribution grid data security, in response to both the Minnesota Public Utilities Commission's (Commission) July 31, 2020 Order in Docket No. E002/M-19-685 and to the Commission's Notice issued in the Commission Investigation on Grid and Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data in Docket No. E999/CI-20-800.

On June 7, 2021, the Department and Synapse submitted an Addendum to the Report (Addendum). The Addendum made various corrections to the Report.

Attached to this letter is a final version of the Report that includes the corrections detailed in the Addendum. Both the Department and Synapse are available to answer any questions that the Commission may have in this matter.

Sincerely,

/s/ MATTHEW LANDI
Rates Analyst

ML/ja
Attachment

85 7th Place East - Suite 280 - Saint Paul, MN 55101 | P: 651-539-1500 | F: 651-539-1547
mn.gov/commerce


Exhibit 3

# Hosting Capacity Analysis and Distribution Grid Data Security

(MPUC Docket Nos. E999/CI-20-800 and E002/M-19-685)

**Prepared for Minnesota Department of Commerce**

September 30, 2021

Prepared by:

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## Acknowledgements

Synapse would like to thank Professor Emeritus Vicki Bier, of the University of Wisconsin Madison, and Associate Professor Tony Cox, of the University of Colorado Denver, for providing their time, guidance, and feedback on the application of the Risk-Benefit Framework. Any opinions, findings, and conclusions or recommendations expressed in this publication are those of the authors and do not necessarily reflect the views of Professors Bier and Cox.

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# Executive Summary

The Minnesota Department of Commerce, Division of Energy Resources (Department) retained Synapse Energy Economics, Inc. (Synapse) in 2021 to support its exploration of privacy and security issues related to Minnesota utilities' hosting capacity analyses (HCA) and distribution grid data. As with other jurisdictions looking ahead to grid transformation, Minnesota seeks to balance the data access needed to support distributed energy resource (DER) uptake with maintaining a secure grid that protects the privacy of customers.

Utilities develop hosting capacity maps to support market-driven, DER deployment. The maps provide an early indicator to project developers seeking areas within the utility service territory where DER additions may contribute the greatest value. By signaling these locations, utilities reduce the possibility of developers having to pay high system upgrade costs to interconnect DERs. However, the amount of system data displayed in hosting capacity maps varies across states. Utilities must balance the need to share this information for the benefit of the public with the potential for grid and customer security threats from bad actors, who could potentially use this same information to launch an attack.

Synapse provided technical support at two stakeholder workshops hosted by the Department as part of the Minnesota Public Utilities Commission's Docket No. E999/CI-20-800. The topic of the first workshop was costs/risks and benefits of public access to grid data, and the topic of the second workshop was sensitive information sharing and classification. Based in part on these workshops, Synapse developed its assessment of the current state of the industry as well as recommendations to guide Minnesota as it continues its dialogue. Specifically, Synapse focused on:

1. the privacy and security implications of Xcel Energy's HCA report and public-facing map; and
2. the privacy and security implications of public display or access to electric distribution grid data.

Below, we provide our recommendations and then summarize our assessment. Recommendations here are not meant to comment on the appropriateness of the 15/15 standard as it relates to the Commission's ongoing proceedings in the following two dockets: the Commission's Inquiry into Privacy Policies of Rate-Regulated Energy Utilities (Docket No. E, G-999/CI-12-1344) (Docket 12-1344), and a Petition by Citizens Utility Board of Minnesota (CUB) to Adopt Open Data Access Standards (Docket No. E, G-999/M-19-505) (Docket 19-505).

<u>Synapse Recommendations</u>

As a result of Synapse's findings, we recommend the Commission take the following short-term actions:

- Allow Xcel to only redact load data when a feeder violates the 15/15 aggregation standard and require Xcel to publish on its map, and in its tabular spreadsheet, all other HCA data.

- Require Xcel to create a transparent process for third parties to access Critical Electric Infrastructure Information (CEII), on a "need-to-know" basis, with appropriate protections (e.g., non-disclosure agreements, or NDAs) in place.

- Allow Xcel to only redact feeders included in the HCA if they satisfy one or more of the following criteria: (1) connected to a dedicated customer or (2) connected to critical infrastructure or serve a critical customer.

- Require Xcel to provide more detailed rationale (e.g., beyond "security concern") for not publishing feeder and substation capacities.

In the long term, we recommend the Commission take the following actions:

- Require Xcel to provide an unblurred HCA map showing its distribution feeders, behind a verified web login portal that is open to the public (i.e., does not require an NDA).

- Encourage Xcel to consider a tiered-access approach that helps streamline access to non-public grid data and does not make requirements unnecessarily burdensome.

- Encourage Xcel to engage in a transparent, Risk-Benefit/Cost-Benefit Framework stakeholder process to help determine whether specific, sensitive grid data should be published on its HCA map, and how secure access to sensitive grid data (deemed non-public) should be provided.

- Require Xcel to estimate the level of effort and cost to incorporate each specific piece of data in the Pre-Application Report that is currently excluded from the HCA map due to technology requirements (e.g., querying and search functionality) rather than security concerns (e.g., distance from site to substation).

These recommendations should help to balance the grid and customer security concerns and data access requirements of all parties involved.

Hosting Capacity Use Cases

"Hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system on a given circuit without adversely impacting power quality or reliability and without requiring infrastructure upgrades. There are three primary applications, or use cases, for an HCA: (1) to support market-driven DER deployment by enabling developers to identify technically suitable and potentially lower-cost interconnection locations; (2) to assist with streamlining DER interconnections by improving or automating parts of the technical screening process; and (3) to enable more robust, long-term distribution system planning, providing visibility into how much DER the grid can host in future years, by identifying potential system constraints and proactive upgrades. Table ES-1 provides more details on these use cases. This report will focus on the first two use cases, using HCA maps as a (1) development guide and (2) to augment or replace interconnection technical screens (e.g., to replace the Pre-Application Report).

**Table ES-1. Hosting Capacity Use Cases**

| | Objective | Capability | Challenges |
|---|---|---|---|
| **Development Guide** | Support market-driven DER deployment | Identify areas with potentially lower interconnection costs | Security concerns; analysis/model refresh; data accuracy and availability |
| **Technical Screens** | Improve the interconnection screening process | Augment or replace rules of thumb; determine need for detailed study | Data granularity; benchmarking and validation to detailed studies |
| **Distribution Planning Tool** | Enable greater DER integration | Identify potential future constraints and proactive upgrades | Higher input data requirements; granular load and DER forecasts |

*Source*: *U.S. DOE, Office of Electricity, Integrated Distribution Planning - Utility Practices in Hosting Capacity Analysis and Locational Value Assessment, 2018, p.3.*

Protection of Sensitive Energy Information and Customer Confidentiality

Critical data is data which must be removed from the public domain to maintain its security. This may include energy information pertaining to critical customer groups or critical infrastructure. U.S. utilities are taking measures to protect customer privacy using aggregation standards and Critical Energy/Electric Infrastructure Information (CEII) criteria.

As defined by the Commission, the purpose of protecting Customer Energy Use Data (CEUD) is to prevent third parties from accessing the energy-use patterns of a specific customer and data that reveals commercially sensitive information. Regarding critical infrastructure, several federal agencies have provided guidance and regulations. At the national level, the Cybersecurity & Infrastructure Security Agency (CISA) of the Department of Homeland Security (DHS) has identified 16 critical infrastructure sectors that it considers vital to U.S. security, national economic security, and national public health or safety. The energy sector is uniquely critical because it provides an “enabling function” across all critical infrastructure sectors.

To align with protecting critical infrastructure sectors, as identified by DHS, Xcel identified customers and their associated feeder(s) that, in its judgement, would warrant protection based on the criticality of the loads they serve. These critical customers fell into the following categories:

- Critical Energy Infrastructure (similar to DHS Energy sector);
- Critical Hospitals - Level 1 or 2 Trauma Centers (similar to DHS Healthcare and Public Health sector);
- Critical Data Centers (similar to DHS Communications and Information Technology sectors); and
- Critical Public Gathering Center (similar to DHS Commercial Facilities sector).

Grid Security

There are three main categories of electric system vulnerabilities which can result in the disruption of the grid's power supply. These are physical security, cybersecurity, and personnel vulnerabilities. This report only focuses on physical and cybersecurity vulnerabilities.

Physical attacks on distribution transformers, circuits (e.g., feeders), protective devices, and other distribution system assets could impact the electricity supply to critical local customers like hospitals. For governing distribution systems, over which states have authority, there are no mandatory federal standards such as the North American Electric Reliability Corporation CIP standards that apply to the bulk power system. Thus, there are varying standards of protection for distribution systems.

A recent U.S. Government Accountability Office (GAO) report for the Department of Energy (DOE) on distribution grid cybersecurity notes that U.S distribution systems are increasingly at risk from cyberattacks. As a result, threat actors can use multiple techniques to access those systems and potentially disrupt operations. However, the scale of the potential impacts of such cyberattacks on the grid's distribution systems is unclear. The GAO report states that none of the cybersecurity incidents reported in the United States have disrupted the reliability or availability of the grid's distribution systems.

Grid and Customer Security and Customer Confidentiality Discussion

The Commission's July 31, 2020 Order required Xcel to further discuss grid and customer security issues related to the public display or access to grid data, including distribution grid mapping, aggregated load data, and critical infrastructure in a proceeding that includes additional parties, experts, and utilities. It also required Xcel to separately evaluate and justify each privacy and security concern and to provide a full description and specific basis for withholding any information in its 2020 HCA.

Xcel provided comments in its 2020 HCA on the main grid and customer security and confidentiality issues related to the public display or access to grid data. This included distribution grid mapping, aggregated and peak load data, and critical infrastructure. To address these concerns, Xcel continues to: (1) remove certain feeders from the heat map to protect critical infrastructure; (2) protect customer privacy by applying the 15/15 standard; (3) treat the peak substation transformer load and peak feeder load data as non-public in the Tabular Results; and (4) blur exact feeder lines in the heat map.

We discuss each of these security and confidentiality controls in turn.

| **Xcel uses 15/15 Standard to Redact Feeder from HCA Map** | |
|---|---|
| **Xcel's Justification** | **Synapse Recommendation** |
| Publicly disclosing feeders which violate the 15/15 standard could compromise customer confidentiality. | Only load information should be redacted from the feeder when the 15/15 standard is violated. |

The Commission should allow Xcel to only redact load data and require it to publish all other HCA data on its map when the application of the 15/15 standard calls for the redaction of CEUD to protect customer privacy. This recommendation is based on stakeholder requests to have HCA results and non-CEUD information made available on the HCA map under such circumstances, how other electric utilities appropriately balance providing HCA results and feeder locations while not revealing customer privacy (e.g., redact only feeder load profile) on their maps when similarly applying the 15/15 standard, and Xcel's prerogative to redact feeders from its map that violate CEII and critical customer group screens.

| Peak Substation Transformer & Peak Feeder Load Confidential | |
|---|---|
| **Xcel's Justification** | **Synapse Recommendation** |
| Load is security information. Publishing this information could aid bad actors in planning a serious attack. It could also compromise the privacy or confidentiality interests of large or critical infrastructure customers. | Apply a Risk-Benefit Framework (Section 4.2) to weigh risk vs. public benefit of publishing information. |

There are competing claims about the value of this information to DER developers and the risks associated with publicly providing it. A Risk-Benefit Framework, as proposed in Section 4.2, should be applied to help determine whether substation and feeder peak loads should be publicly provided as requested by the Commission. This framework will help to weigh the need for this information by a diverse group of DER developers (e.g., storage, electric vehicle, and solar) against the customer and grid security risks of publishing it.

| Xcel Redacts Feeders to Protect Critical Infrastructure Sectors | |
|---|---|
| **Xcel's Justification** | **Synapse Recommendation** |
| Feeders are not shown on HCA Map to align with protecting critical infrastructure sectors. | • Create a transparent process on how third parties can access CEII. |

Given the importance of protecting critical infrastructure and customer groups, Xcel's approach of excluding a feeder from its HCA map when it is connected to critical infrastructure, as defined according to its five critical infrastructure categories, seems reasonable. However, to increase the transparency of the process with the public, Xcel should specify in greater detail the types of customers that are considered critical, grid-dependent customers, which fall outside of its five critical infrastructure categories. Xcel should also create a transparent process for how third parties can access CEII, on a "need-to-know" basis, with appropriate protections (e.g., an NDA) in place.

| Public Display of Distribution Lines on HCA Map | |
|---|---|
| **Xcel's Justification** | **Synapse Recommendation** |
| An unblurred HCA map would make the grid unnecessarily vulnerable to attack and would jeopardize customer security and confidentiality. | Xcel should unblur its HCA map because:<br>• Hosting capacity maps generally show feeder lines.<br>• Knowing the distribution line locations provides significant value to DER developers.<br>• Location of information on distribution facilities is likely already in the public domain.<br>• Various tools are available to help map distribution lines.<br>• A bad actor can conduct reconnaissance by visual observation of distribution line connections.<br>• Focusing on strengthening the grid's physical and cybersecurity defenses, and increasing grid resiliency, is more effective at deterring attackers than concealing information.<br>• Distribution systems are generally lower value targets relative to transmission systems. |

In general, publicly available hosting capacity maps of U.S. electric utilities leading in this space show the distribution system feeder lines at increasingly granular levels of detail (e.g., sub-feeder level). Xcel provides hosting capacity results at the sub-feeder level, but this granularity is lost because the actual feeders are blurred on Xcel's hosting capacity map. Hosting capacity maps should be sufficiently detailed to be useful to stakeholders. There is significant benefit to developers of knowing the locations of distribution lines to optimally site DERs. Xcel frequently gets requests from its developer community to show its feeder lines on the HCA map, and in a recent developer survey, all the participants said that Xcel's current HCA map requires more detailed information to be useful.

Detailed maps of the U.S. power system were once readily available in the public domain and on the Internet and many can still be found. Bad actors could also use publicly available resources such as Google Earth to map distribution lines, or they could simply locate a critical facility and visually trace the power lines emanating in either direction to plan an attack. Rather than focusing on concealing grid data on the locations of feeders and substations, the utility should focus on bolstering its physical and cybersecurity defenses in case of an attack, and on enhancing the reliability and resiliency of the grid. Doing so could deter would-be adversaries from attacking by reducing or removing the perceived benefits that an adversary associates with an attack. Additionally, investments in measures aimed at limiting or denying adversary success serve a broader purpose of improving mission resilience to power disruptions resulting from natural disasters, operator error, or equipment failures.

HCA Integration with Pre-Application Report

Xcel should clearly justify the security concerns it has regarding revealing substation and feeder thermal capacities given the tangible benefits to DER developers of having that information. A Risk-Benefit Framework could assist in balancing the risks of publishing substation and feeder capacities and peak loads against the public benefits.

Frameworks for Assessing Inclusion of Grid Data in HCA Map

*Risk-Benefit Framework*

The Risk-Benefit Framework is used to semi-quantitatively determine the risk to a critical asset (e.g., substation) due to revealing sensitive information about it (e.g., on an HCA map) over a one-year period. It helps estimate the probability of an attack and the resulting consequence if the attack were successful. Based on the expected value of the risk, it can be categorized as a low, moderate, or significant risk. The risk level for each critical asset evaluated would then be compared to the value of revealing information about the same asset to the public.

*Cost-Benefit Framework*

The Cost-Benefit Framework could be used to compare the costs and benefits to the public/ratepayer of publicly revealing specific grid information. The benefits would include the incremental customer and societal benefits of making the information public and the costs would include the costs to the utility of providing this information and of defending against a better-informed attack. A net public benefit would inform whether the specific grid information would be made public.

*Deciding Which Framework to Apply*

In general, the Risk-Benefit Framework should be applied first to determine the overall level of risk to an asset from revealing information about it. The Cost-Benefit Framework can supplement it, adding more details about the actual cost of providing the information when there is an incremental labor cost to doing so (e.g., HCA map enhancements such as formulas and search functionality). If there is no risk involved with providing specific information, then the Cost-Benefit Framework should be used instead since it primarily focuses on weighing the economic costs versus the benefits.

*Framework Limitations*

Every framework or model has its limitations, and it is important to acknowledge them. However, it is unacceptable to state that there are myriad undefined threats or attack vectors that exist, and consequently, no sensitive grid information should be revealed on an HCA map. Using a risk-based framework helps stakeholders gain a shared understanding of the information under consideration and to discuss risk more tangibly.

Models for Information Sharing

There are different approaches for sharing grid information with third parties. Utilities in different states share grid data in a variety of ways, including through their HCA maps and interconnection processes. A tiered-access approach is one way to selectively share sensitive data on a "need-to-know" basis. A web portal with different levels of access is one way to implement this approach. Investor-owned utilities in Minnesota, New York, New Hampshire, and California either use, or plan to use, a tiered-access framework to effectively share data with third parties. Xcel should consider using a tiered-access approach to share additional HCA information with the public.

# 1. Introduction

In this era of electric utility transition, utilities will be responsible for optimizing all cost-effective energy resources, regardless of size or ownership. Hosting capacity maps can be used by utilities to support market-driven distributed energy resource (DER) deployment. These maps provide early indicators to project developers looking to identify areas within the utility service territory where DER additions may contribute the greatest value and/or cause the least negative impact to the operation of the grid. By signaling these locations, utilities facilitate the optimization of DER deployment. Hosting capacity maps can also help the utility streamline its DER interconnection process, thereby reducing an expense and barrier to DER deployment. Utility approaches for implementing hosting capacity maps vary from static maps of constrained areas with limited system data to dynamic maps that provide additional system data at each location. The amount of system data displayed in hosting capacity maps varies. It depends upon the balance each state's regulatory framework has established between the utility's grid security concerns around making data public and the public interest benefits of advancing a flexible, reliable, and resilient grid through cost-effective DER deployment. Examples of potentially sensitive data include the location of sensitive loads and critical energy infrastructure.

## 1.1. Background

On July 31, 2020, the Minnesota Public Utilities Commission (Commission) issued its Order in Docket No. E002/M-19-685. Among other things, the order requested that the Commissioner of Commerce seek authority from the Commissioner of Management and Budget to incur costs for specialty services to (a) provide a recommendation on privacy and security in the next hosting capacity report proceeding and (b) participate in related analysis and stakeholder engagement. The Commission requested further development of issues surrounding customer privacy and system security in the context of Northern States Power Company's (d/b/a Xcel Energy) hosting capacity map and whether its 2020 Hosting Capacity Analysis (HCA) report complied with the Commission's directives in its orders in Docket Nos. E002/M-18-684 and E002/M-19-685. On October 30, 2020, the Commission opened a Commission Investigation proceeding related to grid and customer security issues in Docket No. E999/CI-20-800.

In February 2021, the Minnesota Department of Commerce, Division of Energy Resources (Department) retained Synapse Energy Economics, Inc. (Synapse) to provide technical expertise for regulatory proceedings before the Commission on issues related to:

1. the privacy and security implications of Xcel Energy's HCA report and public-facing map; and
2. the privacy and security implications of public display or access to electric distribution grid data.

## 1.2. Report Overview

This report provides insight regarding distribution grid and customer security as it pertains to sharing sensitive information on hosting capacity maps. It focuses on the current state of the industry and provides recommendations to help guide the ongoing discussion on HCA and distribution grid data security in Minnesota.

Hosting capacity maps are useful information-sharing tools for different stakeholders that need access to distribution grid data. However, balancing the public benefits associated with sharing specific types of sensitive grid data with the corresponding risks can be challenging. This report reviews grid data security and related customer energy use privacy practices and standards in the United States. We draw from these best practices to provide a recommendation based on our findings in the context of the state of Minnesota. Moreover, the report investigates the application of risk- and cost-based frameworks for determining a path forward for securely sharing sensitive hosting capacity map data for the public good in Minnesota.

A summary of each chapter of the report is as follows:

- Chapter 1 provides background on the Commission-ordered proceedings related to Docket No. E002/M-19-685. It also gives an overview of the report and discusses the two workshops that helped inform the study.

- Chapter 2 highlights the various applications of hosting capacity maps and discusses how several states are using them to accelerate DER deployment and to help modernize the grid.

- Chapter 3 provides an in-depth review of the types of sensitive information, motivations for and methods to protect this information. It assesses the current industry standards for sharing distribution system information. The chapter specifically discusses customer energy use data and critical energy infrastructure information in the context of hosting capacity, reviews grid security vulnerabilities and threats, and offers examples of how to balance the risks with the public benefits of publishing distribution system data. Finally, it applies these findings to Minnesota to inform the final recommendations.

- Chapter 4 discusses two frameworks that can be used to compare the incremental benefit and risk/cost of releasing specific grid data. It first describes and evaluates the Risk-Benefit Framework, which can be used to measure and compare the risks and benefits of incremental data release. It then offers the Cost-Benefit Framework, which is a systematic approach for comparing the costs and benefits of alternative options. Electric utilities use both methods to optimize internal resource investment decisions and to justify these decisions to regulators and stakeholders.

- Chapter 5 reviews models for information sharing. After providing an overview of the types of data-sharing models, this chapter benchmarks industry standards and then offers a recommendation for the Commission to consider.

- Chapter 6 provides final recommendations to the Commission.
- Chapter 7 concludes the report and highlights points for future discussion.

In summary, this report examines grid security and customer confidentiality issues as they pertain to hosting capacity maps, develops frameworks and models to implement risk-based sharing of sensitive data, and provides recommendations for application in Minnesota. It surveys industry practices, explains the risks of sharing distribution grid data, and lays out frameworks and models that can be used to measure and expand the usefulness and variety of data shared on hosting capacity maps.

### 1.3. Workshops

Although not required by the Commission's Order, the Department hosted stakeholder workshops on March 17 and March 31 to discuss and better understand issues related to electric distribution system data privacy and security. The topic of the first workshop was costs/risks and benefits of public access to grid data. The topic of the second workshop was sensitive information sharing and classification.

The objectives of the workshops were two-fold:

1. to convene a stakeholder forum to discuss grid security and customer confidentiality issues related to the public display of grid data; and
2. to create a framework to balance (a) grid security and customer privacy concerns associated with public access to grid data with (b) the public interest.

In Workshop 1, national security expert Dr. Paul Stockton[1] presented a statement on behalf of Xcel Energy on grid security risk scenarios and specific attack vectors that adversaries can employ; Xcel Energy presented on its current grid security and resiliency efforts; the Interstate Renewable Energy Council (IREC) presented on the benefits of public access to grid data; and Synapse presented on risk-based classification of data and risk-benefit and cost-benefit frameworks. In preparation for the first workshop, the Department sent a survey to members of the public to better understand the usefulness of Xcel Energy's hosting capacity map and the public benefits of certain grid data for, among other applications, identifying potential project sites for DER interconnection. The survey results informed the workshop discussion. Fifty-two people participated in the first workshop.

In Workshop 2, Synapse expanded on the risk/cost-benefit frameworks discussed in Workshop 1, presented on classification criteria for Critical Electric Infrastructure Information (CEII), discussed hosting capacity map security and confidentiality considerations by comparing utility HCA map practices nationally, and reviewed different models for data sharing. Fifty-four people participated in the second workshop.

[1] Dr. Paul Stockton provides strategic advice to industry and government clients on critical infrastructure resilience and national security. He chairs the Grid Resilience for National Security Subcommittee of the Department of Energy's Electricity Advisor Committee.

There was robust participation from the Minnesota utilities in both workshops but participation from DER developers was limited. While the number of developers attending was sufficient to conduct the workshops, it can be a goal to increase developer participation in future discussions.

The Department posted a written summary of both workshops, including presentation materials, to the Commission's electronic docket filing system. Developers or others that were unable to attend can review these materials.

# 2. Hosting Capacity

## 2.1. Hosting Capacity Use Cases

Hosting capacity refers to the amount of DERs that can be accommodated on the distribution system on a given circuit without adversely impacting power quality or reliability and without requiring infrastructure upgrades.[2] Hosting Capacity Analysis is a useful tool for assessing the locational value of DERs at increasing levels of penetration on the grid. Hosting capacity maps, a visual representation of an HCA, can be used to transparently share information between regulators, developers, electric customers, and utilities. This results in more efficient and economical DER deployment on the grid.[3]

There are three primary applications, or use cases, for an HCA: (1) to support market-driven DER deployment by enabling developers to identify technically suitable and potentially lower-cost interconnection locations; (2) to assist with streamlining DER interconnections by improving or automating parts of the technical screening process; and (3) to enable more robust, long-term distribution system planning, which provides visibility into how much DER the grid can host in future years by identifying potential system constraints and proactive upgrades. Table 1 summarizes the main HCA use cases.

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[2] Electric Power Research Institute (EPRI). 2020. *Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process.* p. 3. https://www.epri.com/research/programs/108271/results/3002020010.

[3] Stanfield, Sky and Stephanie Safdi. 2017. *Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources.* Interstate Renewable Energy Council (IREC). p. 1. https://irecusa.org/wp-content/uploads/2017/12/Optimizing-the-Grid_121517_FINAL.pdf.

**Table 1: Hosting Capacity Use Cases**

| | Objective | Capability | Challenges |
|---|---|---|---|
| **Development Guide** | Support market-driven DER deployment | Identify areas with potentially lower interconnection costs | Security concerns; analysis/model refresh; data accuracy and availability |
| **Technical Screens** | Improve the interconnection screening process | Augment or replace rules of thumb; determine need for detailed study | Data granularity; benchmarking and validation to detailed studies |
| **Distribution Planning Tool** | Enable greater DER integration | Identify potential future constraints and proactive upgrades | Higher input data requirements; granular load and DER forecasts |

*Source: U.S. DOE, Office of Electricity, Integrated Distribution Planning - Utility Practices in Hosting Capacity Analysis and Locational Value Assessment, July 1, 2018, p.3.*

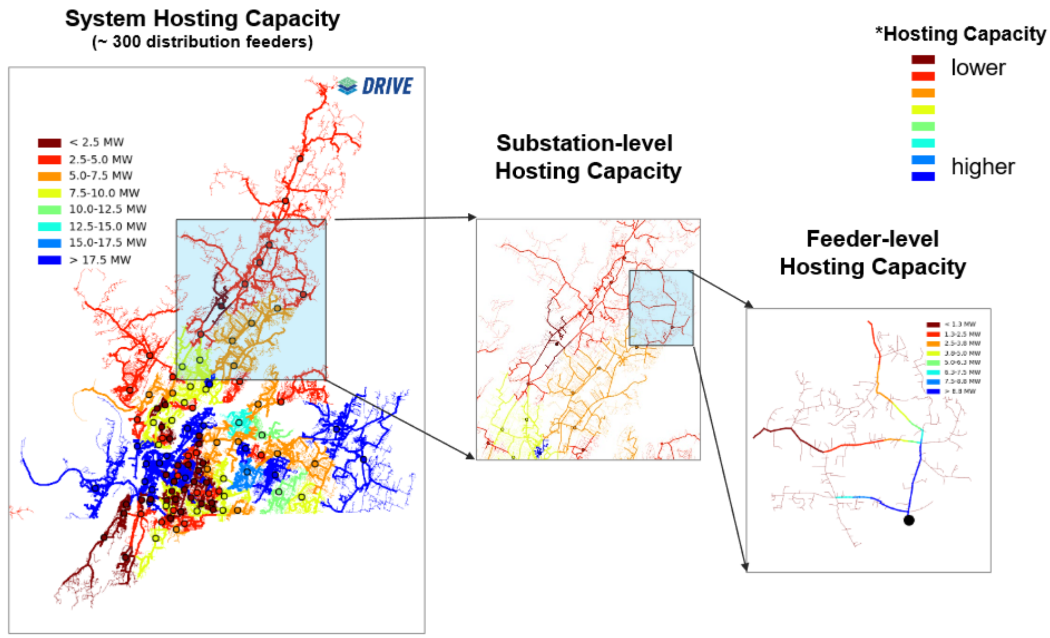
### 2.1.1. Hosting Capacity as a Development Guide

Some utilities are using hosting capacity maps to help energy developers identify optimal locations for interconnecting DERs on the distribution system to minimize project costs. Developers can face considerable uncertainty around the costs of interconnecting DERs.[4] Connecting DERs to capacity-constrained circuits may require system upgrades, resulting in higher interconnection costs and potentially an uneconomical project.

Hosting capacity maps give an indication of how much generation can be added to a circuit or feeder before it reaches its capacity, or other limitations that reduce its ability to reliably serve electric customers. With these insights, developers can identify locations where the circuits have capacity to accommodate additional DERs, without triggering a system upgrade. Figure 1 provides a color-coded illustration of a system's hosting capacity at both the substation and feeder levels. Hosting capacity information can also be provided at the sub-feeder or line segment level. Feeders with lower hosting capacity (e.g., red lines) may require system upgrades to overcome circuit constraints. However, hosting capacity maps only provide a snapshot of the distribution system at a given point in time and are not meant to replace a detailed system interconnection study for a particular site.

[4] U.S. DOE. 2018. *Office of Electricity, Integrated Distribution Planning - Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*. p. 11. https://static1.squarespace.com/static/5b736be575f9eeb993c4d5f1/t/5b8f4055032be49d0ccfd2bf/1536114780361/ICF+DOE+Utility+IDP+FINAL+July+2018+%28003%29.pdf.

**Figure 1: Hosting Capacity Illustration**




*Source: Jeff Smith, Methods, Applications, Opportunities and Challenges, EPRI. MPSC Distribution Planning Stakeholder Meeting, June 27, 2019, p.4.*

Hosting capacity maps generally inform the early stages of DER project development, enabling developers to more efficiently allocate their time and resources to focus on the most promising sites. Providing developers with this high-level distribution system view could also help accelerate the interconnection process by channeling applications to the grid locations where they are most likely to be quickly approved,[5] reducing interconnection queue backlogs, and making more efficient use of utility resources.

### *2.1.2. Hosting Capacity as an Interconnection Technical Screen*

The utility interconnection process is intended to maintain grid safety and reliability, and it determines whether and how a DER can connect to the distribution system.[6] However, ambitious new state and federal policies, growing customer demand, and steadily declining prices are accelerating DER growth and increasing the volume of interconnection applications. Utilities are finding it difficult to keep pace. Thus, it is becoming increasingly important for utilities to carry out interconnection processes efficiently and effectively.[7] Figure 2 shows that an interconnection application must pass through several stages of evaluation before receiving approval.[8] The process often includes a set of technical screens that

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[5] Stanfield, Sky and Stephanie Safdi. 2017. *Optimizing the Grid.* p. 8.

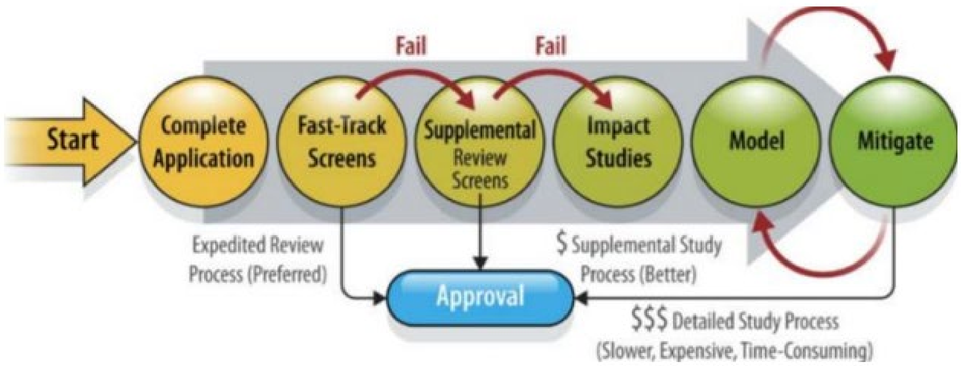
[6] U.S. DOE. 2018. *Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*. p. 16.

[7] Ibid.

[8] Ibid.

evaluate whether the application can receive fast-track status allowing an application to bypass some or all the additional supplementary technical screens or the detailed study process.[9]

**Figure 2: Interconnection Screening Process**




*Source: NREL, Emerging Issues and Challenges in Integrating Solar with the Distribution System, May 2016.*

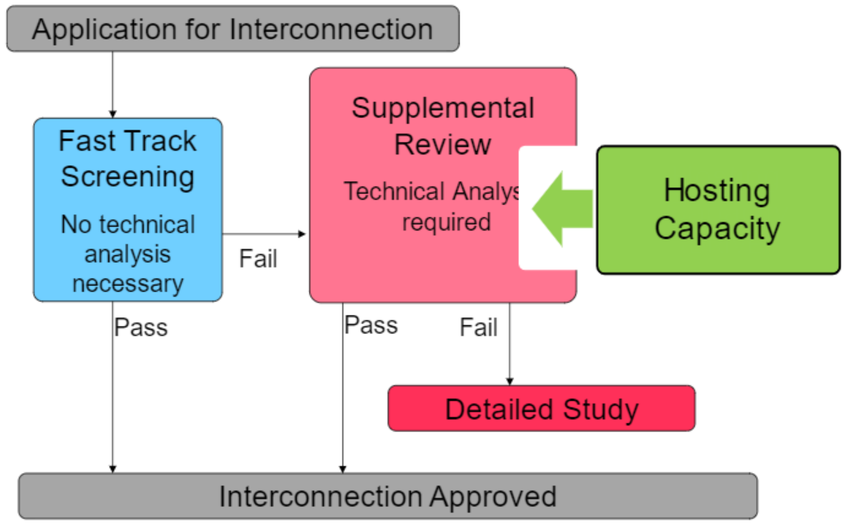
As shown in Figure 3, hosting capacity is being used as a means to either inform or supplant some fast track and supplemental review screens, though it cannot replace a detailed system impact study.[10] With frequent hosting capacity analysis updates (e.g., monthly), utilities can move toward more automated and streamlined interconnection processes, enabling them to balance higher volumes of interconnection applications more efficiently with the need to complete detailed interconnection studies. However, for many DER applications, the hosting capacity analysis and maps are a sufficient proxy for the technical screens employed by the utility.[11]

[9] Ibid.

[10] EPRI. 2020. *Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process.* pp. 5, 8.

[11] U.S. DOE. 2018. *Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*. p. 18.

**Figure 3: Hosting Capacity Analysis Can Assist in Interconnection Screening**




*Source: Jeff Smith, Methods, Applications, Opportunities and Challenges, EPRI. MPSC Distribution Planning Stakeholder Meeting, June 27, 2019, p. 24.*

### *2.1.3. Hosting Capacity Analysis for Long-Term Planning*

HCA can be used as a tool for long-term, integrated distribution system planning. In the other two use cases, hosting capacity is evaluated in the context of current system conditions. In this use case, HCA is used to plan for future scenarios with higher levels of DER penetration and load growth. This is especially important considering progressive DER adoption policies that accelerate the use of electric vehicles and energy storage. This type of forecasted hosting capacity could enable utilities to proactively assess the need for system upgrades in anticipation of DER growth, consider the potential to utilize DERs to defer or avoid planned capital upgrades (e.g., non-wire alternatives), and optimize the deployment of DERs on the grid in support of system reliability and resiliency.

## 2.2. Current State of the Industry

### *2.2.1. Overview*

Hosting capacity maps are currently available from a relatively small number of utilities. However, the maps are becoming an increasingly important tool for project developers looking to interconnect DERs to the distribution system and to industry advocates and regulators who want to increase the amount of DERs deployed on the grid for the public good. Currently, at least ten states require utilities to produce hosting capacity maps: California, Colorado, Illinois, Massachusetts, Nevada, Minnesota, New York, Maryland, New Jersey, and Connecticut. [12] Several other states are having regulatory discussions about

[12] Driscoll, William. June 16, 2020. "Solar hosting capacity maps must be accurate to be useful." pv magazine. Available at: https://pv-magazine-usa.com/2020/06/16/solar-hosting-capacity-maps-must-be-accurate-to-be-useful/#:~:text=Seven%20states%20now%20require%20utilities,represents%20IREC%20in%20state%20proceedings; and

requiring hosting capacity analyses, or improving existing ones, including Kentucky, Michigan, New Mexico, New Hampshire, Ohio, Oregon, and Vermont .[13] The following sections provide an overview of how leading utilities are applying HCA and compare the types of information being made publicly available in hosting capacity maps.

### *2.2.2. Utility Applications of Hosting Capacity Analyses*

Across the United States, electric utilities are using hosting capacity maps for different applications. Table 2 provides a snapshot of how Xcel Energy, Potomac Electric Power Company (Pepco), Hawaiian Electric Company (HECO), and the California, and New York investor-owned utilities (IOU) are currently applying HCA on distribution systems. The following sections will discuss this in greater detail.

**Table 2: Utility Hosting Capacity Analysis Benchmark**

| Use Case | Description | CA IOUs | HECO | NY IOUs | Pepco | Xcel |
|---|---|---|---|---|---|---|
| Development Guide | HCA to identify favorable locations to interconnect DER | X | X | X | X | X |
| Interconnection Technical Screen | HCA to improve the interconnection screening process | X | X |  | X |  |
| Distribution Planning Tool | HCA as a tool to enable greater DER integration by identifying potential future constraints and proactive upgrades | X | X | X |  |  |

*Source: Lisa Schwartz, Lawrence Berkeley National Lab, Distribution Planning Regulatory Practices in Other States, Oregon Public Utility Commission Webinar, May 21, 2020, p. 40 (Synapse modified).*

### *2.2.3. HCA Development Guide Case Study*

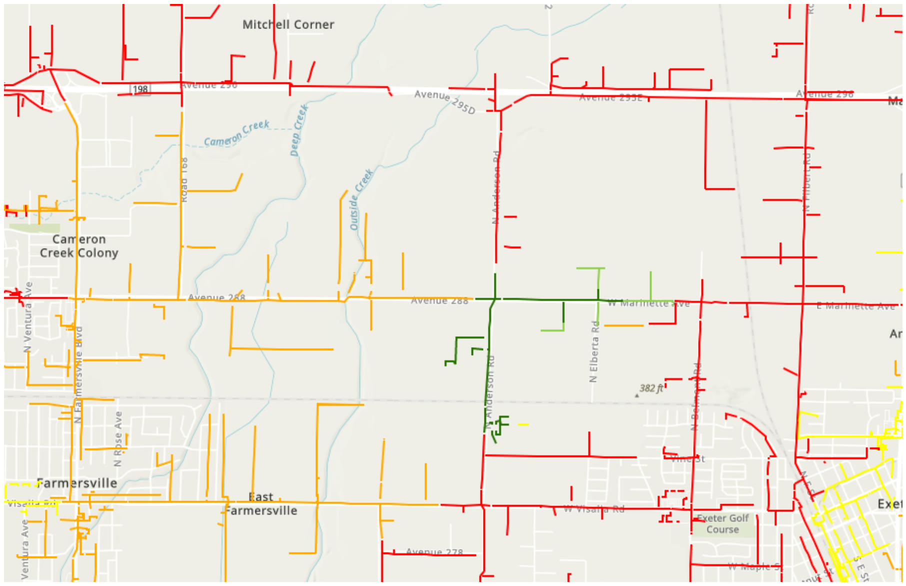
Some utilities are using hosting capacity maps to support DER developers. The California IOUs published their first hosting capacity maps called Integration Capacity Analysis (ICA) maps, in 2015 to provide an indication of hosting capacity across their systems.[14] Figure 4 provides an example of Southern California Edison's (SCE) hosting capacity map. Developers are provided with online access to the maps, which indicate the amount of DERs that can be added at each location without substantial system upgrades. The maps display information—such as load profiles, hosting capacity, total distributed generation on a feeder (existing and queued), and related grid information—at the substation, feeder, and sub-feeder (line section) levels. The maps also indicate where violations due to thermal, voltage, protection, or operational (e.g., reverse power flow) limitations could arise.

Driscoll, William. September 20, 2021. "IREC guide aims to help states deploy solar hosting capacity maps." pv magazine. Available at: https://pv-magazine-usa.com/2021/09/20/irec-guide-aims-to-help-states-deploy-solar-hosting-capacity-maps/.

[13] Ibid.

[14] U.S. DOE. 2018. *Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*. p. 11.

**Figure 5: SCE Integration Capacity Analysis Map**




*Source: https://ltmdrpep.sce.com/drpep/*

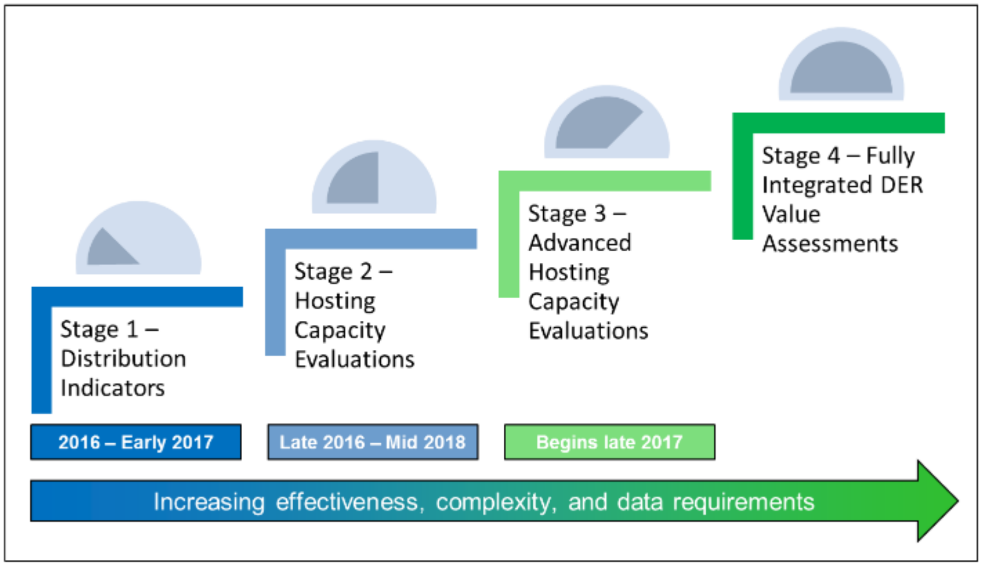
Several other utilities have published similar maps of their service territories. In New York, efforts to develop hosting capacity maps arose as part of the state's *Reforming the Energy Vision* (REV) proceeding, and in 2015 the New York Public Service Commission (NY PSC) required the utilities to include hosting capacity efforts in their Distributed System Implementation Plans (DSIP).[15] The Joint Utilities of New York[16] (JU) outlined four stages (Figure 6) in the development of their hosting capacity maps, with each stage adding greater granularity and data requirements, and increasing in computational complexity as modeling tools evolved.[17] This phased approach allows the JU to incorporate stakeholder feedback to help inform the prioritization of specific hosting capacity map enhancements that add the most value to developers.

[15] Stanfield, Sky and Stephanie Safdi. 2017. *Optimizing the Grid.* p. 35.

[16] The Joint Utilities are comprised of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation.

[17] U.S. DOE. 2018. *Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*. p. 13.

**Figure 6: Joint Utilities Hosting Capacity Roadmap**




*Source: Electric Power Research Institute ("EPRI"), Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, June 2016, p. 5.*

Currently, the JU is in Stage 3 of their roadmap and continues to add new functionality and upgrades to their hosting capacity maps based on stakeholder feedback. Some of these upgrades include an increased HCA refresh rate and a separate map layer focused on a load-based hosting capacity analysis.[18]

In Minnesota, Xcel provides an HCA heat map, which shows locations that may be more favorable for developers planning to interconnect DERs to the grid.

### *2.2.4. HCA Interconnection Technical Screen Case Study*

Where DER penetration is high, like in Hawaii and California, the use of hosting capacity to inform DER interconnection technical screens has gained traction.[19] Hawaiian Electric Company (HECO) has implemented this approach and reports that use of hosting capacity for interconnection screening has substantially increased the amount of rooftop systems that they could fast-track.[20] California IOUs have also used hosting capacity information to inform and improve the Rule 21 interconnection[21] process to help expedite the interconnection of DERs. In 2020, the California Public Utilities Commission (CPUC) ordered the California IOUs to incorporate "Integration Capacity Analysis (ICA) results into the

[18] Joint Utilities of New York. "Hosting Capacity Stakeholder Webinar." November 19, 2020, p. 7. Available at: https://jointutilitiesofny.org/sites/default/files/JU%20Hosting%20Capacity%20Stakholder%20Session%20-%20November%202020.pdf.

[19] U.S. DOE. 2018. *Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*. p. 18.

[20] Ibid.

[21] California Public Utilities Commission (CPUC). "Rule 21 interconnection." Available at: https://www.cpuc.ca.gov/Rule21/.

interconnection process to: (1) determine where and when existing circuits can accommodate additional distributed generation without requiring distribution upgrades and (2) allow interconnecting resources to export up to those limits."[22]

Washington, DC-based Pepco also uses the results of its HCA to help streamline the interconnection process in its service territory.[23] In combination with its Heat Map, which gives an indication of how much generation is currently installed and pending installation on a feeder, Pepco's HCA results allow a customer to analyze a point of interconnection to approximate the amount of remaining feeder capacity compared to the active and pending solar photovoltaic (PV) generation in the queue.[24] This provides a more accurate representation of the feasibility of interconnection at a particular location. However, all applications for interconnection still require a full review. Figure 7 provides an example of Pepco's hosting capacity map.

In Hawaii, HECO has an integrated interconnection queue for all areas, including those that currently exceed available hosting capacity, and customers can check the status of their interconnection application online.[25] HECO is also beginning to apply hosting capacity results for interconnection process automation and the development of the Fast Track process.[26]

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[22] Kim, Anne Y. 2021. *California's Grid Modernization Report to the Governor and Legislature*. CPUC. p. 40.

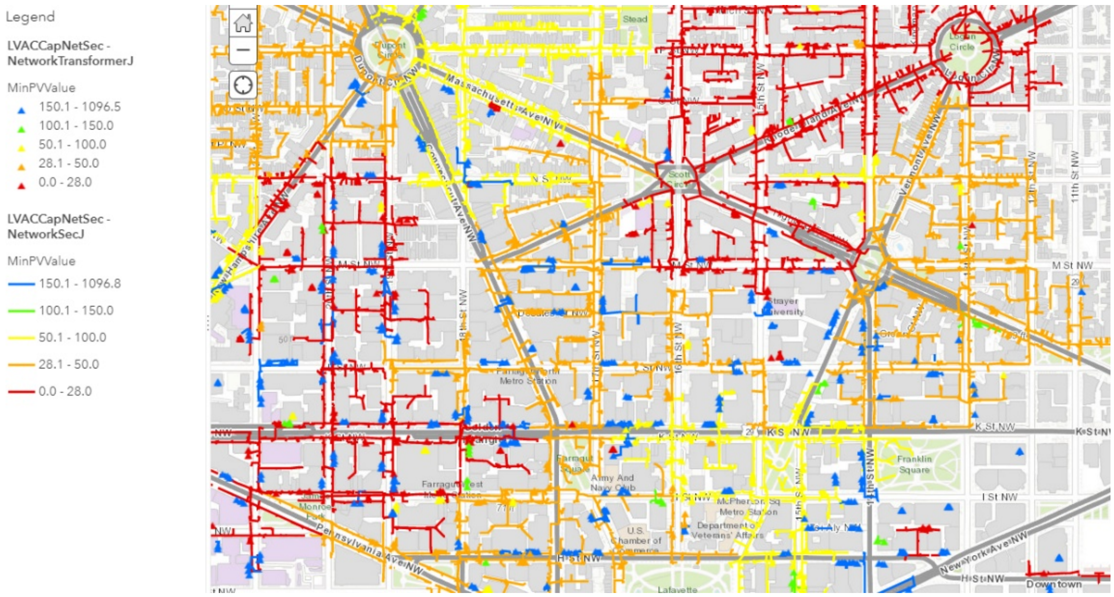
[23] Stanfield, Sky and Stephanie Safdi. 2017. *Optimizing the Grid.* p. 41.

[24] Potomac Electric Power Company. "Heat Map." Available at: https://www.pepco.com/SmartEnergy/MyGreenPowerConnection/Pages/HeatMap.aspx.

[25] Schwartz, Lisa. "Distribution Planning Regulatory Practices in Other States, Oregon Public Utility Commission Webinar." Lawrence Berkeley National Lab presentation for the U.S. Department of Energy's Office of Electricity, Transmission Permitting and Technical Assistance. May 21, 2020. p. 39. https://eta-publications.lbl.gov/sites/default/files/schwartz_puc_regulatory_practices_opuc_20200521.pdf.

[26] The Hawaiian Electric Companies. 2017. *Modernizing Hawai'i's Grid for Our Customers*. p. 29. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/final_august_2017_grid_modernization_strategy.pdf.

**Figure 7: Pepco Hosting Capacity Map**




*Source: https://www.pepco.com/SmartEnergy/MyGreenPowerConnection/Pages/HostingCapacityMap.aspx*.

In Minnesota, while Xcel does not currently utilize hosting capacity results in its interconnection process, it has investigated doing so, and it continues to improve its HCA to align with interconnection screens where possible.[27]

### *2.2.5. HCA Distribution Planning Case Study*

In California, the IOUs are planning to use hosting capacity information as an input into their system planning processes to identify when and where capacity upgrades are needed on the distribution system in response to various DER growth scenarios.[28] They also proposed using the HCA results to help guide sourcing and procurement of DER solutions with additional locational granularity in the future.[29]

In Stage 4 of the New York JU’s hosting capacity roadmap, the maps will be used to conduct fully integrated hosting capacity and value evaluations; they will indicate areas where DERs can bring additional value to the grid and identify ways to increase system hosting capacity. These fully integrated value assessments will help utility planners identify the locations where the deployment of DERs has the highest potential to reduce the overall net cost of operating the system.[30] A long-term goal of the JU is

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[27] EPRI. 2020. *Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process.* p. 13.

[28] Pacific Gas and Electric Company (PG&E). 2016. *California Distribution Resources Plan (R.14-08-013) Integration Capacity Analysis Working Group Final ICA WG Report.* Appendix to Final ICA WG Report. p. 8. https://drpwg.org/wp-content/uploads/2016/07/ICA-WG-Final-Report.pdf.

[29] Ibid.

[30] Joint Utilities of New York. 2016. *Supplemental Distributed System Implementation Plan*. pp. 56-57.

developing the valuation methods and tools necessary for achieving the objectives of this stage.

In Hawaii, HECO is using its HCA in the planning process to assess potential system upgrades due to DER growth forecasts. Simultaneously, it is assessing portfolios of DERs to further optimize hosting capacity.[31]

### *2.2.6. Hosting Capacity Map Comparison Across Advanced Utilities*

Publicly available hosting capacity map data can be beneficial to a variety of stakeholders including regulators, local governments, non-profits, electric customers, entrepreneurs, and DER developers. Some of the types of information that DER developers find useful include hosting capacity criteria violations, substation and (sub)feeder location and data, load profile (monthly and hourly), distributed generation (in queue and connected), and system upgrade cost estimates at specific locations given technical constraints. Utilities vary in the type and level of detail of grid data which they publish in their hosting capacity maps. Table 3 below compares the types of HCA grid data shown by states with utilities that are leading in the development of hosting capacity maps.

[31] The Hawaiian Electric Companies. 2017. *Modernizing Hawai'i's Grid for Our Customers*. p. 29.

**Table 3: Hosting Capacity Map Comparison Across Advanced Utilities**

| Hosting Capacity Map System Data | States with Advanced Practices | | | | | | |
|---|---|---|---|---|---|---|---|
| | California | D.C., DE, MD, NJ | Hawaii | Mass. | Minnesota | Nevada | New York |
| Solar PV HCA Availability | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Load HCA Availability | ✓ | | | | | ✓ | * |
| HCA Refresh Date | ✓ | | ✓ | ✓ | ✓ | ✓ | ✓ |
| Substation Name | ✓ | | | ✓ | ✓ | ✓ | |
| Substation Location | ✓ | | | | ✓ | ✓ | ✓ |
| Substation Bank Capacity | ✓ | | | ✓ | | | ✓ |
| Substation Peak Load | ✓ | | | | | ✓ | ✓ |
| Substation Load Profile | ✓ | | | | | ✓ | |
| Substation DG Connected/In Queue | ✓ | | | | ✓ | | ✓ |
| Substation Total DG | ✓ | | | | | | ✓ |
| Feeder ID | ✓ | ✓ | | ✓ | | ✓ | ✓ |
| Circuit map layout (Feeder location) | ✓ | ✓ | | ✓ | | ✓ | ✓ |
| Heat map layout (No Feeder location) | | | ✓ | | ✓ | | |
| Feeder Capacity | ✓ | | | ✓ | | | |
| Feeder Peak Load | ✓ | | | ✓ | | ✓ | |
| Feeder Load Profile | ✓ | | | | | ✓ | |
| Feeder DG Connected/In Queue | ✓ | | | ✓ | ✓ | ✓ | ✓ |
| Feeder Total DG | | | | | | | ✓ |
| DG Connected/In Queue Refresh Date | N/A | | | N/A | ✓ | N/A | ✓ |
| Nominal Voltage | ✓ | | | ✓ | ✓ | ✓ | ✓ |
| HCA Criteria Violations | ✓ | | | | ✓ | ✓ | ✓ |
| Distance from feeder to substation | | | | | | ✓ | |
| Impedance Data | | | | | | ✓ | |
| Customer Type Breakdown | ✓ | | | | | | |

*✓ Indicates the data is present in the current public facing hosting capacity map.*

** Indicates the data will be included in a future version of the hosting capacity map.*

*"N/A" for the DG Connected/In Queue Refresh Date field indicates the same refresh rate as the rest of HCA data*

California and Nevada provide the most detail on their hosting capacity maps. The California IOUs were ordered by the California Public Utilities Commission (CPUC) to provide this detailed information in support of DER developers and Nevada followed California's lead in terms of the provision of granular hosting capacity data. IOUs in these states provide both solar PV and load hosting capacity analyses to determine the incremental amount of DERs (e.g., solar PV, storage, electric vehicles) that can be accommodated on a feeder before causing a hosting capacity violation. They also both provide seasonal load profiles for the feeders. The California IOUs also provide substation load profiles. The California IOUs provide the percentage breakdown by customer type on their feeders and Nevada (NV) Energy provides other useful data on the distance from the feeder of interest to the substation along with the corresponding impedance data.

All the utilities provide the last date that the hosting capacity map was refreshed except for Pepco (e.g., Washington D.C., Maryland, Delaware, New Jersey) which updates a feeder's HCA results once per month if it has been flagged for one of the following reasons: (1) if 500kW of additional solar is approved; (2) if load on the feeder increases or drops significantly; or (3) if the feeder configuration changes. However, Pepco updates its entire hosting capacity map at least quarterly.[32]

Many of the utilities provide hosting capacity results on a nodal or line segment basis. However, Pepco provides its feeder hosting capacity results in terms of the maximum solar PV system size (in kW) given the substation transformer and feeder's hosting capacity constraints. HECO in Hawaii provides the percentage of space remaining for solar PV on the feeder as well as the total capacity output available (in kW) for customers to connect to the feeder. This is a proxy for the total distributed generation (shown in the table as DG) connected on the feeder. Additionally, all the utilities except Pepco and HECO provide nominal feeder voltage and hosting capacity violation information.

Xcel and the California and New York IOUs explicitly provide information about the existing or connected and queued distributed generation on a feeder and substation, while NV Energy only provides information about the connected distributed generation on a feeder. Pepco has a separate Heat Map, which provides pending, active, and total generation from all PV and non-PV generators.

While the California IOUs and NV Energy provide feeder load profiles that include minimum and peak loads, the New York IOUs only provide substation peak load. The California IOUs also provide the capacities of the feeders and substation banks, albeit on a separate public online map (the predecessor to the hosting capacity maps, called the PV RAM map). The New York IOUs provide the substation bank capacity. Xcel provides daytime minimum and absolute minimum loads for both its feeders and substations, but not peak load information.

Finally, all the utilities discussed here reveal their feeder lines, apart from HECO[33] and Xcel,[34] who present their hosting capacity results on a heat map. Xcel presents its HCA map as a "heat map" due to grid security concerns. HECO's locational value map (LVM) provides developers with a high-level view of approximately how much space may be available for private rooftop solar installations at a location on its primary system (e.g., not at the secondary level). While it is unclear exactly why HECO uses a heat map for its LVM, it is likely driven by its desire to maintain system reliability in the face of increasing DER penetration levels, rather than grid security concerns. Supporting evidence regarding this point are: (1) HECO does not typically have much supervisory control and data acquisition (SCADA) coverage on the

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[32] Stanfield, Sky and Stephanie Safdi. 2017. *Optimizing the Grid.* p. 42.

[33] Hawaiian Electric Companies. "Oahu Locational Value Map." Available at: https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps/oahu-locational-value-map-(lvm).

[34] Xcel Energy. "Hosting Capacity Map." Available at: https://www.xcelenergy.com/working_with_us/how_to_interconnect/hosting_capacity_map.

island, and thus primarily obtains grid data from its substations, reducing its ability to provide granular sub-feeder data and (2) HECO is careful not to reveal specific circuits that have additional hosting capacity since solar developers may heavily target them for DER interconnection. Regarding the first point, without sufficient SCADA coverage, HECO relies primarily on its substations for grid data, and cannot obtain data at the granularity necessary for a sub-feeder level HCA. Concerning the second point, Hawaii is closer than any other jurisdiction (e.g., New York or California) to experiencing the effects of high levels of DER penetration on system operations and reliability.[35] More specifically, in the near-term, it faces the dual challenge of reaching system and circuit hosting capacity levels.[36] Therefore, until HECO can modernize the grid and upgrade its infrastructure to accommodate additional generation from DERs, it does not necessarily want to advertise specific circuits where hosting capacity may be available.

NV Energy and the California and New York IOUs all reveal their feeders at the sub-feeder or line-segment level while Pepco reveals both its primary and secondary feeder locations. Additionally, all the utilities show distribution substations except HECO and Pepco. However, Pepco reveals the locations of its secondary transformers.

# 3. Customer Confidentiality And Grid Security

## 3.1. Overview

The Commission sought to elicit comments on grid and customer security issues related to the public display or access to grid data. These issues included, but were not limited to, distribution grid mapping, aggregated load data, and critical infrastructure. This section will discuss grid security and resiliency measures, how different utilities are balancing grid and customer security concerns with the release of sensitive hosting capacity map information, and the types of measures some utilities are taking to protect customer privacy using aggregation standards and CEII criteria.

## 3.2. Aggregation Standards and Customer Confidentiality

### *3.2.1. Overview of Customer Energy Use Data*

As defined by the Commission, the purpose of protecting Customer Energy Use Data (CEUD) is to prevent third parties from accessing the energy-use patterns of a specific customer and data that reveals commercially sensitive information.[37] The Commission defined CEUD as “data collected from the

[35] The Hawaiian Electric Companies. 2017. *Modernizing Hawai'i's Grid for Our Customers*. Appendix C, p. 29.

[36] Ibid.

[37] Order Governing Disclosure of Customer Energy Use Data to Third Parties, Requiring Filing of Privacy Policies and Cost Data, and Soliciting Comment, Dkt. E,G-999/CI-12-1344, at 7-8 (Jan. 19, 2017) (“CEUD Privacy Order”).

utility customer meters that reflects the quantity, quality, or timing of customers' natural gas or electric usage or electricity production."[38] It includes data regarding "the amount and timing of energy use and production; peak load contributions and the amount and timing of demand; and rate class."[39]

The Commission recognized that while the usefulness of this data generally increases with granularity, so does the potential for its misuse. The use cases for CEUD are numerous. Potential benefits of CEUD include helping to identify opportunities to pursue conservation, energy efficiency, and demand response programs. CEUD also helps third parties to implement these types of programs and gives policymakers the data needed to measure the effectiveness of those programs. The data may also be helpful in permitting greater use of electricity from renewable sources and reducing greenhouse gas emissions to help mitigate climate change.[40] Standards for the collection and sharing of CEUD for use by third parties should be designed to ensure that:

- Third parties may access aggregated or anonymized, disaggregated CEUD;
- The data be identified at the closest level of geographical specificity possible to maintain customer anonymity and at the finest practicable time interval;
- The utility, to the best of its ability, shall in a timely manner furnish this data in a consistent, standard format, aligned with industry best practices regarding ease of access and granularity of data; and
- Unless authorized by a customer, a third party shall not have access to any personally identifiable information (PII) for a customer.[41]

The Commission supports third parties having access to customer data if it does not violate the privacy of the individual without their consent.

Some risks that electric utilities face when sharing CEUD include:

- liability for the improper disclosure of their data and potential privacy violations;
- a damaged reputation should information be misused;
- administrative costs associated with organizing and transferring the data; and

[38] Id., p. 6.

[39] Minnesota Public Utilities Commission (MPUC). *Order Adopting Open Data Access Standards and Establishing Further Proceedings*. Dockets 12-1344/19-505, (November 20, 2020). Open Data Access Standards, p.1.

[40] Id., p. 3.

[41] MPUC. *Order Adopting Open Data Access Standards and Establishing Further Proceedings*. Dockets 12-1344/19-505, (November 20, 2020). Open Data Access Standards, p. 1.

- the lost ability to profit off exclusive knowledge of the data.[42]

Customers may also be concerned about the improper use of their data if sharing it could potentially "reveal information consumers would rather keep private."[43] The risks to customers, and to some extent the utilities, can be mitigated by removing PII that would violate customer privacy.

To remove PII, utilities in Minnesota can apply both aggregation and anonymization to CEUD. The utilization of both aggregation and anonymization can reduce the risk of revealing a specific customer's energy-use habits or of his/her PII being identified. The Department defined these terms as follows:

- Aggregated CEUD - data of individual customers located in a defined geographical area, which is combined into one collective data point per time interval.
- Anonymized CEUD - data of individual customers, which has been modified sufficiently to prevent the release of PII, collected over a number of time intervals from a defined geographical area. [44]

In summary, aggregated data refers to information that is grouped, while anonymized data refers to data where PII has been removed or modified.[45] By definition, all aggregated data is also anonymized.

Having outlined what CEUD is, the standards for collecting and sharing it, the purpose of protecting it and ways to do so, and the risks associated with its unauthorized disclosure, we will now focus on the different ways to aggregate CEUD.

### *3.2.2. Aggregation Standards for Customer Energy Use Data*

When sharing data, utilities must do their best to make sure customer confidentiality is protected. Sometimes, customers explicitly allow their data to be shared. However, when this is not the case, certain protective measures must be put in place to assure that customer data is sufficiently protected. Methods that "prevent the release of aggregated or anonymized data sets that would put privacy at risk" are known as screens.[46] The Commission required utilities to establish defined practices to protect the anonymity of CEUD before releasing it to third parties.[47] Xcel selected the 15/15 standard to

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[42] University of Chicago Law School, Abrams Environmental Law Clinic. 2016. *Regulatory Guide - Freeing Energy Data.* p. 15. Available at: https://www.law.uchicago.edu/files/file/freeing_energy_data_report_abrams_environmental_clinic_june_2016.pdf.

[43] Id., p. 20.

[44] MPUC. *Order Adopting Open Data Access Standards and Establishing Further Proceedings*. Open Data Access Standards, p.1.

[45] University of Chicago Law School, Abrams Environmental Law Clinic. p. 20.

[46] Seidman, Nancy, John Shenot. "Open Data Access Standards: Approaches in Other Jurisdictions." Presentation at the Minnesota Public Utilities Commission Technical Conference. Feb 26, 2021. p. 6. https://mn.gov/puc-stat/documents/pdf_files/RAP_Seidman%20and%20Shenot_State%20Policies%20for%20Aggregated%20or%20Anonymized%20Data%20Access_MN%20PUC_2021_FEBRUARY_26.pdf.

[47] *Order Governing Disclosure of Customer Energy Use Data to Third Parties, Requiring Filing of Privacy Policies and Cost Data, and Soliciting Comment*, Dkt. E,G-999/CI-12-1344. (Jan. 19, 2017). pp. 7-8.

determine if CEUD is sufficiently aggregated to be released.[48] Under this standard, data given to requestors must be aggregated into groups of at least 15 customers with no customer comprising more than 15 percent of the load in the given dataset.[49] Table 4 provides an overview of common aggregation standards used to protect customer data. Some prioritize customer protection while others favor providing more granular data to third-party data requestors.

**Table 4: Typical Aggregation Standards**

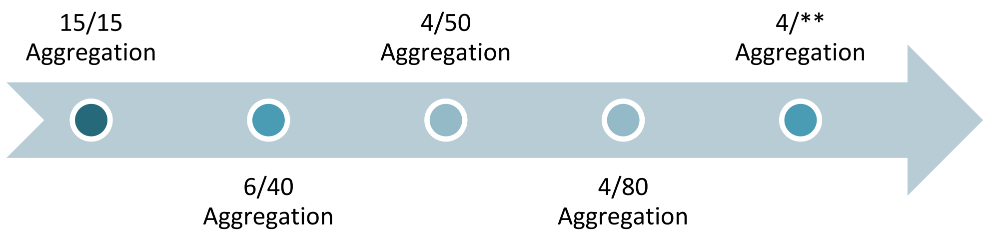
| Standard | Overview | Level of Customer Privacy |
|---|---|---|
| 15/15 | Requires at least 15 customers to be included in a dataset, with no customer accounting for more than 15% of the total energy use | • High level of customer protection<br>• Data is less granular for third-party use |
| 6/40 | Requires at least 6 customers to be included in a dataset with no customer accounting for more than 40% of the total energy use | • More customers are included, but risk of identification is higher than 15/15 standard<br>• Data is somewhat granular for third-party use; some customers are still redacted |
| 4/50 | Requires at least 4 customers to be included in a dataset, with no customer accounting for more than 50% of the total energy use | • Lower level of customer protection<br>• Data is more granular, and more data is included for third-party use |
| 4/80 | Requires at least 4 customers to be included in a dataset, with no customer accounting for more than 80% of the total energy use | • Lower level of customer privacy/protection<br>• Nearly all information is included, and data is relatively granular for third-party use |
| 4/** | Requires at least 4 customers to be included in a dataset | • Customers may be identified under some circumstances<br>• Data is granular for third-party use; only datasets that serve less than 4 customers are not available |

Most states apply the 15/15 standard to CEUD, while many of the other standards are applied to whole building energy-use data. Generally, CEUD is held to a higher standard of protection, and increasing the number of customers and decreasing the maximum percentage of total energy use leads to greater data anonymization and protection. Figure 8 portrays how changing the aggregation standard increases the data's usability while decreasing the level of protection for customers.

[48] *Xcel Energy Compliance Filing Annual Report.* Docket Nos.E,G999/CI-12-1344 and E,G999/M-19-505. (March 1, 2021), p. 4.

[49] Ibid.

**Figure 8: Data Granularity for Aggregation Standards**




*Increasing Levels of Data Usability but Reduced Customer Protection*

### *3.2.3. Discussion of Aggregation Standards in Minnesota*

In November 2020, the Commission discussed the appropriateness of the 15/15 aggregation standard and explored the use of multiple standards to aggregate and anonymize datasets when provided to different third parties.[50] The Commission also discussed the use of a 4/50 aggregation standard for the same federal and state government entities, with the addition of "property owners or managers, so long as the CEUD requested applies only to the property the requestor owns or manages."[51] The Commission requested further expertise on topics including uniform customer access forms, segmented aggregation screens, and the refinement of contract requirements for anonymized data access.[52] The Commission continued to approve the Open Data Access standards proposed by the Citizens Utility Board which included standards for the types and format of data released.[53]

This report will focus on the application of the 15/15 aggregation standard in the context of protecting customer privacy on Xcel's hosting capacity map. The use of the 15/15 standard here is not meant to prejudice any decisions related to the access and privacy of CEUD in the context of the Commission's ongoing proceedings pertaining to its adoption of the Open Data Access Standards.

## 3.3. Critical Energy Infrastructure Information

### *3.3.1. Overview of CEII*

Critical data is data which must be removed from the public domain to maintain its security. This may include information such as the location of feeders leading to critical customer groups or critical infrastructure. Several federal agencies have provided guidance and regulations regarding critical

[50] *Order Adopting Open Data Access Standards and Establishing Further Proceedings*, Dockets 12-1344/19-505, (November 20, 2020). pp. 7-8.

[51] Ibid.

[52] Ibid.

[53] Ibid.

infrastructure. At the national level, the Cybersecurity & Infrastructure Security Agency (CISA) of the Department of Homeland Security (DHS) has identified 16 critical infrastructure sectors that it considers "so vital to the United States that their incapacitation or destruction would have a debilitating effect on security, national economic security, national public health or safety, or any combination thereof."[54] These sectors were identified as part of Presidential Policy Directive 21 (PPD-21) on Critical Infrastructure and Resilience and advance national policy to "strengthen and maintain secure, functioning, and resilient critical infrastructure."[55] Table 5 lists the 16 sectors.

**Table 5: DHS Critical Infrastructure Sectors**

| Critical Infrastructure Sectors | |
|---|---|
| • Chemical<br>• Commercial<br>• Communications<br>• Critical Manufacturing<br>• Dams<br>• Defense Industrial Base<br>• Emergency Services<br>• Energy | • Financial Services<br>• Food and Agriculture<br>• Government Facilities<br>• Healthcare and Public Health<br>• Information Technology<br>• Nuclear Reactors, Materials, and Waste<br>• Transportation Systems<br>• Water and Wastewater Systems |

In addition to knowing which sectors to protect, it is also important to know how to protect them. Specifically, for bulk power system entities, the North American Electric Reliability Corporation (NERC) established mandatory Critical Infrastructure Protection (CIP) standards, including for the protection of sensitive data. For example, CIP-011-2, Information Protection, is structured "to prevent unauthorized access to Bulk Electric System (BES) Cyber System Information by specifying information protection requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES."[56] There are currently 12 CIP standards subject to enforcement which include the Physical Security Reliability Standard (CIP-014) and 11 cybersecurity standards. Table 6 provides several examples of CIP standards.

**Table 6: NERC Critical Infrastructure Protection Standards**

| Standard | Name | Status |
|---|---|---|
| CIP-003-8 | Cyber Security – Security Management Controls | Subject to Enforcement |
| CIP-004-6 | Cyber Security – Personnel & Training | Subject to Enforcement |
| CIP-007-6 | Cyber Security – System Security Management | Subject to Enforcement |

54 Cybersecurity & Infrastructure Agency. "Critical Infrastructure Sectors." Available at: https://www.cisa.gov/critical-infrastructure-sectors.

55 Ibid.

56 North American Reliability Corporation. "Critical Infrastructure Protection Standards." Available at: https://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx.

| | | |
|---|---|---|
| CIP-011-2 | Cyber Security – Information Protection | Subject to Enforcement |
| CIP-012-1 | Cyber Security – Communication btw. Control Centers | Subject to Enforcement |
| CIP-014-2 | Physical Security | Subject to Enforcement |

No corollary to the NERC Critical Infrastructure Protection Standards for the bulk power system exists for distribution system infrastructure.

The Federal Energy Regulatory Commission (FERC) oversees the designation of critical infrastructure. FERC Regulation 18 C.F.R. § 388.133 defines Critical Energy Infrastructure Information (CEII) as specific engineering, vulnerability, or detailed design information related to a "system or asset of the bulk-power system (physical or virtual)" in which "the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters" which:

1. Relates details about the production, generation, transmission, or distribution of energy;
2. Could be useful to a person planning an attack on critical infrastructure;
3. Is exempt from mandatory disclosure under the Freedom of Information Act (5 U.S.C. § 552); and
4. Gives strategic information beyond the location of the critical infrastructure.[57]

It is important to note that the FERC's process for requesting CEII treatment of information only refers to an asset(s) or system(s) of the bulk power system and is not defined with respect to the distribution system. Furthermore, only the FERC can designate information as CEII.[58] Requestors who wish to designate information as CEII must explain the legal justification for such treatment according to the FERC's criteria. For specific locational information, requestors need to justify their request and explain why the information is not already publicly known.[59] When making its determination, the FERC considers the public's need to have access to the information to effectively participate in proceedings. In addition, the FERC provides an administrative appeal process to challenge CEII designations or disclosures and provides the opportunity for the public to request access to CEII by submitting a detailed statement of need and executing a non-disclosure agreement (NDA), limited to one calendar year.[60]

### 3.4. Grid Security and Resilience

[57] Federal Energy Regulatory Commission, "Critical Energy Infrastructure Information." Available at: https://www.ferc.gov/enforcement-legal/ceii.

[58] Ibid.

[59] Ibid.

[60] Ibid.

### 3.4.1. *Overview of Grid Security*

A reliable electric grid is a key pillar of the nation's economic and national security, and federal government authorities, nonprofit organizations, and the electric utility industry have made significant strides towards maintaining a secure and reliable electric system. The *Energy Policy Act of 2005* included provisions to strengthen the electric grid through the introduction of mandatory reliability standards, although they are not specifically aimed at protecting the grid against terrorist attack.[61]

However, a 2013 sniper attack on Pacific Gas and Electric's Metcalf transmission substation in California marked a turning point for the U.S. electric power sector. The attack led to the NERC establishing mandatory CIP standards for the physical and cyber security of the BES in 2015.[62] The attack also prompted electric utilities across the country to reassess their grid security programs and to apply closer scrutiny to the vulnerability of critical distribution assets to various kinds of physical and cyber-attacks.

### 3.4.2. *Grid Security Vulnerabilities and Threats*

There are three main categories of electric system vulnerabilities which can result in the disruption of the grid's power supply. These are physical security, cybersecurity, and personnel vulnerabilities. This report will only focus on physical and cybersecurity vulnerabilities.

<u>Physical Security Vulnerability and Threats</u>

*Overview*

In the United States, the electric power grid consists of over 200,000 miles of high-voltage transmission lines interspersed with hundreds of large electric power transformers.[63] Once electricity is generated, it is stepped up in voltage and transported over long distances before being distributed to consumers. The major components of transmission systems are substation transformers, which step-up and step-down voltage to more efficiently transport power over long distances, transmission towers to connect high-voltage power lines, and control centers to manage the delivery of power from generation resources to the distributed system loads.[64] Figure 9 displays the operations of the U.S. electric grid.

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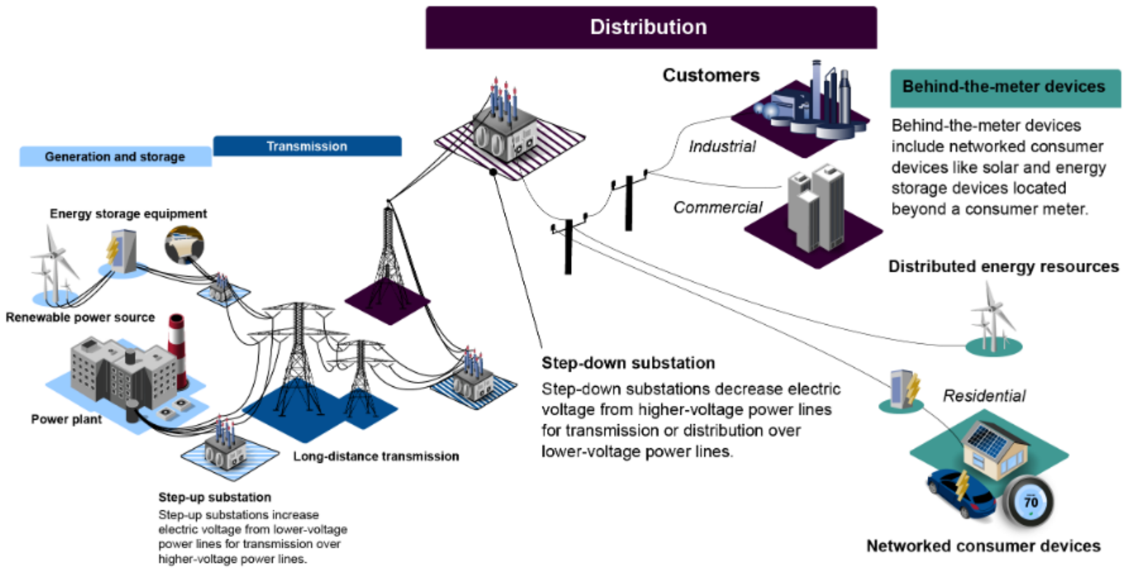
[61] National Research Council. 2012. *Terrorism and the Electric Power Delivery System Washington, DC.* The National Academies Press. p. 2. Available at: https://doi.org/10.17226/12050.

[62] Parfomak, Paul. 2018. *NERC Standards for Bulk Power Physical Security: Is the Grid More Secure?* Congressional Research Service. p. 20. Available at: https://fas.org/sgp/crs/homesec/R45135.pdf.

[63] Parfomak, Paul. 2014. *Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations.* p.2. Available at: https://assets. documentcloud.org/documents/1303171/2014-crs-report.pdf.

[64] Idaho National Laboratory. 2016. *Cyber Threat and Vulnerability Analysis of the U.S. Electric Sector*. p.10. Available at: https://www.energy.gov/sites/prod/files/2017/01/f34/Cyber%20Threat%20and%20Vulnerability%20Analysis%20of%20the%20U.S.%20Electric%20Sector.pdf.

**Figure 9: Functions of the U.S. Electric Grid**




*Source: U.S. Government Accountability Office (GAO), Electric Grid Cybersecurity, DOE Needs to Ensure its Plans Fully Address Risks to Distribution Systems, March 2021, p.6. https://www.gao.gov/assets/gao-21-81.pdf.*

*Transmission*

To significantly impact transmission of power throughout the grid, an attacker would have to simultaneously interrupt or destroy multiple high-voltage transmission lines or high-voltage transformers.[65] Large power/high-voltage transformers, which step power down from transmission to distribution levels, are critical to the nation's power grid. These critical devices account for fewer than three percent of the transformers in U.S. substations but carry 60–70 percent of the nation's electricity.[66] The impact of extended power outages from the loss of one or more of these high-voltage transformers could disrupt electricity services over a wide area of the country and is of significant concern.[67] Risk from loss of these transformers is heightened by the lack of alternate electricity delivery paths or the lack of access to spare transformers in many transmission utilities.[68]

A 2017 report from the National Academy of Sciences (NAS) concludes: "While to date there have been only minor attacks on the power system in the United States, large-scale physical destruction of key parts of the power system by terrorists is a real danger. Some physical attacks could cause disruption in

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[65] Ibid.

[66] Parfomak, Paul. 2014. *Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations*. p.2.

[67] U.S. DOE. "Addressing Security and Reliability Concerns of Large Power Transformers." Available at: https://www.energy.gov/oe/addressing-security-and-reliability-concerns-large-power-transformers.

[68] Idaho National Laboratory, p. 10.

system operations that last for weeks or months."[69] Substations and the high-voltage transformers they contain are especially vulnerable to physical attack, as well as some transmission lines where the destruction of a small number of towers could bring down many kilometers of line.[70] High-voltage transformers face several challenges which make them particularly vulnerable, including being very large, difficult to transport, typically custom-made, generally expensive (sometimes costing $3 million each[71]), and hard to replace with procurement lead times of one year or longer.[72] Most are also no longer built in the United States.[73]

High-voltage transformers are also the most vulnerable to intentional damage from malicious acts.[74] Recent domestic terrorist attacks on high-voltage transformers highlight their particular vulnerability to physical attack. The 2013 high-powered rifle assault on the 500 kilovolt (kV) transformer Metcalf substation only lasted 19-minutes but caused $15 million in damages.[75] In 2016, a similar high-powered rifle attack on a 69 kV transformer in Garkane Energy Cooperative's Buckskin substation in southern Utah reportedly left 13,000 rural customers without power for up to eight hours.[76]

*Distribution*

Physical attacks are not limited to the transmission system. Physical attacks on distribution transformers, circuits (e.g., feeders), protective devices, and other distribution system assets could impact the electricity supply to critical local customers like hospitals. There are no mandatory federal standards, like the NERC CIP standards which apply to the bulk power system, that are governing distribution systems, over which states have authority. Thus, there are varying standards of protection for distribution systems. However, the Metcalf attack has led to calls to not only guard against potential attacks on federally regulated, critical bulk power assets, but also to protect distribution assets under state-level purview.[77] For example, following the Metcalf incident, California lawmakers passed new legislation (SB 6991) that directed the CPUC to consider adoption of new standards and rules to address

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[69] National Academy of Sciences, Engineering, and Medicine. 2017. *Enhancing the Resilience of the Nation's Electricity System*. p. 64. Available at: https://doi.org/10.17226/24836.

[70] National Research Council. 2012. *Terrorism and the Electric Power Delivery System.* p. 2.

[71] Pagliery, Jose. October 17, 2015. "Sniper attack on California power grid may have been 'an insider' DHS says." *CNN Business*. Available at: https://money.cnn.com/2015/10/16/technology/sniper-power-grid/.

[72] U.S. DOE. "Addressing Security and Reliability Concerns of Large Power Transformers." Available at: https://www.energy.gov/oe/addressing-security-and-reliability-concerns-large-power-transformers.

[73] National Research Council. 2012. *Terrorism and the Electric Power Delivery System.* p. 2.

[74] Parfomak, Paul. 2014. *Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations.* p. 2.

[75] Pagliery, Jose. 2015.

[76] Parfomak, Paul. 2018. *NERC Standards for Bulk Power Physical Security: Is the Grid More Secure?* p. 2.

[77] CPUC. January 2018. *Security and Resilience for California Electric Distribution Infrastructure: Regulatory and Industry Response to SB 699. CPUC staff white paper*. p. 4. Available at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/Safety/Risk_Assessment/physicalsecurity/Final%20CPUC_Physical_Security_White_Paper_January_2018(1).pdf.

any physical security risk to the distribution system to ensure "high-quality, safe, and reliable service."[78] Additionally, some utilities are voluntarily taking action to strengthen their distribution systems to make them more resilient to potential attacks.

Cyber Security Vulnerability and Threats

*Overview*

The modern grid relies heavily on high-speed communications, automation, and centralized monitoring, control, and protection of equipment. The cyber-physical systems of the electric sector include industrial control systems (ICS), which allow for synchronous, digital control of sensitive processes and the physical operations of equipment at the generation, transmission, and distribution system levels. These operations include physical functions such as the opening and closing of circuit breakers on the grid. Advances in ICS technology have resulted in advantages such as easier system operation and maintenance, and more detailed systems data. However, they have also increased the vulnerability of the systems to cyberattacks through internet or network connections from remote sites (e.g., virtual private network).[79] Any telecommunication link that is even partially outside the control of the system operators is a potentially insecure pathway into operations and a threat to the grid.[80] Figure 10 shows the typical types of cyber-attack techniques which can be used to gain access to ICS.

The most critical ICS are the supervisory control and data acquisition (SCADA) systems that gather real-time measurements from substations and send out control signals to equipment such as circuit breakers.[81] If hackers could gain access, they could manipulate SCADA systems to disrupt the flow of electricity, transmit erroneous signals to operators, block the flow of vital information, or disable protective systems.[82] Such cyberattacks would require a high level of sophistication and expertise.

[78] Ibid.

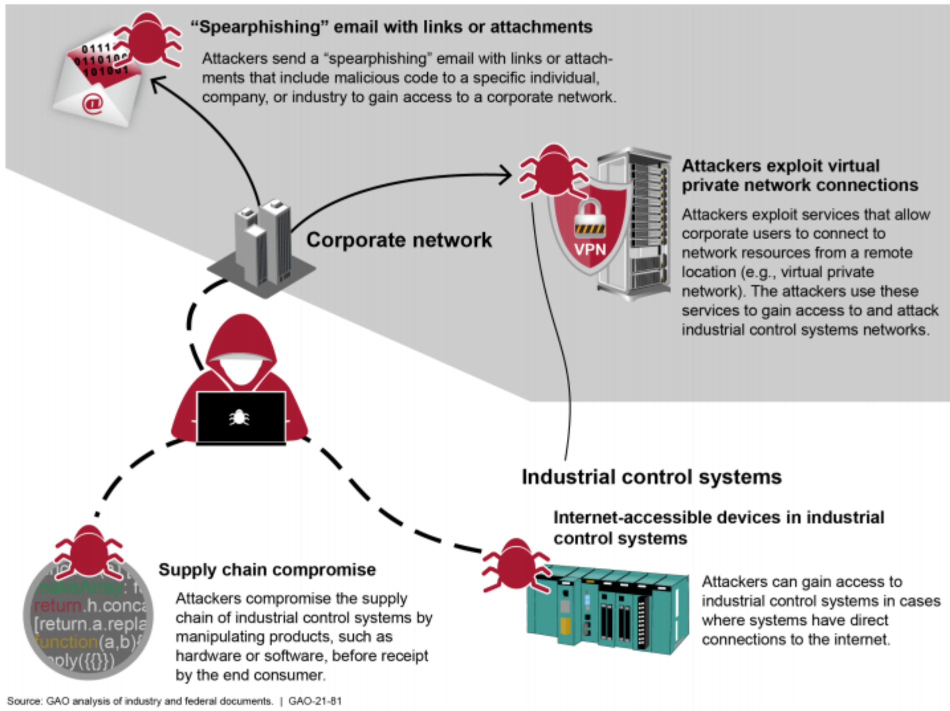
[79] U.S. Government Accountability Office (GAO). 2021. *Electric Grid Cybersecurity, DOE Needs to Ensure its Plans Fully Address Risks to Distribution Systems*. p. 13. Available at: https://www.gao.gov/assets/gao-21-81.pdf.

[80] National Research Council. 2012. *Terrorism and the Electric Power Delivery System.* p. 2.

[81] Ibid.

[82] Ibid.

**Figure 10: Examples of Techniques for Gaining Initial Access to Industrial Control Systems**




*Source: U.S. GAO, Electric Grid Cybersecurity, DOE Needs to Ensure its Plans Fully Address Risks to Distribution Systems, March 2021, p.14. https://www.gao.gov/assets/gao-21-81.pdf.*

Cyber-attacks are unlikely to cause extended outages, but if well-coordinated, they could magnify the damage of a physical attack.[83] For example, a cascading power outage resulting from a physical attack on the transmission system would be aggravated, if a cyber-attacker exploited an ICS vulnerability, causing a loss of visibility into grid operations, which delayed the system operator's response time.[84] Furthermore, ICS experts note that if a threat actor can physically access a substation, there is virtually no limit to potential damage, since malware could be directly introduced to computers and devices resulting in the manipulation (e.g., protective relays), and destruction of electrical equipment.[85]

*Transmission*

Cyber threats to utilities responsible for transmission depend on several variables, such as network configuration within a substation, and means of communicating data.[86] Modern substations use several kinds of communication to manage local functions. Transmission substations are subject to mandatory NERC CIP cyber security standards, making unauthorized access to substation networks difficult, and

[83] Ibid.

[84] Ibid.

[85] Idaho National Laboratory. 2016. p. 11.

[86] Ibid.

likely requiring advanced skill by a threat actor.[87] However, controllers and other devices increasingly used in substation automation are often sources of numerous ICS vulnerabilities and can serve as entry points to networks. Once inside the digital operations of a substation, an attacker with the necessary skills and tools could disrupt, desynchronize, or impact data communications necessary for communications and controls causing load instability.[88] Substation networks without detection capabilities to identify intrusions and malicious data injection could allow an attacker to manipulate multiple substations over time without discovery.[89] In these networks, the risk of a coordinated cyber-attack powerful enough to disrupt a portion of the grid is greater.[90]

*Distribution*

A recent U.S. Government Accountability Office (GAO) report for the Department of Energy (DOE) on distribution grid cybersecurity notes that the U.S distribution systems are increasingly at risk from cyberattacks and are growing more vulnerable, in part, because their ICS connect to business networks and allow remote access.[91] As a result, threat actors can use multiple techniques to access those systems and potentially disrupt operations. However, the GAO report states that "none of the cybersecurity incidents reported in the United States have disrupted the reliability or availability of the grid's distribution systems, according to the DOE, which requires all U.S. electric utilities to report significant electrical incidents or disturbances."[92]

However, just because there has not been a cyber-attack on a U.S. distribution system does not mean one could not occur. The first confirmed cyber-attack to affect a distribution grid occurred in the Ukraine and resulted in a localized power outage in 2015.[93] Attackers launched an email phishing campaign to target IT personnel of power distribution companies and used malware to gain access to IT infrastructure.[94] They then hijacked the SCADA distribution management system (DMS) to "cause undesirable state changes to the distribution electricity infrastructure and attempted to delay…restoration by wiping SCADA servers after they caused the outage," while simultaneously preventing calls reporting power outages from reaching customer service centers.[95] The event resulted in a 3- to 6-hour outage that left more than 230,000 customers without electricity.[96]

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[87] Ibid.

[88] Ibid.

[89] Ibid.

[90] Ibid.

[91] U.S. GAO. 2021. p. 2.

[92] Id., p. 22.

[93] Idaho National Laboratory, p. 11.

[94] Ibid.

[95] Ibid.

[96] Ibid.

Several energy utility companies stated that physical attacks on energy distribution machines are much more effective at taking out the power grid than a computer hack and are easy to pull off.[97] However, cyber-attacks on distribution systems could also have a significant impact if they reach the bulk power system. The GAO report notes that the scale of potential impacts on the bulk power system from a cyberattack on the grid's distribution systems is not well understood.[98]

As the deployment of DERs on the grid increases, so does the potential for these devices to face cyber threats. DER devices, owned and controlled by consumers and third parties, are equipped with digital communications and control interfaces to communicate, and interconnect with the grid.[99] These DER communication interfaces enable utility features such as remote access and control, but also provide a possible entry point for a cyberattack. The National Renewable Energy Laboratory (NREL) notes that utilities that interconnect with third-party DERs should consider cybersecurity measures at the business process and network layers of the grid's devices, communication channels, and higher-level applications.[100]

## 3.5. Grid Resilience

### *3.5.1. Overview*

Resilience is a relatively new concept in utility resource planning and currently, no formal grid resilience definitions, metrics, or analysis methods have been universally accepted. The staff of the Hawaiian Public Utilities Commission defined resilience, in the context of the electric distribution system, as the ability of the system or its components to anticipate, absorb, adapt to, and rapidly recover from disruptions or a catastrophic event.[101] NREL defines the magnitude of resilience provided by renewable energy hybrid systems (e.g., microgrids) as the amount of time that the critical load is served during a grid outage and the value of the resilience as the economic value of serving the critical load.[102] All relevant costs must be captured, including the costs that utilities might incur to mitigate (and recover from) severe outages, as well as the cost of the outage to customers and the community.[103] It might

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[97] Pagliery, Jose. 2015.

[98] U.S. GAO. 2021. p. 22.

[99] Horowitz, Kelsey, Zac Peterson, Michael Coddington, Fei Ding, Ben Sigrin, Danish Saleem, Sara E. Baldwin, et al. 2019. *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions.* NREL, p. 47. Available at: https://www.nrel.gov/docs/fy19osti/72102.pdf.

[100] Ibid.

[101] Hawaiian Public Service Commission (HI PSC). 2020. *Resilience Working Group Report for Integrated Grid Planning, Hawaiian Electric Company, Maui Electric Company, and Hawaiʻi Electric Light Company.* p. 6. Available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/resilience/20200429_rwg_report.pdf.

[102] Kate Anderson, Nicholas D. Laws, Spencer Marr, Lars Lisell, Tony Jimenez, Tria Case, Xiangkun Li, Dag Lohmann and Dylan Cutler. 2018. *Quantifying and Monetizing Renewable Energy Resiliency.* National Renewable Energy Lab and City University of New York. p. 2. Available at: https://www.mdpi.com/2071-1050/10/4/933.

[103] HI PSC, Resilience Working Group Report for Integrated Grid Planning. p. 11.

also include costs that customers incur to mitigate the impact of severe outages, especially if those measures might be more cost effective than those incurred by the utility.[104] However, metrics to measure the resilience of electrical distribution systems are not strictly limited to costs. For example, to evaluate community resilience in response to electricity service disruptions in Puerto Rico, Sandia National Labs employed a resilience metric, which measures the burden on members of the community to satisfy their basic needs. Burden is a function of the effort required to satisfy each need, as well as each individual's ability to acquire each infrastructure service.[105] The idea is that a more resilient community will better prepare for, withstand, respond to, and recover from extreme shocks, thereby decreasing the burden imposed on its citizens following a disruption.[106]

Some resilience objectives include:

- Reducing the likelihood of power outages during a severe event;
- Reducing the severity and duration of any outages that do occur during and after a severe event;
- Reducing restoration and recovery times following a severe event;
- Returning critical infrastructure customers' power rapidly to enable mutual support and recovery during an emergency;
- Returning all customers' power within appropriate times; and
- Limiting the environmental impacts of a severe event.[107]

### *3.5.2. Grid Resilience in the Face of Threats*

It is also important to consider the categories of threats, such as extreme weather events and physical and cyber-attacks, and how the electric utility would prepare for and respond to these threat scenarios to help ensure a resilient grid.

Table 7 highlights some measures that a utility could take to help reduce distribution system vulnerabilities and enhance grid resiliency.

[104] Ibid.

[105] Robert F. Jeffers, Michael J. Baca, Amanda M. Wachtel, Sean DeRosa, Andrea Staid, William Fogleman, Alexander Outkin, Frank Currie, 2018. "Analysis of Microgrid Locations Benefitting Community Resilience for Puerto Rico." Sandia National Labs. p. 6. Available at: https://doi.org/10.2172/1481633.

[106] Ibid.

[107] HI PSC*, Resilience Working Group Report for Integrated Grid Planning*. p. 11.

**Table 7: Options for Enhancing Grid Resiliency**

| Threat Scenario | Resiliency Measures |
|---|---|
| Cyber-attack | • Elimination of non-essential pathways to external systems<br>• Improved cybersecurity for sensors, communication, and control systems<br>• Systems to monitor for, and help avoid, operator error |
| Physical Attack | • Hardening of key substations and control centers<br>• Substation fencing<br>• Increased surveillance<br>• Stockpiling of spare and mobile transformers |
| Extreme Weather Event | • Vegetation management<br>• Hardening of overhead poles and crossarms (e.g., fiberglass)<br>• Undergrounding cables<br>• Fault Location, Isolation, and Service Restoration (FLISR) |

*Source: National Research Council 2012. Terrorism and the Electric Power Delivery System, p.3. https://doi.org/10.17226/12050.*

### Xcel's Grid Resilience Efforts

Xcel takes several measures to enhance the resilience of its distribution system. For example, Xcel's cyber security program has five categories (identify, protect, detect, respond, recover) of controls to protect and detect cyber threats to its network.[108] These controls include user access controls, encryption, use of digital certificates for user authentication, scanning equipment for known security vulnerabilities, monitoring and detecting potentially anomalous activity, data validation, communications firewalls, and periodic software updates to improve system performance and address security vulnerabilities.[109] Among other things, to enhance the physical security of its system, Xcel encloses all of its substations primarily with fencing and in some cases walls, uses motion security lighting and conducts remote surveillance of critical assets, and undergrounds some of its power lines.[110] Xcel also has spare and mobile transformers which it can deploy as needed. To make the grid more resilient to extreme weather events, Xcel has a vegetation management program, hardens its overhead poles and crossarms, and a subset of its feeders have an automated IntelliTeam scheme, which can automatically isolate and restore service to most customers when a fault occurs through switching from adjacent feeders.[111] However, most switching is done manually. When there is a power disruption, Xcel can typically address a routine outage in under two hours, a more severe outage in 4-6

[108] Xcel Energy. *2019 Integrated Distribution Plan.* Docket No. E002/M-19-666. Attachment M1, p. 240. Available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/IntegratedDistributionPlan.pdf.

[109] Ibid.

[110] Conversation about system resiliency with Xcel distribution planning team, April 23, 2021.

[111] Ibid.

hours through switching and/or substation transformer restoration, and in approximately 24 hours if a mobile transformer must be deployed to replace a damaged transformer.[112]

Xcel is also enhancing the resiliency of the grid through grid modernization programs and related efforts. For example, Xcel's Advanced Grid Intelligence and Security (AGIS) Initiative consists of multiple elements that work together to create a more modern and advanced distribution grid. These elements include:

1) Advanced Distribution Management System (ADMS): Consists of a real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices; and

2) Advanced Metering Infrastructure (AMI): Consists of an integrated system of advanced meters, communication networks, and data management systems that enable secure two-way communication between Xcel's data systems and customer meters.[113]

Protective cyber security and information technology (IT) support underlie these components.[114]

Lastly, Xcel is investigating programs like its Community Resiliency and Resiliency as a Service Program to make its distribution system more resilient through the use of distributed generation and microgrids. The Community Resiliency program involves working with communities to identify strategic locations, such as a community center or facility that provides essential services, where Xcel would provide additional back-up power with a microgrid during an extended or widespread outage.[115] Xcel plans to install the equipment necessary to provide back-up power at one strategic location in 2022.[116] In the Resiliency as a Service Program, Xcel is seeking qualified vendors to interconnect DERs and microgrids to commercial and industrial customers that have a need for higher than standard service reliability.[117]

## 3.6. Balancing grid security with the public benefits of HCA map data

### *3.6.1. Overview*

In recent years, there has been a growing trend towards access of large amounts of data as it has become increasingly important for innovation, smart decision-making, economic growth, and the public good. Data access can support disaster response, agricultural and food security, mitigating climate change, and improving healthcare. For example, public access to sensitive health records sped up the

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[112] Ibid.

[113] Xcel Energy. 2019. *2019 Integrated Distribution Plan.* p. 147.

[114] Ibid.

[115] Id., p. 114.

[116] Ibid.

[117] Xcel Energy. "Resiliency as a Service: Request for Qualifications." Available at: https://www.xcelenergy.com/working_with_us/renewable_developer_resource_center/resiliency_as_a_service_request_for_qualifications.

development of lifesaving medical treatments like the coronavirus vaccines produced by Moderna and Pfizer. And the federal government has created a website (data.gov) that hosts and assembles hundreds of thousands of data sets for public use, democratizing knowledge for the digital age. Economics tells us that society needs more data sharing rather than less, because the benefits of publicly available data often outweigh the costs.[118]

Access to distribution grid data for energy developers and other third parties is in the public's interest because it can increase the transparency of the utility's provision of electrical services, assist in the identification of potential DER interconnection sites, and help enable developers to accelerate progress towards decarbonizing Minnesota's grid through the efficient deployment of DERs.

However, there is also a growing recognition that vulnerabilities exist in the energy sector, including in the distribution system, and can potentially be exploited by domestic and foreign bad actors. Therefore, there must be a balance between increasing the availability of grid data for the public good while also appropriately protecting it from foreign and domestic threats.

The Commission has provided an opportunity to reconcile these competing objectives. On October 30, 2020, the Commission requested comments on "Grid and Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data" to help address the question of how we can increase the availability of grid data for the public good, while also protecting it from threats which could potentially lead to an attack on the grid.[119]

The following sections outline how energy developers benefit from increasing access to distribution grid data, how utilities in Minnesota and California currently address grid and customer security risks posed by revealing sensitive grid data on their hosting capacity maps, the types of hosting capacity information that utilities leading in this space reveal, the severity of the types of risks posed by making this grid data available, and recommendations on how to potentially move forward with addressing the competing demands of making the grid data public.

### *3.6.2. Public Benefits of Access to Hosting Capacity Grid Data*

<u>Overview</u>

Fundamentally, hosting capacity maps provide information on the distribution system that can be used by third parties such as energy customers and developers, entrepreneurs, researchers, policy makers, clean energy advocates, and others, to deploy DERs more efficiently and effectively on the grid. This helps make the grid more reliable and resilient to threats (e.g., natural disasters) while simultaneously

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[118] Deming, David. February 19, 2021. "Balancing Privacy with Data Sharing for the Public Good." *New York Times*. Available at: https://www.nytimes.com/2021/02/19/business/privacy-open-data-public.html.

[119] Docket No. E002/M-19-685, *In the Matter of Xcel Energy's 2019 Hosting Capacity Analysis Report, Notice of Comment Period*, October 30, 2020; Docket No. E999/CI-20-800*, In the Matter of a Commission Investigation on Grid and Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data, Notice of Comment Period*, October 30, 2020.

advancing clean energy policy goals. Access to this information also increases transparency, which reduces the effects of utility monopoly control that result from the information asymmetry that naturally exists between electric utilities, and DER developers trying to supply customers' energy needs. Leveling the information playing field boosts public participation and results in more informed competition, thereby strengthening the local economy.

Benefits of Hosting Capacity Map Information for Policymakers

Hosting capacity map data can help inform public policymakers' efforts to decarbonize and modernize the electric grid, meet renewable portfolio standard (RPS) targets, and mitigate the effects of climate change. The transition to a low-carbon economy requires the electrification of vehicles and buildings, and the public infrastructure necessary to do so. The data in hosting capacity maps could help inform city planning programs to build public infrastructure in support of beneficial electrification. For example, the City of Minneapolis noted that publishing distribution grid data on hosting capacity maps would be helpful in its efforts to expand electric vehicle charging.[120]

Benefits of Hosting Capacity Map Information for Entrepreneurs and Companies

As we transition to an increasingly digital economy, data-driven innovation is at the heart of its success. Data made available on hosting capacity maps could be used by innovative entrepreneurs and companies to create new systems, processes, or products to solve a societal problem or meet a measurable need. One innovative U.S. startup layers hosting capacity map information on top of its data analytics platform, which enables DER developers to quickly screen sites across multiple locations based on hosting capacity, topography, and environmental characteristics (e.g., wetlands). Facebook applies custom algorithms to various public datasets to predict the locations of existing medium-voltage electrical distribution infrastructure (e.g., distribution lines) to help governments, non-governmental organizations (NGOs), and businesses plan future infrastructure and community development projects.[121] These are just a few examples of the innovation resulting from public access to grid data.

Benefits of Hosting Capacity Map Information for DER Developers

Hosting capacity maps are an integral tool for energy developers to identify prime locations for siting DERs on the distribution grid. Solar and storage developers rely on these maps to inform their prospects for locating projects, and ultimately to interconnect DERs to the grid. This not only benefits DER project developers, but also utilities that are looking to defer or avoid more costly traditional grid infrastructure. It may also help streamline the interconnection process since developers will have the necessary distribution system information to conduct their own preliminary project screens before formally applying for interconnection. The value of different types of hosting capacity information to developers for optimally siting DERs is shown in Table 8.

[120] *Hosting Capacity Analysis and Distribution Grid Data Security Workshop.* Docket No. E999/CI-20-800. (March 17, 2021).

[121] Facebook, Inc. "Data for Good. Electrical Distribution Grid Maps." Available at: https://dataforgood.fb.com/tools/electrical-distribution-grid-maps/.

**Table 8: Benefits of Hosting Capacity Information to Developers**

| Hosting Capacity (HCA) Map Elements | Benefits to DER Developer |
|---|---|
| Substation location and HCA data | • Determine substation level constraints (e.g., size and voltage of transformer)<br>• Identify equipment that may impact hosting capacity (e.g., load tap changer or regulator)<br>• Determine approximate distance from circuit to substation |
| Feeder location and HCA data | • Determine feeder HCA constraints for DER load and generation<br>• Assess if costly system upgrades are likely at a location given constraints<br>• Identify equipment that may impact HCA (e.g., voltage supervisory reclosing) |
| HCA criteria violations | • Determine which violation criteria (e.g., thermal, voltage) is causing the limit, identify appropriate technical solutions to overcome constraint(s), and estimate associated costs (e.g., for system upgrade) |
| Substation/feeder load profiles | • Screening tool for locating DER load interconnections (e.g., storage, EV chargers)<br>• Assess if costly system upgrades are likely at a location given constraints |
| DER connected and in queue | • Determine if hosting capacity is likely available to new projects |

In an April 2021 HCA map survey (Appendix B) of developers in Xcel's service territory, substation data was identified as particularly important for inclusion in the HCA map given its value in evaluating substation constraints for hosting additional DERs. 70 percent of those surveyed said the substation transformer's rating (e.g., size) and available generation capacity were essential information to have. 60 percent said substation load profile and forecasted feeder peak load were of significant benefit. Other information identified as very important was local voltage, secondary conductor size, and hosting capacity criteria violations for designing projects to avoid certain system constraints. 60 percent of survey respondents indicated that sub-feeder and secondary level data were both essential for making informed decisions about siting DER. All of the survey respondents noted that Xcel's HCA map needed more infromation to be useful, and 70 percent stated that it is currently not helpful as a tool for informing their decision to complete a DER interconnection request. Specific suggestions for improving the HCA map's utility as an indicator for optimally siting DER projects included updating the map more frequently, ensuring the accuracy of its information, and revealing the feeder lines so that developers can trace the power lines from an address to a specific node where HCA data is provided.

### *3.6.3. Grid and Customer Security: California*

<u>Background</u>

California had robust stakeholder discussions on balancing the benefits of making sensitive distribution grid data public, via online maps, with the grid and customer security concerns associated with doing so.

In 2010, the CPUC established the Renewable Auction Mechanism (RAM) program through Decision (D.) 10-12-048 to provide a streamlined process for California's three big IOUs[122] to procure RPS-eligible generation.[123] To provide stakeholders with greater access to information about the distribution grid in support of this program, the CPUC ordered the IOUs to publish grid data, at the substation and circuit-levels, in an online map.[124] In response, the IOUs created public PV RAM maps to make it easier for developers to identify prime locations on the grid to interconnect DERs. Figure 11 is an example of a PV RAM map and the type of grid data it provides. These maps were the precursor to California's ICA maps (e.g., hosting capacity maps).[125]

In 2018, during the process of working with the CPUC and several stakeholders to define what distribution grid data should continue being publicly shared, the California IOUs unilaterally removed the PV RAM maps from their websites. (Note: The maps were publicly accessible except for a two-month period between September and November 2018).[126] The California IOUs argued that no location-specific, distributed grid information (e.g., substations, feeders, circuits, and all related safety-and-security-sensitive data) should be made publicly available on their maps due to physical and cybersecurity concerns. Utility security officials elaborated that the information on the PV RAM maps: (1) provided a full connectivity layout of the distribution system, which would otherwise be very difficult to piece together and (2) could be used by a bad actor to commit a physical or cyber-attack on the grid.[127] They stated that malicious intent existed and that there was evidence of suspicious and unknown actors accessing the maps.[128] They also claimed that the maps were protected from public disclosure under the Critical Infrastructure Information Act of 2002[129] and that the release of the maps to the public should be done under an NDA, only giving access to third parties who demonstrated both a legitimate, specified need, and sufficient controls to protect the data from disclosure to the public.[130]

[122] PG&E, San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE).

[123] PG&E. "PG&E Renewable Auction Mechanism." Available at: https://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/RAM2011/index.page.

[124] R.08-08-009, Renewable Portfolio Standard Program, D.10-12-048, Decision Adopting the Renewable Auction Mechanism, December 16,2010, pp. 70-72.

[125] Integration Capacity Analysis (ICA) is interchangeable with hosting capacity analysis (HCA).

[126] IREC. *Comments of The Interstate Renewable Energy Council, Inc. on Xcel Energy's 2019 Hosting Capacity Analysis*. Docket No. E002/M-19-685. (December 30, 2019) Appendix B, p. 4.

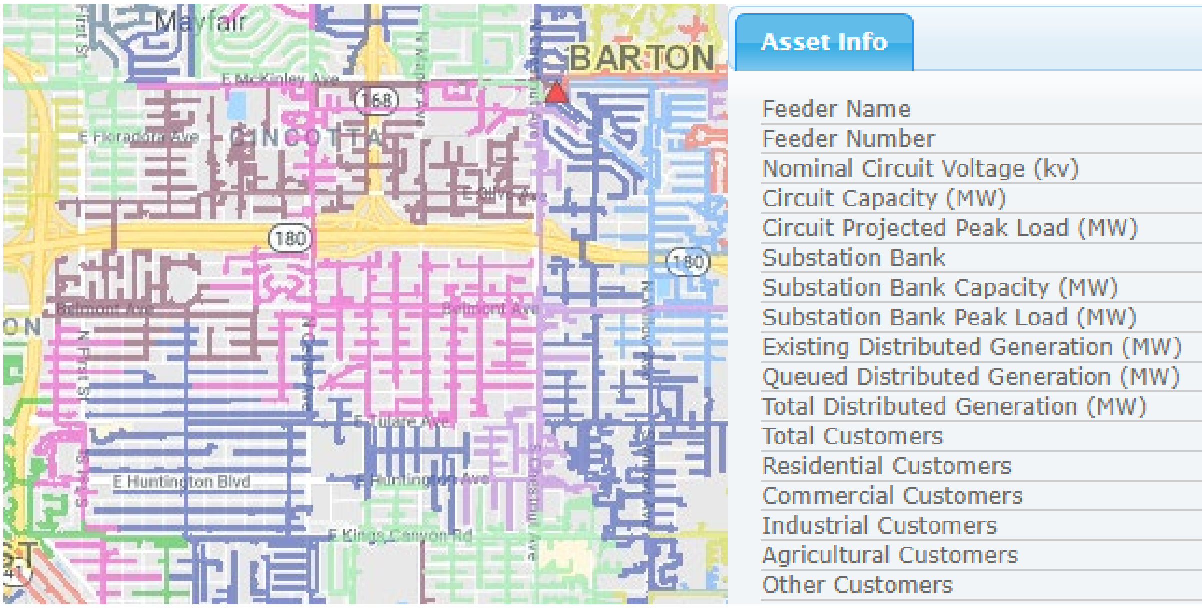
[127] Id., pp. 9-10.

[128] Id., pp. 9, 12.

[129] Id., p. 3.

[130] Id., p. 7.

**Figure 11: Example California PV RAM Map and Data Fields**




*Source: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page?ctx=large-business.*

In 2018, an Administrative Law Judge ruled that the CA IOUs had to make all of their distribution system maps, as well as related analyses, publicly available through a web portal; and allow third parties to access these maps through a user registration process without having to execute an NDA. [131] He also ruled that all information that is not confidential customer data under the 15/15 aggregation standard be published, unless the utilities are able to prove that the information they wish to redact or make subject to an NDA, meets the definition of CEII that should be protected from public disclosure on confidentiality grounds.[132]

Customer Confidentiality

The CPUC adopted the 15/15 standard to require the redaction of data "in order to ensure that the released data is sufficiently aggregated to prevent the identification of [CEUD] on individuals."[133] California ruling 14-08-013 described how customer privacy should be protected on hosting capacity maps:

> Data that includes distribution load, energy usage, or demand data at a local geo-spatial level shall be anonymized and aggregated to meet

[131] CPUC. *Order, Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*. Rulemaking 14-08-013. (July 24, 2018.) p. 15.

[132] Ibid.

[133] *Decision Adopting Rules to Provide Access to Energy Usage and Usage-Related Data While Protecting Privacy Of Personal Data.* (D.) 14-05-016. (May 1, 2014). p. 26-27.

> customer privacy requirements. The IOUs shall use the 15/15 Rule that the Commission established in D.97-10-031 and D.14-05-016 for data in the ICA...With respect to ICA, if the circuit level passes the 15/15 Rule but the line section does not, the IOUs shall aggregate the ICA results to the circuit level for display in the online maps and datasets. Stakeholders shall use the basic registration and log-in process to review the public DRP data with the customer privacy information redacted.[134]

As a result, California IOUs redact feeder load profile information, not the feeder itself, if it does not meet the 15/15 aggregation threshold.

Critical Infrastructure Protection and Customer Security

Initially, each IOU had a different approach to identifying and handling CEII. However, Rulemaking 14-08-013 established uniform criteria, informed by FERC and DHS definitions, for identifying data that should be classified as CEII for redaction purposes.[135] The rule also made it incumbent on the IOUs to show that the data met the redaction criteria. Each IOU that wants to redact CEII from the public-facing hosting capacity map must demonstrate that the redacted information fits within one or more of the following examples:

1. Distribution Facility necessary for crank path, black start, or capability essential to the restoration of regional electricity service that are not subject to the California Independent System Operator's operational control and/or subject to North American Electric Reliability Corporation Reliability Standard CIP-014-2 or its successors;
2. Distribution Facility that is the primary source of electrical service to a military installation essential to national security and/or emergency response services (may include certain airfields, command centers, weapons stations, emergency supply depots);
3. Distribution Facility that serves installations necessary for the provision of regional drinking water supplies and wastewater services (may include certain aqueducts, well fields, groundwater pumps, and treatment plants);
4. Distribution Facility that serves a regional public safety establishment (may include County Emergency Operations Centers; county sheriff's department and major city police department headquarters; major state and county fire service headquarters; county jails and state and federal prisons; and 911 dispatch centers);
5. Distribution Facility that serves a major transportation facility (may include International Airport, Mega Seaport, other air traffic control center, and international border crossing);

[134] CPUC. *Order, Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*. Rulemaking 14-08-013. (July 24, 2018.) pp. 11-12.

[135] Id., p. 20.

6. Distribution Facility that serves as a Level 1 Trauma Center as designated by the Office of Statewide Health Planning and Development; and
7. Distribution Facility that serves over 60,000 meters.[136]

To date, none of the California IOUs have taken these steps. Following FERC's approach, the ruling also adopted a protocol for interested stakeholders to get access to desired CEII by entering an NDA with the utility.[137] More specifically, stakeholders seeking to gain access to CEII must file a motion that explains what information they need, how they plan on using it, and why it is not available from a different source. If they are approved, they may then sign an NDA with the utility to access the requested information.

### *3.6.4. Grid and Customer Security: Minnesota*

Background

The Commission's July 31, 2020 Order in Docket No. E002/M-19-685 (the 2020 Order)[138] required Xcel to further discuss grid and customer security issues related to the public display or access to grid data, including distribution grid mapping, aggregated load data, and critical infrastructure in a proceeding[139] that includes additional parties, experts, and utilities.[140] It also required Xcel to separately evaluate and justify each privacy and security concern and to provide a full description and specific basis for withholding any information in its 2020 HCA.[141]

Public Display of Distribution Lines on HCA Map

In Pt. 12 of the 2020 Order, the Commission directed Xcel, to the extent practicable, to show the actual locations of distribution system lines instead of broad blocks of color on the HCA map. Figure 12 provides an example of Xcel's HCA map with blurred grid lines providing a "heat map" presentation.

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[136] Id., pp. 20-21.

[137] Id., p. 21.

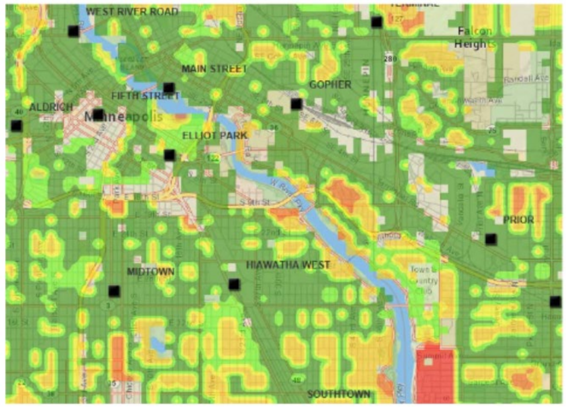
[138] *Order Accepting Report and Setting Further Requirements*. Docket No. E002/M-19-685. (July 31, 2020).

[139] The Commission initiated the proceeding on October 30, 2020, issuing a Notice of Comment Period in Docket Nos. E002/M-19-685 (Xcel's 2019 HCA proceeding) and E999/CI-20-800.

[140] Xcel Energy. *Distribution System–Hosting Capacity Analysis Report (HCA Report)*. Docket No. E002/M-20. (November 2, 2020). Attachment E, p. 1.

[141] Ibid.

**Figure 12: Example of Xcel Energy HCA Map Results**




*Source: 2020 HCA Report, p.9.*

While Xcel provides sub-feeder (e.g., line segment) level hosting capacity results, which vary at different points along the feeder, the map cannot be used to specifically identify the locations of the feeder line-segments for which those results are provided. Local energy developers frequently request that Xcel show the exact feeder lines on its map to help them more easily identify suitable DER interconnection locations. However, Xcel continues to state that doing so would risk grid security and customer confidentiality.[142] Xcel argues that an unblurred map would clearly lay out the electrical connectivity configuration of its distribution network, providing a bad actor with the information needed to plan an attack for maximum impact. Xcel further explains that revealing this information would allow a bad actor to identify which lines extend to specific substations and/or critical customer facilities and to determine the location of the system's major loads, rendering the distribution grid unnecessarily vulnerable. Xcel states that it does not intend to make it "easy" for a bad actor to obtain this type of information and claims that not publicly providing the detailed connectivity of its distribution system mitigates the increased threat of cyber and physical attacks.[143]

Customer Confidentiality

Xcel applies the 15/15 aggregation standard to determine if CEUD is sufficiently aggregated to be released. Xcel marks information that falls under the 15/15 threshold as protected data (e.g., Trade Secret information) and does not make it public.[144] Xcel excluded the feeders that did not meet its 15/15 aggregation threshold from its HCA map but included them in the HCA tabular spreadsheet with the rationale that publicly disclosing these feeders on the map would make it easier to identify actual customer connections and could compromise customer confidentiality.[145]

[142] Xcel Energy. 2020. HCA Report. Attachment A, p. 19.

[143] Id., Attachment E, p. 6.

[144] Id., p. 4.

[145] Id., p. 5.

Peak Substation Transformer and Feeder Load Data

The Commission's 2018 HCA Order required Xcel to "provide hosting capacity data by substation and feeder," including "peak load," in its public-facing hosting capacity map, "except to the extent that publicly disclosing this data would violate specific data privacy requirements or pose a significant security risk to Xcel's system or its customers."[146]

Xcel does not publicly provide the peak substation transformer load or peak feeder load data in its HCA map or table. Xcel states that load information is security information and contends that publishing peak load or maximum capacity information for its distribution system facilities could aid bad actors in planning an attack for maximum impact and disruption.[147] Xcel elaborates that such information can help adversaries plan and execute load manipulation attacks in ways that could lead to equipment damage and other disruptive effects.[148] Xcel adds that the data could also compromise the privacy or confidentiality interests of large or critical infrastructure customers.[149] Xcel legally justifies withholding this information noting that it is classified as "security " and "Trade Secret" information.[150]

Critical Infrastructure Protection and Customer Security

To align with protecting critical infrastructure sectors, as identified by DHS, Xcel identified customers and their associated feeder(s) that, in its judgement, would warrant protection based on the criticality of the loads they serve. These critical customers fell into the following categories:

- Critical Energy Infrastructure (similar to DHS Energy sector);
- Critical Hospitals - Level 1 or 2 Trauma Centers (similar to DHS Healthcare and Public Health sector);
- Critical Data Centers (similar to DHS Communications and Information Technology sectors); and
- Critical Public Gathering Center (similar to DHS Commercial Facilities sector).[151]

Xcel excluded a feeder from its HCA map when it was connected to critical infrastructure or did not meet its 15/15 aggregation threshold. Xcel excluded 115 out of a total of 1,050 feeders from its map.[152] However, Xcel provided data for all feeders in the HCA tabular spreadsheet. Xcel notes that the spreadsheet does not identify which feeders fall under the critical infrastructure sectors categories or

[146] *Order Accepting Study and Setting Further Requirements.* Dkt. E-002/M-18-684 (Aug. 15, 2019). Paragraphs 2.B, 2.C.

[147] Xcel Energy. 2020. HCA Report. Attachment E, p. 5.

[148] Xcel Energy. *Comments–Response to Notice Distribution Grid and Customer Security Docket Nos.E002/M-19-685 and E999/Ci-20-800* , Docket Nos. E002/M-19-685 and E999/CI-20-800, (January 21, 2021). Attachment B, p 3.

[149] Ibid.

[150] Xcel Energy. 2020. HCA Report. Attachment E, p. 5.

[151] Id., p. 4.

[152] Id., p. 3.

which are subject to privacy concerns, to not make it apparent for a bad actor to target sensitive feeders.[153]

### 3.6.5. *Discussion of Grid and Customer Security Concerns and Public Benefits*

Overview

Xcel states that there is growing recognition that the vulnerabilities of the energy sector are of particular concern to national security and that the electric grid is both highly vulnerable to attack and attractive to potential adversaries due to the dependence of all other critical infrastructure on it.[154] During the first HCA and Distribution Grid Data Security workshop, Xcel mentioned that it is constantly assessing threats and upgrading its defensive capabilities to secure the grid but noted that attackers only have to be successful once, while the utility has to be successful every time. Xcel further states that there are risks associated with access to certain distribution grid data whether it is provided publicly or with protections.[155]

While the likelihood and the scale of potential threats to the distribution systems are unclear, and the risk of disclosure of specific grid data may be unknown, it is not enough to state that risk exists. There is no disagreement that there is always some level of risk involved with sharing sensitive information, but attempting to quantify the level of risk and weigh it against the benefits of making certain grid data available to the public is essential. Xcel is generally aligned with this idea, and proposed a tiered-access approach to the provision of distribution grid data, which would enable appropriate access to relevant information while taking steps to reasonably maintain the security of the grid.[156] The following sections discuss some of the grid and customer security concerns associated with information that is currently withheld from Xcel's hosting capacity map as well as the potential benefits that this information could provide to the public.

Distribution Lines Should be Publicly Displayed on HCA Map

Xcel claims that an unblurred map would clearly lay out the electrical connectivity configuration of its distribution network, providing a bad actor with the information needed to plan an attack for maximum impact. Xcel maintains that revealing this information would also jeopardize customer security and confidentiality, by enabling bad actors to identify which lines extend to critical customer facilities, and to determine the locations of the system's major loads. Xcel also states that it does not want to make it "easy" for a bad actor to obtain this type of information, and claims that not publicly providing the

[153] Ibid.

[154] Xcel Energy. 2020. HCA Report. Attachment E, p. 1.

[155] Xcel Energy Comments, January 2021. p. 13.

[156] Id., p. 4.

detailed connectivity of its distribution system mitigates the increased threat of cyber and physical attacks.[157]

While it may be more difficult for a bad actor to piece together a map of the electrical connectivity of the distribution system than if Xcel provided it, that does not make it impossible to do so. There are publicly available resources, like Google Earth and Maps, which can assist in this task. Moreover, obscurity is not security. A less well-known target may appear more secure than it is. This is evident from the growing list of recent cybersecurity data breaches of U.S. companies. In fact, believing that concealed data is inherently more secure may provide a false sense of security and reduce a company's sense of urgency for bolstering its cybersecurity defenses. Furthermore, providing distribution system connectivity information does not necessarily lead to, or mitigate, physical or cyber threats from a bad actor, but strengthening the grid's physical and cybersecurity defenses, and enhancing the grid's reliability and resiliency does.

The following sections further elaborate on these comments.

<u>Various Tools Available to Map Distribution System Infrastructure</u>

There are a variety of tools available to help map the locations of distribution system facilities and an attacker could use a combination of these tools to launch an attack. For example, an attacker could easily identify substation locations in Minnesota using the publicly available geospatial substation data on the DHS Homeland Infrastructure Foundation-Level Data website[158] and use it with satellite imagery from Google Earth to trace the path of distribution lines to a substation. Google Maps can also be used to identify the physical locations of substations. There are also private companies such as Kevala Analytics, which uses its Grid Assessor[159] software to identify distribution system infrastructure, including substations and feeders, across the United States to help developers quickly find ideal project locations for DERs. Facebook created a predictive model using publicly available datasets, including NASA satellite imagery, to predict the locations of distribution lines.[160] Facebook also provides information on how to use the model and the code is open source. However, it is not necessary for a bad actor to use an online geospatial tool or analytical model. S/he could simply locate a substation and/or a critical customer facility, like a hospital, and visually trace the power lines emanating in either direction to plan an attack. The National Research Council (NRC) further highlights the fact that sensitive grid information is already in the public domain, stating:

> High-value choke points, those facilities which, if destroyed, will significantly degrade power systems capabilities, are easily located either on the ground or

[157] Xcel Energy. 2020. HCA Report. Attachment E, p. 6.

[158] Department of Homeland Security (DHS). "Homeland Infrastructure Foundation-Level Data." Available at: https://hifld-geoplatform.opendata.arcgis.com/.

[159] Kevala Analytics. "Grid Assessor." Available at: https://kevalaanalytics.com/grid-assessor/.

[160] Facebook, Inc. "Data for Good, Electrical Distribution Grid Maps." Available at: https://dataforgood.fb.com/tools/electrical-distribution-grid-maps/.

> from system maps. Detailed maps of the U.S. power system were once readily available in the public domain and on the Internet. Despite attempts to control access to such maps, they can still be easily obtained. Commercially available satellite data, as well as direct observation on the ground, can also be used to readily update and confirm system map information for potential attackers.[161]

Thus, rather than focusing on not providing access to information about the locations of feeders and substations, which is likely already in the public domain or can be constructed, the utility should focus on bolstering its physical and cybersecurity defenses in case of an attack, and on enhancing the reliability and resiliency of the grid in general. Some ways to accomplish this are to harden distribution infrastructure (e.g., feeders and substations), underground feeder lines, improve surveillance equipment, and improve planning on how to repair and restore facilities in case of an attack.[162] In a report for the Department of Defense, the RAND Corporation, a research organization that helps develop public policy solutions to address security risks, highlighted the importance of improving the reliability and resiliency of the grid to deter would-be adversaries from attacking or "deterrence by denial."[163] RAND states that knowledge of such investments to strengthen the grid might have a deterring effect by reducing or removing the perceived benefits that an adversary associates with an attack.[164] RAND further notes, that "in addition to providing value through deterrence of adversary attacks (cyber-related or otherwise), investments in measures aimed at limiting or denying adversary success serve a broader purpose of improving mission resilience to power disruptions resulting from natural disasters, operator error, or equipment failures."[165]

<u>Hosting Capacity Maps Generally Show Feeder Lines</u>

Typically, publicly available hosting capacity maps of U.S. electric utilities leading in this space show the distribution system feeder lines to assist developers in locating optimal sites for DER deployment. HCA maps should be sufficiently detailed to be useful to stakeholders. Xcel provides HCA results at the sub-feeder level. Other U.S. electric utilities leading in the development of HCA maps are also providing HCA results at the sub-feeder level. This is a granular level of distribution system detail, which is useful for DER developers who want to determine the part (e.g., line segment) of a feeder with the most hosting capacity. In Xcel's HCA map, this granularity is lost because the actual feeders are blurred.

High voltage transmission lines are generally less resilient to attack than distribution lines due to distribution circuit redundancy (e.g., "auto-loop" radial grids or network grids) which helps to quickly

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161 National Research Council. 2012. *Terrorism and the Electric Power Delivery System.* pp. 32-33.

162 Id., pp. 34-36.

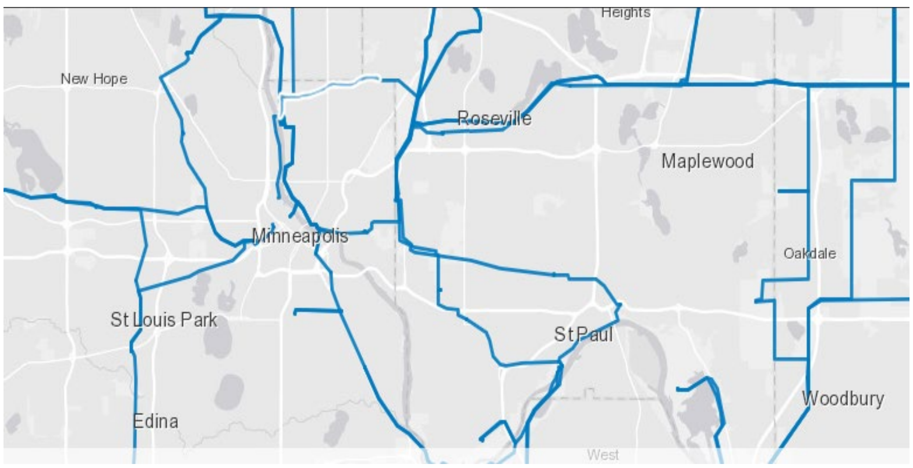
163 Narayanan, Anu, Jonathan William Welburn, Benjamin M. Miller, Sheng Tao Li, and Aaron Clark-Ginsberg. 2020. *Deterring Attacks Against the Power Grid: Two Approaches for the U.S. Department of Defense.* RAND Corporation. p. x. Available at: https://www.rand.org/content/dam/rand/pubs/research_reports/RR3100/RR3187/RAND_RR3187.pdf.

164 Ibid.

165 Ibid.

isolate a fault or provide redundant sources of backup power in the case of failures on the grid. Yet, despite the inherent, and generally higher, vulnerabilities in transmission lines and their potential to cause widespread outages when down, the DHS provides public, searchable, geospatial maps showing the locations and voltages of transmission lines across the United States in support of community preparedness, resiliency, and research.[166] Figure 13 provides an example of the DHS transmission line map. If the DHS, which has identified energy as a critical infrastructure sector whose assets and networks are vital to U.S. national security, publicly displays the entire country's electric power lines, it also seems reasonable that a local electric utility should show the distribution lines on its HCA map for the public good.

**Figure 13: DHS, Homeland Infrastructure Foundation-Level Data Transmission Lines**




*Source: DHS, Homeland Infrastructure Foundation-Level Data. https://hifld-geoplatform.opendata.arcgis.com/*

Distribution Systems Are Lower Value Targets than Transmission Systems

While the likelihood and the scale of potential threats to distribution systems are unclear, to date there have been no reported terrorist attacks on distribution system infrastructure in the United States. This could be due, in part, to the fact that distribution systems are lower value targets relative to the transmission (e.g., bulk power) system. A 2018 CPUC staff report noted that distribution assets are not attractive, high-value targets and that the vast majority of "physical security" incidents on the distribution system consist of minor property crimes including vandalism, copper theft, and trespassing.[167] Moreover, distribution system resiliency and redundancy to ensure reliability make it a lower value target. The CPUC report noted that distribution systems that incorporate automation can often isolate a problem and restore service for affected customers in a matter of seconds or minutes.[168]

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[166] DHS. "Homeland Infrastructure Foundation-Level Data." Available at: https://hifld-geoplatform.opendata.arcgis.com/.

[167] CPUC. 2018. *Security and Resilience for California Electric Distribution Infrastructure: Regulatory and Industry Response to SB 699.* pp. 38-39.

[168] Ibid.

It further explains that if a distribution substation transformer were targeted by a physical attack, operators typically could respond by remote-grid-switching to bypass the affected substation, and reliability response teams could dispatch replacement parts such as distribution transformers, often within 24 hours.[169]

In contrast, there is general agreement among security planners that key high-voltage substations are the most worrisome terrorist targets within the power transmission system.[170] They are difficult to protect and replace. Additionally, transmission lines can temporarily be disabled by fairly simple means such as shooting insulators on a tower.[171] On some transmission lines, taking out a tower can cause a domino effect, resulting in a cascade collapse of several adjacent towers, and taking out a tower where two lines cross, can disable both circuits simultaneously.[172]

Significant Benefit to Developers of Knowing Locations of Distribution Lines

There is a considerable benefit to developers knowing the locations of distribution lines on Xcel's HCA map to identify potentially suitable sites for deploying DERs. During the second HCA and Distribution Grid Data Security workshop, Xcel remarked that it frequently gets requests from DER developers to reveal the locations of its feeder lines. This is a clear indication of the value to, and need for, DER developers to have this information. Xcel suggests striking a balance between the need to share sensitive information with the need to protect it[173] and supports "a tiered-access approach to the provision of distribution grid data, based on its necessity and value to achieving a defined and specific public purpose."[174] While this sounds reasonable at the surface, it is important to dig deeper into what Xcel means by this statement. Greater clarity is provided in Xcel's discussion of integrating its Pre-Application Report with the HCA. Xcel states: "the Pre-Application Data Report requires the requestor to sign a Non-Disclosure Agreement, which is necessary because the Company maintains some of the data provided as non-public. This would not change with an integrated process/tool."[175]

A tiered-access approach that requires an NDA to view the distribution lines on the HCA map is unduly burdensome. This would essentially make the entire HCA map confidential instead of specific pieces of grid data (e.g., feeder peak load). In general, HCA maps are created to provide stakeholders with greater access to information about the distribution grid with the goals of promoting competition, decreasing the costs of achieving RPS policy objectives, and increasing transparency so that DER developers, and not just the electric utility, can make informed decisions about how best to site DERs on the grid.

[169] Ibid.

[170] National Research Council. 2012. *Terrorism and the Electric Power Delivery System.* p. 33.

[171] Ibid.

[172] Ibid.

[173] Xcel Energy Comments, January 2021, p. 12.

[174] Id., p. 4.

[175] Xcel Energy. 2020. HCA Report. Attachment F, p. 16.

Knowing the locations of feeder lines is a fundamental component of a useful HCA map. Over-classifying essential HCA map information, like the locations of feeder lines, creates a significant barrier to developers for obtaining the requisite information needed to conduct quick, initial screens for locating preferred interconnection points. These barriers to information about the distribution grid would increase costs for developers and customers and decrease the efficiency of the interconnection process.[176] Borrego Solar, a leading U.S. commercial-scale solar and storage project developer, amplified this point. It noted that the Borrego Solar development team frequently uses HCA maps during the early stages of project development to identify optimal grid locations for siting its systems.[177] The company explained that requiring an NDA to access this information would "hamstring" the development process by adding layers of bureaucracy which would "significantly slow down" its efforts to develop large-scale solar and storage projects.[178] It elaborated that an NDA would require multiple parties within the company to sign it to utilize the information, and by extension, its customers, who would have to sign as well for the company to be able to communicate information in the map applicable to the customer's project.[179] The NDA would also create liability for disclosure or misuse of the data, and an inadvertent disclosure by a small solar company to a customer over the course of its interactions while developing a project could be legally and financially devastating.

Customer Confidentiality

Xcel applies the 15/15 aggregation standard to determine if CEUD is sufficiently aggregated to be released and uses this aggregation threshold to exclude feeders from its HCA map. Other states like Colorado and California also use the 15/15 standard to protect CEUD.[180] However, the issue is not using the 15/15 standard to protect CEUD but rather its application to Xcel's HCA map, where it is used to remove the feeder, and all corresponding HCA data, even if it is unrelated to a customer's energy use. Xcel justifies redacting the feeder when it violates the 15/15 threshold stating that "showing this information on the heat map would make it easier to identify actual customer connections and risk erosion of customer confidentiality protection."[181] Xcel explains that low density feeders serving fewer than 15 premises, which is the same threshold it applies to requests for aggregated CEUD feeders, may provide insights into those customer locations that could compromise customer confidentiality and/or customer energy security.[182] The Interstate Renewable Energy Council (IREC), a non-profit organization

[176] *Response of the Joint Parties to Joint Petition of PG&E, SDG&E and SCE for Modification of D.10-12-048 and Resolution E.4414 to Protect the Physical Security and Cybersecurity of Electric Distribution and Transmission Facilities,* Rulemaking 08-08-009. (January 9, 2019). p. 16.

[177] Declaration of Rachel Bird on behalf of Borrego Solar Systems, Inc., Rulemaking 08-08-009, D.10-12-048 and Resolution E.4414. Appendix B.

[178] Ibid.

[179] Ibid.

[180] *Comments of the Interstate Renewable Energy Council, Inc. (IREC) on Xcel's 2020 Hosting Capacity Analysis.* Docket No. E002/M-20-812. (April 7, 2021). p. 21.

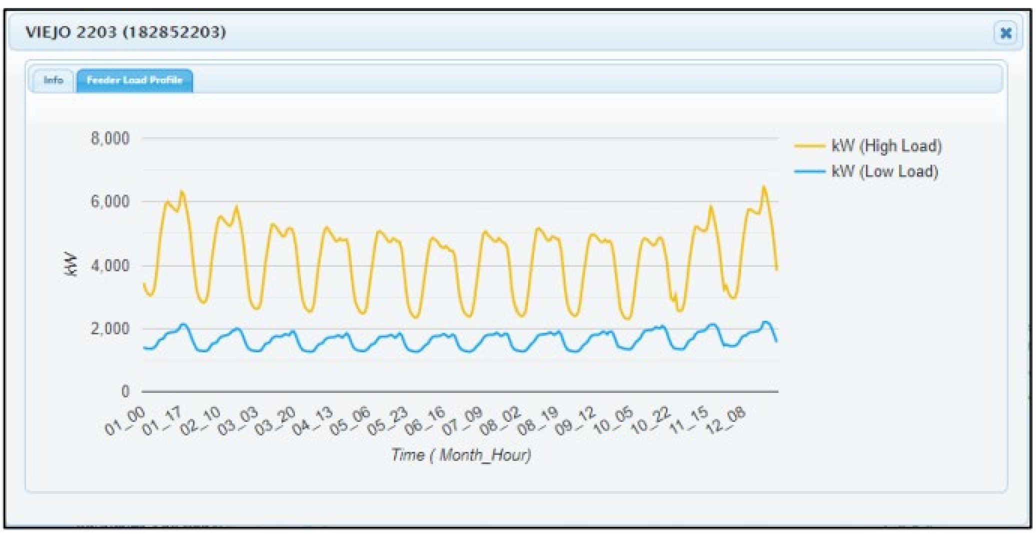
[181] Xcel Energy. 2020. HCA Report. Attachment E, p. 5.

[182] Ibid.

working to expand consumer access to clean energy, stated that "using the 15/15 standard to redact data that is not in any way related to a customer's energy use is an incorrect application of the standard" and noted that "protecting customer privacy is not a valid rationale for withholding data that has nothing to do with customer energy use."[183] IREC stated that the purpose of protecting CEUD is to prevent third parties from accessing the energy use patterns of a specific customer and not to prevent the identification of the feeder that the customer connects to.[184] IREC explained that knowing that a feeder has fewer than 15 customers or one customer with more than 15 percent of the load does not reveal the customer's data.[185] Participants in Xcel's September 2020 HCA stakeholder workshop also requested that the HCA map include all the basic distribution system data, as long as it does not violate the 15/15 rule regarding customer data privacy.[186]

California utilities also apply the 15/15 standard to protect customer load information in their HCA maps; when a feeder or substation violates this standard, the load profile data, which includes minimum and peak load, is redacted. However, the exact location of the feeder lines are published on the map and all non-load (e.g., non-CEUD) data is published. Figure 14 provides an example of how one California IOU displays a feeder's load profile in its HCA map.

**Figure 14: PG&E Feeder Load Profile**




*Source: PG&E ICA Map User Guide, p. 9, https://www.pge.com/b2b/distribution-resource-planning/downloads/integration-capacity/PGE_ICA_Map_User_Guide.pdf*

[183] IREC Comments on Xcel's 2020 Hosting Capacity Analysis. p. 22.

[184] IREC Comments on Xcel's 2019 Hosting Capacity Analysis. p. 21.

[185] Ibid.

[186] Xcel Energy. 2020. HCA Report. Attachment E, p. 2.

It is important not to conflate the issues of customer confidentiality and grid security. If a feeder violates the 15/15 standard, the appropriate measure to protect a customer's privacy is to remove CEUD. Customer load data directly relates to CEUD. Thus, it would be appropriate to redact different types of load information like peak load and absolute minimum load from the feeder. However, the feeder itself should not be redacted based on a violation of the 15/15 standard unless it is dedicated to a single, large energy consuming customer (e.g., skyscraper), which could then reveal its energy use patterns. Generally, this would represent a spot network, which is a small network grid that is implemented for a single, large energy user. However, Xcel's HCA excludes network feeders so this should not be an issue.[187] Furthermore, if the feeder is connected to a critical customer or infrastructure, as defined by Xcel's critical infrastructure categories, then that feeder should be redacted. One northeast IOU[188] follows a similar approach, only redacting feeders from its HCA map which are connected to critical customers or that serve a dedicated customer. The utility noted that it does not redact information that could easily be identified by simple visual surveillance (e.g., walking around the block and examining distribution lines). Finally, HCA maps which reveal feeder lines do not show locations of any individual customer or service connections (e.g., how they are electrically fed from equipment). For example, to protect customer privacy on its hosting capacity map, Pepco notes that distribution circuits are represented as a colored line without any equipment shown. These colored lines extend to premises which are just depicted as gray blocks.[189]

In summary, given stakeholders' desire to have HCA results and non-CEUD information made available on the HCA map when a feeder does not meet the 15/15 standard, how other utilities appropriately balance providing HCA results and feeder locations while not revealing customer privacy (e.g., CEUD) on their maps when similarly applying the 15/15 standard, and Xcel's prerogative to redact feeders from its map that violate CEII and critical customer group screens, the Commission should allow Xcel to only redact load data, and require it to publish all other HCA data on its map when the application of the 15/15 standard calls for the redaction of CEUD to protect customer privacy.

<u>Peak Substation Transformer and Feeder Load Data</u>

Xcel does not publicly provide the peak substation transformer load or peak feeder load data in its HCA map or table. It claims that publicly publishing peak load or maximum capacity information for its distribution system facilities could aid bad actors in planning an attack for maximum impact and disruption.[190] Xcel noted that the data could also compromise the privacy or confidentiality interests of large or critical infrastructure customers, and noted that while it can mitigate customer privacy and

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[187] Id., p. 3.

[188] Synapse communication, April 7, 2021.

[189] Steffel, Steve. 2020. *Hosting Capacity - Lessons Learned*. Pepco Holdings. p. 24. Available at: https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-SSteffel.pdf.

[190] Xcel Energy. 2020. HCA Report. Attachment E, p. 3.

confidentiality concerns by applying the 15/15 standard, customer and grid security concerns remain.[191] Xcel also noted that developers who attended its 2019 Workshop, or participated in the post-workshop survey, did not state that peak load was a necessary or useful piece of information, even when prompted.[192] IREC countered that Xcel did not survey a diverse enough group of developers to make that assertion and argued that customers and developers need peak load data to strategically locate DERs that are load sources, such as electric vehicles and energy storage.[193] IREC added that a load profile could be used by customers with DERs (e.g., energy storage) looking to provide the valuable service of peak load shaving (e.g., reducing peak load hours).[194]

Given competing claims about the value of this information to DER developers, and the risks associated with publicly providing it, a Risk-Benefit Framework, as proposed in Section 4.2, should be applied to help determine whether substation and feeder peak loads should be publicly provided as requested by the Commission. This framework will help to weigh the need for this information by a diverse group of DER developers (e.g., storage, electric vehicle, and solar) against the customer and grid security risks of publishing it.

Critical Infrastructure Protection and Customer Security

Xcel excluded a feeder from its HCA map when it was connected to critical infrastructure as defined according to its five critical infrastructure categories.[195] Given the importance of protecting critical infrastructure and customer groups, this approach seems reasonable. However, to increase transparency with the public, Xcel should specify in greater detail the types of customers that may fall into any other categories of critical, grid-dependent customers. During the second HCA and Distribution Grid Data Security workshop, Xcel noted that other types of critical customers could include airports, for example. However, Xcel should make this list explicit. It is clear what Xcel means by Critical Hospitals (Level 1 or 2 Trauma Centers), Critical Data Centers, and Critical Public Gathering Centers (e.g., stadiums); and while slightly less clear, in the case of the Critical Energy Infrastructure category, it is still understandable.

Like California, Xcel should also create a transparent process for how third parties can access CEII, on a "need-to-know" basis, with appropriate protections (e.g., NDA) in place.

## 3.7. HCA Map Integration with Pre-Application Data Report

[191] Ibid.

[192] Ibid.

[193] IREC Comments on Xcel's 2019 Hosting Capacity Analysis. p. 23.

[194] Ibid.

[195] Xcel Energy. 2020. HCA Report. Attachment E, p. 4.

### 3.7.1. Background on Pre-Application Report Integration

Xcel stated that one of the most common stakeholder requests was integration of the information contained in the pre-application data report with the HCA map for potential interconnection customers. Together, these two items provide a baseline determination of whether DER interconnection in a particular location is viable. According to Xcel, although there would be clear benefits to integrating pre-application data with the HCA map, there would also be significant costs and technical barriers. For example, additional querying functionality would need to be added to the map, and some information would need to be excluded for security and privacy reasons.[196] In the 2020 HCA report, Xcel estimated that fully integrating the Pre-Application Report with the HCA would take one year and cost between $600,000 and $1.2 million.[197] The Commission directed Xcel to continue working with stakeholders to identify opportunities to integrate the HCA and the Minnesota DER Interconnection Process (MN DIP) Pre-Application Report in future iterations of the HCA.

### 3.7.2. Pre-Application Report Confidentiality

Xcel Energy, Minnesota Power, and Otter Tail Power require that interested parties sign a confidentiality agreement prior to receiving a Pre-Application Report. The Minnesota Power and Otter Tail Power's Pre-Application Request Forms include the following text:

> I understand that the confidentiality provisions of MN DIP Section 5.9 apply to the contents of the Pre-Application Report...Each Party shall hold in confidence and shall not disclose Confidential Information, to any person (except employees, officers, representatives and agents, who agree to be bound by this section). Confidential Information shall be clearly marked as such on each page or otherwise affirmatively identified. … Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information. … Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

Xcel has the same MIN DIP confidentiality provisions embedded in its tariff[198] and on its Pre-Application Request Form it states: "Xcel Energy will require that you sign an NDA prior to receiving Pre-Application Data Report - you will receive the NDA after we receive this form and associated fees. Note that a

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[196] *In the Matter of Xcel's 2019 HCA Report. Order Accepting Report and Setting Further Requirement*. Docket No. E-002/M-19-685. (July 31, 2020).

[197] Xcel Energy. 2020. HCA Report. Attachment F, p. 16.

[198] Northern States Power Company. *Minnesota Electric Rate Book – MPUC No. 2. Distributed Resources.* Section No. 10-212. Available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/Renewable%20Developers/Me_Section_10.pdf.

separate NDA will be required for each location screened." [199] Xcel also states that the data listed below are:

> Confidential Information, are non-public, and are subject to the Confidentiality provisions in MN DIP section 5.9, as well as the confidentiality provision contained in the signed Pre-Application Report Request Form:
>
> - Transformer Rating (MVA)
> - Transformer Peak Loading (MVA)
> - Available Transformer Generation Capacity
> - Feeder Rating at head end (MVA)
> - Feeder Peak Loading at head end (MVA)
> - Available Feeder Generation Capacity at the head end
> - Protective devices and regulators between site and substation
> - Conductor(s) between sites and substation
> - Other existing or known constraints, including, but not limited to, short circuit interrupting capacity issues, power quality or stability issues, capacity constraints.

Dakota Electric Association currently does not have any confidentiality requirements that Pre-Application Report requestors must sign but indicated that it may do so in the future. [200]

To date, Dakota Electric, Minnesota Power, and Otter Tail Power have received few Pre-Application Request Forms. Dakota Electric received three Pre-Application Request Forms since it began offering them.[201] Minnesota Power processed two Pre-Application Reports in 2020 and eight so far as of April 2021.[202] Otter Tail Power has not had to process a Pre-Application Report.[203] However, Xcel received and processed 368 Pre-Application Report requests in 2020.[204]

### *3.7.3. Value to Stakeholders of Integrating Pre-application Report with HCA*

On September 10, 2020, Xcel held a stakeholder workshop exploring how the HCA could be integrated with the Pre-Application Report. Participants stated that they use the Pre-Application Report to find suitable project sites, to identity potential landowners, and to obtain more detailed information about relevant feeders and substations of interest, among other applications. Participants also noted that the

[199] Xcel Energy. "Pre-Application Data Request." Available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/Renewable%20Developers/Pre-Application-Data-Request.xlsx.

[200] Synapse email correspondence with Dakota Electric Association on April 12, 2021.

[201] Synapse email correspondence with Dakota Electric Association on April 13, 2021.

[202] Synapse email correspondence with Minnesota Power on April 13, 2021.

[203] Synapse email correspondence with Otter Tail Power on April 12, 2021.

[204] *Xcel Energy Compliance Filing – 2020 Interconnection – Corrected Generic Standards for Interconnection and Operation of Distributed Generation Facilities*, Docket Nos. E999/CI-01-1023 and E999/CI-16-521, (March 17, 2021), p. 7.

accuracy of the Pre-Application Report was the top priority, followed by a fast turnaround time.[205] One participant stated that the Pre-Application Report should be available quickly and that the current turnaround time of 15 business days is too long.[206] Participants also noted that the HCA map should provide the total queued and connected generation, at both the substation and feeder levels, to help developers better understand how an application may potentially be impacted by substation or feeder queue backlogs or substation capacity constraints.[207]

### *3.7.4. Comparison of Pre-Application Report Information with HCA*

Section 1.4.2 of the MN DIP requires the Minnesota electric utilities to "identify the substation/area bus, bank or circuit likely to serve the proposed Point of Common Coupling" in their Pre-Application Reports.[208] Xcel provides most of the information listed in its Pre-Application Report in its HCA in either map and/or tabular format. Table 9 lists all the data elements in Xcel's Pre-Application Report which are not included in the HCA in either map and/or tabular format, and Xcel's rationale for not doing so.[209] Table A-1 provides a complete list of Xcel's pre-application data elements and whether they are included in the HCA.

The Pre-Application Report information that is not included in the HCA is currently excluded for either privacy and security reasons, technical barriers, or both.

**Table 9: Comparison of Pre-Application Report data elements with HCA**

| Pre-application Data Element | Information Available on Map | Information Available in Tabular Format | Notes |
|---|---|---|---|
| Transformer Rating | No | No | Privacy/Security Concerns. |
| Transformer Peak | No | No | Privacy/Security Concerns. |
| Transformer Gen Capacity | No | No | Security concerns and significant technology requirement. Equation would need to be implemented within the map or prior to map creation. |

[205] Xcel Energy. 2020. HCA Report. Attachment D2, p. 12.

[206] Id., 13.

[207] Id., 4.

[208] MPUC. *Minnesota Distributed Energy Resource Interconnection Process (MN DIP) Version 2.3.* p.5. Available at: https://mn.gov/puc/assets/MN%20DIP_tcm14-431769.pdf.

[209] *Comments of the Interstate Renewable Energy Council, Inc. on Xcel Energy's 2019 Hosting Capacity Analysis.* Docket No. E002/M-20-812. (December 30, 2019). Attachment A: Xcel Energy's Response to IREC Information Requests Nos. 1-6. Dec. 17, 2019.

| Pre-application Data Element | Information Available on Map | Information Available in Tabular Format | Notes |
|---|---|---|---|
| Distance from site (PCC) to substation | No | No | Significant technology requirement. Query function would need to be built into Hosting Capacity Map. |
| Feeder Rating | No | No | Privacy/Security Concerns. |
| Feeder Peak | No | No | Privacy/Security Concerns. |
| Feeder Gen Capacity | No | No | Security concerns and significant technology requirement. Equation would need to be implemented within the map or prior to map creation. |
| Distance to 3 phase circuit | No | No | Significant technology requirement. Query function would need to be built into Hosting Capacity Map. |
| Protective devices and regulators between site and substation | No | No | Security concerns and significant technology requirement. Query function would need to be built into Hosting Capacity Map. |
| Conductor between site and substation | No | No | Security concerns and significant technology requirement. Query function would need to be built into Hosting Capacity Map. |

*Source: Xcel Energy's Response to IREC Information Requests Nos. 1-6. Dec. 17, 2019.*

### *3.7.5. Recommendation on Integrating Pre-Application Report with HCA*

During Xcel's workshop on integrating the HCA with the interconnection process, participants commented that the current interconnection process (MN DIP) was not working due to feeders and substation transformers that had capacity constraints, and long DER project queues (e.g., many projects "On Hold").[210] Xcel acknowledged that there have been problems with the MN DIP process; it stated that it is committed to making sure the process works better and is implementing process improvements.[211] One way for Xcel to help streamline the MN DIP process and address some of these issues is to integrate specific data fields from the Pre-Application Report into the HCA.

[210] Xcel Energy. 2020. HCA Report. Attachment D2, p. 3.

[211] Ibid.

Filing a Pre-Application Report adds time and expense to an initial DER project screen. There is currently not a central data repository at Xcel for all the information needed to complete a Pre-Application Report, which adds to the complexity and time required to fulfill these requests.[212] Furthermore, Xcel's Pre-Application Report states that data provided may become outdated and not useful at the time of submission of the complete Interconnection Request. To acquire additional information on various substations and circuits across multiple locations in the service territory using a Pre-Application Report would cost $300 per interconnection address. Therefore, if the HCA map were to include the Pre-Application Report data, especially the substation and feeder level generation capacity, this would make it quicker for developers to screen for beneficial DER sites and less expensive for them to apply for interconnection. It would also help to increase the overall efficiency of the interconnection process. This assumes that the information provided by the HCA map is current (e.g., refreshed monthly) [213] and accurate (e.g., data validation).

There is value to developers of integrating information which is currently listed in the Pre-Application Report into the HCA map. Xcel notes that the information in the Pre-Application Report, which is not provided in the HCA map, is not included for two main reasons. Capacity and loading data are not revealed for security reasons, while location-specific information, such as distance and equipment types, are impeded by technical limitations and the need for a query to be implemented within the map.[214] Where the information in the Pre-Application Report is not made public due to security concerns, the benefits to developers of having this information should be weighed against the risk of publicly revealing it.

While a Risk-Benefit Framework (Section 4.2) could be helpful in assessing whether to make some of the confidential information public based on the level of risk involved in doing so, special examination is needed to understand why the available generation capacity at the substation transformer and feeder levels is not already being made public. The security rationale for not providing the available generation capacity at the substation and feeder levels in the HCA is unclear, yet the benefit to DER developers of having access to this information is substantial. More specifically, it enables them to determine how to appropriately size their systems to mitigate constraints or informs their decision of whether to avoid certain constrained feeders altogether. Xcel states in its January 2021 Distribution Grid and Customer Security Comments that, at the substation and feeder levels, "aggregate levels of connected or in-queue distributed generation do not represent grid security risk" and could be made public.[215] HCA maps in New York and California provide connected/existing and in-queue distributed generation at the circuit level. California and New York IOUs provide substation capacity while California IOUs also provide feeder

[212] EPRI. 2020. *Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process*. p. 12.

[213] Xcel estimates that monthly HCA updates will take 3-4 years to complete, will have a project cost of $1.4M -$2.8M, and an annual incremental labor cost of $375,000 - $500,000.

[214] Xcel Energy. 2020. HCA Report. Attachment F, p. 16.

[215] Xcel Energy. *Comments – Response to Notice Distribution Grid and Customer Security.* Docket Nos.E002/M-19-685 and E999/CI-20-800 Nos. E002/M-19-685 and E999/CI-20-800. (January 21, 2021). Attachment B, pp. 4, 6.

capacity in their HCA maps. Given that Xcel does not classify installed, queued, or total distributed generation as confidential information, by extension, available capacity at the substation and feeder levels could also be made public. In a sense, Xcel is possibly providing feeder capacity by publishing maximum HCA results for a feeder. Hosting capacity at the head end of a feeder could possibly be the same as the "feeder rating" at the head. The former is based on the results of load flows, which account for impacts beyond just thermal limits, while the latter is only looking at the thermal (ampacity) of the equipment at the head end of the feeder. However, while the values may be different, they may also be the same. Thus, it seems reasonable that Xcel could publish the "feeder rating at the head end" on its HCA map. Or at minimum, Xcel could provide appropriate ranges for substation capacity (e.g., 10 MVA-20 MVA).

Where there are technology requirements rather than security concerns limiting integration of the Pre-Application Report data with the HCA, such as in the case of the distance from the site to the substation, Xcel should estimate the level of effort and cost to incorporate these data elements into the HCA. For example, Xcel estimated the cost of hiring a Geographic Information System (GIS) specialist to assist with updating and maintaining its HCA map.[216] Thus, Xcel could estimate the cost required to implement the equation(s) necessary to include the transformer and feeder generation capacity values in the map, as well as the cost for incorporating querying and search functionality. The latter improvement would enable users of the HCA map to determine the distance from the site to the substation or the distance to a 3-phase circuit, for example. DER developers in other states have noted the importance of querying functionality in hosting capacity maps for identifying suitable locations to interconnect DERs. However, an HCA map must first display the distribution lines before the querying/search functionality is incorporated. In the case of Xcel's HCA map, this feature would only be useful once the distribution lines are unblurred and so this should be the priority. Once this is achieved, Xcel could survey developers and other interested parties to determine the value of integrating the remaining Pre-Application Report data elements (such as the circuit distance from the point of coupling (PCC) to the substation, where a visual representation would be helpful) into the HCA map. The incremental benefits of integrating this additional information in the HCA could be balanced against the costs using a Cost-Benefit Framework as described in Section 4.3.

In summary, to really capture the value from integrating the Pre-Application Report with the HCA map, the priority should be for Xcel to unblur the map to reveal the feeder lines so that spatial information like the distance from the feeder to the substation can easily be visualized. Xcel should also prioritize increasing the refresh rate of its HCA map and validating its data so that it is accurate and current. This will enable customers to quickly screen for promising sites to inform their decision to interconnect DERs to the grid. Once Xcel accomplishes those tasks, integrating the remaining Pre-Application Report data into the HCA will be more useful to developers. However, in the interim, Xcel should clearly justify the security concerns it has regarding revealing substation and feeder thermal capacities given the tangible benefits to DER developers of having that information, and the fact that the feeder rating (thermal

[216] Xcel Energy. 2020. HCA Report. Attachment F, p. 14.

ampacity) at the head might already be public by using a feeder's max hosting capacity results as a proxy. A Risk-Benefit Framework could also assist in balancing the risks of publishing substation and feeder capacities and peak loads against the public benefits.

# 4. Frameworks for Assessing Inclusion of Grid Data in HCA Maps

## 4.1. Overview

Minnesota DER developers and other renewable energy stakeholders want to increase the availability of specific types of grid data on Xcel's HCA map to identify ideal locations for DERs and to promote beneficial electrification. Xcel also supports increasing DER penetration in its service territory and sharing grid data with developers but expresses concern that this needs to be done in a secure manner. There is always some level of risk or the possibility of an attack on the grid, but an appropriate framework can help to estimate and/or bound the risk and inform the Commission's decision on whether, and how, sensitive grid distribution data should be shared. Application of a relatively simple and transparent framework could help to balance the grid security risks of revealing sensitive data with the public benefits. The results of such a framework could then provide a basis to develop risk mitigation plans and data-sharing policies to satisfy competing stakeholder objectives.

The Risk-Benefit Framework (Section 4.2) and the Cost-Benefit Framework (Section 4.3) are two possible frameworks that could be applied to help strike a balance between the need to block adversary access to sensitive grid information and providing information to developers who could use it to deploy DERs more effectively.

The Risk-Benefit Framework is used to semi-quantitatively determine the risk to a critical asset (such as a substation) due to revealing sensitive information about it (e.g., on an HCA map) over a one-year period. The framework does this by estimating the probability of an attack and the resulting consequence if the attack were successful. Based on the expected value of the risk, it can be categorized as a low, moderate, or significant risk. The risk level for each critical asset evaluated would then be compared to the value of revealing information about the same asset to the public.

The Cost-Benefit Framework could be used to compare the costs and benefits to the public/ratepayer of publicly revealing specific grid information. The benefits would include the incremental customer and societal benefits of making the information public and the costs would include the costs to the utility of providing this information and of defending against a better-informed attack. A net public benefit would inform whether the specific grid information should be made public.

In general, the Risk-Benefit Framework should be applied first to determine the overall level of risk to an asset from revealing information about it. The Cost-Benefit Framework can supplement it, adding more details about the actual cost of providing the information when there is an incremental labor cost to doing so (e.g., HCA map enhancements such as formulas and search functionality). If there is no risk involved with providing specific information, then the Cost-Benefit Framework should be used instead since it focuses primarily on weighing the economic costs versus the benefits.

Every framework or model has its limitations, and it is important to acknowledge them. There are several limitations to the risk formula in the Risk-Benefit Framework, including trying to directly assess probabilities for the actions of bad actors instead of modeling their ability to intelligently adapt; its failure to adjust for correlations among its components; and the intrinsic subjectivity and ambiguity of the threat, vulnerability, and consequence numbers.[217] Despite the framework's limitations, it still has some value given its relative simplicity, and for using it as a starting point for transparent discussions between stakeholders regarding the level of risk to the grid from revealing sensitive information. It is unacceptable to state that there are myriad undefined threats or attack vectors that exist, and consequently, no sensitive grid information should be revealed on a hosting capacity map. Using a risk-based framework helps stakeholders gain a shared understanding of the information under consideration so they can discuss risk more tangibly. These discussions will likely need to take place in a secure setting. Additionally, while the Cost-Benefit Framework is useful in weighing the costs and benefits of competing demands, it is not an exact science and has limitations. However, it can be useful as another data point when evaluating the net societal benefits of publicly releasing sensitive grid data.

Regardless of the framework selected, stakeholder discussions of the framework(s) need to be transparent and inclusive. A diverse stakeholder group including but not limited to DER developers, clean energy entrepreneurs, electric utilities, consumer advocates, local government and non-governmental organizations, and grid security experts should actively engage in these discussions to enable a broad range of contributions. This will ensure a more transparent and fair process for balancing the grid security risks with the public benefits of sharing sensitive information. Input from developers and other grid stakeholders will be essential to help determine the value of specific types of information for DER projects and other related renewable energy development efforts. It is important to recognize that there will be asymmetric access to the information needed to analyze the frameworks between the utilities and the public (e.g., DER developers, energy organizations), and that only the utilities may have sufficient resources (e.g., time and staff) to fully engage. These are inherent limitations of the stakeholder working group process.

## 4.2. Risk-Benefit Framework

### *4.2.1. Overview*

Terrorist attacks such as 9/11 and natural disasters have heightened the nation's awareness of the risks to critical infrastructures. DHS released a risk-based performance standard, which is widely used by government agencies and industry, to estimate risk using the formula:

[217] Cox, Louis. 2008. *Some Limitations of "Risk = Threat × Vulnerability × Consequence" for Risk Analysis of Terrorist Attacks.* The Society for Risk Analysis. 28. 1749-61.

*Risk = Threat x Vulnerability x Consequence [Equation 1].*

Where:

Risk = The potential for loss or harm due to the likelihood of an unwanted event and its adverse consequences.

Threat = The probability that an adverse event will occur within a specified period, usually one year. The event could be any with the potential to cause the loss of or damage to an asset or population.

Vulnerability = The probability that the estimated consequences of the adverse event will ensue. For example, if the adverse event is a terrorist attack, the "threat" is the probability of the attack occurring and the "vulnerability" is the probability of the attack succeeding.

Consequence = The outcomes of an event occurrence, including immediate, short- and long-term, and direct and indirect losses and effects. Loss may include human fatalities and injuries, economic damages, and environmental impacts, which can generally be estimated in quantitative terms, and non-quantifiable effects, including reductions in operational effectiveness or readiness, etc.[218]

Another closely related concept, *resilience*, is central to the purposes of risk management for critical infrastructures. It is defined as the ability of an asset, system, or facility to withstand an adverse event while continuing to function at acceptable levels or, if functioning is diminished, the speed by which an asset can return to the acceptable level of function (or a substitute function or service provided) after the event.[219] Resilience can be incorporated into Equation 1 as follows:

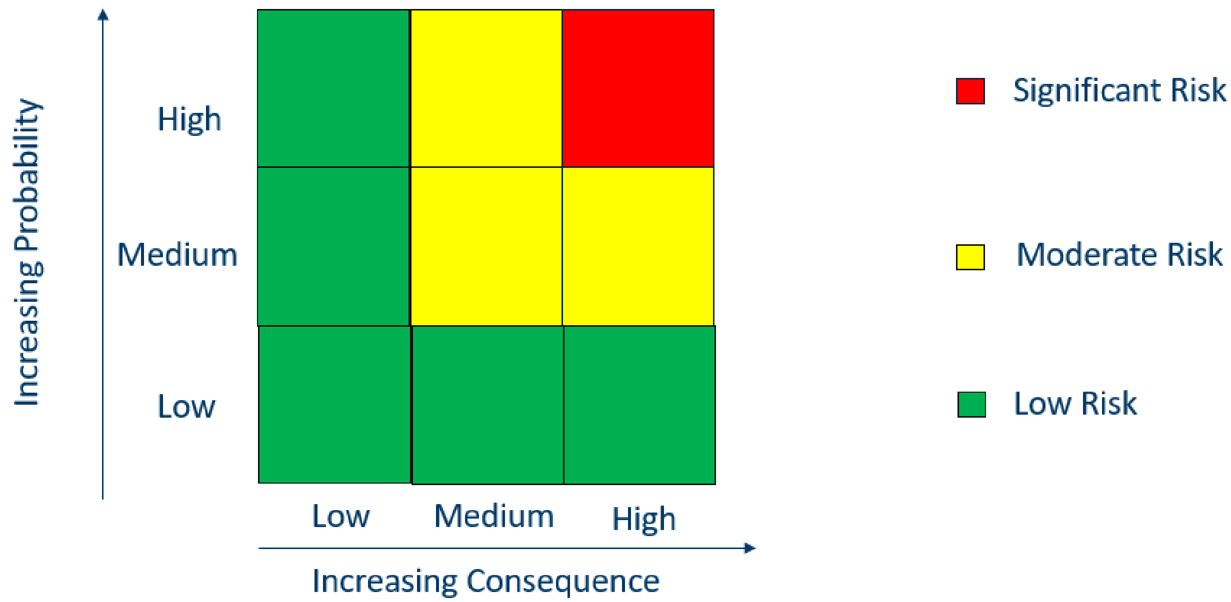
*Risk = Threat x Vulnerability x Resilience x Consequence [Equation 2].*

Figure 15 provides a qualitative representation of the overall level of risk based on the increasing probability of the threat occurring, as shown on the vertical-axis, and the increasing consequence of a successful attack, as displayed on the horizontal-axis. The colored squares in the figure indicate whether there is a low, moderate, or significant level of risk.

[218] Brashear, Jerry & Jones, James. 2010. *Risk Analysis and Management for Critical Asset Protection (RAMCAP Plus)*, p. 3. Available at: https://onlinelibrary.wiley.com/doi/abs/10.1002/9780470087923.hhs003.

[219] Ibid.

**Figure 15: Risk Framework**




*Source: https://www.stakeholdermap.com/risk/risk-assessment-matrix-simple-3x3.html*

The framework could also apply to coordinated, simultaneous cyber and physical attacks against a single asset, or multiple assets at different locations on the distribution system, which could result in greater damage. Fundamentally, risk is an expectation, and expectations are additive in nature. Thus, the framework could be used to compute the expected risk for each attack type, on each critical asset. Those risks could then be added to obtain the overall risk for a coordinated, simultaneous, blended attack scenario.

The Risk Analysis and Management for Critical Asset Protection (RAMCAP™) Plus framework used by the DHS is an all-hazard risk and resilience management process for critical infrastructure.[220] A description of each step as applied for the purpose of determining the risk of a cyber or physical attack on the electric distribution system is listed below and summarized in Table 9.

[220] Id., p. 1.

**Table 10: Risk Framework Analysis**

| Critical Asset Characterization | Threat Characterization | Threat Assessment | Vulnerability Assessment | Resilience Analysis | Consequence Analysis |
|---|---|---|---|---|---|
| • Substations/ Transformers<br>• Feeder lines<br>• Communication and control systems (e.g., SCADA) | • Physical attack<br>• Cybersecurity attack<br>• Sabotage (insider/ outsider) | • Terrorist intent & capabilities<br>• Asset value to terrorist<br>• Security intel on potential grid attacks<br>• Benchmark terrorist threat against natural hazard threat | • Identify system vulnerabilities<br>• Assess security defense capabilities<br>• Estimate probability of successful attack | • Ability of grid resilience to avoid, reduce, or restore damage from potential attack | • Cost for utility to repair or replace damaged asset<br>• Economic impact on local community |

*Source: Brashear, Jerry & Jones, James. (2010). Risk Analysis and Management for Critical Asset Protection (RAMCAP Plus modified), p.5. 10.1002/9780470087923.hhs003*

1. Critical Asset Characterization – List all the critical distribution system assets that could be attacked given public disclosure on a hosting capacity map.
   - Substations
   - Feeder lines
   - Other distribution facilities (please specify)

2. Threat Characterization – Determine the specific types of terrorist threat(s) or attack modes, in the local context, for each critical asset identified in 1.
   - Physical attack (e.g., sniper shooting a substation)
   - Cybersecurity attack (e.g., load manipulation)
   - Sabotage – physical/cyber by insider

3. Threat Assessment – Estimate the probability that a specific terrorist threat, as identified in 2, will occur in a specific city (e.g., Minneapolis) on a critical distribution system asset, in a given timeframe (typically a year). Can use information based on historical attacks of the distribution system in combination with subjective probability judgements to ascertain the probability of current and future risk. Other factors to consider include:
   - Potential terrorist motivations, intent, and capabilities
   - Attractiveness of grid facility relative to alternative targets
   - Critical asset's expected value (e.g., asset value to terrorist and consequence of asset damage/loss)
   - Intelligence from state homeland security officials and local law enforcement agencies
   - Comparisons with natural hazard risks to help deduce a terrorism threat probability

4. Vulnerability Assessment – Estimate the conditional probability that, if a given attack occurs, it will succeed. Vulnerability analysis involves an examination of existing system vulnerabilities, security capabilities, as well as countermeasures and their effectiveness. A process to assist in this determination is to:
   - Identify and rank potential distribution system critical asset vulnerabilities (e.g., physical, cyber, and personnel)

- Identify security capabilities to defend against threats given critical asset vulnerabilities (e.g., physical surveillance, asset hardening, cybersecurity, screening of personnel)
- For each specific attack vector, estimate the probability it will succeed given defense measures
  - Benchmark probability estimates of a successful threat from a natural hazard (e.g., severe weather causing a power outage) against probability estimates of a successful terrorist attack on a critical asset

5. Resilience Analysis – Estimate the ability of the electric distribution system to avoid or withstand grid stress events without suffering operational compromise, or to adapt to and compensate for the resultant strains to minimize damage, and to rapidly recover from breakdown.[221]

6. Consequence Analysis – Identify and estimate the worst reasonable consequences generated by each specific asset/threat combination to estimate economic impacts. Economic impacts occur at two levels: (1) the financial consequences to the electric utility and (2) the economic consequences to the regional community in the electric utility's service territory. The primary concern for the public or community is the duration of the power outage and the direct and indirect economic consequences of service denial.

Figure 16 shows several grid security and resiliency factors which should be analyzed when conducting the distribution system threat and vulnerability assessments and resilience analysis. This includes a thorough assessment of the physical, cyber, and personnel vulnerabilities pertaining to grid security, and an assessment of the system's resilience. The system can be made more resilient through grid modernization, maintaining equipment stockpiles, contingency planning, and the strategic placement of DERs and microgrids to power critical services during an outage.

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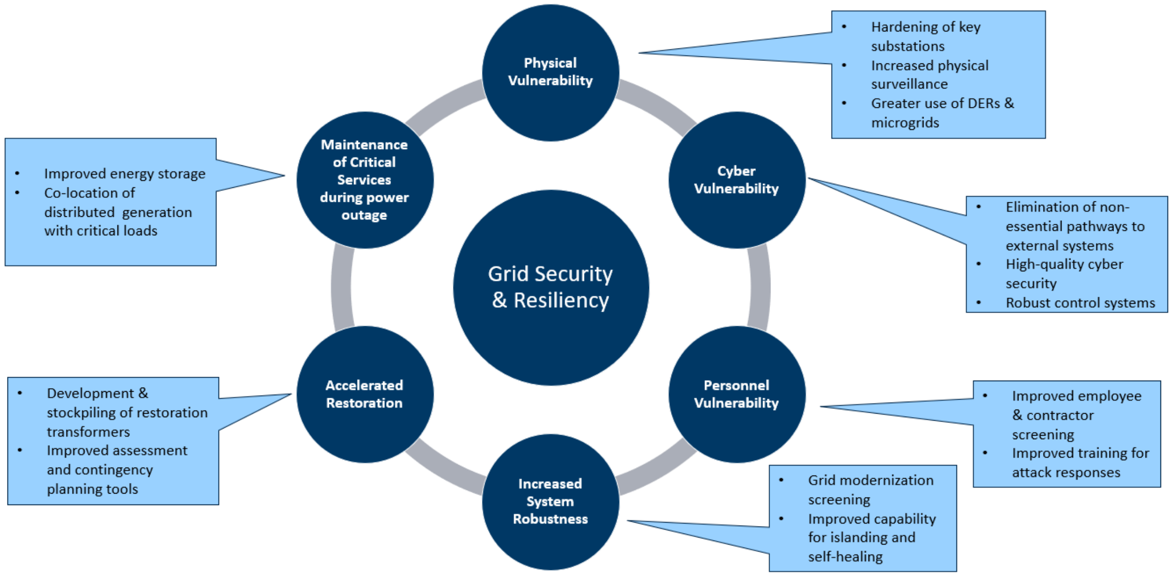
[221] *Hosting Capacity Analysis and Distribution Grid Data Security Workshop.* Docket No. E999/CI-20-800. (March 17, 2021). Attachment 3, p. 11.

**Figure 16: Grid Security and Resiliency Factors**




*Source: National Research Council 2012. Terrorism and the Electric Power Delivery System, p.3. https://doi.org/10.17226/12050*

### *4.2.2. Vulnerability Assessment*

In conducting the vulnerability assessment in Step 4, specific points of vulnerability can be evaluated for each major component of the distribution system:

- Substation Transformers
- Feeder Circuits
- Protective Equipment/Switches
- Telecommunications
- Automation & Control Systems (e.g., supervisory control and data acquisition (SCADA), Distributed Energy Resource Management System (DERMS), Distribution Automation)
- Advanced Metering Infrastructure (AMI)

For example, when evaluating the vulnerability of a substation, security criteria to be considered include:

- Potential threat and probability of attack
- Frequency and duration of past security breaches
- Severity of damage
- Cost of breaches
- Safety hazards in the substation
- Equipment types and design
- Number and types of customers served

- Substation location
- Criticality of load
- Overall cost of facility
- Quality of service at existing substations
- Exposure to vandalism, sabotage, and terrorist attack of control houses, control equipment, and key electrical system components.[222]

Additionally, criteria can be established to categorize the different levels of critical asset vulnerability (Table 11). Critical distribution system assets which are especially vulnerable to attack fall into the red category and require immediate attention. Lower value, less vulnerable assets fall into the green category and require minimal attention but should not be ignored. Other distribution assets fall into the orange and yellow categories which represent the second and third priority for counterterrorism efforts.

**Table 11: Vulnerability Characterization**

| Vulnerability | Description |
|---|---|
| **Red** | • Represents a severe vulnerability in infrastructure reserved for the most critical assets that are highly susceptible to attack.<br>• Requires the most immediate attention. |
| **Orange** | • Represents the second priority for counterterrorism efforts.<br>• These assets are generally moderately to extremely valuable and susceptible. |
| **Yellow** | • Represents the third priority for counterterrorism efforts.<br>• These assets are generally less vulnerable because they are either less susceptible or less valuable than the terrorist desires. |
| **Green** | • Final category for action. It gathers all assets not included in the more severe cases, typically those that are low (and below) on the susceptibility and value scales.<br>• Constrained fiscal resources are likely to limit efforts in this category, but it should not be ignored. |

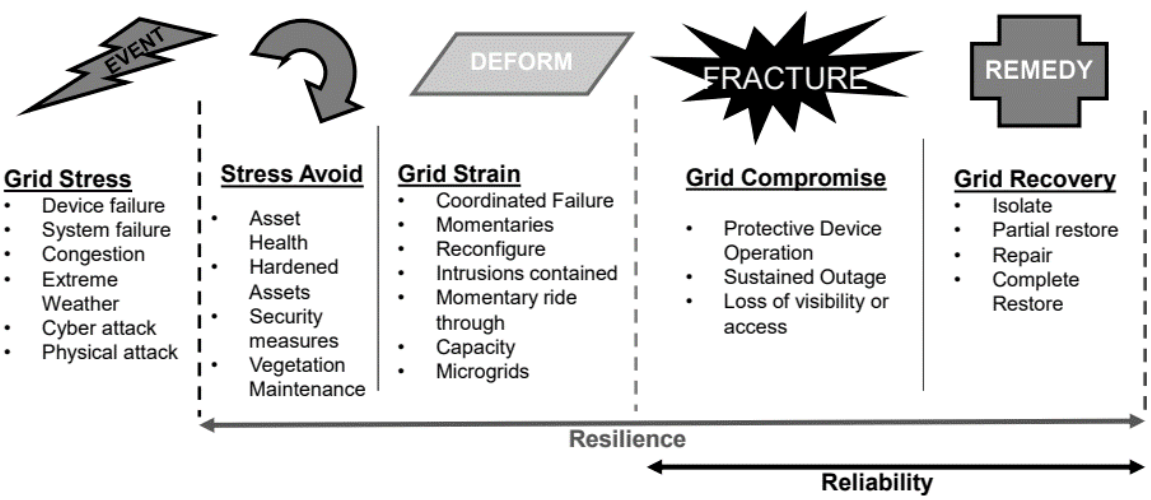
*Source: Apostolakis, G. & Lemon, Douglas. (2005). A Screening Methodology for the Identification and Ranking of Infrastructure Vulnerabilities Due to Terrorism. Risk analysis: an official publication of the Society for Risk Analysis. 25. 361-76.*

[222] National Research Council 2012. *Terrorism and the Electric Power Delivery System*. p. 33.

### *4.2.3. Resilience Analysis*

In Step 5, the utility will conduct a resilience analysis to assess its ability to recover from deliberate attacks, accidents, or naturally occurring threats or incidents.[223] While there is no industry definition of grid resilience, a perfectly resilient grid would be self-healing. This means that it could avoid, withstand, or minimize the effects of grid stress events. Figure 17 characterizes grid resilience along a spectrum ranging from grid stress to grid recovery based on the impact of the event (e.g., terrorist attack or natural hazard) given the distribution system's ability to withstand, respond to, or recover from it.

**Figure 17: Characterization of Distribution System Operational Resilience**




*Source: Based on PNNL "Electric Grid Resiliency and Reliability for Grid Architecture" report, March 2018.*

Table 12 provides an example of how the effects of resilience could be incorporated into Equation 2 using a resilience multiplier. When the distribution system has a high level of resilience (e.g., resilience level 3), and can avoid grid stress in response to a specific threat, then it would have a resilience multiplier close to zero, since it is fully able to mitigate or nullify the threat. On the other extreme, when the system has low or no level of resilience (e.g., resilience level 0) in response to a threat, then it would have a resilience multiplier closer to one, since it is unable to mitigate the impact of the threat.

[223] *Hosting Capacity Analysis and Distribution Grid Data Security Workshop.* Docket No. E999/CI-20-800. (March 17, 2021). Attachment 3, p. 6.

Table 12: Resilience Characterization

| Resilience Level | Description | Resilience Multiplier |
|---|---|---|
| 3 | Resilience results in grid stress avoidance in response to threat | 0.01 |
| 2 | Resilience results in grid strain in response to threat | 0.25 |
| 1 | Resilience results in significant grid compromise in response to threat | 0.75 |
| 0 | No grid resilience in response to threat | 1.00 |

#### ***4.2.4. Consequence Analysis***

In conducting the consequence analysis in Step 6, it is important to separate the consequence of a successful physical or cybersecurity attack into two parts: (1) the consequence to the utility and (2) the consequence to the community. The consequence to the electric utility measures the economic impact of the attack on the utility. Table 13 shows how an attack's economic impact on a utility could be characterized. The consequence level indicates the severity of the damage to the electric utility and the disutility values are different weighting factors that could be applied based on the severity of the consequence. For example, if the attack would result in catastrophic grid equipment damage (e.g., on the order of more than $10 million) then it would have a disutility of one. However, if the attack would not result in any grid equipment damage, then it would have a disutility of zero.

Table 13: Consequence Characterization - Economic Impact to Utility

| Consequence Level | Description | Disutility |
|---|---|---|
| 3 | Catastrophic grid equipment damage, greater than $10 million | 1.00 |
| 2 | Major grid equipment damage, $1 million to $10 million | 0.75 |
| 1 | Minor grid equipment damage, less than $1 million | 0.25 |
| 0 | No grid equipment damage | 0.00 |

Similarly, Table 14 provides an example of how an attack's economic impact on a community could be characterized. The consequence level indicates the severity of the damage to the community in terms of the duration of a power outage, and the disutility values are different weighting factors that could be applied based on the severity of this consequence. For example, if the attack would result in a long duration power outage (e.g., 2-3 days), which would severely impact customers in the utility's service territory, then it would have a disutility of one. However, if the attack did not have any impact on customers, then it would have a disutility of zero. It is important to note that power outage duration is used as a proxy for community impacts more broadly and does not encapsulate all possible societal impacts to avoid making the framework overly complex. For example, an extended power outage which occurred during extreme weather conditions could result in loss of life. The power outage duration partially captures this dynamic given that a longer power outage is more likely to cause death than a shorter one.

**Table 14: Consequence Characterization - Economic Impact to Community**

| Consequence Level | Description | Disutility |
|---|---|---|
| 3 | Severe impact to customers in utility service territory, power outage of 2-3 days | 1.00 |
| 2 | Major impact to customers in utility service territory, power outage lasting 24 hours | 0.75 |
| 1 | Minor impact to customers in utility service territory, power outage of 4-6 hours | 0.25 |
| 0 | No impact to customers in utility service territory | 0.00 |

For each threat, the disutility of the consequence to the community and of the consequence to the electric utility could be appropriately weighted and combined. Assuming that both types of consequences are equally weighted, the disutility values could simply be averaged.

#### *4.2.5. Example of Risk-Benefit Framework*

Once all the threats, vulnerabilities, resiliency measures, and potential consequences have been assessed, the risk can be calculated using Equation 2. More explicitly writing out the components of Equation 2:

*Risk = Threat x Vulnerability x Resilience x Consequence [Equation 2].*

Where:
Threat = Probability of an attack: P(attack);
Vulnerability = Probability of a successful attack: P(success|attack);
Resilience = Resilience multiplier (e.g., a constant between 0 and 1); and
Consequence = Consequence of successful attack as represented by disutility (e.g., a constant between 0 and 1).

Table 15 displays how the risk components of Equation 2 could be summarized in a table for each critical asset (e.g., feeder, substation) and attack type (e.g., physical, cybersecurity) in a given year. The numbers in Table 15 are for illustrative purposes only.

**Table 15: Risk Analysis**

| Critical Asset | Attack Type | Threat | Vulnerability | Resilience | Consequence | Risk per Asset |
|---|---|---|---|---|---|---|
| Substation | Physical | 0.90 | 1.00 | 0.75 | 1.00 | 0.68 |
| Feeder | Cyber | 0.65 | 0.80 | 1.00 | 0.75 | 0.40 |
| Feeder | Physical | 0.40 | 0.30 | 1.00 | 0.25 | 0.03 |

Once the risk is calculated, the result can be matched according to the risk lower and upper bounds in Table 16 to determine the level of risk. The lower and upper risk bounds inTable 16 are for illustrative purposes.

**Table 16: Risk Characterization**

| Risk Level | Risk Lower Bound | Risk Upper Bound |
|---|---|---|
| **Significant Risk** | 0.66 | 1.00 |
| **Moderate Risk** | 0.36 | 0.65 |
| **Low Risk** | 0.00 | 0.35 |

The second part of the Risk-Benefit Framework involves estimating the public benefits of revealing sensitive-grid data on the hosting capacity map. Interested stakeholders should collaboratively develop survey questions that identify the main points of contention, such as whether to provide substation transformer ratings on the HCA map. The survey would be sent to members of the public including DER developers, entrepreneurs, clean energy organizations and advocates, and local energy policymakers to assess the value in making certain distribution system information available on Xcel's HCA map. An appropriate survey sample size would have to be determined at the outset to ensure a statistically significant response rate. The survey could ask for the respondent to rank the benefit of receiving substation transformer ratings, for example, on the HCA map as having "No Benefit," "Low Benefit," "Moderate Benefit," "Significant Benefit," or "Essential Benefit." The results for each question could then be analyzed using the values associated with each level of benefit shown in Table 17.

**Table 17: Public Benefit Valuation**

| Public Benefit | Value |
|---|---|
| Essential Benefit | 1.00 |
| Significant Benefit | 0.75 |
| Moderate Benefit | 0.50 |
| Low Benefit | 0.25 |
| No Benefit | 0.00 |

For example, if the survey question received 100 responses with the following response breakdown:

- No Benefit = 2 responses
- Low Benefit = 5 responses
- Moderate Benefit = 5 responses
- Significant Benefit = 60 responses
- Essential Benefit = 28 responses

The public benefit of having substation transformer ratings could be calculated using a value-weighted (e.g., benefit value x number of responses selecting this benefit) average as follows:

*Public benefit of substation transformer ratings = [(0.00) x 2 + (0.25) x 5 + (0.50) x 5 + (0.75) x 60 + (1.00) x 28]/100 = 0.77.*

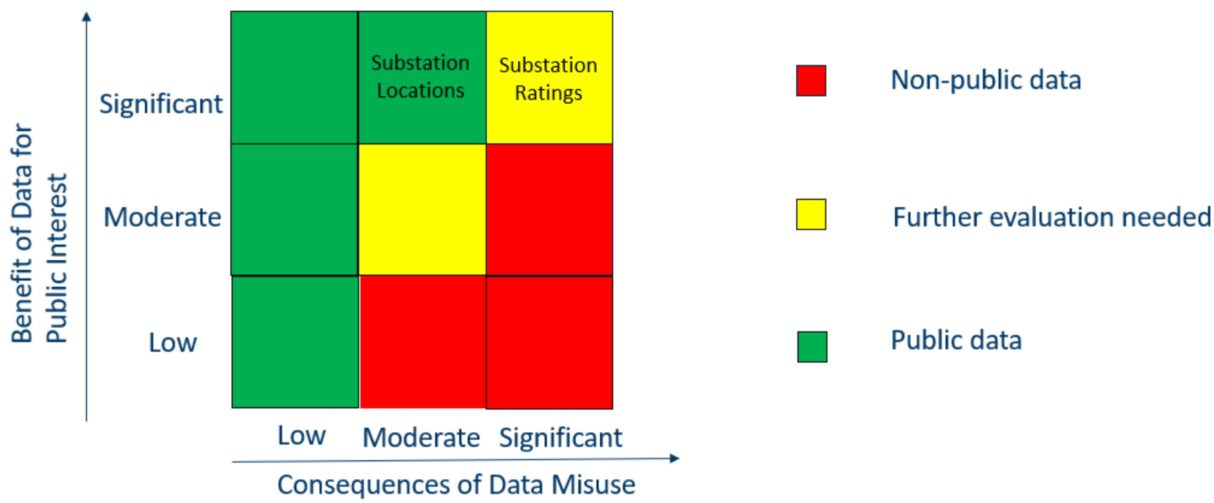
The public benefit value calculated for each question could then be matched to the public benefit category, between the appropriate lower and upper bounds, in Table 18. The lower and upper benefit bounds in Table 18 are for illustrative purposes only.

**Table 18: Public Benefit Characterization**

| Public Benefit | Benefit Lower Bound | Benefit Upper Bound |
|---|---|---|
| Essential Benefit | 0.85 | 1.00 |
| Significant Benefit | 0.75 | 0.84 |
| Moderate Benefit | 0.36 | 0.74 |
| Low Benefit | 0.00 | 0.35 |

Once the benefit has been calculated for each sensitive piece of grid information, such as substation transformer ratings or peak substation/feeder load, the benefits can then be weighed against the risks using the Risk-Benefit Framework. In this framework, grid data is categorized by the public benefit and the severity of the consequence from its misuse. Data becomes increasingly beneficial to the public up the vertical axis and the consequence of data misuse increases along the horizontal axis. The vertical axis uses the value-based classification for data: low benefit, moderate benefit, and significant benefit. The horizontal axis is categorized by the three levels of risk mentioned before: low risk, moderate risk, and significant risk. Where the data falls on the risk-benefit matrix determines whether it should be made publicly available. Figure 18 shows how the framework could be used to assess whether to make substation locations and substation transformer ratings publicly available on the hosting capacity map. Where those grid data points fall on the matrix is only for illustrative purposes. For example, grid data with significant benefit and a low level of risk regarding data misuse would clearly be made public. On the other hand, grid data with low benefit and a high level of risk for data misuse would not be made public. In scenarios where the grid data provided a significant public benefit but at a significant level of risk, further evaluation would be needed.

**Figure 18: Risk-Benefit Framework**




It is important that there be an open, transparent process, involving a diverse group of stakeholders, for evaluating and categorizing the benefits and risk levels associated with different types of grid data when determining whether they should be made public. The Commission should ultimately decide on the data's classification under this framework and should take stakeholder discussions into account.

## 4.3. Cost-Benefit Framework

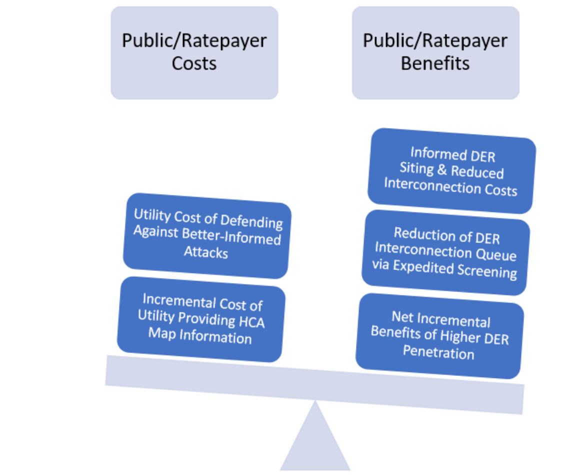
### *4.3.1. Overview*

Cost-Benefit Analysis is a systematic approach for comparing the costs and benefits of alternative options. It is often used by electric utilities, both to optimize internal resource investment decisions and to justify these decisions to regulators and stakeholders.[224] A Cost-Benefit Framework can also be used to estimate the public/ratepayer benefits and costs of making specific distribution grid information public. The benefits would include the incremental customer and societal benefits of making the

[224] National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. 2020. p. 1-2. Available at: https://lpdd.org/wp-content/uploads/2020/08/NSPM-DERs_08-04-2020_Final.pdf.

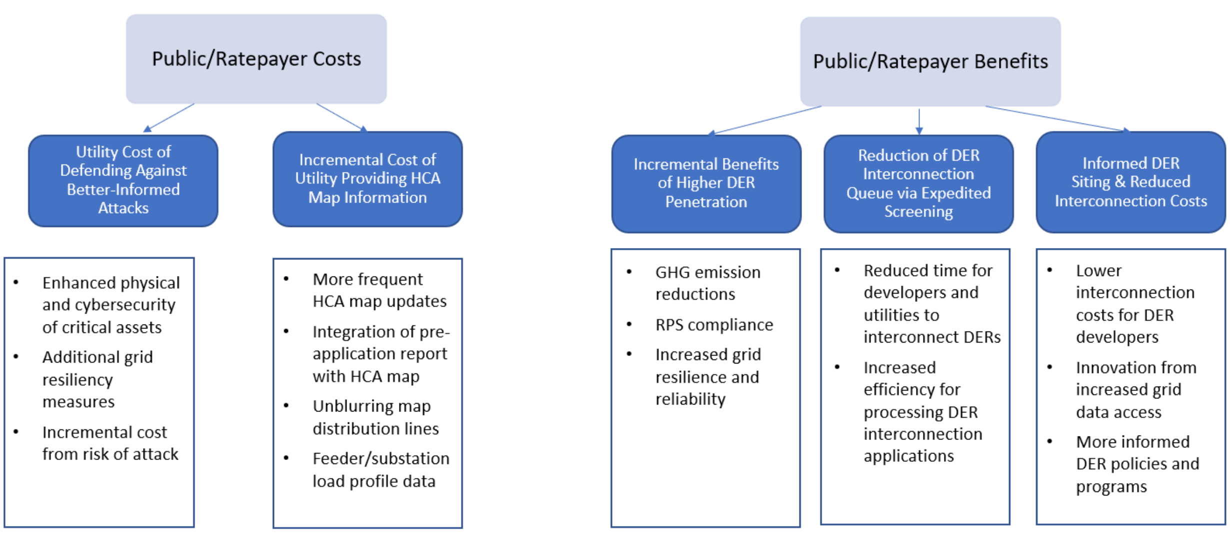
information public and the costs would include the costs to the utility of providing this information and of defending against a better-informed attack (Figure 19). A net public benefit would inform whether the specific grid information would be made public.

**Figure 19: Cost-Benefit Framework**




When conducting this analysis, it is important to compare the incremental costs and benefits to the public or ratepayer for revealing specific types of grid data on the HCA map. For example, the calculation could weigh the incremental cost in releasing feeder location and peak loads against the incremental benefits of releasing the same data. Figure 20 further illustrates this comparison in greater detail.

**Figure 20: Detailed Cost-Benefit Framework**



#### 4.3.2. *Assessing Benefits*

Beginning with the ratepayer benefits side of the equation, for each piece of grid information (e.g., peak load), the relevant stakeholders (e.g., developers, entrepreneurs, local energy policymakers, etc.) could be surveyed to better understand the incremental value of that specific information in terms of effectively siting DERs, lowering interconnection costs (e.g., screening out locations which may require costly system upgrades), informing policy, and/or other potential benefits. This same question could be repeated more specifically for DER developers in terms of how having access to that information could enable expedited screening of potential opportunities, and ultimately help to speed up the interconnection process.

Given that Xcel's HCA map has always been blurred (e.g., never displayed its feeder lines), it is difficult to estimate the incremental benefits of higher DER penetration due to providing more detailed information. However, lacking this information in Xcel's service territory, one could use as a proxy information from utilities on the coasts (e.g., New York and California) that went from less revealing hosting capacity maps (e.g., indicator maps) to detailed sub-feeder level hosting capacity maps to determine if the level of interconnections significantly increased because of that change. However, there is the possibility that other external factors, such as ramping up DER deployment to meet RPS targets, or policy changes leading to reductions in barriers to interconnection, could have also led to increases in DER interconnections. These external factors should be appropriately addressed in the framework. Alternatively, one could use the two-month period of September to November 2018 when California IOUs removed public access to their PV RAM maps, to assess the incremental impact that that change had on DER project development and interconnections. That information could then be used as a proxy to estimate how a change in hosting capacity information affected DER interconnections (e.g., percentage change) and deployment. This estimated effect could be used to approximate the corresponding societal benefits including environmental (e.g., reduced greenhouse gas emissions) and grid modernization (e.g., increased grid resiliency) benefits.

#### 4.3.3. *Assessing Costs*

When assessing the incremental costs to the public/ratepayer from making certain grid data public on the hosting capacity map, one must examine the incremental costs to the utility of (1) providing the information and (2) the marginal cost of defending against a better-informed attack. With respect to the first point, Xcel has provided the costs of making several hosting capacity map improvements such as integrating its Pre-Application Report data and refreshing the map monthly. The cost (in dollars) of unblurring the distribution circuits on its map and providing substation and feeder load profiles could also be estimated. At the end of this part of the cost analysis, there would be a total dollar value associated with making these hosting capacity map improvements.

To approximate the marginal cost of defending against a better-informed attack, for each piece of grid data (e.g., revealing distribution lines), the utility would have to estimate the incremental cost of protecting its distribution infrastructure. This could include hardening additional distribution substations, and other critical infrastructure, burying more feeder lines underground, upgrading its cybersecurity defense capabilities, and other resource investments that would make the grid more resilient to an attack. The risk values determined in the Risk-Benefit Framework could inform the calculation of the incremental cost from the risk of an attack. In the Risk-Benefit Framework, the probability of an attack(s) on critical distribution system assets is estimated. Xcel could quantify the costs of potentially having to repair or replace damaged distribution infrastructure from an attack, and if it resulted in a power outage, estimate the costs to the public using metrics such as value of lost load and time to restore the system. Similar analyses are conducted to estimate the cost of a power outage due to a natural disaster. The Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) calculator is a useful electric reliability planning tool that can be used to estimate the cost of an electric power interruption in the United States.[225]

#### *4.3.4. Example of Cost-Benefit Framework*

The following Cost-Benefit Framework example is for illustrative purposes only and an actual Cost-Benefit Analysis should be informed by data and assumptions from the utilities and stakeholder input.

The Cost-Benefit Framework could be applied for weighing the costs and benefits of integrating the Pre-Application Report grid data into the HCA map. The main benefits from Figure 20 that would be assessed are “Lower interconnection costs for DER developers,” “Increased efficiency for processing DER interconnection applications,” and “GHG emission reductions.” The other benefits included in Figure 20, while tangible, are more qualitative in nature. The primary costs from Figure 20 which would be analyzed in this example are the cost of the “Pre-Application Report Integration with HCA” and the “incremental cost from risk of an attack.” The other costs in Figure 20 including “enhanced physical and cybersecurity of critical assets” and “additional grid resiliency measures” could also be included, if Xcel provided cost information on implementing these measures as a direct result of revealing additional Pre-Application Report data in the HCA map. For simplicity, these costs were not included in the Cost-Benefit Analysis. Table 18 displays the results of this Cost-Benefit Analysis.

[225] Lawrence Berkeley National Laboratory, Nexant Inc., and U.S. Department of Energy. “Interruption Cost Estimate (ICE) Calculator.” Available at: https://www.icecalculator.com/home.

**Table 19: Cost-Benefit Analysis**

| 2020 Cost-Benefit Analysis | Total ($MM) |
|---|---|
| **Benefits** | **$12.7** |
| Lower Interconnection Costs for Developers | $0.2 |
| Increased Efficiency of Processing DER Interconnection Applications | $6.0 |
| GHG Emission Reductions | $6.5 |
| **Costs** | **$3.0** |
| Pre-Application Report Integration with HCA | $1.0 |
| Incremental Cost for Risk of an Attack | $2.0 |
| **Net Benefit (Benefits – Costs)** | **$9.7** |
| **Benefit-Cost Ratio** | **4.2** |

Costs

*Pre-Application Report Integration with HCA*: Xcel estimates that fully integrating the Pre-Application Report with the HCA would take one year to implement and would cost between $600,000 and $1.2 million.[226]

*Incremental Cost for Risk of an Attack*: There are several pieces of information within the Pre-Application Report (listed below) that have security concerns associated with publishing them.

- Substation and feeder peaks loads
- Substation and feeder capacities
- Distance between site and substation
- Protective devices and regulators between site and substation
- Conductor types between site and substation

Regarding these data elements, Xcel could estimate the incremental cost from risk of an attack, on a critical asset (e.g., substation) using the expected risk value calculated in the Risk-Benefit Framework. The probability of a successful attack on the asset would then be multiplied by the economic consequence (in dollars) of an attack on the asset to determine the total cost. For example, if the probability of a successful attack on a distribution substation transformer was 10 percent due to revealing more information about it (e.g., substation transformer peak load or capacity), the cost to replace the damaged substation transformer was $10 million,[227] and the attack resulted in a severe

[226] Xcel Energy. 2020. HCA Report. Attachment F, p. 16.

[227] Utility Dive. "Xcel assesses non-wires alternatives to distribution upgrade as it enters new proceedings in Colorado, Minnesota." January 30, 2020. Available at: https://www.utilitydive.com/news/xcel-assesses-non-wires-alternatives-to-distribution-upgrade-as-it-enters-n/571290/.

power outage resulting in economic damages of $10 million to customers, then the incremental cost from the risk of an attack would be $2 million (10% x $20 million).

*Other Costs*: Other costs, such as the cost to make the substation transformers more resilient to physical attack, because of publishing more information about them, could also be included in the total cost.

*Total Costs*: However, assuming no additional costs (e.g., grid resilience), and that the actual cost to integrate the data fields in the Pre-Application Report with the HCA map costs $1 million, the estimated total cost to the ratepayer would be $3 million.

Benefits

To determine the benefits (in dollars) of incorporating the Pre-Application Report data into the HCA map, we could analyze the lower interconnection costs for DER developers, and any incremental increases in Xcel's efficiency in processing DER interconnection applications. The Commission recently fined Xcel $1 million for numerous complaints over delays in connecting solar projects to the grid.[228] This incident highlights the economic value of making additional information available to developers that could help inform their interconnection applications and streamline the MN DIP.

*Benefits to Developers Regarding Lower Interconnection Costs*: We could use the number of Pre-Application Reports in a given year as a proxy. For example, Xcel processed 368 Pre-Application Report requests in 2020. With each report costing $300, this resulted in a total cost to developers of $110,400, which would be saved because of the integration of the Pre-Application Report with the HCA. There would also be a corresponding time savings for the electric utility engineer who has to process the Pre-Application Reports. Assuming it takes five hours for an Xcel engineer who is paid $50 per hour (e.g., approximately $100k per year) to process each report, the time savings for processing the 368 reports in 2020 would equal $92,000. Thus, the total cost savings to Xcel and the DER developers would be $202,400 or approximately $200,000.

*Increased Efficiency of Processing DER Interconnection Applications*: In 2020, Xcel received 2,901 solar PV interconnection applications and interconnected 1,539 solar PV projects.[229] If Xcel were to share more grid information on its HCA map, this could lead to higher quality developer interconnection applications, help to reduce the number of applications Xcel receives, and/or increase Xcel's ability to process more applications. Reducing Xcel's project interconnection queue could save DER developers time and money by expediting approval of their projects and helping them to meet their project deadlines. The savings accrued for developers, the reduced time for Xcel engineers to process interconnection applications, and the avoided costs (e.g., fines) for Xcel not meeting its interconnection and utility customer performance rating targets, would result in economic benefits to ratepayers. All

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[228] Energy Central News. "State regulators fine Xcel Energy $1M over dispute with solar developers." January 22, 2021. Available at: https://energycentral.com/news/state-regulators-fine-xcel-energy-1m-over-dispute-solar-developers?utm_medium=eNL&utm_campaign=DAILY_NEWS&utm_content=400384&utm_source=2021_01_25.

[229] Xcel Energy. *2020 DER Interconnection Report*. Docket No. E999/PR-21-10. (March 15, 2021).

these benefits from a streamlined interconnection process could be added together to provide a total benefit.

For purposes of this example, we will focus on the benefits gained from an Xcel engineer more efficiently processing interconnection applications. For example, if it takes three months for an Xcel engineer earning $50 per hour to complete a full system interconnection study while working on it half-time (e.g., 20 hours per week), the total value of her time would be $12,000 per application. In 2020, Xcel interconnected roughly 1,500 solar PV projects. Theoretically, if the same engineer reviewed all these interconnection applications, the total cost for her time would be $18 million. Assuming the integration of the Pre-Application Report with the HCA led to greater efficiencies processing interconnection applications, and that now the same engineer could review each application in two months, instead of three, the total value of her time would be $8,000 per application. This results in a new total cost for her to process 1,500 interconnection applications of $12 million, a savings of $6 million.

*Emission Reductions*: Additional benefits could include increased DER project installations, and the corresponding reduction in greenhouse gas emissions. For example, in 2010, Xcel estimated that the annual avoided emissions costs (including $CO_2$, $SO_x$) in the year 2020 was $26.34 per MWh.[230] The average annual capacity factor of Minnesota solar facilities in 2018 was approximately 19 percent.[231] Applying this capacity factor to the 1,539 solar PV projects (≤ 1 MW) interconnected in 2020 results in generation from these solar PV systems of roughly 246,762 MWh. Thus, there were emission reduction benefits worth approximately $6.5 million (246,762 MWh x $26.32/MWh) in 2020. However, there would have to be a direct link between this value and revealing additional grid data on the HCA map, which led to an incremental deployment of solar PV systems on the grid.

In this example, there is a net benefit, as shown in Table 18, to the ratepayer of integrating the information from the Pre-Application Report into the HCA.

# 5. Models for Information Sharing

## 5.1. Introduction

Regulators are tasked with designing effective models to share data. Accessible energy-use data can help customers better manage their energy bills, local governments to measure the effectiveness of

[230] Xcel Energy Public Service Company of Colorado. 2010. *2009 Demand-Side Management Annual Status Report.* p. 99. Available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/CODSM2009AnnualStatusReport.pdf.

[231] Orr, Isaac. 2020. "Federal Data Confirms Minnesota Solar Panels Don't Work Well in Winter." American Experiment, Energy and Environment. Available at: https://www.americanexperiment.org/federal-data-confirms-minnesota-solar-panels-dont-work-well-in-winter/.

energy programs more effectively, and energy service providers to better design new services.[232] In order to be effective, these models must weigh the benefits and risks associated with providing secure access to data. Effective models for information sharing can decrease this risk while still allowing access to valuable data. These models should be built upon standards and principles that govern secure and useful access to data.

While not specific to energy, DHS has provided principles that have been used globally. Its Fair Information Practice Principles (FIPPs) are used to guide many data-sharing policies.[233] The FIPPs include eight principles: "Transparency, Individual Participation, Purpose Specification, Data Minimization, Use Limitation, Data Quality and Integrity, Security, and Accountability and Auditing."[234] Together, these principles guide how the DHS treats PII. When applying these principles, the following questions regarding data-sharing should be considered:

1. Who needs access to the data and why?
2. Who is responsible for granting access to the data?
3. How can the data be delivered securely and efficiently (e.g., streamlined process)?

Answers to these questions can help provide a framework for sharing information. An effective data-sharing model must be transparent, clearly stating data access requirements for different data user groups (e.g., academic researcher), identify what information is confidential, and the criteria, if any, for accessing the confidential information.

### *5.1.1. When and How to Protect Data*

The "Need-to-Know" and the "Need-to-Protect" principles can help regulators decide when and how information needs to be protected.[235] Using the "Need-to-Know" criteria would help to determine when customers who require sensitive information should receive it. In the context of hosting capacity, this might include energy developers who need to know specific distribution grid data (e.g., substation capacity) to develop and implement DER projects. The "Need-to-Protect" criteria could, for example, restrict data on specific feeders based on the criticality of the loads they serve (e.g., critical customer groups). This data could then be accessed under an NDA, or in another secure manner, as the utility and/or Commission sees fit.

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[232] American Council for an Energy-Efficient Economy (ACEEE). 2020. "Facilitating Access to Community Energy Usage Data." Available at: https://www.aceee.org/toolkit/2020/02/facilitating-access-community-energy-usage-data.

[233] Teufel III, Hugo. 2008. *The Fair Information Practice Principles: Framework for Privacy Policy at the Department of Homeland Security.* DHS. Available at: https://www.dhs.gov/xlibrary/assets/privacy/privacy_policyguide_2008-01.pdf.

[234] Ibid.

[235] Xcel Energy. *Response to Notice distribution Grid and Customer Security*. Docket Nos. E002/M-19-685 and E999/CI-20-800. (January 29, 2021). Appendix B, p. 23.

To protect data, third parties requesting it may be required to register for data access, log into web portals, sign an NDA, or meet other screening criteria as defined by the party providing access. Each of these security measures protects data in a separate way. For example, requiring users to register for web portal access allows the utility to verify the users, monitor user activity, and question suspicious behavior. Alternatively, NDAs prevent users from sharing data, thereby limiting the potential for another party to misuse the data. In short, data-sharing models determine who can access a given set of data and outline the conditions for such access. Additionally, frameworks such as a Risk-Benefit Framework (Section 4.2) can be used to determine when to apply different data security measures.

## 5.2. Types of Data-Sharing Models

### *5.2.1. Overview*

The most basic model for information sharing is one that simply determines if information can be made public.[236] Once the decision is made to withhold public access to data, other ways of sharing the information should be considered. These data-sharing methods range from a simple email or phone call to an in-person consultation or tiered-access using a web portal. The following sections describe different models for data-sharing.

### *5.2.2. Data Classifications*

Once data is identified as sensitive, it can be classified according to the level of damage that could result from its release. For example, the United States Government groups "classified" into three categories."[237]

> Top Secret: Applied if the data's release could be expected to cause "exceptionally grave damage to the national security."[238]
>
> Secret: Applied if the data's release could be expected to cause "serious damage to the national security."[239]
>
> Confidential: Applied if the data's release could be expected to cause "damage to national security."[240]

Additionally, some information may be categorized as sensitive but unclassified, meaning that the data is "not classified for national security reasons, but that [it] warrants/requires administrative control and

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236 Google Inc*. Mobility Best Practice: Tiered Access at Google.* Available at: https://lp.google-mkto.com/rs/248-TPC-286/images/eBook%202%20-%20Tiered%20Access_v5%20-%20Google%20Cloud%20Branding.pdf.

237 Quist, Arvin. 1993. *Security Classification of Information Volume 2. Principles for Classification of Information. Chapter 7 Classification Levels*. Oak Ridge National Laboratory.

238 Ibid.

239 Ibid.

240 Ibid.

protection from public or other unauthorized disclosure for other reasons."[241] The classification of data is often derived from the risk associated with its release (e.g., risk-based). However, classification can also be derived from other measures, such as which parties have access to it. For example, the Minnesota Government Data Practices Act established several classifications for accessing non-public data.[242]

> Private: "data identifying an individual that are only available to the individual or with the individual's consent (Minn. Stat. § 13.02, subd. 12)."[243]
>
> Confidential: "data identifying an individual that are not available to anyone outside the entity holding the data, including the individual (Minn. Stat. § 13.02, subd. 3)."[244]
>
> Non-public: "data on a business or other entity that are only available to the subject of the data or with the subject's consent (Minn. Stat. § 13.02, subd. 9)."[245]
>
> Protected non-public: "data on a business or other entity that are not available to the subject of the data or anyone else outside the entity holding the data (Minn. Stat. § 13.02, subd. 13)."[246]

Data can be classified in a variety of ways according to different criteria. These classifications can be used to inform models for information sharing.

### *5.2.3. Tiered Access to Information*

Once data has been classified, it can be broken into tiers to determine who should access information and how they should access it. Figure 21 displays how a tiered-access model might function. In this example, data that is sensitive is assigned a classification based on its security level. The security level determines if the information needs to be protected, and if it does, by what mechanism. For example, certain grid data might have a moderate security restriction level, in which case, an NDA could provide third-party access to the data.

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[241] The Office of Cybersecurity. 2021. "Sensitive but Unclassified Information (SBU)". Available at: https://fam.state.gov/fam/12fam/12fam0540.html.

[242] Minnesota House of Representatives. 2010. "Minnesota Government Data Practices Act: An Overview." Available at: https://www.house.leg.state.mn.us/hrd/pubs/dataprac.pdf.

[243] Ibid.

[244] Ibid.

[245] Ibid.

[246] Ibid.

**Figure 21: Tiered Access to Information**

| Security Level | Data Access |
|---|---|
| Publicly Available | Data is published on the utility's website. |
| Limited Restriction | Parties must register to access data. |
| Moderate Restriction | Parties must register online and sign an NDA to access data. |
| Information That Is Never Available | Data is not available under any circumstances. |

At a national level, DHS uses the traffic light protocol (Figure 22) to determine when and how sensitive information can be shared.[247] This risk-based, tiered system restricts the spread of sensitive information by limiting who can discuss and reference it. When the traffic light is green, for example, information can be shared within a community. When the traffic light is red, information may only be shared by the parties that participated in the exchange where the information was originally disclosed. Information with the red designation should only "be exchanged verbally or in person" under most circumstances.[248]

[247] DHS Cybersecurity & Infrastructure Security Agency. "Traffic Light Protocol (TLP) Definitions and Usage." Available at: https://www.cisa.gov/tlp.

[248] Ibid.

**Figure 22: Traffic Light Protocol**

| Color | When should it be used? | How may it be shared? |
|---|---|---|
| TLP:RED<br>Not for disclosure, restricted to participants only. | Sources may use TLP:RED when information cannot be effectively acted upon by additional parties, and could lead to impacts on a party's privacy, reputation, or operations if misused. | Recipients may not share TLP:RED information with any parties outside of the specific exchange, meeting, or conversation in which it was originally disclosed. In the context of a meeting, for example, TLP:RED information is limited to those present at the meeting. In most circumstances, TLP:RED should be exchanged verbally or in person. |
| TLP:AMBER<br>Limited disclosure, restricted to participants' organizations. | Sources may use TLP:AMBER when information requires support to be effectively acted upon, yet carries risks to privacy, reputation, or operations if shared outside of the organizations involved. | Recipients may only share TLP:AMBER information with members of their own organization, and with clients or customers who need to know the information to protect themselves or prevent further harm. **Sources are at liberty to specify additional intended limits of the sharing: these must be adhered to.** |
| TLP:GREEN<br>Limited disclosure, restricted to the community. | Sources may use TLP:GREEN when information is useful for the awareness of all participating organizations as well as with peers within the broader community or sector. | Recipients may share TLP:GREEN information with peers and partner organizations within their sector or community, but not via publicly accessible channels. Information in this category can be circulated widely within a particular community. TLP:GREEN information may not be released outside of the community. |
| TLP:WHITE<br>Disclosure is not limited. | Sources may use TLP:WHITE when information carries minimal or no foreseeable risk of misuse, in accordance with applicable rules and procedures for public release. | Subject to standard copyright rules, TLP:WHITE information may be distributed without restriction. |

*Source: DHS Traffic Light Protocol. https://www.cisa.gov/tlp*

The type of information can also play a role in a tiered-access model. For example, aggregated data at the community level could be published on the utility's website, while aggregated data at the zip code level could require prior registration. Similarly, data might only be made available to certain parties under certain conditions. As discussed in Chapter 3, the Commission ruled in Docket No. E, G999/CI-12-1344 that access to CEUD is tiered based on whether the customer has given consent.[249] In this case, there are two tiers of data available, with more granular information only being provided if a customer opts to allow their data to be shared.

The tiered access information sharing model is dynamic in the sense that it can be applied in many ways. It is also flexible because it can account for any number of tiers based on the use case. In one sophisticated example of tiered access, Google is considering temporal tiered-selection where team members can "voluntarily move across trust tiers in real-time, dropping tiers when access is no longer

[249] *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities,* Docket No. E,G-999/CI-12-1344. (June 17, 2013).

needed (e.g., to be at 'fully trusted' for the next two hours only)."[250] By having tiers, additional information becomes available in a manner appropriate with its risk.

### *5.2.4. Models for Accessing Energy Data*

While third parties may be reasonably required to protect information, the way in which information is shared plays a critical role in its overall security. For example, in some cases, a simple email or phone call may be enough to securely transmit information. However, other situations may require a different mode for securely sharing sensitive information, such as requiring a third-party to go to a secure location before gaining access to the information. More frequently, however, data is made available online via a web portal or platform. In the 2020 New York Department of Public Service (DPS) Staff Whitepaper Regarding a Data Access Framework, the DPS noted that, "when considering what cybersecurity protections need to be in place for access to energy-related data, it is necessary to evaluate the means in which that data will be transmitted or accessed."[251] Different models or platforms may provide increased ease of access or protection for data. The DPS whitepaper lists the following five ways for sharing energy data online.[252]

1. *Direct Connection to Data Custodian IT System*: In most cases the "Data Custodian" is the utility. In this case, the data custodian provides a third-party requesting data with direct access to its IT system (not a data portal). Both parties must ensure that proper data security procedures are in place. The DPS notes that this connection will entail the "highest level of cybersecurity requirements."[253]

2. *Centralized Data Warehouse*: In this system, an alternative location is developed to store and access energy data. This could be a portal or platform and would need to be built by the data custodian. The third-party requesting the data would still need to meet certain requirements. These requirements would be based on how the data would be accessed, either "through a direct connection or through a platform or portal."[254]

3. *Secondary Access Platform or Portal*: A secondary access platform or portal would take data from the data custodian's IT system and place it on a platform or portal as needed. Essentially, the secondary access point would transmit data between the IT system (where the data is stored) and the third-party (where data is received). There is significant variability in the cybersecurity requirements for this type of platform. These requirements would depend on whether the data is public and what cybersecurity measures both the third-party and the data custodian have in place.

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[250] Google Inc. *Mobility Best Practice: Tiered Access at Google.* Available at: https://lp.google-mkto.com/rs/248-TPC-286/images/eBook%202%20-%20Tiered%20Access_v5%20-%20Google%20Cloud%20Branding.pdf.

[251] New York Department of Public Service (NY DPS). *Department of Public Service Staff Whitepaper Regarding a Data Access Framework*. Case 20-M-0082, (May 29, 2020). p. 25.

[252] Ibid.

[253] Ibid.

[254] Ibid.

4. *Public Platform*: On a public platform, all data is protected using aggregation or anonymization before being made available. This type of platform would not require the third-party to register before accessing it. An example of this would be the current Utility Energy Registry in New York.[255] Third parties can access aggregated and anonymized data without registration or cybersecurity protections in place. Since the data is already public, there is no need to protect it.

5. *Secure Portal or Platform*: Under this system, sensitive data is stored on separate servers, and third parties can access it using a secure portal/platform such as Green Button Connect. The DPS described the secure platform as representing a "lower risk" because of the separation of servers and "because many of these secure access points have been designed with cybersecurity and privacy controls built in."[256]

Developing a secure and accessible access mechanism for transferring third-party information could be an important step for Minnesota to take as it seeks to further support the growth of DERs. Each of the data release mechanisms above should be analyzed with respect to their security and the ease of data accessibility. In choosing a mechanism, Minnesota Commissioners should consider the burden placed on the utility to create the mechanism, the security of the customer information, and the need to provide developers with access to energy information. Finally, models for information sharing in other states can give insight into national best practices.

#### *5.2.5. Green Button*

Green Button is a specific example of a model used for sharing CEUD in many states.[257] The Green Button Standard was developed by the North American Energy Standards Board (NAESB) with the support of the DOE, the National Institute of Standards and Technology (NIST), and the White House Office of Science and Technology Policy. These industry standards are designed to define the "data exchange protocol for the transfer of energy usage information between a utility and a third-party with customer authorization."[258] The listing of the standards themselves is proprietary information. The standards inform the Green Button model, which is used as a model for data-sharing by many utilities in North America.

The Green Button model has two main sub-programs: Green Button Download My Data (DMD) and Green Button Connect My Data (CMD).[259] CMD provides energy customers and third parties with a secure and automated way to access standardized energy usage data. CMD enables utility customers to

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[255] New York State Energy Research and Development Authority. "Utility Energy Registry." Available at: https://utilityregistry.org/app/#/.

[256] NY DPS. *Department of Public Service Staff Whitepaper Regarding a Data Access Framework*. Case 20-M-0082, (May 29, 2020). p. 26.

[257] North American Energy Standards Board. "The NAESB Energy Services Provider Interface Model Business Practices Information Page." Available at: https://www.naesb.org/ESPI_Standards.asp.

[258] Ibid.

[259] Green Button Data. "Green Button Connect My Data". Available at: https://www.greenbuttondata.org/cmd.html.

both access their own data and to conveniently authorize third parties to do the same. Utility data can also automatically be uploaded to these CMD platforms. Once on the platform, CMD secures the data and ensures its integrity and accuracy, while DMD provides downloadable data that complies with the consistent data format provided by the Green Button Standard. Utilities receive Green Button Certification after the Green Button Alliance confirms that the utility has properly implemented the Green Button Standard and provided consistently formatted data.

## 5.3. Benchmarking Sharing Hosting Capacity Map Data

Table 20 depicts how utilities across the United States share energy data, including hosting capacity map information, in a variety of ways.[260] Even utilities within the same state can differ on their requirements for sharing hosting capacity information. For example, both the New York and California IOUs have different protocols for accessing hosting capacity map data. In California, both PG&E and SDG&E require registration and user logins to access their hosting capacity maps while SCE provides open access. In New York, most of the IOUs require registration and user log-in to access their hosting capacity maps, while NYSEG/RG&E and O&R do not.

Several utilities require NDAs to receive what they determine to be confidential or trade secret information. In Minnesota, all the utilities require an NDA to access sensitive information in their Pre-Application Reports except for Dakota Electric. In California, the IOUs are not requiring an NDA to access hosting capacity or pre-application report data but require NDAs for the release of CEII on a "need-to-know" basis. To date, the California IOUs have not designated any data CEII per the CPUC process.

**Table 20: Models for Information Sharing Pre-Interconnection**

| | MN IOUs | | | | NY IOUs | | | | | CA IOUs | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Data Sharing Model** | **Dakota Electric** | **MN Power** | **Otter Tail** | **Xcel Energy** | **Central Hudson** | **Con Ed** | **National Grid** | **NYSEG/ RG&E** | **O&R** | **PG&E** | **SCE** | **SDG&E** | **Pepco** | **HECO** | **NV Energy** |
| HCA Map Open Access | | | | ● | | | ● | ● | ● | | ● | | ● | ● | |
| Web Portal (HCA /System Data) | | | | | ● | ● | ● | ● | ● | ● | | ● | | | ● |
| Pre-application Report | ● | ● | ● | ● | ● | ● | ● | ● | ● | ● | ● | ● | ● | ● | ● |
| Non-Disclosure Agreement | | ● | ● | ● | | | | | | | | | | | |

260 *Sensitive Information Classification and Sharing Workshop*. Docket No. E002/M-19-685. (March 31, 2021).

## 5.4. Models for Data-Sharing in Minnesota

### *5.4.1. Sharing Sensitive Customer Information*

In Minnesota, aggregated customer information is shared with third parties through the utilities. This decision was established in Minnesota Docket No. E,G999/CI-12-1344.[261] In this docket, the Commission decided that "utilities that already have a practice for releasing CEUD to third parties after taking steps to anonymize the data—for example, by aggregating that data with other customers' data before releasing it—should file these practices with the Commission."[262] This left the final decision in the hands of the utility. Most of the utilities currently provide access to aggregated CEUD data.[263] The exception is Dakota Electric, which provides "member account information, such as electric consumption, billing and collections, and credit history" to members either in-person or over the phone if specific identification is given.[264] Moreover, none of the utilities release specific individual CEUD without customer consent.[265] Most of the utilities in Minnesota are using a tiered-access system based on whether the customer has given consent. With customer consent, third-party requestors gain access to more granular information. However, if they have not received consent, then they only get access to appropriately aggregated information.

### *5.4.2. Sharing System Information: The MN DIP Process*

Utilities in Minnesota apply a tiered-access approach to sharing information with third parties during the DER[266] interconnection process (e.g., MN DIP).[267] Before going through the MN DIP, developers may use the hosting capacity map to gain public interconnection information. Next, the developers may begin the MN DIP interconnection process by signing an NDA and receiving a Pre-Application Report, which details non-public, site-specific information. Finally, the most detailed interconnection information is available during the MN DIP process. Xcel notes that even CEII information may be available and emphasizes that the "MN DIP does not identify which distribution grid information is designated as CEII, but does provide for another level of protection for this critical infrastructure information."[268] Figure 23

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[261] *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities,* Docket No. E,G-999/CI-12-1344. (June 17, 2013).

[262] *Order Adopting Open Data Access Standards and Establishing Further Proceedings*. Docket Nos. E,G-999 and M-19-505. (November 20, 2020) p. 4.

[263] Minnesota Department of Commerce. *Staff Briefing Papers-CORRECTED. Docket 16-777. (*July 16, 2020). pp. 76-77.

[264] *Dakota Electric Association Comments in Response to October 30, 2020 Notice of Comment Period. In the Matter of a Commission Investigation on Grid and Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data*. Docket Nos. E999/CI-20-800 and E002/M-19-685. (January 29, 2021) p. 7.

[265] Minnesota Department of Commerce. *Staff Briefing Papers-CORRECTED. Docket 16-777. (*July 16, 2020). p. 77.

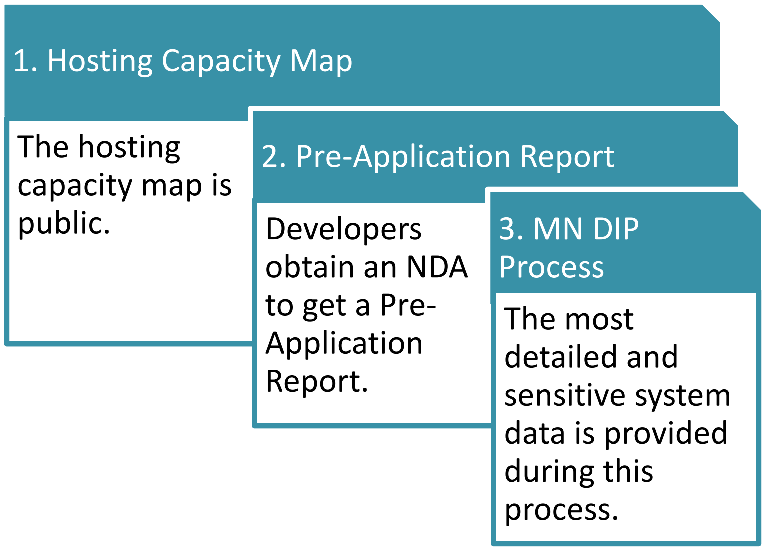
[266] Only DER projects up to 10 MW are considered as part of the MN DIP process.

[267] MPUC. "Distributed Energy Resources Interconnection Process (MN DIP)." Available at: https://mn.gov/puc/assets/MN%20DIP_tcm14-431769.pdf.

[268] *Xcel Energy Comments. Response to Notice Distribution Grid and Customer Security Docket Nos.* E002/M-19-685 and E999/CI-20-800. (January 29, 2021). p. 17.

summarizes how this approach uses tiered methods to protect more detailed information from public access.

**Figure 23: Tiered-Access Interconnection in Minnesota**




### *5.4.3. Tiered-Access Approach for Sensitive Grid Data*

Xcel proposed a matrix that uses a tiered-access approach to balance grid security with public benefits ( Figure 24).[269] The matrix applies Xcel's "internal policy on information lifecycle management" to distribution grid data access to develop grid security risk levels.[270] These internal criteria put data into three categories based on the risk associated with disclosure of the data.

1. Unrestricted (U) – includes information that may or must be provided to the public, and internal company information where public disclosure is unlikely to cause harm.
2. Confidential Information (CI) – information where unauthorized disclosure has the potential to cause harm.
3. Confidential Restricted Information (CRI) – information where unauthorized disclosure has the potential to cause significant harm.[271]

These criteria are applied to the x-axis of the matrix. On the y-axis, a ranking of zero through three is applied based on the increasing benefit of public access to the data. In addition, each location on the matrix is given a label, which distinguishes whether the data is public, and assigns safeguards in

[269] Id., p. 16.

[270] Id, p. 10.

[271] Id., pp. 8-9.

proportion to the balance between grid security and public benefit. For example, data that is considered unrestricted and essential is public (U, 3, P). Conversely, data that is considered confidential restricted information, and which would create a significant benefit to the public, is provided only with an encrypted email and an NDA (CRI, 3, NP-2).

**Figure 24: Xcel's Proposed Tiered-Access Framework**

| Benefit of Public Access: 0 = lowest, least benefit; 1 = moderate benefit; 2 = significant benefit; 3 = essential | | U | CI | CRI |
|---|---|---|---|---|
| | 3 | P | NP-1 | NP-2 |
| | 2 | P | NP-2 | NP-3 |
| | 1 | P | NP-3 | NP-4 |
| | 0 | P | NP-4 | NP-4 |

Grid Security Risk Level:
U = Unrestricted
CI = Confidential Information
CRI = Confidential Restricted Information

Definitions – Tiered Level of Access:
P = Public
NP-1 = Non-public, verified web log-in under NDA terms
NP-2 = Non-public, NDA needed, use encrypted email
NP-3 = Non-public, NDA with in-office on in-person viewing only
NP-4 = Non-public, not provided

*Source: Xcel 1.29.21 Comments on Distribution Grid Security and Customer Privacy, p.10.*

In summary, the Minnesota utilities provide a tiered approach to sharing both customer and interconnection information. Customer energy information is shared based on customer consent, and interconnection information is shared using a series of security screens. Xcel has proposed using a matrix tool to assess data in a tiered-access framework.

## 5.5. Models for Data-Sharing in New York

### *5.5.1. Sharing Sensitive Customer Information*

There are currently several models for sharing different types of information in New York. While each utility's DSIP outlines its specific plans for sharing data, the DSIP Order established the process by which utilities should share information.[272] Specifically, each utility with AMI was required to set a timeline for implementing Green Button Connect. Utilities without AMI were directed to identify other methods for sharing customer data with third parties. To date, the New York IOUs have struggled to implement

[272] NY DPS. *Department of Public Service Staff Whitepaper Regarding a Data Access Framework.* Case 20-M-0082. (May 29, 2020) p. 5.

Green Button Connect, with only three of the utilities currently utilizing it, and both data requestor and customer opt-in being minimal.[273]

The utilities are required to provide customer data for both municipalities and public use.[274] To support community choice aggregation, utilities provide municipalities with aggregated data, customer contact information, and detailed customer energy-usage data. For public use of customer data, the New York State Energy Research and Development Authority (NYSERDA) maintains the Utility Energy Registry (UER) with support from the utilities.[275] The UER is an online database platform that provides streamlined public access to aggregated, community-scale, utility energy data. Semi-annually, the utilities provide aggregated data for the platform and remove data that does not pass the privacy screens (e.g., 15/15 for residential customers, and 6/40 for nonresidential customers). This platform is considered a "starting point" for energy data access and is expected to evolve over time.[276]

### *5.5.2. Sharing System Information*

In addition to each utility's hosting capacity map, each utility currently maintains one or more portals to share useful grid information. The New York PSC has determined that the types of system data that should be shared include:

- Distributed System Implementation Plans
- Capital Investment Plans (via the JU web site or the DPS DMM)
- Planned Resiliency/Reliability Projects (via the JU web site or the DPS DMM)
- System Reliability Statistics
- Hosting Capacity
- Beneficial Locations for DERs (partially available)
- System Load Forecasts (partially available)
- Historical System Load Data (partially available)
- Opportunities for Non-Wires Alternatives (partially available)
- Distributed Generation Queued for Interconnection
- Installed Distributed Generation
- System Interconnection Request (SIR) Pre-Application Information [277]

The Commission has directed the utilities to make all this information publicly available online. Currently, data requestors must visit each of the utilities' websites to access their data, but recently the

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[273] Id., p. 6.

[274] Id., p. 5.

[275] NY DPS. *In the Matter of the Utility Energy Registry, Order Adopting Utility Energy Registry*. Case 17-M-0315. (April 20, 2018).

[276] NY DPS. Department of Public Service Staff Whitepaper Regarding a Data Access Framework. Case 20-M-0082. (May 29, 2020). p. 7.

[277] NY DPS. *Department of Public Service Staff Whitepaper Regarding a Data Access Framework.* Case 20-M-0082. (May 29, 2020). p. 9.

Commission ordered the creation of a centralized portal that would gather each of the utilities' information in one place.

### *5.5.3. Order Implementing an Integrated Energy Data Resource*

The REV Track One Order in New York acknowledges the importance of data availability for the future adoption of DER and customers' management of their energy use.[278] This served as an essential motivation for the Commission's Order Implementing an Integrated Energy Data Resource (IEDR) in February 2021.[279] The IEDR will be a centralized online resource that "securely collects, integrates, and provides useful access to a large and diverse set of energy-related information on one statewide data platform."[280] Furthermore, the Commission ordered that the platform provide access to both standardized customer, and system energy data, while expanding useful access of such data to all types of entities. To date, NYSERDA has led the process, which has involved stakeholder collaboration with a broad range of input. A full list of the data items recommended by DPS for inclusion in the IEDR are listed in Appendix B of its White Paper.[281]

A main item which the DPS used to inform its decision on what information should be available was the creation of a minimum viable data set (MVDS). This dataset was built by a group of DER industry members and consultants in 2019, with input from DPS and NYSERDA. The group was called the DER industry group, and a main outcome of their collaboration was a report that summarized the "most basic set of utility-sourced information needed to accelerate DER market animation."[282] Table 21 shows the types of data included in the MVDS.[283]

**Table 22: MVDS Data Categories and Elements**

| Grid Condition/Performance Data | Business Case/Market Data | Customer Data |
|---|---|---|
| System Elements | Distribution Network Value- Tariff | Customer Class |
| Hosting Capacity Analysis | Distribution Network Value - Non-Wires Solution | Tariff |
| Network Demand | Bulk Power Market Value | Bill |
| Voltage & Power Quality | Distribution Investment Plan | Interval Usage |
| Reliability Statistics | Other | Location |

[278] NY DPS. *Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan.* Case 14-M-0101. (February 26,2015).

[279] NY DPS. *Order Implementing an Integrated Energy Data Resource*. Case 20-M-0082. (February 11, 2021).

[280] Id., p. 2.

[281] Id., Appendix B.

[282] NY DPS. *Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource*. (May 29, 2020). p. 6.

[283] Id., p. 8.

*Source: NY DPS Staff IEDR Whitepaper, p.8.*

The report also noted that most of the data listed in Table 22 was already publicly available. However, the DER Industry Group emphasized that the needed information was only currently accessible though “disparate sources.”[284] The group also stated that “the significant differences in the meaning, format, attributes, and integrity of their respective data is an inconsistency that presents a barrier to DER market animation as it severely hinders DER developers’ ability to effectively and efficiently use the data that they obtain from those sources.”[285] These comments, in part, motivated the Commission to order the IEDR be created as a single, all-encompassing platform with standardized information.

To guide the IEDR, a corresponding data access framework was released that provided an outline on how data would be accessed and detailed key terms and data quality standards.[286] NYSERDA recommended that the Commission adopt this framework in regards to the IEDR; however, the Commission required that the IEDR comply with a new data access framework that has yet to be released.[287] In the proposed framework, an entity seeking data would need to be certified as “data-ready.” This certification would only be granted if the entity met all the requirements of the Commission, utilities, and DPS. With this certification, the entity would become an authorized energy service entity (ESE). Next, the entity would detail its “purpose for accessing the data, the mechanism by which the data are being accessed or transmitted, and the data type for which access is being requested.”[288] The provider (a group processing the entity’s request) would utilize a matrix to determine the requirements for accessing the requested data based upon these three conditions.[289]

*Purpose*: During this step, the provider would determine if the entity should have access to unconsented data. Valid purposes for access to unconsented data include: (1) providing or reliably maintaining customer-initiated service; (2) including compatible uses in features and services to the customer that do not materially change reasonable expectations of customer control and ESE data sharing; or (3) disclosure pursuant to Commission Order and/or State, Federal and Local Laws or regulations.[290] Entities with a Purpose that did not meet these conditions would receive anonymized or aggregated data.

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[284] Ibid.

[285] Ibid.

[286] NY DPS. *New York Department of Public Service Department of Public Service Staff Whitepaper Regarding a Data Access Framework*. Case 20-M-0082. (May 29, 2020).

[287] NY DPS. *Order Implementing an Integrated Energy Data Resource*. CASE 20-M-0082. (February 11, 2021).

[288] NY DPS. *New York Department of Public Service Department of Public Service Staff Whitepaper Regarding a Data Access Framework*. Case 20-M-0082. (May 29, 2020). p. 23.

[289] Id., pp. 24-31.

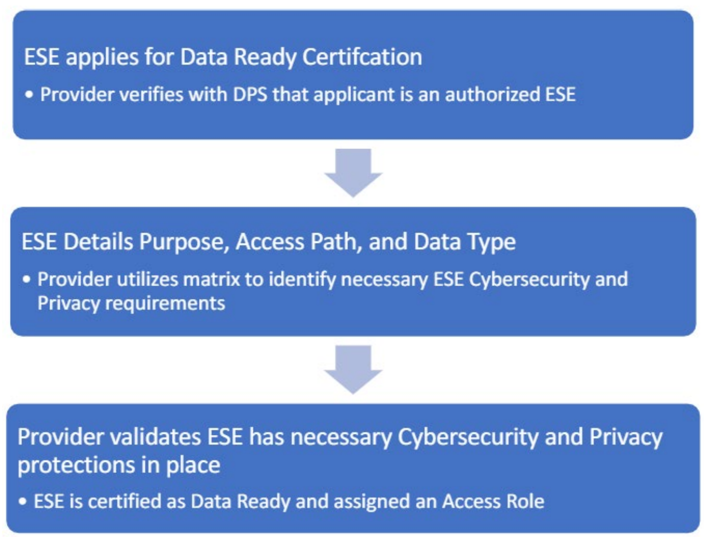
[290] Id., p. 24.

*Transmittal or Access Mechanism*: The provider would take into consideration how the data will be accessed or transmitted. This could be as simple as an email or it could involve access through a secure portal/platform. Ultimately, it is up to the provider to determine how the entity will access the data.

*Data Type Requested*: The type of data requested by an entity will determine the necessary privacy requirements. DPS outlines a risk-based approach based on the risk associated with releasing sensitive data and maintains the customers right to share their data. Furthermore, data is broken into two categories: (1) system data and (2) customer data. Customer data would include customer contact information, CEUD, and billing data. System data would include information about the components and activity on the distribution system. Notably, the framework is clear that for "system data, except for those pieces of system data that may impact customer privacy or critical infrastructure protection, there should be no protections on the availability of such data because it is aggregated data itself. Since it is not CEUD, it is not subject to customer consent."[291]

Once the matrix has been used to determine the necessary steps and protections, the entity would receive an access role which would determine the types of data they could access, and how they could access it. Figure 25 outlines this process.[292]

**Figure 25: Data Ready Certification Process**




*Source: NY DPS Staff IEDR Whitepaper, p.31.*

A Pilot Data Platform, like the IEDR, has been launched with the Orange and Rockland Utility. The platform automates the process for providing data to DER developers, among other functions, and the

[291] Id., p. 31.

[292] Ibid.

development and rollout of the platform costs $240,000.[293] To obtain access to the Pilot Data Platform, a DER provider "must be registered with the DPS, comply with the applicable Uniform Business Practices provisions, and complete and submit the DER Provider Pilot IEDR Registration Form."[294] The pilot's early results have been positive.[295] Lastly, the IEDR will be implemented over 2 phases.[296] Phase 1 has a total budget cap of $13.5 million and will include designing, implementing, and managing the IEDR. Phase 2 does not yet have a budget and will include further improvements to the IEDR.
Figure 24 summarizes the differences between the current model in New York, and the new one outlined in the proposed Data Access Standards.[297]

**Figure 26: Proposed vs. Current Data Access Framework in New York**

| Current ESE Access Process | Proposed Data Ready Certification Process |
|---|---|
| 1) ESE registers with DPS and completes all requirements under applicable UBP (including privacy and cybersecurity).<br>2) ESE contacts utility to request access to data.<br>3) ESE must sign a DSA with utility and provide. Verification.<br>4) ESE must go through onboarding and connectivity testing with utility.<br>5) ESE must meet any other utility specific obligations.<br>6) ESE requests data from utility.<br>7) ESE receives data from utility.<br>8) ESE must review the data for consistency and verify integrity.<br>9) ESE works with utility to correct any data issues.<br>10) ESE must repeat this process for EACH UTILITY from which it seeks to access data. | 1) ESE registers for access:<br>a) Provider verifies applicant is an authorized ESE.<br>b) ESE details purpose, transmittal/access mechanism, and data type.<br>c) Necessary ESE cybersecurity and privacy protections, based upon registration information, are validated.<br><br>ESE is assigned an Access Role that dictates the data they are approved to access and how they can access it.<br><br>2) ESE requests data from data custodian (utility, centralized data warehouse, etc.).<br>3) Data custodian verifies ESE Access Role.<br>4) ESE receives data from data custodian that is uniform and correct. |

*Source: NY DPS Staff IEDR Whitepaper, p.18.*

In summary, New York is in the process of developing a resource that would streamline the process for accessing information. While the creation of the IEDR is still very much a work in progress, the reasons for its development are apparent. By streamlining the data release process, the NY PSC seeks to lessen

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[293] NY DPS. Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource. Case 20-M-0082. (May 29, 2020) pp. 5-7.

[294] NY DPS. "Distributed Energy Resource Regulation and Oversight." Available at: https://www3.dps.ny.gov/W/PSCWeb.nsf/All/EAB5A735E908B9FE8525822F0050A299.

[295] NY DPS. *Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource.* (May 29, 2020), p. 8.

[296] Order Implementing an Integrated Energy Data Resource. Case 20-M-0082. (February 11, 2021). pp. 15-22.

[297] NY DPS. *New York Department of Public Service Department of Public Service Staff Whitepaper Regarding a Data Access Framework*. (Case 20-M-0082). (May 29, 2020), p. 18.

the burden of collecting interconnection data and decrease the number of times utilities must go through data access protocols with third parties.

## 5.6. Models for Data-Sharing in California

### *5.6.1. Sharing Sensitive Customer Information*

The CPUC's Order on September 23, 2013, authorized third-party access to customer energy data to "provide higher quality, standardized data to encourage the market for DERs."[298] The order required third parties that requested data to be pre-approved by utilities as a trusted vendor. This allowed groups such as developers to become a trusted vendor, request access to a specific customer's data, and then tailor their offer to the needs of that customer. As described by the DPS, this order increased the "value of potential products" and maximized "the value derived from these DERs."[299]

In 2014, the CPUC released its Decision Adopting Rules to Provide Access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data (Rulemaking 08-12-009).[300] In its ruling, the CPUC explained that access to energy data can advance policy goals and it explicitly listed seven goals including the "deployment and integration of cost-effective distributed resources and generation, including renewable resources."[301]

In addition to identifying goals, the order established a tiered-access approach to customer information within California. Government entities and academic researchers were allowed access to anonymized data, while other groups were granted access to aggregated data without customer consent. The CPUC also detailed a process for requesting and releasing customer energy data.[302] It included requiring a single point of contact for energy data requests, requiring the utilities to publish a list of all requests and their purpose, and establishing a clear timeline for the utility's response to data requests. Entities seeking access to data are also required to provide their purpose for accessing data; a description of the data requested; an address, name, and phone/email; and are required to execute a standard NDA (apart from local governments on certain conditions). Finally, the Order established an Energy Data Access Committee and standard formats and mechanisms for utility data release. Today, one of the ways in which third-party data is authorized for release is through the "click-through authorization process,"

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[298] NY DPS. *Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource*. Case 20-M-0082. (May 29, 2020). p. 20.

[299] Ibid.

[300] NY DPS. *Decision Adopting Rules to Provide Access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data.* Decision 14-05-016. (May 1, 2014).

[301] Id., p. 21.

[302] Id., Attachment A, p. 1.

which allows customers to easily authorize their utility to share their energy data with third parties.[303] The California IOUs recently proposed improvements to the process including expanding it to bring in DER and energy management providers, improving data delivery, and delivering data within 90 seconds. The potential benefits of the proposal include streamlining the processes for: (1) customers to authorize service providers to access their data and (2) utilities to transfer customer data quickly and efficiently to such authorized DER and energy management service providers.[304] The Commission is expected to decide on the utilities' proposals in early 2021.

### *5.6.2. Sharing System Information*

Each of the California IOUs have a web portal which gives access to several types of information including the hosting capacity maps which have been discussed. For example, PG&E offers a Distribution Investment Framework (DIDF) map and a PV RAM map. PG&E describes the use of the DIDF map as a location to "show assumptions and results of the distribution planning process that yield grid needs related to distribution grid services," while the purpose of the PV RAM map is to show selected electric distribution lines, substations, and transmission lines paired with general electric system information.[305] For PG&E, both maps require user registration. Similarly, SDG&E requires registration to access its ICA map (which includes a locational net benefits layer).[306] SCE takes a slightly different approach. On its interactive portal, it provides the following information:

- General locations of SCE distribution circuits, substations, sub-transmissions systems;
- Load and DER Integration Capacity Analysis (ICA) results (e.g., hosting capacity);
- Current, queued, and total distributed generation interconnections amounts;
- Downloadable datasets for DER developers, with Application Programming Interface (API) capabilities;
- Locational Net Benefit Analysis (LNBA) results; and
- Grid Needs Assessment (GNA), Distribution Deferral Opportunity Report (DDOR).[307]

In addition to maps, utilities in California follow an interconnection process known as Rule 21 to help developers connect DERs to the grid. Each IOU is responsible for implementing an interconnection

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[303] Kim, Anne Y. 2021. California's Grid Modernization Report to the Governor and Legislature. CPUC. p. 64.

[304] Ibid.

[305] PG&E. "Distribution-Resource Planning Data Portal." Available at: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page?ctx=large-business.

[306] SDG&E. "Accessing the Map." Available at: https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica.

[307] SCE. *Integration Capacity Analysis (ICA) User Guide.* Available at: https://ltmdrpep.sce.com/drpep/downloads/ICAUserGuide.pdf.

procedure in Electric Rule 21 as established in Interconnection Rulemaking (R.17-07-007).[308] By having a robust ICA map, both utilities and developers can move through the interconnection process more swiftly. In some ways, the process is very similar to the MN DIP process. It includes an optional Pre-Application Report for additional system information, and the potential release of CEII information during the interconnection process. The applicant may also be required to sign an NDA.[309] Similar to Minnesota, this represents a tiered-access approach to information sharing. Additional information is supplied to the developer during the interconnection process to help streamline DER development.

In summary, California utilizes a tiered-access system to release both interconnection and customer data. However, California provides a considerable amount of information in support of DER deployment early in the pre-interconnection process, which helps to accelerate DER interconnection.

## 5.7. Models for Data-Sharing in New Hampshire

New Hampshire, similar to New York, is in the midst of a proceeding that would establish an online energy data platform to provide a variety of energy-use information to ratepayers, third parties, and IOUs.[310] The State's Office of Consumer Advocacy has proposed six core use datasets including, "billing, [time-of-use], demand study, multi-state and utility, multi-fuel, and a Statewide index, the last dataset referring to the idea that the SB284 platform will act as a single source of truth for all electricity and other fuel information in the State."[311] The platform intends to incorporate a tiered-access system. The New York DPS has noted that it is "monitoring this proceeding closely to ensure that the state will be able to exchange lessons learned to encourage the adoption of these platforms in both states," as the potential New Hampshire platform is very similar to the in-progress IEDR in New York.[312]

## 5.8. Comparison of Energy Access Platforms

Table 23 reviews and compares some of the fundamental elements incorporated into each state's energy access platforms. All the states discussed, use some form of tiered access to release standardized data to third parties. One notable difference between the states is the recent development of single-access platforms. While both New Hampshire and New York have not fully implemented a single-access platform, both seek to streamline the process of data-sharing by limiting the number of locations where data is stored.

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[308] CPUC. "Rule 21 Interconnection." Available at: https://www.cpuc.ca.gov/General.aspx?id=3962.

[309] PG&E. *Electric Rule No. 21: Generating Facility Interconnections.* p. 89. Available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf.

[310] Ibid.

[311] Ibid.

[312] Ibid.

**Table 23: Overview of Energy Access Platforms**

| State | Standardized Data | Single Access Platform | Tiered Access |
|---|---|---|---|
| Minnesota | Established in the November 2020 Order | No | Tiered access to customer data based on customer consent and MN DIP process with increased security for CEII information. |
| New York IEDR | Data will be standardized in the IEDR | Yes | Proposed data-access framework uses a matrix to determine what level of information is shared with a requesting party. |
| California | Utilities use or model their data standards like Green Button Connect | No, each utility has a website | Increased security for CEII information and segmented aggregation screens for customer information. |
| New Hampshire (Proposed) | Data will be standardized | Yes | The platform intends to incorporate a tiered-access system. |

### 5.9. Guiding Principles for Tiered Access

After reviewing the various practices used by states for releasing information to third parties, we recommend that the Commission consider the following two recommendations.

Firstly, the Commission should consider a risk-based, tiered-access approach that transparently shares energy data. Each case study discussed provided criteria for restricting access to highly sensitive information. While we do not necessarily recommend the tiered-access approach as proposed by Xcel, we do recognize that having protections in place for highly sensitive information should be required. We also recommend that the criteria for evaluation be transparent and that the development of such criteria include an array of input from a diverse group of stakeholders.

Secondly, we recommend that the Commission consider approaches that expedite the process for accessing data. As described in Section 5.5, the process proposed in New York by which entities become "data ready" and receive an "access role" could expedite data access for all parties involved. In the case of Minnesota, parties that repeatedly interconnect could save time by only being screened for security requirements on an annual basis. Establishing this user access role could increase the security for sharing data but the user registration process should not be overly burdensome for the parties involved.

## 6. Recommendations

Striking the right balance between Xcel's grid and customer security and confidentiality concerns around publishing sensitive hosting capacity map data and the public benefits in having access to this information to increase DER deployment can be challenging.

Synapse developed the recommendations below to help Minnesota find that balance. To develop them, we worked with the Department to host two stakeholder workshops on grid and customer security; conducted an extensive literature review; benchmarked the hosting capacity data-sharing practices of leading utilities in this space; sent a survey to Minnesota DER developers and other interested parties; and spoke with utility representatives and risk management experts. As a result of Synapse's findings, our recommendations regarding the privacy and security implications of Xcel's HCA and public-facing map are as follows.

In the short-term, we recommend the Commission take the following actions:

- Allow Xcel to only redact load data when a feeder violates the 15/15 aggregation standard and require Xcel to publish on its map, and in its tabular spreadsheet, all other HCA data.
- Require Xcel to create a transparent process for how third parties can access CEII, on a "need-to-know" basis, with appropriate protections (e.g., NDA) in place.
- Allow Xcel to only redact feeders included in the HCA if they satisfy one or more of the following criteria: (1) are connected to a dedicated customer or (2) are connected to critical infrastructure or serve a critical customer.
- Require Xcel to provide more detailed rationale (e.g., beyond "security concern") for justifying not publishing feeder and substation capacities.

In the longer-term, we recommend the Commission take the following actions:

- Require Xcel to provide an unblurred HCA map, which shows its distribution feeders, behind a verified web login portal that is open to the public (e.g., does not require an NDA).
- Encourage Xcel to consider a tiered-access approach that helps streamline and does not make requirements to access non-public grid data unnecessarily burdensome.
- Encourage Xcel to engage in a transparent, Risk-Benefit/Cost-Benefit Framework stakeholder process to help determine whether specific, sensitive grid data should be published on its HCA map, and how secure access to sensitive grid data, deemed non-public, should be provided.
- Require Xcel to estimate the level of effort and cost to incorporate each specific piece of data in the Pre-Application Report that is currently not in the HCA map, where technology requirements (e.g., querying and search functionality) rather than security concerns are the limiting factor (e.g., distance from site to substation).

These recommendations should help to balance the grid and customer security concerns and data access requirements of all parties involved.

# 7. Conclusion

Hosting capacity maps provide information that benefits a wide range of users. Use cases for these maps range from helping developers interconnect DERs to providing locational information to industry advocates who wish to increase the amount of DERs deployed on the grid for the public good. As regulators seek to support these use cases, there has been a noticeable shift throughout the United States towards increasing the amount of information available on hosting capacity maps. Seven states already have functioning hosting capacity maps, while five more are significantly enhancing the functionality of their maps.

As states continue to increase the data provided on their hosting capacity maps, they must determine what information should be publicly disclosed. For example, some information like CEUD or CEII may be confidential. States have employed a range of strategies to protect this type of information. These strategies have included redacting critical information, aggregating customer data, and developing tiered-access systems that provide access to sensitive information with appropriate protections in place. Furthermore, frameworks such has the Risk-Benefit Framework can be used to weigh the benefit of public data release with the risk of its misuse. It is important to develop a transparent model that allows for the robust sharing of information. States such as New York, California, and New Hampshire have all taken steps to ramp up the ease of accessing data while balancing the need for its security.

Minnesota is currently in the process of increasing the information displayed on its hosting capacity map. The lessons learned and recommendations discussed in this report are designed to help Minnesota regulators make informed decisions based on current industry standards and practices. By employing an appropriate model for information sharing, Minnesota will be able to balance its ability to support increasing amounts of DERs on the grid with the need to protect grid and customer security.

APPENDIX A. Pre-Application Report Data

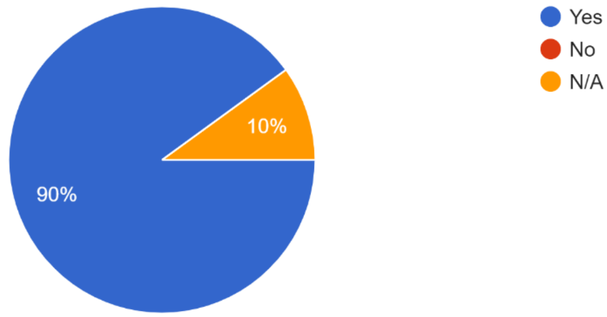
Table A.1 compares the information currently provided in Xcel Energy's Pre-Application Report with the information contained in its hosting capacity analysis in both map and tabular formats.

**Table A.1. Comparison of Pre-Application Report data elements with HCA**

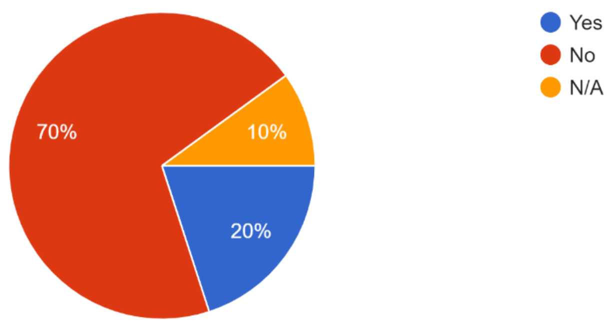
| Pre-application Data Element | Information Available on Map | Information Available in Tabular Format | Notes |
|---|---|---|---|
| Substation Name | Yes | Yes | N/A |
| Transformer Name | Yes | Yes | N/A |
| Transformer Rating | No | No | Privacy/Security Concerns |
| Transformer Peak | No | No | Privacy/Security Concerns |
| Transformer DML | Yes | Yes | N/A |
| Transformer Absolute Min | Yes | Yes | N/A |
| LTC or Regulator | Yes | Yes | N/A |
| Transformer Existing Gen | Yes | Yes | N/A |
| Transformer Queued Gen | Yes | Yes | N/A |
| Transformer Gen Capacity | No | No | Security concerns and significant technology requirements; equation would need to be implemented within the map or prior to map creation |
| Distance from site (PCC) to substation | No | No | Significant technology requirements; query function would need to be built into Hosting Capacity Map |
| Feeder Name | Yes | Yes | N/A |
| Feeder Rating | No | No | Privacy/Security Concerns |
| Feeder Peak | No | No | Privacy/Security Concerns |
| Feeder DML | Yes | Yes | N/A |
| Feeder Absolute Min | Yes | Yes | N/A |
| Feeder Voltage | Yes | No | N/A |
| Feeder Existing Gen | Yes | Yes | N/A |
| Feeder Queued Gen | Yes | Yes | N/A |
| Feeder Gen Capacity | No | No | Security concerns and significant technology requirements; equation would need to be implemented within the map or prior to map creation |
| Nominal Voltage at PCC | Yes | No | N/A |
| Network or Radial | Yes | Yes | N/A |
| # of Phases | Yes | No | N/A |
| Distance to 3 phase circuit | No | No | Significant technology requirements; query function would need to be built into Hosting Capacity Map |
| Protective devices and regulators between site and substation | No | No | Security concerns and significant technology requirements; query function would need to be built into Hosting Capacity Map |
| Conductor between site and substation | No | No | Security concerns and significant technology requirements; query function would need to be built into Hosting Capacity Map |

APPENDIX B. Developer Survey Results

Have you ever applied to interconnect a DER project in Xcel Energy's service territory?
10 responses




If you answered "yes" to the prior question, was Xcel Energy's hosting capacity map helpful in your decision to complete a DER interconnection request?
10 responses

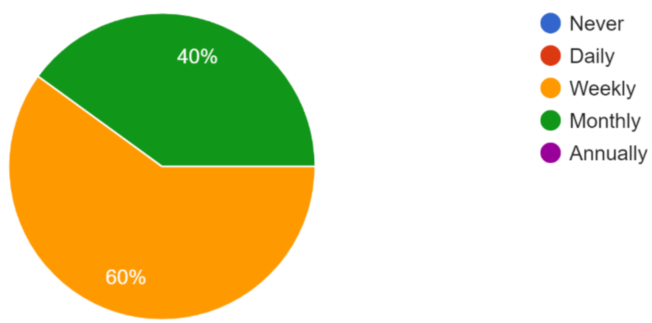



If you answered "yes" to the prior question, please explain what you used the hosting capacity map for and what value it provided. (4 responses)

1. We utilized the map to identify the size and scope of a project which could be interconnected at the selected location.
2. We used it to help indicate capacity, but it never seems to be up-to-date and the capacity available seems to inconsistently change.
3. I used the map, but it was so old that I did NOT trust the data.
4. To see if my project would fit or if the grid was at capacity.

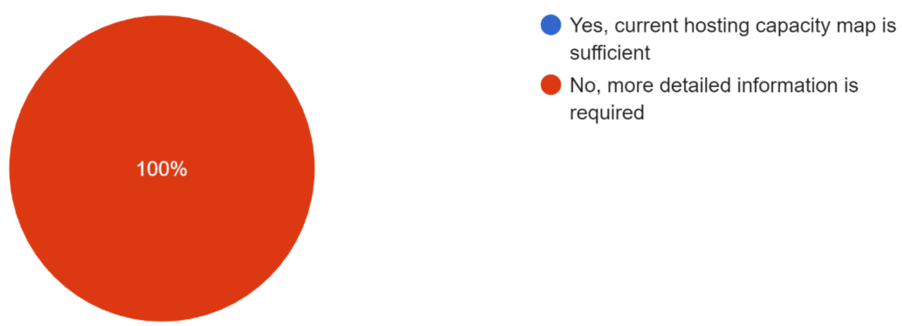
How often do you use Xcel Energy's hosting capacity map?

10 responses

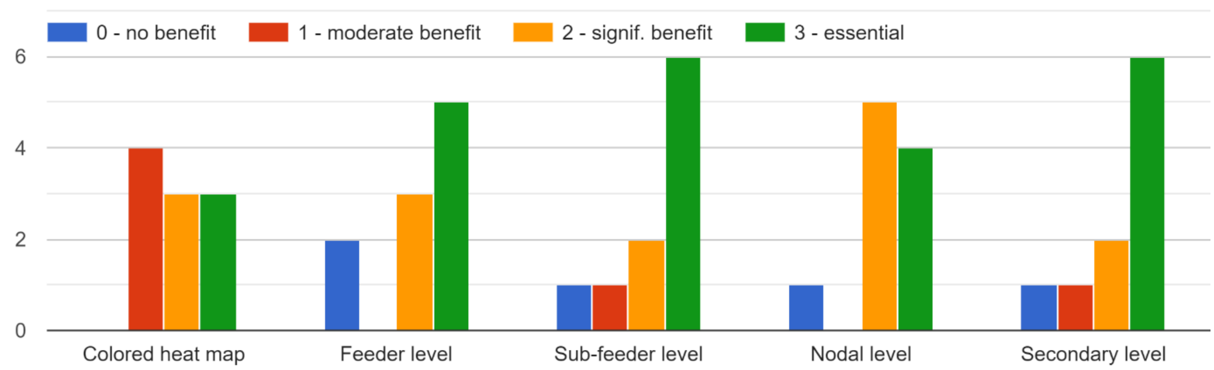



Is the current hosting capacity map sufficient to meet DER developers needs or does it require more detailed information?

10 responses



Please rank the utility of having a hosting capacity map at the indicated levels of granularity for determining the optimal project sites for DERs. [N... beyond the transformer to the customer premise.]




Please explain your rationale behind the designations you chose in the prior question. (10 responses)

1. As detailed of information as possible is essential to ensuring we can accurately and efficiently develop projects. Other regions and utilities have extraordinarily more detailed data than Xcel, which provides a significant benefit to DER development.

2. Sub-feeder level data is the basic level of data needed to make informed decisions about siting DER. Nodal level would be even more powerful and would enable utilization of an actual value-based approach to DER siting, such as true locational marginal pricing. Secondary level would provide an even stronger level of clarity about capacity, but these benefits are limited as compared to Nodal level data and could dramatically increase the complexity of analysis.

3. Customers need to be able to trace the power lines from a specific address to a specific node where hosting capacity analysis data are provided. Without being able to trace a line from an address to the node with hosting capacity data, the map does not give all customers data necessary to optimally design and site DERs.

4. The more we know the better to get good projects sited.

5. All of this information is HIGHLY valuable but totally useless if 16+ months old...

6. More granularity would help avoid surprise charges for customers that want to have solar.

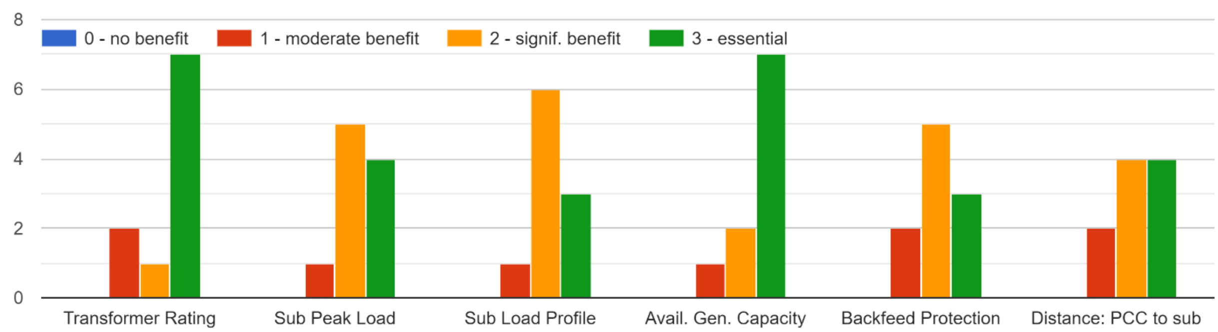
7. We need to know at the customer level if they can have net metered DER.

8. I use it for behind-the-meter projects, so it's nice to know what you're gonna be up against early on in the project. The most useful information to me is existing transformer size, voltage/phase, and secondary conductor size.

9. Information was inaccurate beyond a very general level.

10. Most of the needed content is there, it just needs to be updated more often. We view displaying substation transformer size as being critically important, however we understand there are potentially security issues with doing that as well as other formal methods to acquire that information.

Please rank the importance of having the following grid data available on a hosting capacity map for determining the optimal project sites for DERs at the substation level...tation, Gen = generation, PCC = point of common coupling]




Please explain your rationale behind the designations you chose in the prior question. (10 responses)

1. As detailed of information as possible is essential to ensuring we can accurately and efficiently develop projects.

2. All of this data is highly valuable for planning DERs. Without transformer ratings, peak load, and Available Generation Capacity, you can't really do much. The other piece of information that feels key is Minimum load/ daytime load.

3. The substation data listed is essential to determining if the substation can support additional DERs. Providing substation data is particularly important because Xcel's hosting capacity analysis does not currently evaluate substation constraints.

4. We need to know how much electricity can flow and where how etc.

5. This would significantly increase our ability to assess out projects and give the community we serve an accurate idea of what they're in for.

6. N/A to my projects - you should invalidate my responses to the previous question as this form would not let me submit without putting something on each line.

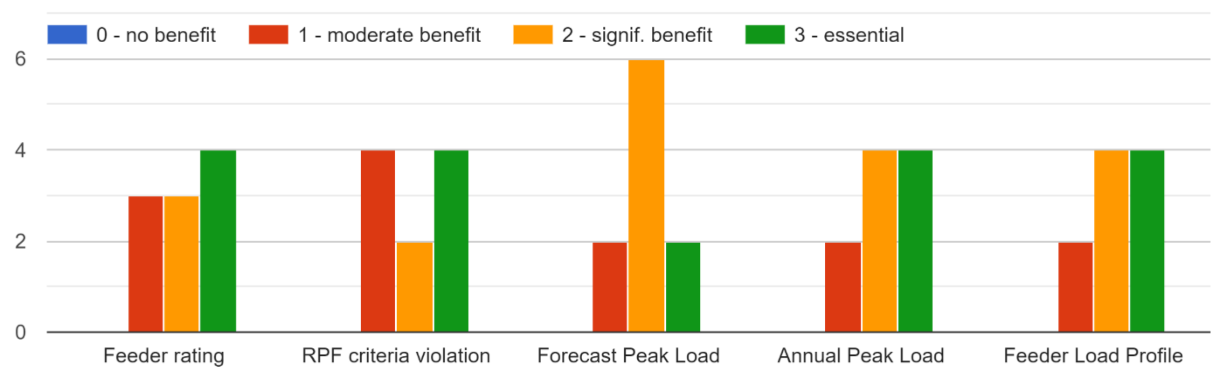
7. Knowing the limits allows for better design considerations on our end.

8. The main one is transformer size. That comes into play more often than the rest of them but still all are helpful.

9. Initial screening is the only utility from the system at the current time.

10. If the available generation capacity was able to be trusted, that would be essential, but as of now we pretty much ignore it. The more information provided up front, the fewer questions we will have tying up Xcel's time and higher quality projects we will be attempting to push through.

Please rank the importance of having the following grid data available on a hosting capacity map for determining the optimal project sites for DERs at the feeder level. [Note: RPF = reverse power flow]




Please explain your rationale behind the designations you chose in the prior question. (10 responses)

1. As detailed of information as possible is essential to ensuring we can accurately and efficiently develop projects.

2. All of this data is extremely valuable. Without the essential items, you can't really do much.

3. Criteria violations and load profiles are essential to understanding how to design projects to avoid certain constraints, both technologically and temporally.

4. See above.

5. Again - this is all crucial info!

6. N/A to my projects - you should invalidate my responses to the previous question as this form would not let me submit without putting something on each line.

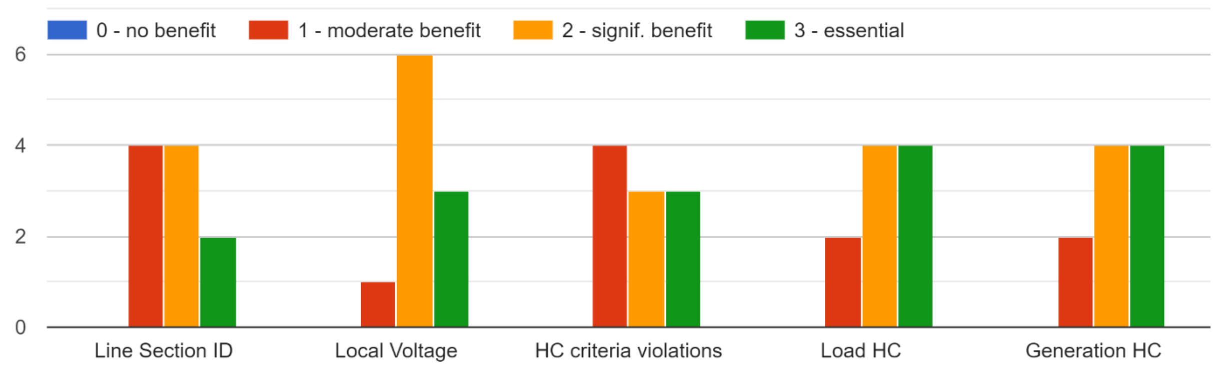
7. Knowing the limits allows for better design considerations on our end.

8. At this time, I see less benefit from these attributes but still very valuable information.

9. Would establish a threshold for further due diligence.

10. This information is more helpful to BESS decisions, and we have not engaged in such a system in this market as of yet.

Please rank the importance of having the following grid data available on a hosting capacity (HC) map for determining the optimal project sites for DERs at the sub-feeder/line level.




Please provide a detailed explanation of your rationale behind the designations you chose in the prior question. (10 responses)

1. As detailed of information as possible is essential to ensuring we can accurately and efficiently develop projects.
2. The last three items help define the key opportunity and constraints at the sub-feeder level. ID of line sections and local voltage information is extremely valuable, but not quite as key.
3. Criteria violations and load profiles are essential to understanding how to design projects to avoid certain constraints, both technologically and temporally.
4. See above.
5. Meh - this is pretty far in the weeds for a rooftop installation. We don't do the large fields.
6. Local voltage would help projects move more quickly.
7. Knowing the limits allows for better design considerations on our end.
8. At this time, I see less benefit from these attributes but still very valuable information.
9. These issues can be largely addressed by interconnection upgrades.

10. These in conjunction with the public queue and other sourced data help complete a full picture of an interconnection scenario so that we aren't submitting projects directly into a woodchipper.

In addition to the information above, are there any other grid data that would be useful for inclusion in the hosting capacity map? Please explain.

1. Visibility into the scope and potential budget required to upgrade a given location for a given project or project range would be significantly helpful, even if the data was an estimate or range pending final quoting and confirmation.
2. When do we transition from asking "how much solar can fit on the existing system" to asking "how do we build a system based on solar"?
3. Transformer secondary voltage and phase, and secondary conductor sizing.
4. More general information on the status of other distributed generation projects in the queue; schedule for grid improvements, if any, based on the approved Integrated Distribution Plan.
5. More clarity on existing protective devices and the listed limiting element that restricts further capacity would be nice. Maybe if transformer ratings cannot be disclosed, then classify the substation on the HCM into ranges like (10 MVA-20 MVA), specially to identify the smaller substations that have like a 3 MVA transformer, and the large substations that can likely take on a great deal more projects even though it may appear saturated.

Direct Testimony and Schedules
Ravikrishna Duggirala

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(RD-1)

**Advanced Grid Cost Benefit Analysis**

November 1, 2019

Exhibit 4

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## Schedules

## I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ravikrishna Duggirala. I am the Director of Risk Strategy for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I joined Xcel Energy in 2002, and have held my current position, in which I am responsible for Enterprise Risk Management, Asset Risk Management, risk analytics, and modeling, since 2008. Previously, I was the Manager of Energy Sales Risk for XES, where I was responsible for retail sales risk analysis, key risk analysis, sensitivity analysis, and risk analytics. I was also a Risk Consultant at Xcel Energy between 2002 and 2005. I received my Ph.D in Engineering from Purdue University in 1996, and my Master's Degree in Business Administration from Washington University in St. Louis in 2000. My Statement of Qualifications is provided as Exhibit___(RD-1), Schedule 1.

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

A. The purpose of my Direct Testimony is to present the Company's overall assessment of the costs and quantifiable benefits of the future components of its Advanced Grid Intelligence and Security (AGIS) initiative. I present the structure of the Company's overall cost benefit model, which is provided with the Company's AGIS supporting files compact disc in Volume 2B of this filing. I identify its purpose as one tool to utilize in assessing the quantifiable costs and benefits of the Company's overall plans for the AGIS initiative. I also support specific types of benefits in the model, which include avoided peak capacity and customer savings resulting from the implementation of time-of-use rates with our Advanced Metering Instructure (AMI) component of AGIS. Additionally, I summarize some of the qualitative benefits that are difficult to capture in a quantitative model.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony supports the Company's cost benefit model for the AGIS initiative, which was required by the Minnesota Public Utilities Commission (Commission) for our advanced grid planning. Overall, I explain why the model is appropriate and presents a reasonable comparison of the costs and quantifiable benefits of the future components of the AGIS initiative from the customer perspective. I note that the model has some limitations, in that it only presents costs and benefits that the Company has converted to dollars – whereas some benefits (like customer satisfaction) cannot be quantified, and the Company is not comfortable attaching a cost basis to other benefits (like human safety). As such, the cost benefit analysis (CBA) is simply one useful tool to assess certain aspects of the Company's proposed AGIS initiative.

In my Direct Testimony, I begin by introducing the structure of, and our approach to the model. I explain that the model is intended to present a conservative comparison of the net present value (NPV) of the costs of the components of the AGIS initiative with the NPV of benefits of those components, on a revenue requirements basis. The model also presents a composite NPV comparison between costs and benefits of the overall AGIS initiative. I identify the cost and benefit inputs, stated in terms of capital, operations and maintenance (O&M), or other benefits. While I present these inputs within the cost benefit model itself, the costs and benefits are largely supported by our business area witnesses, namely Mr. David C. Harkness on Information Technology (IT) components, Ms. Kelly Bloch on Distribution Operations, Mr. Michael Gersack on Program Management, and Mr. Christopher Cardenas on Customer Care. These witnesses support costs and benefits for each component of the AGIS initiative (AMI, Fault Location Isolation and Service Restoration (FLISR), Integrated Volt-VAr Optimization (IVVO), and associated components of the Field Area Network (FAN)). In my testimony, I identify where information about the costs and benefits can be found. I also support the aspects of our modeling assumptions related to avoided peak capacity and peak pricing avoidance as a result of AMI, and reduced carbon emissions as a result of AMI and IVVO, illustrating why those assumptions are reasonable.

Next, I provide the ranges of results of the Company's CBA for each of the components of the AGIS initiative, as well as the overall AGIS CBA. Our model results in a ratio of estimated benefits to costs for each component, as well as the composite ratio of estimated benefits to costs for the overall initiative. A ratio of 1.0 or higher indicates quantifiable benefits are expected to equal to or exceed the costs, whereas a ratio of less than 1.0 indicates costs are expected to exceed quantifiable benefits:

**Table 1**
**Range of AGIS Benefit-to-Cost Ratios[1]**
**(Includes allocated components of FAN)**

| | <u>LOW SENSITIVITY</u> *IVVO 1.0% Energy Savings, With Contingency* | <u>BASELINE</u> *IVVO 1.25% Energy Savings, With Contingency* | <u>HIGH SENSITIVITY</u> *IVVO 1.5% Energy Savings, No Contingency* |
|---|---|---|---|
| AMI | 0.83 | 0.83 | 0.99 |
| FLISR | 1.31 | 1.31 | 1.53 |
| IVVO | 0.46 | 0.57 | 0.72 |
| **Overall AGIS** | **0.86** | **<u>0.87</u>** | **1.03** |

I also provide discussion regarding the limitations of a cost benefit model, both with respect to unquantifiable qualitative benefits and in relation to the need to update aging distribution infrastructure that is a central requirement of an electric service delivery business. While Company witnesses Mr. Gersack and Ms. Bloch describe those benefits in their testimony, I provide context for these unquantifiable benefits and explain how they support the Company's overall advanced grid strategy.

Finally, I provide "Least-Cost/Best-Fit" summaries of the relative functions, limitations, costs, and benefits (to the extent applicable) for metering and communications network alternatives. These comparisons underscore why we have selected our AMI and FAN solutions, as described in extensive detail in the testimony of Ms. Bloch and Mr. Harkness.

Overall, I conclude that the Company's cost benefit model is one reasonable means of assessing quantifiable costs and benefits of the overall AGIS

[1] The Overall AGIS ratio is not intended to be a sum or simple average of other ratios, but rather is a consolidated ratio as I discuss in Section II.C of my Direct Testimony.

initiative, but a comprehensive assessment requires consideration of additional factors that are discussed by the Company's other AGIS witnesses.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present the remainder of my testimony in the following sections:

- Section II: AGIS Quantitative Cost Benefit Model
- Section III: Least-Cost/Best-Fit Alternatives
- Section IV: Qualitative Benefits of AGIS
- Section V: Conclusion

## II. AGIS QUANTITATIVE COST BENEFIT MODEL

### A. Model Structure and Requirements

Q. WHAT IS THE PURPOSE OF THE AGIS CBA, FROM THE COMPANY'S PERSPECTIVE?

A. The Company is presenting its CBA to illustrate its assessments of the quantitative value of the requirements for and benefits of the AGIS initiative. This model is intended to aid the Commission and other stakeholders in evaluating the overall prudence of the AGIS proposals, and was likewise required by the Commission's Order Point 9.B in its Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements, dated September 27, 2019 in our 2017 Transmission Cost Recovery (TCR) rider (Docket No. E002/M-17-797) (TCR Rider Order).

Q. PLEASE INTRODUCE THE COMPANY'S COST BENEFIT MODEL IN THIS MATTER.

A. The CBA model compares the costs with the quantifiable benefits of each component of the Company's AGIS initiative, as well as the overall costs and quantifiable benefits of the initiative. More specifically, the model calculates the benefit-to-cost ratios for the proposed components of the AGIS initiative that the Company is planning to pursue at this time – namely, AMI, FLISR, and IVVO. The cost components of the FAN are also incorporated into the CBA because the FAN benefits are realized through its support of the other components of the AGIS initiative. The CBA utilizes specific cost and quantifiable benefit estimates and assumptions provided by Company witnesses Mr. Gersack, Ms. Bloch, Mr. Harkness, and Mr. Cardenas. I also support certain benefits, as discussed later in my Direct Testimony.

The Company's CBA model utilizes the Discounted Cash Flow (DCF) procedure and the 2019 Net Present Value (NPV) for quantifiable costs and benefits, to determine the value of the AGIS investments. Specifically, the benefit-to-cost ratio evaluates the standalone costs and benefits of each of AMI, IVVO, and FLISR respectively, including the FAN costs allocated to each of these components. Finally, the model evaluates the NPV benefit-to-cost ratio for AMI, IVVO, and FLISR on a combined basis.

Q. HOW WAS THE COST BENEFIT MODEL DEVELOPED?

A. The structure and form of the CBA are consistent with the Company's general approach to CBAs, including the CBA provided to the Colorado Public Utilities Commission in our Public Service Company of Colorado AGIS Certificate of Public Convenience and Necessity (CPCN) proceeding. (That matter, Proceeding No. 16A-0588E, resulted in an unopposed settlement approving the Company's need for the components of AGIS for which it needed a CPCN.) In structuring the CBA for grid modernization investments specifically, we also looked at similar analyses conducted by others for similar types of assets. For example, our framework is similar to that used by Ameren Illinois in their grid modernization efforts. We also considered the Electric Power Research Institute (EPRI's) technical report on Estimating the Costs and Benefits of the Smart Grid.[2]

Q. WHY DID THE COMPANY SELECT THIS FORM OF QUANTITATIVE MODEL?

A. This CBA is just one phase of a much more extensive assessment performed by the Company prior to seeking Commission approval for the four AGIS components presented in this case. This assessment included evaluation of the needs and goals of our distribution system, customers, the Commission, and other stakeholders, and then assessments of the alternatives to meet those needs and goals. These processes are described in detail in the testimony of Company witnesses Mr. Gersack, Ms. Bloch, Mr. Cardenas, and Mr. Harkness. (For example, Ms. Bloch and Mr. Cardenas explain the status of the current meters on our system and the extensive planning, information gathering, RFP processes, and consideration of alternate vendors, devices, systems, and programs that we undertook prior to selecting our current AMI plan.[3]) Now, as we are at the point of proposing our overall strategy and plan to the Commission, we provide this cost benefit model to identify and discuss the cost-effectiveness of the components of that plan (including the avoided costs of necessary alternative solutions) and of the total AGIS initiative.

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[2] https://www.smartgrid.gov/files/Estimating_Costs_Benefits_Smart_Grid_Preliminary_Estimate_In_201103.pdf.

[3] To the extent it makes sense, I have summarized these considerations in the least-cost/best-fit segment later in my testimony, which illustrates our conclusions with respect to alternatives to AMI and the FAN.

Q. HOW DID THE COMPANY STRUCTURE THE CBA PRESENTED IN YOUR TESTIMONY?

A. The model compares the upfront and ongoing project implementation costs (including planning and installation), as well as avoided costs, against the quantifiable benefits of the Company's proposed project over the analysis period. The model incorporates the Distribution costs and Customer Care costs of the systems, as well as the Business Systems costs required for the implementation of the projects, including integration, software-hardware, project management, and other costs in order to provide a complete picture of AGIS initiative costs.

Further, the model views costs and benefits from the customer perspective, meaning that it quantifies the estimated net impact of costs and savings to customers, including Commission-approved measures of societal benefits.[4] In this respect, all quantifiable utility costs and benefits were estimated in the model as they would be effectuated through utility electric rates. For example, the Company estimated the total cost of meter installation and operation in terms of revenue requirements.

We also estimated reasonably quantifiable direct customer benefits of improvements in the Company's electric service. These benefits can take many different forms, such as cost savings in system management or reduced energy and generation needs that benefit the customer through rates; pricing opportunities for customers through time-of-use rates; reduced outage impacts to customers' own activities; and avoidance of lost revenue through

[4] For example, carbon dioxide emission reductions can be measured and quantified via the Commission-ordered externality values.

meter tampering. In measuring such benefits, we took into account past Commission determinations of value (as with the social cost of carbon, as described in my testimony) and feedback on previous submissions (as with the CMO values, as described in Ms. Bloch's testimony).

Q. ONCE THE QUANTIFIABLE COSTS AND BENEFITS FROM THE OTHER WITNESSES ARE IN THE MODEL, WHAT CALCULATIONS DOES THE MODEL MAKE TO ESTIMATE THE CUSTOMER IMPACT?

A. First, it is necessary to take the projected capital costs and benefits and estimate a net capital revenue requirement. The net capital revenue requirement is the aggregate impact of both the capital costs and the capital savings over the analysis period. Therefore, the net capital revenue requirement estimates how the capital related costs and benefits would impact the customer through electric rates.

The model takes the annual capital costs and capital benefits and makes assumptions regarding how those costs and benefits may be reflected in rate base, and estimates a net capital revenue requirement as a function of depreciable book and tax lives for the assets, as well as the Company's weighted average costs of capital (WACC) and tax rates. The estimated net revenue requirement associated with the capital costs and benefits represents the annual impact of the capital spend, which is how the Company would calculate electric rate recovery on the underlying investment.

Second, for O&M costs and savings, fuel savings, and other benefits, the model assumes that those costs and benefits would be expensed or earned in the year they were incurred, and are embedded in the Company's electric rates. Any such changes will flow through to the customers.

Q. HOW DOES THE MODEL CONVERT THE ESTIMATES OF NET CAPITAL REVENUE REQUIREMENT, O&M COSTS, AND BENEFITS TO A BENEFIT-TO-COST RATIO?

A. Once the stream of the net capital revenue requirements, O&M costs and benefits are calculated, the streams are compared on an NPV basis. Each stream of costs or benefits is present-valued back to 2019 dollars utilizing the Company's WACC as a discount rate. Then, by dividing the net present value of benefits by the net present value of costs, a benefit-to-cost ratio is calculated. A benefit-to-cost ratio of 1.0 indicates benefits of that component of the AGIS initiative – or of the overall initiative – equal costs; a ratio of less than 1.0 means costs exceed benefits; and a ratio of greater than 1.0 means benefits exceed costs.

Q. PLEASE DESCRIBE THE PERIOD OF TIME THE MODEL EXAMINES.

A. The model for AMI (including the TOU Pilot) examines the period beginning in 2019 and ending 2035. The period for IVVO and FLISR is longer (2019 through 2038), due to the longer useful life of the underlying assets.

Q. WHY DOES THE MODEL EXAMINE THESE PERIODS OF TIME?

A. For AMI, the model reflects the current phase of work beginning in 2019, and future installation phases beginning in 2021, as described by Ms. Bloch. This includes the assumption that AMI meters and associated software and hardware, as well as the necessary components of the FAN will begin depreciation upon installation. It also includes the meters we are installing for 2019 and 2020 for the TOU pilot evaluation period, which will subsequently be replaced with meters with Distributed Intelligence capabilities at no cost to the Company or customers.

While additional meters will be installed after 2021, the IT components will need to be in place by the time of the initial meter installations in order for the system to function. Thus by 2035 (after the fifteen-year period from 2021-2035), the network will be fully depreciated. Additionally, while the potential service life of AMI meters is between 15 and 20 years in the industry, we have utilized a fifteen-year period for AMI examination. This is consistent with the 15-year depreciation terms presently approved by the Commission for our existing automated meter reading (AMR) meters and reflects the challenging climate in Minnesota.

As Ms. Bloch further describes, the FLISR and IVVO assets are expected to have a 20-year life. The twenty-year life for IVVO and FLISR follows the industry standard for the life cycle evaluation of similar projects. While FLISR and IVVO devices will be installed beginning in 2020 and 2021 respectively, as with AMI the underlying IT systems must be in place before device installation. As a result, the 2019-2038 IVVO and FLISR CBA timelines capture the estimated costs and benefits from installation for the projected life of the system.

While some of the distribution assets installed may be useful beyond this timeframe, overall, our timeframes are intended to be conservative and therefore support a conservative assessment of total benefits and costs.

Q. CAN YOU PROVIDE MORE INFORMATION ON HOW THE COMPANY DEVELOPED THE COST AND BENEFIT INPUTS INTO THE MODEL?

A. Yes. The capital and O&M costs and benefits of AMI (including the TOU pilot), FLISR, and IVVO, including the associated FAN components, were determined by our Customer Care, Business Systems, and Distribution areas (including business area financial teams), with additional support from the AGIS Program Management Office, as discussed in more detail below. Our Program Management Office, Risk Management, and the Regulatory Department coordinated and developed modeling assumptions consistent with these cost and benefit estimates. The testimonies of Mr. Gersack, Ms. Bloch, Mr. Harkness, and Mr. Cardenas provide detail regarding the cost and benefit assumptions for each component of the AGIS projects, while I summarize those model inputs and provide explanations on the overall results of our CBAs.

Q. WHY DO YOU REFER TO AMI, FLISR, AND IVVO COSTS AND BENEFITS AS "INCLUDING THE ASSOCIATED FAN COMPONENTS"?

A. As Company witnesses Ms. Bloch and Mr. Harkness discuss in their Direct Testimony, the FAN will be a single, general-purpose, field area wireless networking resource that enables two-way communication of information and data to and from infrastructure at the Company's substations and the field devices. The FAN will provide the necessary communication capacity for the AGIS initiative, while also ensuring that the data being transmitted is secure. However, the FAN is not a standalone program and does not provide benefits on its own; rather, it is the communications network to enable AMI, IVVO, and FLISR functionality and provide their respective benefits to customers.

As such, we have incorporated FAN costs into the models for AMI, FLISR, and IVVO.

Q. HOW WERE THE FAN COMPONENTS THEN INCORPORATED INTO THE MODEL?

A. The model allocated FAN costs across the analyses for the individual AGIS components the FAN serves. Specifically, as explained by Mr. Harkness in his Direct Testimony, the FAN structure is primarily made up of two technological modules: WiMAX and WiSUN. WiMAX (Worldwide Interoperability for Microwave Access) is used to transfer data over different transmission modes such as point to point and multipoint modes. WiSUN (Smart Utility Network) is a low rate wireless system that must be in place to enable AMI device-to-device and device-to-headend communication. Because AMI is the predominant beneficiary of the WiSUN system, WiSUN costs have been completely allocated to AMI.

The meters and repeaters that constitute the AMI, the IVVO capacitors and voltage monitors, and the FLISR reclosers will each have embedded communication modules that will allow them to communicate directly with the FAN's access points on the WiMAX core infrastructure. But while the WiMAX system will provide coverage for all of NSPM's service territory, including 1050 feeders that all will contain AMI meters, Ms. Bloch explains that only a subset of the feeder population will have FLISR and IVVO equipment installed. Specifically, FLISR equipment will be initially installed on 208 feeders, while IVVO will be installed on 189 feeders. Likewise, each program will benefit from the communication system based proportionally on the amount of data needed and transferred. WiMAX costs are therefore distributed between AMI, FLISR, and IVVO according to the number of devices in proportion to the number of feeders.

Based on the total number of devices installed by feeder for each program, and given that additional devices affecting the WiMAX component may be installed in the future for both IVVO and FLISR, the business has estimated an allocation to capture that growth of AMI at 80 percent, IVVO at 5 percent, and FLISR at 15 percent. These percentages are also consistent with the total initial capital investment required by each program.

Consequently, the AMI, IVVO, FLISR, and consolidated models assume implementation of the FAN from 2019 through 2024, consistent with the timeline to subsequently implement the AMI meters, IVVO, and FLISR assets.

Q. CAN YOU ALSO PROVIDE MORE DETAIL AS TO HOW THE IT COMPONENTS ARE INCORPORATED INTO THE MODEL?

A. Yes. As described by Company witness Mr. Harkness, IT efforts include the costs of integrating the components of the AGIS initiative with existing Company back-end applications that will utilize the data. Similarly, IT efforts are necessary to ensure the security of the data collected and transmitted from advanced metering. As with the FAN, IT work is not a standalone program that provides benefits on its own; rather, it is a necessary component of the AGIS programs. Therefore, the costs of IT efforts for AMI, FLISR, and IVVO are included in the cost benefit model for these components.

Q. WHY IS THE CBA FOCUSED ON AMI (INCLUDING THE TOU PILOT), FLISR, AND IVVO, WITH ASSOCIATED COMPONENTS OF THE FAN?

A. These are the components of the AGIS initiative that are forward-looking, and which the Company plans to undertake as an integrated plan for the advancement of our distribution system. While they build on the Advanced Distribution Management System (ADMS), the ADMS was previously approved by the Commission through Docket No. E002/M-15-962 under Minn. Stat. § 216B.2425, before other components of the AGIS initiative were submitted or approved, and is necessary regardless of other selected advanced grid efforts. Consequently, the CBA is structured to aid the Commission's decision-making for the future, both from rate recovery and Integrated Distribution Planning (IDP) perspectives.

Q. HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR THE FIRST FIVE-YEAR PERIOD, FROM 2019 THROUGH 2023?

A. Each subject matter expert provided estimated capital and O&M costs and benefits in 2019 dollars, by year, for the period 2019 through 2023. The dollars for 2020-2022 align with the Company's multi-year rate plan (MYRP) in this proceeding (plus one year).

These costs and benefits, except for fixed price items, were then converted into nominal dollars within the model using assumptions for labor and non-labor inflation over the analysis period.

Q. HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR 2024 THROUGH 2038?

A. The additional capital and O&M costs beyond 2023 were estimated for each respective part of the project through 2035 for AMI and 2038 for IVVO and FLISR, in order to capture the costs and benefits of each of the programs beyond the initial implementation period. These O&M and capital costs were provided in 2019 dollars by or at the direction of Company witnesses Mr. Gersack, Ms. Bloch, and Mr. Harkness, and were escalated to nominal dollars for either the full twenty-year (FLISR, IVVO) or fifteen-year (AMI) analysis period.

Benefits were also estimated for this period based on when we expect customers to experience these benefits, including continued escalation of benefits beginning in 2023 or earlier to the appropriate future year.

Q. HAVE THE COSTS LISTED IN THE MODEL BEEN CORRELATED TO THE COMPANY'S RATE CASE BUDGET?

A. Yes. My group worked closely with the Financial Planning area to ensure that the two are consistent. However, it is important to be clear that there are some differences in how the numbers are presented. In particular, the analysis is based on net present value of revenue requirements, with capital investment costs captured in the year the investment is in service and costs stated in 2019 dollars. The MYRP budgets presented by other AGIS witnesses are stated in annual capital expenditure and capital addition dollars. As a result, the numbers in the CBA correspond to the rate case budgets but will not look exactly the same.

Q. HOW ARE THE COSTS IN THE MODEL CATEGORIZED?

A. It is possible to review the costs in the model from several perspectives. The costs, which are set forth in Exhibit___(RD-1), Schedules 2, 3, 4 and 5 of my Direct Testimony, are identified as:

- Rate case budgets to the extent they are for the years of the Company's MYRP, or longer-range planning costs for the years after 2022;
- Either capital or O&M;
- Either Business Systems or Distribution costs; and
- Direct, Indirect, Tangible, or Intangible costs, consistent with Order Point A.3 in the Commission's September 27, 2019 TCR Rider Order.

Q. PLEASE PROVIDE THE COMPANY'S DEFINITIONS OF DIRECT, INDIRECT, TANGIBLE, INTANGIBLE, AND "REAL" COSTS FOR PURPOSES OF ITS AGIS INITIATIVE.

A. The Company defines these categories of costs as follows:

- *Direct costs* – the cost of the materials and the workers that are involved when a company makes a particular product or provides a particular service that can be easily traced to that product, department, or project – similar to costs that are assigned rather than allocated.
- *Indirect costs* – a cost that cannot be directly traced to a particular product, department, activity, project, or providing a particular service – similar to overhead, or costs that are allocated rather than assigned.
- *Tangible costs* – Like direct costs, a tangible cost (or benefit) is a quantifiable cost related to an identifiable source or asset. It can be directly connected to a material item used to conduct operations or run a business. Tangible costs represent expenses arising from such things

as purchasing materials, paying employees or renting equipment. The costs in the CBA are tangible.

- *Intangible costs* – an unquantifiable cost (or benefit) relating to an identifiable source. Intangible costs represent a variety of expenses such as losses in productivity, customer goodwill, drops in employee morale, or damage to corporate reputation. Most qualitative costs and benefits are intangible, although the Company has chosen not to assign a dollar value to some potentially tangible costs (like human safety).
- *Real costs* – total costs the utility incurs to produce a good or service or to implement a program, including the cost of all resources used and the cost of not employing those resources in alternative uses. Real costs analysis gives a greater picture of a product and the spending associated with it. The CBA model is intended to identify Real Costs throughout.

These categories do at times overlap, as most tangible costs are also assigned or allocated and are therefore either an Indirect or Direct cost. Where overlap occurs in the Company's AGIS modeling, both categories are identified.

Q. ARE INTERNAL AND EXTERNAL LABOR COSTS INCLUDED IN THE COSTS OF EACH COMPONENT OF THE AGIS INITIATIVE INCLUDED IN THE MODEL?

A. Yes. As Mr. Gersack discusses, both the model and our overall support for the AGIS initiative in this proceeding are intended to capture the "all-in" costs of the project. Further, the Company is seeking base rate recovery for project costs being incurred or placed-in service during the MYRP; therefore, it is appropriate to include both internal and external labor costs. The support for these costs is provided by Ms. Bloch and Mr. Harkness.

Q. DO THE COST INPUTS FOR AMI, FLISR, AND IVVO INCLUDE CONTINGENCY ASSUMPTIONS?

A. Yes. In addition to the cost estimates, the Distribution and Business Systems areas developed contingency estimates for each aspect of the project that warranted a contingency. These contingency estimates are depicted on Exhibit___(RD-1), Schedule 2 (AMI CBA Summary), Schedule 3 (FLISR CBA Summary), and Schedule 4 (IVVO CBA Summary) as cost line items. Since by definition the amount and type of contingency dollars that will actually be spent cannot be wholly defined up front, the Company prepared CBAs summaries for each component both with and without contingency dollars, to provide insight into how the range of potential contingency amounts could affect the overall benefit-cost ratio. The testimonies of Ms. Bloch, Mr. Harkness, and Mr. Gersack provide additional support for the contingency amounts included in the CBA.

Q. HOW WERE THE ESTIMATES OF CONTINGENCY FOR EACH WORK STREAM INTEGRATED INTO THE MODEL?

A. The estimates of contingency were added to the estimated costs of the project and input into the model as a cost. In essence, the model evaluates the cost of the project as if the Company needed to spend up to the full contingency amounts or none of the contingency. This allows both the most conservative view of potential benefit-to-cost ratios (all contingency used), as well as the greatest calculated benefit-to-cost ratio, providing a view of range of potential outcomes.

Q. WHAT STEPS DID THE COMPANY UNDERTAKE TO VERIFY THAT THE MODEL IS STRUCTURALLY SOUND?

A. The model structure was based on models and similar analyses undertaken by the Company and other utilities in support of similar AMI and grid advancement programs. A number of business areas within the Company, including Regulatory Administration, Risk, Corporate Development, Capital Asset Accounting, Revenue Requirements, Demand Side Management, Business Systems and Distribution, subsequently collaborated to develop and ensure the model incorporated requirements necessary to properly estimate the known and quantifiable life cycle value proposition.

Q. OVERALL, IS THIS CBA AN APPROPRIATE TOOL FOR EVALUATING THE QUANTIFIABLE ASPECTS OF THE AGIS INITIATIVE?

A. Yes. By developing the model from the customer's perspective, the Company is providing clear and comprehensive information about the overall quantifiable impact of implementing these programs to customers. By this we mean that the CBA includes benefits that can be both quantified generally and stated in terms of a reasonably calculable dollar value.

The cost benefit model also provides a high-level look at the costs versus the quantifiable benefits of the overall AGIS initiative for customers, as well as a more detailed breakdown of individual costs and benefits assumptions for each program. However, the cost benefit model does not address all reasons for undertaking the AGIS program or the benefits of the program because many such reasons and benefits cannot be quantified or reduced to a dollar value. Therefore, the cost benefit model provides an appropriate perspective on the quantifiable costs and benefits of the program but not on all relevant considerations.

Q. WHY DO YOU SAY THE MODEL PROVIDES AN APPROPRIATE PERSPECTIVE ON QUANTIFIABLE CONSIDERATIONS?

A. Because a CBA is, by definition, intended to quantify costs and benefit, it can only capture the quantifiable. As discussed later in my testimony, examples of benefits that were not quantified include customer satisfaction, customer choice, planning and control of the grid, greater hosting capacity, job creation, improved quality of service delivered, and safety, among others described by Ms. Bloch, Mr. Cardenas, Mr. Gersack, and myself. This is why the CBA is one tool, but it should not be regarded as a definitive analysis on the merits of AGIS, because it cannot consider factors that are qualitative or on which the Company has not put a price (like human safety).

In addition, a model based on measureable considerations does not take into account any fundamental need for the infrastructure in question. For example, the Company must have meters in order to provide and bill for electric service. We therefore must plan for the pending expiration of the Cellnet AMR service contract while also taking into account that Xcel Energy is the last company using the Cellnet technology embedded in the Company's current meters. However, a cost versus benefit model cannot fully reflect that the primary function of updated meters is not necessarily to reduce the net cost of meters compared to aged technology, but rather to enable the utility to provide services to meet the needs and expectations of the customer.

Finally, while the model can and does reflect the costs of AMI versus AMR technology as an avoided cost alternative, it cannot fully assess whether it would be short-sighted or impracticable for the Company to replace aging technology with other aging technology, nor the effect of using older technology on unquantifiable customer expectations (like better outage and service restoration communications, and more timely energy consumption data) that is more dependent on advanced metering technology. All told, the model is a helpful assessment tool within the scope of its intended purpose. And because the Company has taken a conservative approach to modeling the benefits and costs of the AGIS strategy, we believe it is a reliable and helpful tool.

## B. Quantitative Inputs

### *1. AMI Inputs*

Q. WHAT ARE THE KEY COSTS AND BENEFITS OF AMI?

A. Company witness Ms. Bloch discusses the costs and benefits of AMI in detail in her testimony. At a high level, the benefits of AMI include: (i) providing more granular customer energy usage information that supports greater customer energy usage choice, pricing flexibility, and carbon reduction; (ii) reducing field and meter service and meter reading costs; (iii) reducing unaccounted for energy; (iv) assisting with identification of service outages and foster restoration; (v) providing voltage measurement information to assist in load flow and voltage calculations performed in the ADMS; (vi) serving as signal repeaters for other AMI meters and FAN network components; and (vii) improving infrastructure investment efficiencies. The purchase of AMI meters also enables the Company to retire the end-of-life Cellnet technology that will no longer be supported in the future (as described by Company witness Mr. Cardenas) and avoid the purchase of other, less functional advanced meter reading (AMR) meters in the near future. As discussed below, not all of the benefits of AMI are quantifiable or able to be reduced to a dollar value. In the cost benefit model, however, we have identified and captured the costs and quantifiable benefits associated with the technology.

The key costs of AMI include the meters themselves, including the labor cost of installation and testing, supporting FAN and IT resources, AMI program and management, and other supporting labor for operations.

Q. HOW WERE AMI CAPITAL COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the AMI program were developed by the Company's subject matter experts and are detailed in the Direct Testimonies of Ms. Bloch, Mr. Harkness, Mr. Gersack, and Mr. Cardenas, as set forth in Tables 2 through 6 below. My Exhibit ___ (RD-1), Schedule 2 provides a summary of each component of the quantifiable AMI costs and benefits, as they appear in the CBA.

**Table 2**

**AMI Capital Costs**

| Capital Cost | Description | Supporting Witness (including Section of Testimony) |
|---|---|---|
| Meters and Installation | Capital costs portion of AMI meter purchase and installation. Capital costs of both internal and external support personnel. | Direct Testimony of Ms. Bloch, Section V(D)(5) |
| Field Area Network (AMI) | Capital costs associated with implementation of the WiSUN network and associated assets. | Direct Testimony of Mr. Harkness, Section V(E)(4)(e) |
| | Capital costs associated with installation of pole-mounted devices. | Direct Testimony of Ms. Bloch, Section V(E)(3) |
| IT Systems and Integration | Capital costs associated with the various IT infrastructure and integration in support of AMI. | Direct Testimony of Mr. Harkness, Section V(E)(3)(c) |
| Program and Change Management | Capital costs associated with internal management of AMI. | Direct Testimony of Mr. Gersack, Section V(D)(2) |

**Table 3**

**AMI Capital Benefits**

| Capital Benefit | Description | Supporting Witness (including Section of Testimony) |
|---|---|---|
| Distribution System Management Efficiency | More efficient use of capital dollars to maintain the distribution system. | Direct Testimony of Ms. Bloch, Section V(D)(4) |
| Outage Management Efficiency | Improved capital spend efficiency during outage events. | Direct Testimony of Ms. Bloch, Section V(D)(4) |
| Avoided Meter Purchases for Failed Meters | AMI meters have a lower failure rate as compared to AMR meters. By purchasing new AMI meters, the Company avoids the need to replace failing AMR meters. | Direct Testimony of Ms. Bloch, Section V(D)(4) |
| Avoided investment of an alternative meter reading system | Avoided capital cost of a drive-by meter reading system, instead of the AMI investment, since current Cellnet system requires replacement | Direct Testimony of Ms. Bloch, Section V(D)(4) |

Q. HOW WERE AMI O&M COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. O&M estimates for the AMI program were likewise developed by the Company's other AGIS witnesses, as set forth in Tables 3,4, and 5 below.

**Table 4**

**AMI O&M Costs**

| **O&M Cost** | **Description** | **Supporting Witness (including Section of Testimony)** |
|---|---|---|
| Field Area Network (AMI) allocated portion | O&M costs associated with implementation of the WiSUN network and associated assets. | Direct Testimony of Mr. Harkness, Section V(E)(4)(e) |
| IT Systems and Integration | O&M costs associated with the various IT infrastructure and integration in support of AMI. | Direct Testimony of Mr. Harkness, Section V(E)(3)(c) |
| AMI Operations (Personnel) | O&M costs of both internal and external support personnel. | Direct Testimony of Ms. Bloch, Section V(D)(5) |
| Program Management | O&M costs associated with internal change management and oversight for AMI. | Direct Testimony of Mr. Gersack, Section V(D)(2) |

**Table 5**

**AMI O&M Benefits**

| **O&M Benefit** | **Description** | **Supporting Witness (including Section of Testimony)** |
|---|---|---|
| Avoided O&M Meter Reading Cost | O&M cost component of a drive-by meter reading system alternative to AMI, since current Cellnet system requires replacement | Direct Testimony of Mr. Cardenas, Section V(F) |
| Reduction in Field and Meter Services | Reduction in O&M costs related to addressing meter and outage complaints and connections. | Direct Testimony of Ms. Bloch, Section V(D)(4) |
| Improved Distribution System Spend Efficiency | Increased efficiency of distribution maintenance costs. | Direct Testimony of Ms. Bloch, Section V(D)(4) |
| Outage Management Efficiency | Improved O&M efficiency during outage events. | Direct Testimony of Ms. Bloch, Section V(D)(4) |

**Table 6**

**Other Quantifiable AMI Benefits**

| **Benefit** | **Description** | **Supporting Witness (including Section of Testimony)** |
|---|---|---|
| Reduction in Energy Theft | Easier identification of energy theft and an associated reduction in the amount of theft. | Direct Testimony of Mr. Cardenas, Section V(F) |
| Reduced Consumption Inactive Premise | Expedited ability to turn off power quickly when determined premise has been vacated. | Direct Testimony of Mr. Cardenas, Section V(F) |
| Reduced Uncollectible/Bad Debt | Decreased loss due to uncollectible/bad debt. | Direct Testimony of Mr. Cardenas, Section V(F) |
| Reduced Outage Duration | Direct benefit to customers associated with reduced outage duration. | Direct Testimony of Ms. Bloch, Section V(D)(4) |
| Critical Peak Pricing | Customer demand savings in response to new rate structures. | Brattle Group Report, Exhibit ___ (RD-1), Schedule 6 and additional detail in this Section of my Direct Testimony |
| TOU Customer Price Signals | Difference in energy prices paid by consumers in response to new rate structures. | Integrated Resource Plan – RP-19-368 Appendix F2 and additional detail in this Section of my Direct Testimony |
| Reduced Carbon Dioxide Emissions | Difference in emissions of generation assets due to shifted load. | Additional detail in this Section of my Direct Testimony |

Q. CAN YOU SUMMARIZE THE BENEFITS YOU DESCRIBE IN YOUR TESTIMONY?

A. Yes. As noted in Table 6 above, I discuss how the Company calculated AMI benefits associated with critical peak pricing and TOU customer price signals (combined, "load flexibility" benefits), as well as reduced $CO_2$ emissions. Exhibit ___ (RD-1), Schedule 5 identifies the quantification of these benefits for purposes of the CBA.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE COMPANY'S LOAD FLEXIBILITY ASSUMPTIONS?

A. Yes. The Company engaged The Brattle Group (Brattle) to model likely customer response to Time of Use (TOU) and Critical Peak Pricing (CPP) rates. The Brattle Group produced a study entitled "The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory" (the Brattle Study), which is attached to my Direct Testimony as Exhibit___ (RD-1), Schedule 6. The Brattle Study developed quantification of the benefits of potential TOU and CPP rates, which were in turn incorporated into our CBA.[5] Further, the Company utilized information about shifting demand from on-peak to off-peak periods, resulting in energy price savings for customers and carbon reduction benefits.

Q. WHY DID THE COMPANY RELY ON THE BRATTLE STUDY?

A. Brattle is a well-respected economic consulting and analytics firm, and conducted a similar study for Public Service Company of Colorado (Xcel Energy's Colorado utility operating company), in relation to its portion of the AGIS initiative. As a result, we have experience with this group and have found their studies to be robust and reasonable.

Q. PLEASE DESCRIBE THE TOU ASSESSMENT IN THE BRATTLE STUDY.

A. The Brattle Study assumes a static price signal with higher prices during the five-hour period around system peak on non-holiday weekdays, and models both opt-in and opt-out approaches to time of use rates.[6] Demand reduction

[5] I note that while Brattle modeled CPP rates and we have used this information in our CBA in this case, there are a variety of peak demand rate design structures the Company may explore, such as peak time rebates.
[6] Brattle Study at p.6.

grows modestly as TOU adoption and utilization expands. Based on these assumptions and the base case in the Brattle analysis, this rate has the potential to shift demand approximating 161 Megawatts (MW) for residential customers and 52 MW for medium commercial and industrial customers from on-peak to off-peak.[7] The overall result is cost savings to customers.

Q. WHAT ARE THE BENEFITS ASSOCIATED WITH CRITICAL PEAK PRICING?

A. The potential CPP rate "provides customers with a much higher rate during peak hours on 10 to 15 days per year."[8] CPP rates were modeled by Brattle as being offered on both an opt-in and an opt-out (default) basis, with demand reduction growing modestly as the system and system usage mature. This rate has the potential to reduce peak demand at the generator level by 164 MW for residential customers and 90 MW for medium commercial and industrial customers under the base case scenario.[9]

Q. HOW WERE THESE CHANGES IN THE COMPANY'S CUSTOMER PRICE SIGNALS TRANSLATED TO BENEFITS IN THE AGIS AMI CBA?

A. The Company utilized the peak demand reduction assumptions from the Brattle Study to generate an estimated energy shift from peak to off-peak hours. This shift from peak to off-peak was then multiplied by the difference in the Minnesota Hub on and off-peak price forecasts filed with our Integrated Resource Plan (Docket No. E002/RP-19-368) on page 13 of Appendix F2. This estimates the savings in energy prices customers will experience in shifting their demand from on to off-peak.

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[7] Brattle Study at Appendix D, p.68.
[8] Brattle Study at p.6.
[9] Brattle Study at Appendix D, p. 68.

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT DUE TO REDUCTIONS IN CARBON DIOXIDE EMISSIONS FOR AMI?

A. The Company utilized load shifting estimates in MWh for TOU rates from The Brattle Study. The Company estimated on-peak and off-peak average $CO_2$ emissions by year using internal tools. The difference in those two estimates represents the emissions improvement. This amount is multiplied by the MWh shifted due to TOU rates. The avoided carbon emission is valued by multiplying the avoided emissions by the Commission-ordered externality values from Docket No. E999/CI-14-643.

Q. HOW DOES THE BRATTLE GROUP'S FRAMEWORK COMPARE TO OTHERS FOR MEASURING LOAD FLEXIBILITY?

A. As noted by Brattle on page ii of the Study, its modelling framework "builds upon the standard approach to quantifying [demand response] potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs." The Brattle Group then goes on to identify those differentiating features, each of which is intended to enhance the reliability and sophistication of the analysis. The Company therefore relied upon the Brattle Study to assume that a consistent reduction in peak demand would be reasonable and achievable as a function of the demand rates AMI will enable as part of the Company's proposal. This reduction is then incorporated into the CBA as a benefit of AMI.

Q. WHAT ASSUMPTIONS ARE MADE WITH RESPECT TO CUSTOMER ADOPTION OF THESE NEW TECHNOLOGIES?

A. As discussed in more detail by Company witness Mr. Cardenas, we propose an opt-out approach to AMI metering, meaning that customers will be automatically integrated into the new system unless they actively opt out. In addition, the opt-out deployment approach tends to result in overall higher enrollment rates than when utilities adopt an opt-in approach to AMI, and therefore enables larger aggregate demand impacts via the more advanced rate structures AMI enables. Overall, the Brattle Study notes that an opt-out approach – with the default being the customer receives AMI functionality – "maximizes the overall economic benefit of the program."[10] The Brattle Group modeled this opt-out approach as the default rate offering.

Q. WHAT IS THE IMPACT OF THESE OPT-OUT ASSUMPTIONS ON THE CBA?

A. There is no direct net cost impact because, as Mr. Cardenas explains, we propose to have those customers who opt out pay for the cost of a new meter capable of storing data needed for future rate designs. In addition, customers who opt out would incur a monthly charge to cover the cost of meter reading. Because these charges would be established in an amount that directly offsets the costs of opting out, there is no direct material net cost impact to the CBA. However, the opt-out approach does improve the benefit as described above.

*2. FLISR Inputs*

Q. WHAT IS THE FLISR PROGRAM?

A. The Fault Location Isolation and Service Restoration (FLISR) component of the AGIS initiative is a synchronized system of devices that can reduce the

[10] Brattle Study at p. 31.

number of customers impacted by a fault via automatically isolating the trouble area and restoring service to remaining customers by transferring them to adjacent circuits. The fault isolation feature of the technology can help crews locate the trouble spots more quickly, resulting in shorter outage durations for the customers impacted by the faulted section. In short, the purpose of FLISR is to reduce the duration and impact of outages on our customers. Company witness Ms. Bloch discusses the purpose of FLISR in more detail.

Q. WHAT ARE THE COSTS OF FLISR?

A. The majority of the FLISR costs are the asset/device costs, as well as the labor cost of installation. Other costs include the supporting FAN components and IT resources. As previously noted, FLISR costs also include contingency amounts.

Q. HOW WERE FLISR COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the FLISR program (including contingencies) are detailed in the Direct Testimony of Company witnesses Ms. Bloch and Mr. Harkness, as set forth in Tables 6 through 8 below. FLISR's quantifiable benefits relate primarily to Customer Minutes Out (CMO) measures of reduced customers' outage duration; therefore, the benefits of FLISR are not directly O&M or capital-related. My Exhibit___(RD-1), Schedule 3 provides a summary of each component of the quantifiable FLISR costs and benefits, as they appear in the CBA.

Q. WHAT ARE THE CAPITAL COSTS AND BENEFITS OF FLISR?

A. A summary of capital costs is set forth in Table 7, below.

**Table 7**

**Capital Costs of FLISR**

| **Capital Cost** | **Description** | **Supporting Witness (including Section of Testimony)** |
|---|---|---|
| Assets and Installation | Capital costs of the FLISR devices and installation, including both internal and external support | Direct Testimony of Ms. Bloch, Section V(F)(6) |
| Field Area Network (FLISR) | Capital costs associated with implementation of the WiSUN network and associated assets. | Direct Testimony of Mr. Harkness, Section V(E)(4)(e) |
| IT Systems and Integration | Capital costs associated with the various IT infrastructure and integration in support of FLISR. | Direct Testimony of Mr. Harkness, Section V(E)(5)(b) |

Q. HOW WERE FLISR O&M INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. FLISR O&M costs and benefits were developed by Ms. Bloch and Mr. Harkness as set forth below:

**Table 8**

**FLISR O&M Costs**

| O&M Cost | Description | Supporting Witness (including Section of Testimony) |
|---|---|---|
| Assets and Installation | O&M costs of the FLISR devices and installation. | Direct Testimony of Ms. Bloch, Section V(F)(6) |
| Field Area Network (FLISR) | O&M costs associated with implementation of the WiSUN network and associated assets. | Direct Testimony of Mr. Harkness, Section V(E)(4)(e) |
| IT Systems and Integration | O&M costs associated with the various IT infrastructure and integration in support of FLISR. | Direct Testimony of Mr. Harkness, Section V(E)(5)(b) |

**Table 9**

**Other Quantifiable FLISR Benefits**

| Benefits | Description | Supporting Witness (including Section of Testimony) |
|---|---|---|
| Customer Minutes Outage – Savings | Benefits to customers associated with reduced outage duration | Direct Testimony of Ms. Bloch, Section V(F)(5) |
| Outage Patrol Time Savings | Benefit associated with reduction in time spent by field crews responding to outages | Direct Testimony of Ms. Bloch, Section V(F)(5) |

*3. IVVO Inputs*

Q. WHAT IS INTEGRATED VOLT-VAR OPTIMIZATION?

A. Generally speaking, IVVO is a leading technology that automates and optimizes the operation of distribution voltage regulating devices and VAr control devices to maximize system efficiency. As described in more detail in the Direct Testimony of Ms. Bloch, through the implementation of IVVO the Company will be able to control the voltage on a distribution feeder to a tighter tolerance, permitting the Company to lower the voltage on that controlled feeder while still maintaining a high level of service quality. This lower voltage will effectuate energy and demand savings for the system and for the customer.

Q. WHAT ARE THE PRIMARY COSTS AND BENEFITS OF IVVO?

A. The primary costs of implementing IVVO relate to installation of application assets as well as the labor cost of installation. Other costs include FAN communications, IT systems and integration, and program management. The benefits of IVVO that were quantified in the CBA are the fuel and energy savings and capacity savings associated with the program, which are described by Ms. Bloch, and the associated carbon reduction that I describe. The costs of IVVO also include contingency amounts, which are supported by Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack.

Q. HOW WERE IVVO CAPITAL INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost estimates for the IVVO program (including contingencies) are detailed in the Direct Testimony of Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack, as set forth in Tables 10 through 13 below. My Exhibit___(RD-1), Schedule 4 provides a summary of each component of the quantifiable IVVO costs and benefits, as they appear in the CBA.

Q. WHAT ARE THE CAPITAL COSTS AND BENEFITS OF IVVO?

A. A summary of capital costs and benefits is set forth in Table 10 and 11, below.

**Table 10**

**IVVO Capital Costs**

| **Capital Cost** | **Description** | **Supporting Witness (including Section of Testimony)** |
|---|---|---|
| Assets and Installation | Capital costs of the IVVO devices and installation. Capital costs of both internal and external support personnel. | Direct Testimony of Ms. Bloch, Section V(G)(5) |
| Field Area Network (IVVO) | Capital costs associated with implementation of the WiSUN network and associated assets. | Direct Testimony of Mr. Harkness, Section V(E)(4)(e) |
| IT Systems and Integration | Capital costs associated with the various IT infrastructure and integration in support of IVVO. | Direct Testimony of Mr. Harkness, Section V(E)(6)(b) |
| Program Management | Capital costs associated with internal management of IVVO. | Direct Testimony of Mr. Gersack, Section V(D)(2) |

**Table 11**

**IVVO Capital Benefits**

| **Capital Benefits** | **Description** | **Supporting Witness (including Section of Testimony)** |
|---|---|---|
| Avoided Capacity Costs | Avoided generation, transmission and distribution capacity achieved through demand reduction | Direct Testimony Ms. Bloch, Section V(G)(4) |

Q. HOW WERE IVVO O&M AND OTHER INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. IVVO O&M costs and Other benefits were developed as set forth below:

**Table 12**

**IVVO O&M Costs**

| O&M Cost | Description | Supporting Witness (including Section of Testimony) |
|---|---|---|
| Assets and Installation | O&M costs of the IVVO devices and installation. | Direct Testimony of Ms. Bloch, Section V(G)(5) |
| Field Area Network (IVVO) | O&M costs associated with implementation of the WiSUN network and associated assets. | Direct Testimony of Mr. Harkness, Section V(E)(4)(e) |
| IT Systems and Integration | O&M costs associated with the various IT infrastructure and integration in support of IVVO. | Direct Testimony of Mr. Harkness, Section V(E)(6)(b) |
| Program Management | O&M costs associated with internal management of IVVO. | Direct Testimony of Mr. Gersack, Section V(D)(2) |

**Table 13**

**Other Quantifiable IVVO Benefits**

| Other Benefits | Description | Supporting Witness (including Section of Testimony) |
|---|---|---|
| Fuel Savings (Energy Reduction) | Fuel cost savings associated with avoided energy usage | Direct Testimony of Ms. Bloch, Section V(G)(4) |
| Fuel Savings (Energy Reduction) | Fuel cost savings associated with reduction in line losses | Direct Testimony of Ms. Bloch, Section V(G)(4) |
| Reduced Carbon Dioxide Emissions | Difference in emissions of generation assets due to load reduction. | My Direct Testimony, below |

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT DUE TO REDUCTIONS IN CARBON DIOXIDE EMISSIONS FOR IVVO?

A. As described by Company witness Ms. Bloch, the Company estimated the energy savings associated with the IVVO program. This reduction in energy usage was converted to avoided $CO_2$ emissions based on projected $CO_2$ intensity per MWh. We then calculated the societal benefit of these avoided $CO_2$ emissions using the Commission-ordered externality values from its

January 3, 2018, Order Updating Environmental Cost Values in Docket No. E999/CI-14-643.

Q. ARE THERE ANY UNIQUE ASPECTS OF IVVO FOR CBA PURPOSES, AS COMPARED TO THE OTHER COMPONENTS OF AGIS?

A. Yes. As Ms. Bloch describes in more detail, IVVO benefits depend on assumptions about the level of energy and demand savings that can be achieved on NSPM's specific system. She explains that while the Company feels confident that 1 percent average energy savings and 0.6 percent capacity savings are the most readily achievable levels, the Company also identified 1.5 percent energy savings and 0.8 percent capacity savings as the higher end of the achievable range. For purposes of the CBA, we utilized the mid-point of the range (1.25 percent energy savings and 0.7 percent capacity savings), and also present as sensitivities that utilize the lower (1.0 percent energy/0.6 percent capacity savings) and upper (1.5 energy/0.8 percent capacity savings) ends of the identified range. Below I provide the resulting benefit-to-cost ratios with and without contingency.

Q. OVERALL, HOW WOULD YOU CHARACTERIZE THE COST AND BENEFIT BUDGETING ASSUMPTIONS IN THIS MODEL FOR EACH OF THE COMPONENTS OF THE AGIS INITIATIVE?

A. Particularly for the modeling results that include 100 percent of the Company's planned contingencies, I would characterize this model as a conservative representation of estimated costs and benefits. Because AMI, FLISR, and IVVO are still in their early phases, the contingencies represent early estimates of potential additional costs. Likewise, the Company has estimated customer adoption and response on the basis of the Brattle Study;

as technologies continue to improve, the benefits associated with these technologies may also increase. Our goal is to represent a conservative but realistic analysis to support the Commission's review of our cost benefit model for the AGIS initiative.

### C. CBA Results

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE AMI PROGRAM.

A. Table 14 summarizes the results of the Company's evaluation of AMI, both with and without contingency.

**Table 14**

**AMI Benefit-to-Cost Ratio**

| **NSPM-AMI-NPV** | **Total ($MM)** |
|---|---|
| **Benefits** | 446 |
| O&M Benefits | 53 |
| Other Benefits | 203 |
| CAP Benefits | 190 |
| **Costs** | (538) |
| O&M Expense | (179) |
| Change in Revenue Requirements | (359) |
| **Benefit/Cost Ratio** | **0.83** |
| **Benefit/Cost Ratio (no contingencies)** | **0.99** |

Exhibit___(RD-1), Schedule 3 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of AMI, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF AMI?

A. On a total resource benefit-to-cost ratio basis, AMI is expected to have a benefit-to-cost ratio of approximately 0.83-0.99, which indicates that the costs somewhat exceed quantitative benefits over the analysis period.

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE FLISR PROGRAM.

A. Table 15 summarizes the results of the Company's evaluation of FLISR:

**Table 15**

**FLISR Benefit-to-Cost Ratio**

| **NSPM FLISR- NPV** | **Total ($MM)** |
|---|---|
| **Benefits** | **103** |
| O&M Benefits | 0 |
| Customer Benefits | 103 |
| **Costs** | **(79)** |
| O&M Expense | (5) |
| Change in Revenue Requirements | (74) |
| **Benefit/Cost Ratio** | **1.31** |
| **Benefit/Cost Ratio (no contingencies)** | **1.53** |

Exhibit___(RD-1), Schedule 3 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of FLISR, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF THE FLISR PROGRAM, INCLUDING THE FAN COMPONENT?

A. On a total resource benefit-to-cost ratio basis, FLISR benefits are expected to exceed FLISR cost, with an expected benefit-to-cost ratio of approximately 1.31 to 1.53.

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE IVVO PROGRAM.

A. Table 16 summarizes the results of the Company's evaluation of IVVO, showing sensitivities for contingency ranges and levels of capital/O&M savings assumptions.

**Table 16**

**IVVO Benefit to Cost Ratio**

| **NSPM IVVO- NPV** | **Total ($MM)** |
|---|---|
| **Benefits** | **22** |
| Other Benefits | 19 |
| CAP Benefits | 3 |
| **Costs** | **(39)** |
| O&M Expense | (2) |
| Change in Revenue Requirement | (37) |
| **Benefit/Cost Ratio (CVR 1.25% energy; 0.7% capacity)** | **0.57** |
| **Benefit/Cost Ratio (no contingencies)** | **0.61** |
| | |
| **Low Benefit Sensitivity:** | |
| Benefit/Cost Ratio (CVR 1% energy; 0.6% capacity) | 0.46 |
| Benefit/Cost Ratio (no contingencies) | 0.49 |
| | |
| **High Benefit Sensitivity:** | |
| Benefit/Cost Ratio (CVR 1.5% energy; 0.8% capacity) | 0.67 |
| Benefit/Cost Ratio (no contingencies) | 0.72 |

Exhibit___(RD-1), Schedule 4 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of IVVO, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF THE IVVO PROGRAM, INCLUDING THE FAN COMPONENT?

A. On a total resource benefit-to-cost ratio basis, IVVO costs are expected to exceed quantifiable IVVO benefits, with an expected benefit-to-cost ratio of 0.57 to 0.61, within a range of sensitivities between 0.46 to 0.72.

Q. DO YOU ALSO PROVIDE A COMBINED SUMMARY OF THE COSTS AND QUANTITATIVE BENEFITS OF THE PROGRAMS?

A. Yes. To determine the combined cost benefit ratio for the AGIS initiative, we identified and aggregated the benefits of each project into four different categories: O&M, Capital, Customer, and Other benefits. At the same time, we aggregated the two types of costs of each project: O&M and Capital/ Change in Revenue Requirements. The final combined ratio is the result of dividing the aggregated benefits by the aggregated costs. Table 17 summarizes the results of the Company's evaluation of the combined AMI/FLISR/IVVO program:

**Table 17**

**AGIS Initiative Combined Cost Benefit Ratio**

| **<u>NSPM -AMI, FLISR, IVVO-NPV</u>** | **Total ($MM)** |
|---|---|
| **Benefits** | **571** |
| O&M Benefits | 53 |
| Other Benefits | 222 |
| Customer Benefits | 103 |
| Capital Benefits | 193 |
| **Costs** | **(656)** |
| O&M Expense | (186) |
| Change in Revenue Requirement | (470) |
| **<u>Baseline Benefit-Cost Ratio</u>**<br>(IVVO 1.25% energy, 0.7% capacity, with contingencies) | **0.87** |
| | |
| <u>High Benefit/No Contingency Sensitivity</u><br>(IVVO 1.5% energy/0.8% capacity, no contingency) | 1.03 |
| | |
| <u>Lower Benefit/With Contingency Sensitivity</u><br>(IVVO 1.0% energy/0.6% capacity, with contingencies) | 0.86 |

Exhibit___(RD-1), Schedule 7 to my Direct Testimony provides the overall relative costs and benefits of the AGIS initiative.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL QUANTITATIVE OUTCOMES OF THE AGIS CBA?

A. On a combined basis, the quantifiable benefits of AMI, FLISR, and IVVO are expected to be lower than or in line with program costs, with an expected benefit-to-cost ratio of approximately 0.86 under our low scenario and up to 1.03 with our high sensitivity IVVO benefits and no contingencies. These totals represent a simple combination of AMI, FLISR, and IVVO respective costs and benefits, inclusive of the costs attributable to that portion of the FAN needed to enable AMI, FLISR, and IVVO, presented on a NPV basis.

In the next section of my Direct Testimony, I address other cost/benefit considerations that factor into the overall prudence of the Company's proposed AGIS initiative.

## III. LEAST-COST/BEST-FIT ALTERNATIVES

Q. DID THE COMPANY ALSO DEVELOP ANY LEAST-COST/BEST-FIT ANALYSES TO COMPARE METERING ALTERNATIVES?

A. Yes. While Company witness Ms. Bloch also provides extensive discussion regarding the relative costs and benefits of various meter-reading alternatives, my Table 18 summarizes the results of the Company's evaluation. The aggregated benefits and capabilities provided by the AMI system related to its costs definitely surpasses other options, considering the increasing needs and choices demanded by the customers and the upcoming operational distribution-grid challenges. This assessment essentially summarizes the bases for our selection of the AMI solution we are presenting in this case.

## Table 18

## Meter Reading Least-Cost Best-Fit Alternative

| Item | Description | Alternative: Manual | Alternative: AMR 1 way/ Limited 2 way | Alternative: AMR Drive-By | Alternative: AMI |
|---|---|---|---|---|---|
| Meter Capabilities | Time of use data | ◔ | ◑ | ◔ | ● |
| | Real time notification of power outages | ○ | ◑ | ○ | ● |
| | Fast response to customers inquires | ○ | ◔ | ○ | ● |
| | Support integrated systems that offer customers | ○ | ◔ | ○ | ● |
| | Vehicle to grid interconnects | ○ | ○ | ○ | ● |
| | Remote reconfiguration/ firmware updates | ○ | ○ | ○ | ● |
| | Availability of real time data | ○ | ○ | ○ | ● |
| | Availability of power quality events | ○ | ○ | ○ | ● |
| | Remove availability of meter diagnostic data | ◔ | ◔ | ◔ | ● |
| | Remote disconnect/ connect | ○ | ○ | ○ | ● |
| | Detect unsafe field metering conditions | ○ | ○ | ○ | ● |
| | Energy Theft | ◔ | ◔ | ◔ | ● |
| | Support for advanced rates | ○ | ○ | ○ | ● |
| | Support for ADMS | ○ | ○ | ○ | ● |
| Operational Features | Time consuming activity | A | NA | NA | NA |
| | Labor intensive - Safety Concerns | A | NA | PA | NA |
| | Cost of paying someone to read the meters. | A | NA | PA | NA |
| | Need access to meters to read them. | A | NA | NA | NA |
| | Accuracy of the meter read, human error. | A | NA | NA | NA |
| | Usually carried out infrequently (monthly). | A | PA | PA | NA |
| | Doesn't usually match invoice billing period. | A | PA | PA | NA |
| | Cost of system maintenance | NA | A | A | A |
| | Relying on technology | NA | A | A | A |
| NPV (2019) | Calculated COSTS - CAP Change in RR and O&M | | | $223M | $539M |
| | BENEFITS-Incremental to current reading/ billing | | | $0M | $442M |
| | **NET COST-OUTCOME** | | | **$223M** | **$97M AMI System** |
| | Least-Cost, Best-Fit Alternative Selected | | | | |

**Legend for Capabilities**

| Full | Most | Partial | Minimal | None |
|---|---|---|---|---|
| ● | ◕ | ◑ | ◔ | ○ |

**Legend for Operational Features**

| Applicable | Partially Applicable | Non-Applicable |
|---|---|---|
| A | PA | NA |

Q. HOW DID YOU CALCULATE THE COSTS AND BENEFITS OF THE AMR AND AMI SOLUTIONS FOR PURPOSES OF THIS LEAST-COST/BEST-FIT ANALYSIS?

A. The AMR Drive-by cost and benefit assessments were provided by Company witness Ms. Bloch, and are discussed in her Direct Testimony. The total cost of this system results from the incremental capital and O&M necessary to implement an AMR drive-by solution as a replacement for our current meters. However, this system does not provide any incremental benefit to the current Cellnet meter/billing structure. The costs and benefits of the AMI system were provided by Ms. Bloch, Mr. Harkness, and Mr. Cardenas, as described earlier in my testimony. In contrast, we did not calculate the cost of manual or AMR limited two-way alternatives because we did not consider these realistic solutions given the state of the industry and the needs of our system, customers, and other stakeholders. Table 18 above underscores why we are proposing an AMI solution.

Q. DID YOU COMPLETE A SIMILAR ASSESSMENT WITH RESPECT TO THE COMMUNICATIONS NETWORK NECESSARY TO SUPPORT THE AGIS INITIATIVE?

A. Yes. Company witness Mr. Harkness provides an extensive discussion relative to the costs and benefits of the three communication network alternatives the Company considered. My Table 19 summarizes the results of the Company's evaluation of the aggregated capabilities and protections provided by the FAN with a mesh network, compared to other alternatives.

**Table 19**

**Communications Least-Cost Best-Fit Alternative**

| | | **Alternative** | | |
|---|---|---|---|---|
| **Item** | **Feature/ Requirement** | **Cellular** | **Dedicated AMI** | **FAN Mesh** |
| Network Capabilities | Two way communications | ● | ● | ● |
| | Peer-to-Peer | ◔ | ◕ | ● |
| | Multipurpose | ◕ | ◔ | ● |
| | Latency Requirements | ● | ◕ | ● |
| | Security | ◑ | ● | ● |
| | Dedicated traffic | ◔ | ◕ | ● |
| | Priority traffic | ◔ | ● | ● |
| | O&M Costs Impact (run state) | ◔ | ◑ | ● |
| | Resiliency | ◑ | ◑ | ● |
| Operational Features | Cost of paying a third party for service | A | NA | NA |
| | Unable to fully control the system "end-start" | A | NA | NA |
| | Unable to implement to some AGIS processes | NA | PA | NA |
| | Relying on technology | A | A | A |
| NPV (2019) | Calculated COSTS - CAP Change in RR and O&M | | | $102M |
| | BENEFITS-Incremental to current reading/ billing | | | $0M |
| | **NET COST-OUTCOME** | | | **$102M** |
| Least-Cost, Best-Fit Alternative Selected | | | | **FAN Mesh** |

**Legend for Capabilities**

| Full | Most | Partial | Minimal | None |
|---|---|---|---|---|
| ● | ? | ? | ? | ○ |

**Legend for Operational Features**

| Applicable | Partially Applicable | Non-Applicable |
|---|---|---|
| A | PA | NA |

Q. HOW DID YOU CALCULATE THE COSTS OF THE COMMUNICATION NETWORK ALTERNATIVES IN THE LEAST-COST/BEST-FIT ANALYSIS?

A. The cost of the FAN components and deployment were provided by Company witness Mr. Harkness, and are described in his testimony. Additionally, Mr. Harkness explains that in comparing alternatives to the FAN, the Company determined that a cellular option would likely have a similar device cost with additional O&M costs; therefore, the cost is expected to be at best equal to and more likely higher than FAN costs. Furthermore, Mr. Harkness explains that a dedicated AMI network was ruled out because it would not allow non-AMI devices to connect to each other or to back office applications, affecting overall system functionality. As such, Table 19 does not show specific cost vs. benefit estimates for alternatives to the FAN, but rather focuses on the relative capabilities of all three alternatives.

Q. DID THE COMPANY COMPLETE A LEAST-COST/BEST-FIT ANALYSIS FOR IVVO OR FLISR?

A. No; it would not have made sense for these components of the AGIS initiative. IVVO and FLISR are, more simply, additional ADMS capabilities. In contrast, there are different fundamental types of meter solutions and communication networks. While there are forms of IVVO and FLISR devices that have different individual capabilities, such comparisons were conducted in the RFP processes, as discussed by Ms. Bloch.

Q. WHAT DO THESE LEAST-COST/BEST-FIT ANALYSES SHOW?

A. They provide another means (in addition to the CBA and the extensive narrative testimony) of comparing the AGIS solutions with alternatives. They largely summarize the analyses Ms. Bloch, and Mr. Harkness provide in much greater detail, and underscore why it was prudent to select AMI and the FAN.

## IV. QUALITATIVE BENEFITS OF AGIS

Q. ARE THERE SPECIFICALLY IDENTIFIABLE BENEFITS THE AMI PROGRAM WILL PROVIDE TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. There are a number of benefits of AMI that cannot be quantified either in whole or in part. For example, it is difficult to quantify customers' need and broad expectation to have more choice in and control over their energy usage, or their frustration with older technologies that cannot be updated without better data access. Our analysis captures estimates of customer adoption of technologies to support customer choice and the impacts on energy usage, but cannot fully quantify customer satisfaction associated with having better energy usage and pricing information. Nor can it fully quantify the convenience to customers of better outage management.

The unquantifiable benefits, or benefit the Company did not model in the CBA, are largely discussed by Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack. These include but are not limited to:

- Improved customer choice and experience, leading to customer empowerment and satisfaction;
- Enhanced distributed energy resource integration;
- Environmental benefits of enhanced energy efficiency;
- Improved safety to both customers and Company employees;
- Improvements in power quality; and
- Cyber and data security.

Q. ARE THERE ANY BENEFITS THAT THE FLISR PROGRAM PROVIDES TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. As with AMI, there are benefits of FLISR that the Company did not attempt to quantify. It is important to note that FLISR does not avoid outages altogether, but works to minimize their impacts on customers when they do occur, improving the customer's experience and leading to customer satisfaction. Thus the qualitative benefits include but are not limited to:

- Improved public and employee safety,
- Value of the data provided by FLISR for system planning purposes, and
- Overall customer satisfaction with utility service.

Q. ARE THERE ANY BENEFITS THAT THE IVVO PROGRAM PROVIDES TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. As with AMI and FLISR, there are benefits of IVVO that the Company did not attempt to quantify. They include but are not limited to:

- Customer bill savings specific to customers whose feeders are equipped with IVVO assets;
- Enhanced automatic access of low income customers to energy efficiency savings;
- Greater efficiencies from the customers' personal electrical devices; and
- Increased hosting capacity of distributed energy resources.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THESE QUALITATIVE BENEFITS OF IVVO?

A. Yes. With respect to low income customers' access to energy efficiency savings, I note that Ms. Bloch explains how IVVO can reduce voltage, and therefore save customers money without requiring any change in energy usage or activities on the customers' part. Additionally, IVVO is not tied to any particular energy efficiency program, so it has the added benefit of saving money for customers – including low income customers – who are sometimes unable to take advantage of such programs.

Q. WHY DIDN'T THE COMPANY ATTEMPT TO QUANTIFY THESE BENEFITS?

A. Although the Company feels strongly that these benefits are meaningful to our customers, it is difficult and often highly subjective to attempt to place a dollar value on them. For example, customer satisfaction and empowerment are important to the Company's business model and role as a public utility, but do not easily lend themselves to monetization.

The Company therefore concluded that it was best to provide a cost and benefit analysis to the Commission that fairly represents the cost and benefits of quantifiable projects components, and which we were able to value with reasonable confidence, and then ask the Commission to weigh the other impacts to our customers as it sees fit. In this way, the Commission may rely on the CBA as a baseline of our business case for our projects, and then evaluate and discuss the merits of the additional beneficial impacts to our customers.

Q. WHY SHOULD THE COMMISSION CONSIDER APPROVING COST RECOVERY FOR AMI, FLISR, AND IVVO IF COMBINED PROGRAM COSTS EXCEED THE OVERALL QUANTITATIVE BENEFITS?

A. There are several reasons why AMI, FLISR, and IVVO are overall valuable resources, even if costs slightly exceed estimated quantifiable benefits.

First, the Company AMI, FLISR, and IVVO implementation will allow the Company to achieve greater visibility into its distribution system, greater opportunities for demand side management, and improved reliability. Conversely, we cannot make the same progress in these areas without enhancing the distribution grid. As Mr. Gersack discusses, these are also necessary components of any new rate structures or other initiatives the Commission may wish to implement; right now, the Company simply does not have the technical capability or insight into customer usage to implement such technologies or customer support without AMI, FLISR, and IVVO.

Second, I would not necessarily expect quantifiable benefits to exceed costs, particularly for AMI, because it is necessary to replace aging technology. On the one hand, the Company's current meters will no longer be considered current technology nor supported as the Cellnet contract comes to an end, but on the other hand a CBA does not take into account that we cannot function without metering. Further, the model cannot fully reflect that AMR meters are an outdated option that will not provide the functionality customers, stakeholders, and the Commission have come to expect, nor the system support necessary in the age of DER.

Third, this model is not the only manner in which we measure the value of the grid advancement options available to us. Much of the Company's comparison of alternative options is completed in the Request for Information (RFI) and Request for Proposal (RFP) proceedings, rather than in a CBA based on our final selections. As described by Ms. Bloch, we have made careful and prudent AMI selections and negotiated a strong contract with our new AMI vendor. Ms. Bloch also discusses alternative considerations and vendor options for other system devices. Likewise, the FAN communications network is the product of robust RFP processes discussed by Mr. Harkness.

Given this prudent approach to selection of infrastructure, the ultimate question is whether overall costs are reasonable.

Fourth, this model can only quantify that which is quantifiable. Its expression of benefits does not include such qualitative benefits as customer choice and convenience, human safety, and potential support for future distributed energy resources. We recognize that choice, convenience, and greater control over energy costs and usage are of increasing importance to our customers. Customer satisfaction and customer empowerment with respect to their energy choices are of central importance to the public utility model.

Fifth and finally, the Company's AGIS witnesses describe at length why it is important to advance the NSPM grid to continue providing safe, increasingly reliable electric service to our customers not just in the present but also into the future. While we cannot predict every new technology that will arrive, we know that our current system is not future-proofed. Conversely, the AGIS program will support a fundamental utility function while improving existing infrastructure that is no longer maximizing service to our customers. It makes future applications, optionality, and distributed energy resources available in a way it is not possible to fully measure because it is not possible to fully predict the future. But as Mr. Gersack describes, utilities nationwide are making these important grid investments because "doing nothing" is not a realistic option. Therefore, the Company feels that this is both the right time and an important time to modernize critical components of its distribution grid.

## V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's AGIS CBA is a tool that is helpful, but not sufficient, to assess the overall prudence of the AGIS strategy and investments. We believe it is realistic and appropriate that our CBA shows individual and composite benefit-to-cost ratios that approach 1.0 (or exceed 1.0 in the case of FLISR), even before taking into account unquantifiable benefits. With those qualitative considerations and benefits, the Company believes the value of the AGIS initiative and its respective components substantially exceed the costs. Finally, both the CBA itself and our least cost/best fit summative analyses underscore that our AGIS program is reasonable given the need to replace aging technology, bring our distribution grid into the future, meet customer needs and offer greater customer choice, and take advantage of opportunities to use technology to support demand side management, peak demand reductions, and build a more resilient and responsive grid.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

**Statement of Qualifications**

Ravikrishna Duggirala
Director, Risk Strategy
1800 Larimer Street, Denver, Colorado

Ravikrishna Duggirala has more than 25 years of diverse experience in various industries in the areas of Engineering, Operations, Business Development, and Risk Management. Dr. Duggirala joined Xcel Energy in 2002 and is currently Director of Risk Strategy, where he is responsible for Enterprise Risk Management, Asset Risk Management, risk analytics, and modeling. He has held this position since 2008. Previously, Dr. Duggirala was the Manager of Energy Sales Risk for Xcel Energy from 2005 through 2008, where he was responsible for retail sales risk analysis, key risk analysis, sensitivity analysis, and risk analytics. Dr. Duggirala was also a Risk Consultant with the Company between 2002 and 2005, where he was responsible for monitoring and reporting of trading risks, managing risk policies and procedures and supporting Corporate Risk Management Oversight Committee. Prior to working for Xcel Energy, Dr. Duggirala worked at other companies including Enron, Monsanto, and Purdue University in various capacities.

Dr. Duggirala received his Masters Degree in Business Administration from Washington University in St. Louis in 2000, and his Ph.D in Engineering from Purdue University in 1996.

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | TOTAL | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Total Meters Deployed* | *10,131* | *7,368* | *121,800* | *630,000* | *590,000* | *40,700* | *13,755* | *13,890* | *14,027* | *14,164* | *14,304* | *14,444* | *14,586* | *14,729* | *14,874* | *15,020* | *15,168* | ***1,558,960*** | |
| **CAPITAL COSTS** | | | | | | | | | | | | | | | | | | ***TOTAL DISCOUNTED*** | ***NSPM-NPV*** |
| **AMI Meters** | | | | | | | | | | | | | | | | | | | |
| AMI Meters Purchase | 1,408,513 | 1,024,373 | 13,875,456 | 71,769,600 | 67,212,800 | 4,636,544 | 1,771,935 | 1,826,384 | 1,882,506 | 1,940,352 | 1,999,976 | 2,061,432 | 2,124,776 | 2,190,067 | 2,257,364 | 2,326,730 | 2,398,226 | **182,707,036** | **132,855,955** |
| AMI Meter Installation | 620,017 | 450,922 | 5,054,700 | 26,145,000 | 24,485,000 | 1,689,050 | 645,500 | 665,335 | 685,779 | 706,852 | 728,573 | 750,961 | 774,036 | 797,821 | 822,337 | 847,606 | 873,652 | **66,743,140** | **48,567,278** |
| RTU's (Return to Utility- Estimate 3% of installed meters) | 0 | 0 | 303,282 | 1,568,700 | 1,469,100 | 101,343 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **3,442,425** | **2,619,423** |
| Vendors deployment Project Management | 0 | 381,182 | 733,817 | 1,198,410 | 1,223,217 | 624,270 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **4,160,897** | **3,204,164** |
| AMI Operations (Internal Personnel) | 843,677 | 983,487 | 1,869,203 | 2,046,398 | 2,186,980 | 1,903,327 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **9,833,071** | **7,716,691** |
| AMI Operations (External Personnel) | 0 | 0 | 658,073 | 1,372,663 | 1,365,055 | 637,919 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **4,033,710** | **3,053,879** |
| Shop & Lab equipment (AMI Field Test, Lab equip) | 0 | 25,888 | 217,401 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **243,288** | **203,171** |
| Distribution Contingencies | 442,320 | 441,341 | 3,497,637 | 16,031,519 | 15,083,091 | 1,477,238 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **36,973,146** | **28,259,602** |
| *TOTAL - AMI Meters* | 3,314,527 | 3,307,193 | 26,209,569 | 120,132,290 | 113,025,244 | 11,069,690 | 2,417,435 | 2,491,719 | 2,568,285 | 2,647,205 | 2,728,549 | 2,812,393 | 2,898,813 | 2,987,889 | 3,079,701 | 3,174,336 | 3,271,878 | ***308,136,713*** | ***226,480,162*** |
| **Communications Network** | | | | | | | | | | | | | | | | | | | |
| FAN Infrastructure Distribution | 100,005 | 650,501 | 1,279,994 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **2,030,499** | **1,729,867** |
| FAN Distribution WiMax | 322,537 | 2,097,993 | 4,128,233 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **6,548,763** | **5,579,166** |
| FAN Bus Sys Costs | 1,709 | 51,120 | 88,387 | 59,329 | 56,142 | 15,200 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **271,887** | **217,842** |
| FAN Bus Sys WiMAX Cost | 334,633 | 10,011,076 | 17,309,267 | 11,618,600 | 10,994,506 | 2,976,466 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **53,244,549** | **42,660,847** |
| FAN Bus Sys Contingency | 73,854 | 1,267,037 | 2,253,221 | 1,166,606 | 1,103,942 | 298,863 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **6,163,522** | **4,979,818** |
| *TOTAL - Communications* | *832,739* | *14,077,726* | *25,059,102* | *12,844,535* | *12,154,590* | *3,290,528* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | ***68,259,221*** | ***55,167,540*** |
| **IT Systems and Integration** | | | | | | | | | | | | | | | | | | | |
| IT Hardware | 1,504,080 | 2,537,978 | 2,141,049 | 545,521 | 556,814 | 568,340 | 580,104 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **8,433,885** | **7,028,256** |
| IT Software | 1,064,115 | 1,552,117 | 5,536,877 | 4,669,670 | 323,141 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **13,145,919** | **10,838,063** |
| IT Labor + Project Management | 1,725,374 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,725,374** | **1,621,097** |
| IT Contingency | 0 | 0 | 0 | 11,176,589 | 605,252 | 548,564 | 174,031 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **12,504,436** | **9,642,915** |
| *TOTAL - IT Systems and Integration* | *4,293,568* | *4,090,095* | *7,677,926* | *16,391,780* | *1,485,207* | *1,116,904* | *754,136* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | ***35,809,615*** | ***29,130,330*** |
| **Program Management** | | | | | | | | | | | | | | | | | | | |
| Change Management | 0 | 1,000,000 | 1,035,500 | 1,072,260 | 1,110,325 | 1,149,742 | 1,190,558 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **6,558,386** | **4,950,734** |
| Environment/Release Management | 0 | 28,071 | 2,064,464 | 2,318,348 | 1,044,303 | 355,017 | 99,666 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **5,909,870** | **4,617,070** |
| Finance | 0 | 109,959 | 193,798 | 194,658 | 145,467 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **643,882** | **516,017** |
| PMO | 0 | 288,790 | 506,590 | 508,944 | 381,346 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,685,670** | **1,350,955** |
| Security | 0 | 1,105,737 | 1,144,991 | 1,185,638 | 1,227,728 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **4,664,093** | **3,748,708** |
| Supply Chain | 0 | 477,703 | 487,591 | 497,685 | 507,987 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,970,966** | **1,585,917** |
| Talent Strategy | 238,852 | 349,325 | 361,726 | 185,901 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,135,803** | **977,689** |
| Delivery and Execution Leadership | 0 | 374,158 | 1,294,786 | 1,314,010 | 667,319 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **3,650,273** | **2,916,840** |
| Contingency | 11,943 | 186,687 | 354,472 | 363,872 | 254,224 | 75,238 | 64,511 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,310,947** | **1,033,197** |
| *TOTAL - Program Management* | *250,795* | *3,920,430* | *7,443,919* | *7,641,315* | *5,338,699* | *1,579,997* | *1,354,735* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | ***27,529,891*** | ***21,697,127*** |
| **TOTAL CAPITAL** | 8,691,629 | 25,395,444 | 66,390,515 | 157,009,920 | 132,003,740 | 17,057,120 | 4,526,306 | 2,491,719 | 2,568,285 | 2,647,205 | 2,728,549 | 2,812,393 | 2,898,813 | 2,987,889 | 3,079,701 | 3,174,336 | 3,271,878 | *439,735,439* | *332,475,159* |
| **O&M ITEMS** | | | | | | | | | | | | | | | | | | | |
| **Communications Network** | | | | | | | | | | | | | | | | | | | |
| FAN Network Infrastructure Distribution | 0 | 0 | 130,976 | 298,507 | 271,352 | 225,136 | 105,810 | 54,000 | 55,118 | 56,259 | 57,424 | 58,612 | 59,826 | 61,064 | 62,328 | 63,618 | 64,935 | **1,624,966** | **1,036,835** |
| FAN Network Business Systems | 0 | 0 | 335,766 | 3,171,422 | 2,673,589 | 1,491,278 | 499,575 | 671,918 | 685,827 | 700,023 | 714,514 | 729,304 | 744,401 | 759,810 | 775,538 | 791,592 | 807,978 | **15,552,536** | **9,460,970** |
| FAN WiMAX Cost | 233,600 | 357,245 | 427,150 | 434,290 | 562,241 | 1,048,049 | 653,607 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **3,716,182** | **2,782,723** |
| NOC Opco Allocation | 200,000 | 408,280 | 625,097 | 638,037 | 651,244 | 664,725 | 678,485 | 692,529 | 706,864 | 721,497 | 736,432 | 751,676 | 767,235 | 783,117 | 799,328 | 815,874 | 832,762 | **11,473,181** | **6,445,717** |
| FAN Network Distribution Contingency | 0 | 0 | 59,854 | 136,414 | 124,004 | 102,885 | 48,354 | 24,677 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **496,189** | **363,768** |
| FAN Network Bus Sys Contingency | 0 | 0 | 301,130 | 686,305 | 623,871 | 517,616 | 243,271 | 124,153 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **2,496,348** | **1,830,131** |
| *TOTAL - Communications* | *433,600* | *765,525* | *1,879,974* | *5,364,975* | *4,906,301* | *4,049,690* | *2,229,101* | *1,567,278* | *1,447,809* | *1,477,779* | *1,508,369* | *1,539,592* | *1,571,462* | *1,603,991* | *1,637,194* | *1,671,084* | *1,705,675* | ***35,359,401*** | ***21,920,143*** |
| **IT Systems and Integration** | | | | | | | | | | | | | | | | | | | |
| IT Hardware | 42,114 | 1,654,282 | 1,678,585 | 1,705,324 | 1,740,624 | 1,776,655 | 1,813,432 | 1,850,970 | 1,889,285 | 1,928,393 | 1,968,311 | 2,009,055 | 2,050,642 | 2,093,091 | 2,136,418 | 2,180,642 | 2,225,781 | **30,743,604** | **17,268,781** |
| IT Software | 27,285 | 85,988 | 983,487 | 1,845,314 | 2,011,390 | 2,053,026 | 2,095,523 | 2,138,900 | 2,183,176 | 2,228,367 | 2,274,495 | 2,321,577 | 2,369,633 | 2,418,685 | 2,468,752 | 2,519,855 | 2,572,016 | **32,597,467** | **17,432,600** |
| IT Labor | 0 | 2,056,405 | 1,553,273 | 1,750,246 | 1,680,090 | 1,717,226 | 1,721,011 | 1,789,073 | 1,859,799 | 1,933,290 | 2,009,656 | 2,089,007 | 2,171,461 | 2,257,136 | 2,346,156 | 2,438,653 | 2,534,759 | **31,907,241** | **17,784,018** |
| Common Corporate Business System development-Allocation | 646,904 | 4,270,861 | 5,304,505 | 11,866,886 | 12,378,199 | 10,847,247 | 10,347,121 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **55,661,724** | **41,239,207** |
| IT Contingency | 0 | 997,287 | 9,826,939 | 4,112,864 | 2,099,639 | 2,145,629 | 2,192,624 | 2,240,646 | 2,289,716 | 2,339,857 | 2,391,093 | 2,443,448 | 2,496,946 | 2,551,611 | 2,607,470 | 2,664,547 | 2,722,871 | **46,123,186** | **28,075,602** |
| *TOTAL - IT Systems and Integration* | *716,303* | *9,064,823* | *19,346,789* | *21,280,633* | *19,909,942* | *18,539,783* | *18,169,711* | *8,019,589* | *8,221,975* | *8,429,907* | *8,643,555* | *8,863,087* | *9,088,683* | *9,320,523* | *9,558,795* | *9,803,697* | *10,055,427* | ***197,033,221*** | ***121,800,207*** |
| **Program Management** | | | | | | | | | | | | | | | | | | | |
| Change Management | 0 | 1,825,114 | 2,157,971 | 3,067,323 | 3,176,213 | 2,991,329 | 1,608,666 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **14,826,616** | **11,214,681** |
| Environment/Release Management | 0 | 0 | 22,405 | 23,200 | 24,024 | 24,877 | 11,794 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **106,300** | **78,991** |
| Finance | 0 | 32,456 | 112,027 | 167,045 | 216,218 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **527,746** | **410,061** |
| PMO | 0 | 79,772 | 275,346 | 410,574 | 531,437 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,297,129** | **1,007,876** |
| Talent Strategy | 37,760 | 58,651 | 60,733 | 0 | 55,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **212,144** | **177,898** |
| Delivery and Execution Leadership | 0 | 217,284 | 510,624 | 714,661 | 897,539 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **2,340,109** | **1,829,448** |
| Contingency | 1,888 | 110,664 | 156,955 | 219,140 | 245,022 | 150,810 | 81,023 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **965,502** | **735,948** |
| *TOTAL - Program Management* | *39,648* | *2,323,940* | *3,296,060* | *4,601,944* | *5,145,453* | *3,167,016* | *1,701,483* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | ***20,275,545*** | ***15,454,901*** |
| **AMI Operations (Personnel)** | | | | | | | | | | | | | | | | | | | |
| AMI Operations (Internal Personnel) | 0 | 2,029 | 36,563 | 40,759 | 42,206 | 43,704 | 47,708 | 1,040,317 | 1,077,248 | 1,115,491 | 1,155,090 | 1,196,096 | 1,238,558 | 1,282,526 | 1,328,056 | 1,375,202 | 1,424,022 | **12,445,575** | **5,756,644** |
| AMI Operations (External Personnel) | 0 | 187,968 | 214,121 | 468,050 | 1,576,002 | 1,300,659 | 1,409,575 | 1,475,931 | 1,545,439 | 1,600,302 | 1,657,112 | 1,715,940 | 1,776,856 | 1,839,934 | 1,905,252 | 1,972,888 | 2,042,926 | **22,688,954** | **11,693,307** |
| Customer Claims | 0 | 663 | 1,719 | 48,916 | 48,843 | 7,423 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **107,565** | **81,001** |
| Total AMI- O&M Dist Contingency | 0 | 29,259 | 38,605 | 78,357 | 249,204 | 207,032 | 224,422 | 387,502 | 403,894 | 418,232 | 433,079 | 448,454 | 464,374 | 480,859 | 497,929 | 515,606 | 533,910 | **5,410,717** | **2,687,292** |
| *TOTAL - AMI Operations* | 0 | 219,920 | 291,008 | 636,082 | 1,916,255 | 1,558,818 | 1,681,704 | 2,903,750 | 3,026,581 | 3,134,024 | 3,245,282 | 3,360,490 | 3,479,787 | 3,603,319 | 3,731,237 | 3,863,696 | 4,000,857 | ***40,652,811*** | ***20,218,244*** |
| **TOTAL O&M** | 1,189,551 | 12,374,208 | 24,813,831 | 31,883,634 | 31,877,951 | 27,315,307 | 23,782,000 | 12,490,618 | 12,696,365 | 13,041,711 | 13,397,206 | 13,763,169 | 14,139,931 | 14,527,833 | 14,927,226 | 15,338,477 | 15,761,959 | 293,320,977 | 179,393,496 |
| **GRAND TOTAL CAPITAL & O&M** | 9,881,180 | 37,769,652 | 91,204,347 | 188,893,554 | 163,881,691 | 44,372,427 | 28,308,306 | 14,982,337 | 15,264,650 | 15,688,915 | 16,125,755 | 16,575,562 | 17,038,744 | 17,515,722 | 18,006,927 | 18,512,812 | 19,033,837 | 733,056,417 | 511,868,655 |

XCEL ENERGY

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | TOTAL | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Total Meters Replaced* | *10,131* | *7,368* | *121,800* | *630,000* | *590,000* | *40,700* | *13,755* | *13,890* | *14,027* | *14,164* | *14,304* | *14,444* | *14,586* | *14,729* | *14,874* | *15,020* | *15,168* | ***1,558,960*** | |
| **O&M ITEMS** | | | | | | | | | | | | | | | | | | | |
| **Avoided O&M Meter Reading Costs** | | | | | | | | | | | | | | | | | | | |
| Drive-by Meter Reading Cost - O&M | 2,155 | 86,393 | 1,085,789 | 2,460,063 | 3,740,671 | 3,587,859 | 4,153,792 | 4,287,938 | 4,426,475 | 4,562,493 | 4,702,691 | 4,847,197 | 4,996,143 | 5,149,667 | 5,307,907 | 5,471,011 | 5,639,126 | **64,507,370** | **33,455,306** |
| ***TOTAL - Reduction in Meter Reading Costs*** | ***2,155*** | ***86,393*** | ***1,085,789*** | ***2,460,063*** | ***3,740,671*** | ***3,587,859*** | ***4,153,792*** | ***4,287,938*** | ***4,426,475*** | ***4,562,493*** | ***4,702,691*** | ***4,847,197*** | ***4,996,143*** | ***5,149,667*** | ***5,307,907*** | ***5,471,011*** | ***5,639,126*** | ***64,507,370*** | ***33,455,306*** |
| **Reduction in Field and Meter Services** | | | | | | | | | | | | | | | | | | | |
| Costs savings from remote disconnect capability | 0 | 0 | 0 | 0 | 386,423 | 1,108,454 | 1,592,346 | 1,814,095 | 1,878,495 | 2,060,451 | 2,133,597 | 2,209,340 | 2,287,771 | 2,368,987 | 2,453,086 | 2,540,171 | 2,630,347 | **25,463,562** | **12,291,603** |
| Reduction in trips due to Customer equipment damage | 0 | 0 | 0 | 0 | 32,617 | 67,549 | 139,894 | 144,860 | 150,003 | 155,328 | 160,842 | 166,552 | 172,465 | 178,587 | 184,927 | 191,492 | 198,290 | **1,943,406** | **940,688** |
| Reduction in "OK on Arrival" Outage Field Trips | 0 | 0 | 0 | 0 | 135,529 | 280,680 | 581,288 | 601,924 | 623,292 | 645,419 | 668,331 | 692,057 | 716,625 | 742,065 | 768,408 | 795,687 | 823,934 | **8,075,238** | **3,908,746** |
| Reduction in Field Trips for Voltage Investigations | 0 | 0 | 0 | 0 | 74,833 | 154,978 | 320,960 | 332,354 | 344,152 | 356,370 | 369,021 | 382,121 | 395,686 | 409,733 | 424,279 | 439,341 | 454,937 | **4,458,764** | **2,158,225** |
| ***TOTAL - Reduction in Field & Meter Services*** | ***0*** | ***0*** | ***0*** | ***0*** | ***629,401*** | ***1,611,661*** | ***2,634,487*** | ***2,893,232*** | ***2,995,942*** | ***3,217,567*** | ***3,331,791*** | ***3,450,070*** | ***3,572,547*** | ***3,699,373*** | ***3,830,700*** | ***3,966,690*** | ***4,107,508*** | ***39,940,969*** | ***19,299,262*** |
| **Improved Distribution System Spend Efficiency** | | | | | | | | | | | | | | | | | | | |
| Efficiency gains reliability, asset health and capacity projects- O&M | 0 | 0 | 0 | 0 | 1,159 | 2,401 | 4,972 | 5,148 | 5,331 | 5,520 | 5,716 | 5,919 | 6,129 | 6,347 | 6,572 | 6,805 | 7,047 | **69,067** | **33,431** |
| ***TOTAL - Improved Distribution System Spend Efficiency*** | ***0*** | ***0*** | ***0*** | ***0*** | ***1,159*** | ***2,401*** | ***4,972*** | ***5,148*** | ***5,331*** | ***5,520*** | ***5,716*** | ***5,919*** | ***6,129*** | ***6,347*** | ***6,572*** | ***6,805*** | ***7,047*** | ***69,067*** | ***33,431*** |
| **Outage Management Efficiency** | | | | | | | | | | | | | | | | | | | |
| Outage Management Efficiency (Storm spend O&M) | 0 | 0 | 0 | 0 | 604 | 1,250 | 2,589 | 2,681 | 2,776 | 2,875 | 2,977 | 3,082 | 3,192 | 3,305 | 3,422 | 3,544 | 3,670 | **35,965** | **17,409** |
| ***TOTAL - Outage Management Efficiency*** | ***0*** | ***0*** | ***0*** | ***0*** | ***604*** | ***1,250*** | ***2,589*** | ***2,681*** | ***2,776*** | ***2,875*** | ***2,977*** | ***3,082*** | ***3,192*** | ***3,305*** | ***3,422*** | ***3,544*** | ***3,670*** | 35,965 | 17,409 |
| **TOTAL O&M BENEFITS** | **2,155** | **86,393** | **1,085,789** | **2,460,063** | **4,371,835** | **5,203,171** | **6,795,840** | **7,189,000** | **7,430,524** | **7,788,455** | **8,043,175** | **8,306,268** | **8,578,011** | **8,858,691** | **9,148,602** | **9,448,050** | **9,757,350** | **104,553,371** | **52,805,408** |
| **OTHER BENEFITS** | | | | | | | | | | | | | | | | | | | |
| **Cost reductions** | | | | | | | | | | | | | | | | | | | |
| Reduced Consumption on Inactive Meters | 0 | 0 | 0 | 0 | 350,052 | 714,596 | 1,458,776 | 1,488,973 | 1,519,795 | 1,551,255 | 1,583,366 | 1,616,141 | 1,649,595 | 1,683,742 | 1,718,595 | 1,754,170 | 1,790,482 | **18,879,538** | **9,235,364** |
| Reduced Uncollectible / Bad Debt Expense | 0 | 0 | 0 | 0 | 259,816 | 538,078 | 1,114,360 | 1,153,920 | 1,194,884 | 1,237,303 | 1,281,227 | 1,326,711 | 1,373,809 | 1,422,579 | 1,473,081 | 1,525,375 | 1,579,526 | **15,480,670** | **7,493,278** |
| Reduced outage duration benefit | 0 | 0 | 0 | 0 | 391,289 | 798,777 | 1,630,623 | 1,664,377 | 1,698,830 | 1,733,996 | 1,769,889 | 1,806,526 | 1,843,921 | 1,882,090 | 1,921,050 | 1,960,815 | 2,001,404 | **21,103,587** | **10,323,309** |
| Theft / Tamper Detection & Reduction | 0 | 0 | 0 | 0 | 847,310 | 1,729,700 | 3,531,009 | 3,604,101 | 3,678,706 | 3,754,855 | 3,832,580 | 3,911,915 | 3,992,891 | 4,075,544 | 4,159,908 | 4,246,018 | 4,333,911 | **45,698,446** | **22,354,455** |
| ***TOTAL - Cost Reductions*** | 0 | 0 | 0 | 0 | 1,848,467 | 3,781,151 | 7,734,769 | 7,911,371 | 8,092,215 | 8,277,408 | 8,467,062 | 8,661,292 | 8,860,217 | 9,063,955 | 9,272,633 | 9,486,379 | 9,705,322 | ***101,162,241*** | ***49,406,407*** |
| **Load Flexibility Benefits** | | | | | | | | | | | | | | | | | | | |
| Critical Peak Pricing -CPP-DSM Peak | 0 | 0 | 0 | 0 | 0 | 19,965,050 | 20,415,850 | 21,129,600 | 21,780,000 | 22,361,590 | 23,136,860 | 23,755,800 | 24,531,638 | 25,336,224 | 26,164,958 | 27,023,654 | 27,910,308 | **283,511,530** | **138,479,332** |
| Time Of Usage-TOU-Customer energy price shift | 0 | 0 | 0 | 0 | 0 | 1,819,116 | 1,975,194 | 2,019,888 | 2,037,750 | 2,133,144 | 2,262,273 | 2,392,520 | 2,517,599 | 2,573,992 | 2,725,849 | 2,753,107 | 2,780,638 | **27,991,070** | **13,576,886** |
| Time Of Usage-TOU-Avoided CO2 Emissions | 0 | 0 | 0 | 0 | 0 | 226,876 | 352,119 | 485,400 | 361,972 | 230,903 | 344,421 | 271,720 | 330,772 | 309,477 | 297,166 | 310,767 | 413,652 | **3,935,245** | **1,961,868** |
| ***TOTAL - Load Flexibility Benefits*** | 0 | 0 | 0 | 0 | 0 | 22,011,042 | 22,743,163 | 23,634,888 | 24,179,722 | 24,725,637 | 25,743,554 | 26,420,040 | 27,380,008 | 28,219,692 | 29,187,972 | 30,087,528 | 31,104,598 | ***315,437,845*** | ***154,018,085*** |
| **TOTAL OTHER BENEFITS** | **0** | **0** | **0** | **0** | **1,848,467** | **25,792,193** | **30,477,932** | **31,546,259** | **32,271,937** | **33,003,045** | **34,210,616** | **35,081,332** | **36,240,224** | **37,283,648** | **38,460,605** | **39,573,907** | **40,809,920** | **416,600,086** | **203,424,492** |
| **CAPITAL ITEMS** | | | | | | | | | | | | | | | | | | | |
| **Capital gains and other avoided purchases** | | | | | | | | | | | | | | | | | | | |
| Efficiency gains reliability, asset health and capacity projects- CAP | 0 | 0 | 0 | 0 | 189,547 | 386,940 | 789,900 | 806,251 | 822,940 | 839,975 | 857,363 | 875,110 | 893,225 | 911,715 | 930,587 | 949,850 | 969,512 | **10,222,915** | **5,000,776** |
| Outage Management Efficiency (Storm spend CAP) | 0 | 0 | 0 | 0 | 313,698 | 649,669 | 1,345,465 | 1,393,229 | 1,442,688 | 1,493,904 | 1,546,937 | 1,601,854 | 1,658,719 | 1,717,604 | 1,778,579 | 1,841,718 | 1,907,099 | **18,691,164** | **9,047,289** |
| Avoided Meter Purchases | 9,788 | 18,152 | 185,992 | 1,086,102 | 2,027,125 | 2,203,315 | 2,138,852 | 2,218,752 | 2,301,754 | 2,387,984 | 2,477,572 | 2,570,653 | 2,667,369 | 2,767,866 | 2,872,297 | 2,980,823 | 3,093,609 | **34,008,006** | **17,455,428** |
| ***TOTAL - Efficiency gains and other avoided CAP purchases*** | 9,788 | 18,152 | 185,992 | 1,086,102 | 2,530,369 | 3,239,924 | 4,274,216 | 4,418,231 | 4,567,383 | 4,721,863 | 4,881,872 | 5,047,617 | 5,219,313 | 5,397,185 | 5,581,464 | 5,772,392 | 5,970,221 | ***62,922,085*** | ***31,503,493*** |
| **Avoided Meter Reading CAP investment** | | | | | | | | | | | | | | | | | | | |
| Drive-by Meter Reading Cost - CAP | 20,755 | 412,501 | 3,935,923 | 12,881,148 | 23,340,750 | 29,130,716 | 29,698,551 | 28,887,914 | 28,107,557 | 27,361,868 | 26,557,430 | 25,715,024 | 24,868,419 | 23,999,536 | 23,212,398 | 22,384,139 | 21,406,031 | **351,920,659** | **189,681,697** |
| ***TOTAL - Avoided Meter Reading CAP Investment*** | ***20,755*** | ***412,501*** | ***3,935,923*** | ***12,881,148*** | ***23,340,750*** | ***29,130,716*** | ***29,698,551*** | ***28,887,914*** | ***28,107,557*** | ***27,361,868*** | ***26,557,430*** | ***25,715,024*** | ***24,868,419*** | ***23,999,536*** | ***23,212,398*** | ***22,384,139*** | ***21,406,031*** | ***351,920,659*** | ***189,681,697*** |
| **TOTAL CAPITAL BENEFITS** | **30,543** | **430,653** | **4,121,915** | **13,967,250** | **25,871,119** | **32,370,640** | **33,972,767** | **33,306,145** | **32,674,940** | **32,083,731** | **31,439,303** | **30,762,641** | **30,087,732** | **29,396,720** | **28,793,861** | **28,156,530** | **27,376,252** | **414,842,744** | **221,185,190** |
| **GRAND TOTAL BENEFITS** | **32,698** | **517,046** | **5,207,705** | **16,427,313** | **32,091,421** | **63,366,004** | **71,246,539** | **72,041,404** | **72,377,400** | **72,875,232** | **73,693,094** | **74,150,241** | **74,905,968** | **75,539,059** | **76,403,069** | **77,178,487** | **77,943,522** | **935,996,201** | **477,415,090** |

***NSPM -AMI- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **446** |
| O&M Benefits | 53 |
| Other Benefits | 203 |
| CAP Benefits | 190 |
| **Costs** | **(539)** |
| O&M Expense | (179) |
| Change in Revenue Requirements | (359) |
| **Benefit/Cost Ratio** | **0.83** |

| RATIO SENSITIVITY | VALUE |
|---|---|
| FAN(80% WiMAx)+ Contingencies | 0.83 |
| FAN(80% WiMAx) NO Contingencies | 0.99 |

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | TOTAL | NPV | Cost Category |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CAPITAL ITEMS - SUMMARY** | | | | | | | | | | | | | | | | | | | | | | | |
| **FLISR Assets** | | | | | | | | | | | | | | | | | | | | | | | |
| Asset Cost | 0 | 2,456,519 | 6,604,776 | 3,745,275 | 5,606,776 | 5,852,901 | 4,447,353 | 4,539,413 | 4,633,379 | 4,729,290 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **42,615,682** | **29,507,829** | **Direct and Tangible** |
| Asset Installation | 0 | 661,457 | 1,804,228 | 1,037,932 | 1,576,342 | 1,669,400 | 1,286,894 | 1,332,579 | 1,379,886 | 1,428,872 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **12,177,590** | **8,386,388** | **Direct and Tangible** |
| Device related Vendor Project Management + Other Labor | 0 | 15,533 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **15,533** | **13,712** | **Direct and Tangible** |
| Asset Contingency | 0 | 0 | 0 | 1,499,386 | 1,866,899 | 919,536 | 604,982 | 617,505 | 630,288 | 643,334 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **6,781,930** | **4,638,594** | **Direct and Tangible** |
| ***TOTAL - Assets Cost*** | ***0*** | ***3,133,508*** | ***8,409,004*** | ***6,282,593*** | ***9,050,018*** | ***8,441,837*** | ***6,339,229*** | ***6,489,497*** | ***6,643,552*** | ***6,801,496*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***61,590,735*** | **42,546,523** | |
| **Communications Network** | | | | | | | | | | | | | | | | | | | | | | | |
| FAN Infrastructure Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Direct and Tangible** |
| FAN Distribution WiMax | 60,476 | 393,374 | 774,044 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,227,893** | **1,046,094** | **Direct and Tangible** |
| FAN Bus Sys Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Direct and Tangible** |
| FAN Bus Sys WiMAX Cost | 62,744 | 1,877,077 | 3,245,488 | 2,178,488 | 2,061,470 | 558,087 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **9,983,353** | **7,998,909** | **Direct and Tangible** |
| FAN Bus Sys Contingency | 48,467 | 831,493 | 1,478,676 | 765,585 | 724,462 | 196,129 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **4,044,811** | **3,268,006** | **Direct and Tangible** |
| ***TOTAL - Communications*** | 171,686 | 3,101,943 | 5,498,207 | 2,944,073 | 2,785,932 | 754,216 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | ***15,256,057*** | **12,313,008** | |
| **IT Systems and Integration** | | | | | | | | | | | | | | | | | | | | | | | |
| ADMS FLISR Integration | 0 | 372,780 | 503,962 | 521,853 | 1,023,270 | 1,059,597 | 807,499 | 836,165 | 865,849 | 896,587 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **6,887,562** | **4,636,414** | **Direct and Tangible** |
| IT Contingency | 0 | 0 | 0 | 299,788 | 632,358 | 654,807 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,586,953** | **1,147,107** | **Direct and Tangible** |
| ***TOTAL - IT Systems and Integration*** | ***0*** | ***372,780*** | ***503,962*** | ***821,641*** | ***1,655,629*** | ***1,714,403*** | ***807,499*** | ***836,165*** | ***865,849*** | ***896,587*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***8,474,515*** | **5,783,521** | |
| **TOTAL CAPITAL** | **171,686** | **6,608,231** | **14,411,173** | **10,048,307** | **13,491,578** | **10,910,457** | **7,146,728** | **7,325,662** | **7,509,401** | **7,698,082** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **85,321,307** | **60,643,052** | |
| | | | | | | | | | | | | | | | | | | | | | | | |
| **O&M ITEMS - SUMMARY** | | | | | | | | | | | | | | | | | | | | | | | |
| **Deployment** | | | | | | | | | | | | | | | | | | | | | | | |
| O&M in support of capital deployment | 0 | 85,389 | 229,582 | 130,186 | 194,892 | 203,447 | 154,590 | 157,790 | 161,056 | 164,390 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,481,321** | **1,025,692** | **Direct and Tangible** |
| ***TOTAL - Asset Operations*** | ***0*** | ***85,389*** | ***229,582*** | ***130,186*** | ***194,892*** | ***203,447*** | ***154,590*** | ***157,790*** | ***161,056*** | ***164,390*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***1,481,321*** | **1,025,692** | |
| **Ongoing Support** | | | | | | | | | | | | | | | | | | | | | | | |
| On-going Asset/Device support | 0 | 9,416 | 34,927 | 50,006 | 72,532 | 96,468 | 115,512 | 135,303 | 155,864 | 177,218 | 180,886 | 184,630 | 188,452 | 192,353 | 196,335 | 200,399 | 204,547 | 208,781 | 213,103 | 217,514 | **2,834,248** | **1,296,703** | **Direct and Tangible** |
| Component Replacements | 0 | 2,742 | 10,171 | 14,562 | 21,121 | 28,092 | 33,637 | 39,400 | 45,387 | 51,606 | 52,674 | 53,764 | 54,877 | 56,013 | 57,173 | 58,356 | 59,564 | 60,797 | 62,056 | 63,340 | **825,333** | **377,600** | **Direct and Tangible** |
| On-going Communications Network costs | 0 | 7,324 | 27,166 | 38,894 | 56,414 | 75,031 | 89,843 | 105,236 | 121,227 | 137,836 | 140,689 | 143,601 | 146,574 | 149,608 | 152,705 | 155,866 | 159,092 | 162,386 | 165,747 | 169,178 | **2,204,415** | **1,008,547** | **Direct and Tangible** |
| Vendor costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Direct and Tangible** |
| Training | 0 | 10,355 | 10,723 | 11,103 | 11,497 | 11,906 | 12,328 | 12,766 | 13,219 | 13,688 | 14,174 | 14,677 | 15,199 | 15,738 | 16,297 | 16,875 | 17,474 | 18,095 | 18,737 | 19,402 | **274,254** | **137,195** | **Direct and Tangible** |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Direct and Tangible** |
| Asset Contingency | 0 | 1,974 | 7,321 | 10,482 | 15,204 | 20,221 | 24,213 | 28,361 | 32,671 | 37,147 | 37,916 | 38,701 | 39,502 | 40,320 | 41,154 | 42,006 | 42,876 | 43,763 | 44,669 | 45,594 | **594,092** | **271,804** | **Direct and Tangible** |
| ***TOTAL - Assets Cost*** | ***0*** | ***31,810*** | ***90,308*** | ***125,047*** | ***176,769*** | ***231,717*** | ***275,533*** | ***321,066*** | ***368,368*** | ***417,495*** | ***426,339*** | ***435,374*** | ***444,604*** | ***454,032*** | ***463,663*** | ***473,502*** | ***483,554*** | ***493,822*** | ***504,312*** | ***515,028*** | ***6,732,342*** | **3,091,849** | |
| ***Communications Network*** | | | | | | | | | | | | | | | | | | | | | | | |
| FAN Network Infrastructure Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Direct and Tangible** |
| FAN Network Business Systems | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Direct and Tangible** |
| FAN WiMAX Cost | 43,800 | 66,983 | 80,091 | 81,429 | 105,420 | 196,509 | 122,551 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **696,784** | **521,761** | **Direct and Tangible** |
| NOC Opco Allocation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Indirect and Tangible** |
| FAN Network Distribution Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Direct and Tangible** |
| FAN Network Bus Sys Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **Direct and Tangible** |
| ***TOTAL - Communications*** | 43,800 | 66,983 | 80,091 | 81,429 | 105,420 | 196,509 | 122,551 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **696,784** | **521,761** | |
| **TOTAL O&M** | **43,800** | **184,182** | **399,980** | **336,662** | **477,080** | **631,673** | **552,674** | **478,856** | **529,425** | **581,885** | **426,339** | **435,374** | **444,604** | **454,032** | **463,663** | **473,502** | **483,554** | **493,822** | **504,312** | **515,028** | **8,910,447** | **4,639,301** | |
| | | | | | | | | | | | | | | | | | | | | | | | |
| **GRAND TOTAL CAPITAL & O&M** | **215,486** | **6,792,413** | **14,811,154** | **10,384,969** | **13,968,659** | **11,542,130** | **7,699,402** | **7,804,518** | **8,038,826** | **8,279,967** | **426,339** | **435,374** | **444,604** | **454,032** | **463,663** | **473,502** | **483,554** | **493,822** | **504,312** | **515,028** | **94,231,754** | **65,282,354** | |

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | TOTAL | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **O&M BENEFITS** | | | | | | | | | | | | | | | | | | | | | | |
| Operational Benefits | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** |
| **TOTAL O&M BENEFITS** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **CUSTOMER BENEFITS** | | | | | | | | | | | | | | | | | | | | | | |
| Customer Minutes Out- CMO Patrolling savings | 0 | 0 | 0 | 40,757 | 175,083 | 271,514 | 355,725 | 453,382 | 539,313 | 649,433 | 725,847 | 789,440 | 789,440 | 789,440 | 789,440 | 789,440 | 789,440 | 789,440 | 789,440 | 789,440 | **10,316,013** | **4,528,044** |
| Customer Minutes Out- CMO Customer Savings | 0 | 0 | 0 | 2,754,556 | 4,809,980 | 6,277,181 | 8,295,139 | 10,426,430 | 12,214,741 | 14,325,875 | 15,433,977 | 16,164,602 | 16,164,602 | 16,164,602 | 16,164,602 | 16,164,602 | 16,164,602 | 16,164,602 | 16,164,602 | 16,164,602 | **220,019,300** | **98,458,717** |
| **TOTAL CUSTOMER IMPACTS** | **0** | **0** | **0** | **2,795,313** | **4,985,063** | **6,548,696** | **8,650,864** | **10,879,813** | **12,754,055** | **14,975,308** | **16,159,824** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **230,335,313** | **102,986,762** |
| **GRAND TOTAL BENEFITS** | **0** | **0** | **0** | **2,795,313** | **4,985,063** | **6,548,696** | **8,650,864** | **10,879,813** | **12,754,055** | **14,975,308** | **16,159,824** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **16,954,042** | **230,335,313** | **102,986,762** |

***NSPM FLISR- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **103** |
| O&M Benefits | 0 |
| Customer Benefits | 103 |
| **Costs** | **(78)** |
| O&M Expense | (5) |
| Change in Revenue Requirements | (74) |
| **Benefit/Cost Ratio** | **1.31** |

| RATIO SENSITIVITY | VALUE |
|---|---|
| FAN(15% WiMax)+ Contingencies | **1.31** |
| FAN(15% WiMax) NO Contingencies | **1.53** |

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | TOTAL | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Feeders enabled with IVVO* | 0 | 0 | 26 | 43 | 61 | 59 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 189 | |
| **CAPITAL COSTS** | | | | | | | | | | | | | | | | | | | | | | |
| **Assets/Devices** | | | | | | | | | | | | | | | | | | | | | | |
| Device costs | 0 | 0 | 1,512,735 | 2,824,978 | 2,704,856 | 2,267,749 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **9,310,319** | **6,996,776** |
| Device Installation costs | 0 | 0 | 357,063 | 773,839 | 777,449 | 679,695 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **2,588,046** | **1,936,047** |
| Xcel Personnel | 0 | 0 | 132,317 | 272,663 | 277,896 | 283,603 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **966,479** | **720,811** |
| Xcel Distribution Personnel [ADMS IVVO Integration] | 0 | 0 | 306,666 | 525,184 | 771,477 | 772,672 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **2,375,999** | **1,760,061** |
| External resources (Consultants, contractors etc.) | 0 | 0 | 187,008 | 434,397 | 443,389 | 342,887 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,407,681** | **1,054,169** |
| E&S | 0 | 103,550 | 750,582 | 777,228 | 804,819 | 833,391 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **3,269,570** | **2,482,269** |
| Varentec Engineering (ENGO,caps,ami) | 0 | 0 | 416,731 | 425,358 | 434,163 | 443,150 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,719,402** | **1,299,884** |
| Contingency | 0 | 0 | 107,914 | 269,162 | 256,986 | 175,088 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **809,149** | **607,879** |
| ***TOTAL - Business Assets/Devices*** | ***0*** | ***103,550*** | ***3,771,016*** | ***6,302,808*** | ***6,471,034*** | ***5,798,235*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***22,446,644*** | **16,857,896** |
| **Communications Network** | | | | | | | | | | | | | | | | | | | | | | |
| Communications Operations-IVVO Budget | 0 | 0 | 61,332 | 115,547 | 110,814 | 104,193 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **391,886** | **293,733** |
| FAN Infrastructure Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** |
| FAN Distribution WiMax | 20,159 | 131,125 | 258,015 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **409,298** | **348,698** |
| FAN Bus Sys Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** |
| FAN Bus Sys WiMAX Cost | 20,915 | 625,692 | 1,081,829 | 726,163 | 687,157 | 186,029 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **3,327,784** | **2,666,303** |
| FAN Bus Sys Contingency | 0 | 0 | 0 | 1,482,861 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,482,861** | **1,155,589** |
| ***TOTAL - Communications*** | 41,073 | 756,817 | 1,401,176 | 2,324,571 | 797,971 | 290,222 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | ***5,611,829*** | **4,464,323** |
| **IT Systems and Integration** | | | | | | | | | | | | | | | | | | | | | | **0** |
| Xcel Personnel [ADMS IVVO Integration] | 0 | 0 | 803,466 | 1,375,982 | 2,021,270 | 2,024,401 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **6,225,118** | **4,611,361** |
| External resources (Consultants, contractors etc.) [GEMS] | 0 | 0 | 520,914 | 265,849 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **786,763** | **639,234** |
| GEMS hardware | 0 | 0 | 104,183 | 53,170 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **157,353** | **127,847** |
| Varentec PM & Services | 0 | 0 | 52,091 | 26,585 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **78,676** | **63,923** |
| IT Project Management | 0 | 0 | 52,091 | 26,585 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **78,676** | **63,923** |
| IT Travel Expenses | 0 | 0 | 10,418 | 5,317 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **15,735** | **12,785** |
| Security | 0 | 0 | 104,183 | 53,170 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **157,353** | **127,847** |
| Contingency | 0 | 0 | 130,158 | 158,367 | 190,817 | 188,381 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **667,722** | **500,682** |
| Program Management | 0 | 0 | 104,183 | 319,018 | 325,622 | 332,362 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1,081,185** | **802,089** |
| ***TOTAL - IT Systems and Integration*** | ***0*** | ***0*** | ***1,881,688*** | ***2,284,042*** | ***2,537,708*** | ***2,545,144*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***9,248,582*** | **6,949,692** |
| **Program Management** | | | | | | | | | | | | | | | | | | | | | | |
| Organizational Change Management | 0 | 0 | 468,823 | 850,715 | 651,244 | 553,937 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **2,524,720** | **1,909,732** |
| ***TOTAL - Program Management*** | ***0*** | ***0*** | ***468,823*** | ***850,715*** | ***651,244*** | ***553,937*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | | | | ***2,524,720*** | **1,909,732** |
| **TOTAL CAPITAL** | **41,073** | **860,367** | **7,522,703** | **11,762,136** | **10,457,957** | **9,187,538** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **39,831,775** | **30,181,642** |
| | | | | | | | | | | | | | | | | | | | | | | |
| **O&M ITEMS** | | | | | | | | | | | | | | | | | | | | | | |
| O&M in support of capital deployment | 0 | 0 | 17,731 | 37,764 | 33,658 | 34,745 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **123,898** | **92,683** |
| ***TOTAL - On-going Asset/Device support Costs*** | ***0*** | ***0*** | ***17,731*** | ***37,764*** | ***33,658*** | ***34,745*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | | | | ***123,898*** | **92,683** |
| **Assets/Devices** | | | | | | | | | | | | | | | | | | | | | | |
| On-going Asset/Device support | 0 | 0 | 0 | 0 | 7,991 | 25,537 | 40,714 | 57,063 | 59,089 | 61,187 | 63,359 | 65,608 | 67,937 | 70,349 | 72,847 | 75,433 | 78,110 | 80,883 | 83,755 | 86,728 | **996,591** | **433,842** |
| Device Replacements | 0 | 0 | 0 | 0 | 12,059 | 38,654 | 62,172 | 85,943 | 87,722 | 89,538 | 91,391 | 93,283 | 95,214 | 97,185 | 99,197 | 101,250 | 103,346 | 105,485 | 107,669 | 109,897 | **1,380,003** | **609,942** |
| Training | 0 | 0 | 0 | 0 | 195 | 653 | 1,107 | 1,554 | 1,609 | 1,666 | 1,725 | 1,786 | 1,850 | 1,915 | 1,983 | 2,054 | 2,127 | 2,202 | 2,280 | 2,361 | **27,066** | **11,765** |
| Contingency | 0 | 0 | 0 | 0 | 2,471 | 7,885 | 12,612 | 17,431 | 17,792 | 18,160 | 18,536 | 18,920 | 19,312 | 19,711 | 20,119 | 20,536 | 20,961 | 21,395 | 21,838 | 22,290 | **279,968** | **123,761** |
| ***TOTAL - On-going Asset/Device support Costs*** | ***0*** | ***0*** | ***0*** | ***0*** | ***22,715*** | ***72,730*** | ***116,604*** | ***161,991*** | ***166,212*** | ***170,551*** | ***175,011*** | ***179,597*** | ***184,312*** | ***189,161*** | ***194,146*** | ***199,272*** | ***204,544*** | ***209,965*** | ***215,541*** | ***221,276*** | ***2,683,629*** | **1,179,310** |
| **Communications Network** | | | | | | | | | | | | | | | | | | | | | | |
| On-going Communications Network costs | 0 | 0 | 0 | 0 | 4,920 | 15,829 | 25,585 | 35,371 | 36,103 | 36,850 | 37,613 | 38,392 | 39,187 | 39,998 | 40,826 | 41,671 | 42,533 | 43,414 | 44,312 | 45,230 | **567,832** | **250,941** |
| FAN Network Infrastructure Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** |
| FAN Network Business Systems | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** |
| FAN WiMAX Cost | 14,600 | 22,328 | 26,697 | 27,143 | 35,140 | 65,503 | 40,850 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **232,261** | **173,920** |
| NOC Opco Allocation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** |
| FAN Network Distribution Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** |
| FAN Network Bus Sys Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** |
| ***TOTAL - Communications*** | ***14,600*** | ***22,328*** | ***26,697*** | ***27,143*** | ***40,060*** | ***81,332*** | ***66,435*** | ***35,371*** | ***36,103*** | ***36,850*** | ***37,613*** | ***38,392*** | ***39,187*** | ***39,998*** | ***40,826*** | ***41,671*** | ***42,533*** | ***43,414*** | ***44,312*** | ***45,230*** | ***800,094*** | **424,861** |
| **IT Systems and Integration** | | | | | | | | | | | | | | | | | | | | | | |
| Program Management | 0 | 0 | 22,576 | 35,446 | 36,180 | 36,929 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **131,132** | **98,245** |
| ***TOTAL - IT Systems and Integration*** | ***0*** | ***0*** | ***22,576*** | ***35,446*** | ***36,180*** | ***36,929*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***131,132*** | **98,245** |
| **Business Program Management** | | | | | | | | | | | | | | | | | | | | | | |
| Organizational Change Management | 0 | 0 | 156,274 | 283,572 | 217,081 | 184,646 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **841,573** | **636,577** |
| ***TOTAL - Program Management*** | ***0*** | ***0*** | ***156,274*** | ***283,572*** | ***217,081*** | ***184,646*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***0*** | ***841,573*** | **636,577** |
| **TOTAL O&M** | **14,600** | **22,328** | **223,278** | **383,926** | **349,694** | **410,382** | **183,039** | **197,362** | **202,315** | **207,401** | **212,625** | **217,989** | **223,499** | **229,158** | **234,971** | **240,943** | **247,077** | **253,379** | **259,854** | **266,506** | **4,580,325** | **2,431,676** |
| | | | | | | | | | | | | | | | | | | | | | | |
| **GRAND TOTAL CAPITAL & O&M** | **55,673** | **882,695** | **7,745,981** | **12,146,062** | **10,807,651** | **9,597,920** | **183,039** | **197,362** | **202,315** | **207,401** | **212,625** | **217,989** | **223,499** | **229,158** | **234,971** | **240,943** | **247,077** | **253,379** | **259,854** | **266,506** | **44,412,100** | **32,613,318** |

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | TOTAL | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **OTHER BENEFITS** | | | | | | | | | | | | | | | | | | | | | | |
| **Energy Savings** | | | | | | | | | | | | | | | | | | | | | | |
| Energy Reduction | 0 | 0 | 165,891 | 423,491 | 910,125 | 1,577,997 | 1,904,520 | 1,963,148 | 2,014,173 | 2,063,569 | 2,041,390 | 1,994,758 | 2,019,200 | 2,085,180 | 2,025,146 | 2,026,282 | 2,185,792 | 2,206,891 | 2,172,820 | 2,129,363 | **31,909,736** | $14,934,748 |
| Loss Savings | 0 | 0 | 3,155 | 8,234 | 18,167 | 32,238 | 39,806 | 41,776 | 43,440 | 44,870 | 45,454 | 45,229 | 46,713 | 49,088 | 48,089 | 48,350 | 52,370 | 53,018 | 52,442 | 52,442 | **724,883** | $333,272 |
| ***Total Fuel Savings*** | 0 | 0 | 169,046 | 431,724 | 928,293 | 1,610,235 | 1,944,326 | 2,004,924 | 2,057,613 | 2,108,438 | 2,086,844 | 2,039,988 | 2,065,913 | 2,134,268 | 2,073,236 | 2,074,632 | 2,238,162 | 2,259,909 | 2,225,262 | 2,181,806 | **32,634,620** | $15,268,020 |
| **Carbon Emissions Benefits** | | | | | | | | | | | | | | | | | | | | | | |
| Carbon Reduction | 0 | 0 | 94,698 | 230,703 | 479,367 | 643,180 | 656,339 | 645,988 | 537,529 | 340,791 | 312,713 | 309,097 | 303,111 | 284,879 | 316,482 | 328,421 | 341,160 | 345,262 | 349,364 | 353,466 | **6,872,548** | $3,599,824 |
| ***Total Carbon Emissions Savings*** | 0 | 0 | 94,698 | 230,703 | 479,367 | 643,180 | 656,339 | 645,988 | 537,529 | 340,791 | 312,713 | 309,097 | 303,111 | 284,879 | 316,482 | 328,421 | 341,160 | 345,262 | 349,364 | 353,466 | **6,872,548** | $3,599,824 |
| **TOTAL OTHER BENEFITS** | **0** | **0** | **263,744** | **662,427** | **1,407,660** | **2,253,415** | **2,600,664** | **2,650,912** | **2,595,141** | **2,449,229** | **2,399,557** | **2,349,085** | **2,369,024** | **2,419,147** | **2,389,718** | **2,403,054** | **2,579,322** | **2,605,171** | **2,574,626** | **2,535,271** | 39,507,168 | **$18,867,844** |
| **DEMAND BENEFITS** | | | | | | | | | | | | | | | | | | | | | | |
| Deferral of Capital Investments As Demand Reduction | 0 | 0 | 45,106 | 113,532 | 227,415 | 386,537 | 456,612 | 457,807 | 459,632 | 460,716 | 460,890 | 465,302 | 468,166 | 470,601 | 475,990 | 480,620 | 485,452 | 488,836 | 495,037 | 489,665 | **7,387,915** | $3,481,566 |
| **TOTAL DEMAND** | **0** | **0** | **45,106** | **113,532** | **227,415** | **386,537** | **456,612** | **457,807** | **459,632** | **460,716** | **460,890** | **465,302** | **468,166** | **470,601** | **475,990** | **480,620** | **485,452** | **488,836** | **495,037** | **489,665** | 7,387,915 | **$3,481,566** |
| **GRAND TOTAL DEMAND & OTHER BENEFITS** | **0** | **0** | **308,850** | **775,959** | **1,635,075** | **2,639,951** | **3,057,277** | **3,108,719** | **3,054,774** | **2,909,945** | **2,860,447** | **2,814,387** | **2,837,189** | **2,889,748** | **2,865,708** | **2,883,673** | **3,064,774** | **3,094,007** | **3,069,663** | **3,024,937** | 46,895,083 | **$22,349,410** |

***NSPM IVVO- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **22** |
| Other Benefits | 19 |
| CAP Benefits | 3 |
| **Costs** | **(39)** |
| O&M Expense | (2) |
| Change in Revenue Requirement | (37) |
| **Benefit/Cost Ratio (DVO 1.25% O&M; 0.7% capital)** | **0.57** |

| RATIO BASE (DVO Savings 1.25% O&M, 0.7% CAP) | VALUE |
|---|---|
| FAN(5% WiMax)+ Contingencies | **0.57** |
| FAN(5% WiMax) NO Contingencies | **0.61** |

| RATIO LOW SENSITIVITY (DVO Savings 1% O&M, 0.6% CAP) | VALUE |
|---|---|
| FAN(5% WiMax)+ Contingencies | **0.46** |
| FAN(5% WiMax) NO Contingencies | **0.49** |

| RATIO HIGH SENSITIVITY (DVO Savings 1.5% O&M, 0.8% CAP) | VALUE |
|---|---|
| FAN(5% WiMax)+ Contingencies | **0.67** |
| FAN(5% WiMax) NO Contingencies | **0.72** |

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | TOTAL | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Total Meters Replaced* | *10,131* | *7,368* | *121,800* | *630,000* | *590,000* | *40,700* | *13,755* | *13,890* | *14,027* | *14,164* | *14,304* | *14,444* | *14,586* | *14,729* | *14,874* | *15,020* | *15,168* | ***1,558,960*** | |
| **OTHER BENEFITS** | | | | | | | | | | | | | | | | | | | |
| **Load Flexibility Benefits** | | | | | | | | | | | | | | | | | | | |
| Critical Peak Pricing -CPP-DSM Peak | 0 | 0 | 0 | 0 | 0 | 19,965,050 | 20,415,850 | 21,129,600 | 21,780,000 | 22,361,590 | 23,136,860 | 23,755,800 | 24,531,638 | 25,336,224 | 26,164,958 | 27,023,654 | 27,910,308 | **283,511,530** | **138,479,332** |
| Time Of Usage-TOU-Customer energy price shift | 0 | 0 | 0 | 0 | 0 | 1,819,116 | 1,975,194 | 2,019,888 | 2,037,750 | 2,133,144 | 2,262,273 | 2,392,520 | 2,517,599 | 2,573,992 | 2,725,849 | 2,753,107 | 2,780,638 | **27,991,070** | **13,576,886** |
| Time Of Usage-TOU-Avoided CO2 Emissions | 0 | 0 | 0 | 0 | 0 | 226,876 | 352,119 | 485,400 | 361,972 | 230,903 | 344,421 | 271,720 | 330,772 | 309,477 | 297,166 | 310,767 | 413,652 | **3,935,245** | **1,961,868** |
| ***TOTAL - Load Flexibility Benefits*** | 0 | 0 | 0 | 0 | 0 | 22,011,042 | 22,743,163 | 23,634,888 | 24,179,722 | 24,725,637 | 25,743,554 | 26,420,040 | 27,380,008 | 28,219,692 | 29,187,972 | 30,087,528 | 31,104,598 | ***315,437,845*** | ***154,018,085*** |
| **TOTAL OTHER BENEFITS** | **0** | **0** | **0** | **0** | **1,848,467** | **25,792,193** | **30,477,932** | **31,546,259** | **32,271,937** | **33,003,045** | **34,210,616** | **35,081,332** | **36,240,224** | **37,283,648** | **38,460,605** | **39,573,907** | **40,809,920** | **416,600,086** | **203,424,492** |

# The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory

**PREPARED FOR**

Xcel Energy

**PREPARED BY**

Ryan Hledik
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January 2019

THE Brattle GROUP

# Notice



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# Executive Summary

**Highlights:**

- This study estimates the amount of cost-effective demand response available in Xcel Energy's Northern States Power (NSP) service territory, including an assessment of emerging "load flexibility" programs that can capture advanced sources of value such as geo-targeted distribution investment deferral and grid balancing services.
- Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and grid balancing services, and relatively high costs of emerging DR technologies.
- In later years of the study horizon, and under conditions that are more favorable to the economics of DR, cost-effective DR potential increases significantly, exceeding the PUC's 400 MW DR procurement requirement.
- New, emerging load flexibility programs account for around 30% of the 2030 incremental DR potential estimates in this study.

## Background

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory through 2030.[1] The study addresses the Minnesota PUC's requirement that NSP "acquire no less than 400 MW of additional demand response by 2023" and "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

The scope of this study extends significantly beyond those of prior studies. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies

[1] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions.

This study also takes a detailed approach to assessing the cost-effectiveness of each DR option. While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

The Brattle Group's Load*Flex* model is used to assess NSP's emerging DR opportunities. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program, thus providing a more complete estimate of total cost-effective potential than prior methodologies.
- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. This includes accounting for the market saturation of various end-use appliances, customer segmentation based on size, and NSP's estimates of the capability of its existing DR programs.
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program, including tariff-related program limitations and an hourly representation of load control capability for each program.
- **Realistic accounting for "value stacking":** DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program and accounting for necessary tradeoffs when pursuing multiple value streams.
- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings, a review of experience and studies in other jurisdictions, and conversations with vendors.

# Findings

### Base Case

NSP currently has one of the largest DR portfolios in the country, with 850 MW of load curtailment capability (equivalent to roughly 10% of NSP's system peak). The portfolio primarily consists of an interruptible tariff program for medium and large C&I customers, and a residential air-conditioning direct load control (DLC) program. The DLC program is transitioning from utilizing a conventional compressor switch technology to instead leveraging newer smart thermostats.

There is an opportunity to tap into latent interest in the current NSP programs and grow participation in those existing programs through new marketing efforts. According to our analysis, doing so could provide 293 MW of incremental cost-effective potential by 2023. The majority of this growth could come from increased enrollment in the interruptible tariff program for the medium and large C&I segments, and from the transition to a residential air-conditioning DLC program that more heavily utilizes smart thermostat technology.

NSP's DR portfolio could also be expanded to include new programs that are not currently offered by the company. Our analysis considered eight new programs, including time-of-use (TOU) rates, critical peak pricing (CPP), home and workplace EV charging load control, timer-based water heating load control and a more advanced "smart" water heating program, behavioral DR, ice-based thermal storage, and automated DR for lighting and HVAC of commercial and industrial customers. Some of these programs could provide ancillary services and geo-targeted distribution deferral benefits, in addition to the conventional DR value streams.

Based on current expectations about the future characteristics of the NSP market, smart water heating is the only new program that we find to be cost-effective in 2023 among the emerging options described above, providing an additional 13 MW of incremental cost-effective potential. Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and frequency regulation, and relatively high costs of emerging DR technologies.

This expanded portfolio, which reflects all cost-effective DR options available to NSP across a broad range of potential use cases, would fall short of the PUC's 2023 procurement requirement. In 2023, the current portfolio plus the incremental cost-effective DR identified in this study would equate to 1,156 MW of total peak reduction capability, 154 MW short of the procurement requirement.[2]

In 2025, the potential in the expanded portfolio increases. This increase is driven primarily by the ability to begin offering time-varying rates once smart meters are fully deployed in 2024. However, it is likely that several years will be needed for smart metering-based programs to ramp up to full participation, so the incremental potential associated with these programs is still somewhat constrained in 2025. The current portfolio plus the incremental DR in the expanded portfolio equate to 1,243 MW of cost-effective DR potential in 2025.

[2] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when additionally accounting for line losses.

By 2030, NSP's cost-effective DR potential will increase further. This increase is driven primarily by the maturation of smart metering-based DR programs. Other factors contributing to the increase in cost-effective potential include a continued transition to air-conditioning load control through smart thermostats, an expansion of the smart water heating program through ongoing voluntary replacements of expiring conventional electric water heaters, and overall growth in NSP's customer base. By 2030, we estimate that NSP's current portfolio plus the incremental cost-effective DR would amount to 468 MW. New, emerging DR programs account for 33% of the incremental potential. Achieving this potential would require not only growth in existing programs, but the design and implementation of several new DR program as well.

### High Sensitivity Case

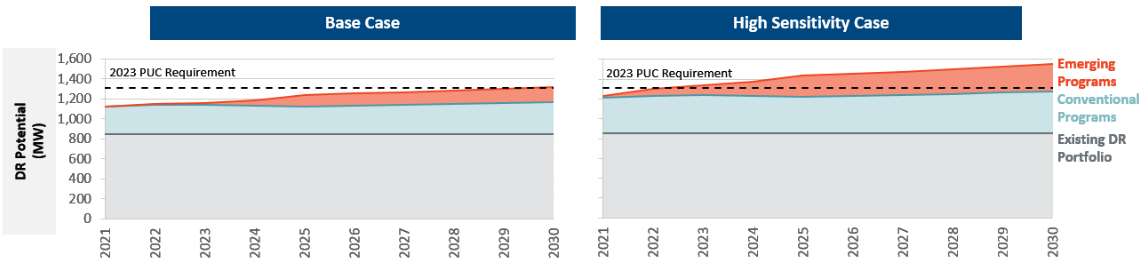
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the costs of emerging DR technologies may decline significantly, or the cost of competing resources (e.g., peaking capacity) may be higher than expected. To understand how these alternative conditions would impact DR potential, we analyzed a sensitivity case. The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. The case is <u>not</u> a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative assumptions of the High Sensitivity Case there is significantly more cost-effective incremental potential. In 2023 there is a total of 484 MW of incremental cost effective potential, which would satisfy the PUC's procurement requirement. By 2030, the total portfolio of DR programs, including the existing programs, could reach 705 MW.

The mix of cost-effective programs in the High Sensitivity case is essentially the same as in the Base Case. However, larger program benefits justify higher incentive payments, which leads to higher participation and overall potential in these programs. Auto-DR for C&I customers also presents an opportunity to increase load flexibility in the High Sensitivity Case, though the potential in this program is subject to uncertainty in technology cost and customer adoption.

Under both the Base Case and the High Sensitivity Case assumptions, avoided generation capacity costs are the primary benefit of the DR portfolio. In the High Sensitivity Case, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Figure ES-1 summarizes the DR potential estimates and benefits of the DR portfolio under Base Case and High Sensitivity Case assumptions.

**Figure ES-1: NSP's DR Potential and Annual Portfolio Benefits**




2030 Avoided Cost ($M/yr)

Base Case

| | Energy | Generation Capacity | System Average T&D Deferral | Geotargeted Distribution Deferral | Frequency Regulation | Total |
|---|---|---|---|---|---|---|
| Conventional Programs | $5.0 | $43.6 | $2.8 | $0.0 | $0.0 | $51.4 |
| Emerging Programs | $5.7 | $7.4 | $0.4 | $0.0 | $1.2 | $14.7 |
| Total | $10.7 | $50.9 | $3.2 | $0.0 | $1.2 | $66.1 |

High Sensitivity Case

| | Energy | Generation Capacity | System Average T&D Deferral | Geotargeted Distribution Deferral | Frequency Regulation | Total |
|---|---|---|---|---|---|---|
| Conventional Programs | $8.6 | $69.7 | $3.3 | $0.0 | $0.0 | $81.5 |
| Emerging Programs | $19.6 | $19.5 | $0.8 | $0.7 | $4.6 | $45.2 |
| Total | $28.2 | $89.2 | $4.0 | $0.7 | $4.6 | $126.8 |

An expanded portfolio of DR programs will have operational flexibility beyond the capabilities of conventional existing programs. For instance, load flexibility programs could be dispatched to reduce the system peak, but also to address local peaks on the distribution system which may occur during later hours of the day. Off-peak load building through electric water heating could help to mitigate wind curtailments and take advantage of negative energy prices. The provision of frequency regulation from electric water heaters could further contribute to renewables integration value.

Specific recommendations for acting on the findings of this study including the following:

- Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program.
- Pilot and deploy a smart water heating program. As a complementary activity, evaluate the impacts of switching from gas to electric heating, accounting for the grid reliability benefits associated with this flexible source of load.
- Prior to the smart metering rollout, build the foundation for a robust offering of time-varying rates, including identifying rate options that could be offered on an opt-out basis.
- Develop measurement & verification (M&V) 2.0 protocols to ensure that program impacts are dependable and can be integrated meaningfully into resource planning efforts.
- Design programs with peak period flexibility, to be able to respond to changes such as a shifts in the net peak due to solar PV adoption, or a shift in the planning emphasis from a focus on the MISO peak to a focus on more local peaks, for instance.

# I. Introduction

## Purpose

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory.[3] Xcel Energy commissioned this study to satisfy the requirements of the Minnesota Public Utilities Commission (PUC) Order in Docket No. E-002/RP-15-21. That Order, established in January 2017, required NSP to "acquire no less than 400 MW of additional demand response by 2023" and to "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

## Background

The Brattle Group conducted an assessment of NSP's DR potential in 2014.[4] That study specifically addressed opportunities to reduce NSP's system peak demand. As such, the assessment had a primary focus on "conventional" DR programs that are utilized infrequently to mitigate system reliability concerns. The study also included price-based DR options that would be enabled by the eventual deployment of smart meters.

The scope of this 2018 study extends significantly beyond that of the 2014 study. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions. The Brattle Group's Load*Flex* model is used to assess these emerging opportunities.

[3] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

[4] Ryan Hledik, Ahmad Faruqui, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," prepared for Xcel Energy, April 2014.

This 2018 study also extends beyond the scope of the 2014 study by evaluating the cost-effectiveness of each DR option.[5] While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A utility with significant market penetration of solar PV may find the most value in advanced load shifting capabilities that address evening generation ramping issues on a daily basis, whereas a system with a near-term need for peaking capacity may find more value in the types of conventional DR programs that reduce the system peak during only a limited number of hours per year. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

This report summarizes the key findings of The Brattle Group's assessment of NSP's DR market potential. Additional detail on methodology and results is provided in the appendices.

# NSP's Existing DR Portfolio

The capability of NSP's existing DR portfolio is substantial. It is the eighth largest portfolio among all US investor-owned utilities when DR capability is expressed as a percentage of peak demand. The portfolio is the largest in MISO in terms of total megawatt capability, and second when expressed as a percentage of peak demand.

As of 2017, Xcel Energy had 850 MW of DR capability across its NSP service territory, accounting for roughly 10 percent of system peak demand. This capability comes primarily from two programs. The largest is an "interruptible tariff" program, which provides commercial and industrial (C&I) customers with energy bill savings in return for a commitment to curtail electricity demand to pre-established levels when called upon by the utility. Roughly 11 percent of the peak-coincident demand of medium and large C&I customers is enrolled in this program.

The second program is NSP's Saver's Switch program. Saver's Switch is a conventional residential load control program, in which the compressor of a central air-conditioning unit or the heating element of an electric resistance water heater is temporarily cycled off to reduce electricity demand during DR events. Saver's Switch is one of the largest such programs in the country. Roughly 52 percent of all eligible residential customers (i.e., those with central air-conditioning) are enrolled in the program, accounting for around 29% of all of NSP's residential customers. Saver's Switch is gradually being transitioned to a program based on newer smart thermostat technology, called "A/C Rewards." A/C Rewards contributes an additional 2 MW to

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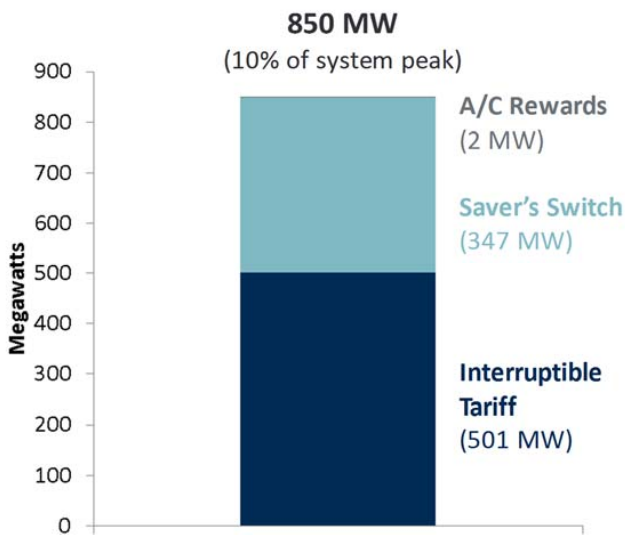
[5] The 2014 study developed a "supply curve" of DR options available to NSP as inputs to its integrated resource plan (IRP), but did not explicitly evaluate the extent to which those options would be less costly than serving electricity demand through the development of new generation resources.

NSP's existing DR capability, though this is expected to grow significantly in coming years. A summary of NSP's DR portfolio is provided in Figure 1.

**Figure 1: NSP 2017 DR Capability**




Sources: NSP 2017 DR program data and 2017 NSP system peak demand (8,546 MW)

# Important Considerations

The focus of this study is on quantifying the amount of cost-effective DR capability that can be achieved above and beyond NSP's current 850 MW DR portfolio. We estimate the incremental DR potential that can be achieved through an expansion of existing program offerings, the introduction of new programs, and consideration of a broad range of potential system benefits that are available through DR. Specifically, this study is structured to quantify all DR potential that satisfies the following three conditions:

1. **Incremental:** All quantified DR potential is incremental to NSP's existing 850 MW DR portfolio.[6]

2. **Cost-effective:** The present value of avoided resource costs (i.e., benefits) must outweigh program costs, equipment costs, and incentives.

[6] For the purposes of this analysis, all incremental potential estimates assume NSP's portfolio of existing programs continues to be offered as currently designed in future years, and that the 850 MW impact persists throughout the forecast horizon.

3. **Achievable:** Program enrollment rates are based on primary market research in NSP's service territory and supplemented with information about utility experience in other jurisdictions.

The findings of this study should be interpreted as a quantitative screen of the DR opportunities available to NSP. Further development of individual programs, and testing of the programs through pilots, will provide additional insight regarding the potential benefits and costs that such programs may offer to NSP and its customers when deployed on a full scale basis.

# II. Methodology

This study analyzes three ways to increase the capability of NSP's existing DR portfolio. First, we assess the potential to increase enrollment in existing programs. Increased enrollment could be achieved through targeted program marketing efforts, for example. Second, the menu of DR programs offered to customers could be expanded to include new, non-conventional options. These non-conventional options include emerging "load flexibility" programs which go beyond peak shaving to provide around-the-clock decreases and increases in system load. Third, consistent with the introduction of more flexible DR programs, we consider a broadened list of potential benefits in the cost-effectiveness screening process, such as ancillary services and geographically-targeted deferral of distribution capacity upgrades.

## Conventional DR Programs

Our analysis considers conventional DR programs that have been offered by utilities for many years, including in some cases by NSP.

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch on the compressor. The modeled program is based on NSP's Savers Switch program.

- **Smart thermostats:** An alternative to conventional DLC, smart thermostats allow the temperature setpoint to be remotely controlled to reduce A/C usage during peak times. The modeled program is based on NSP's A/C Rewards program, which provides customers with options to use their own thermostat, self-install a thermostat purchased from NSP's online store, or use a NSP-installed thermostat. Smart thermostat programs are based on newer technology than the other "conventional" DR programs in this list, but included here as the program is already offered by NSP.

- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate.

- **Demand bidding:** Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty. While a conventional option, demand bidding is not currently offered by NSP.

# Non-conventional DR Programs

Pricing programs are one type of non-conventional DR option. We consider two specific time-varying rate options which generally span the range of impacts that can be achieved through pricing programs: A static time-of-use rate and a dynamic critical peak pricing rate.

- **Time-of-use (TOU) rate:** Currently being piloted by NSP for residential customers and offered on a full-scale basis to C&I customers. Static price signal with higher price during peak hours (assumed 5-hour period aligned with system peak) on non-holiday weekdays. Modeled as being offered on an opt-in and an opt-out (default) basis. The study also includes an optional TOU rate for EV charging.

- **Critical peak pricing (CPP) rate:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1/kWh) during peak hours on 10 to 15 days per year. CPP rates are modeled as being offered on both an opt-in and an opt-out (default) basis.

The second category of non-conventional DR programs relies on a variety of advanced behavioral and technological tools for managing customer electricity demand.

- **Behavioral DR:** Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

- **EV managed charging:** Using communications-enabled smart chargers allows the utility to shift charging load of individual EVs plugged-in from on-peak to off-peak hours. Customers who do not opt-out of an event receive a financial incentive. The managed EV charging program was modeled on three recent pilots: PG&E (with BMW), United Energy (Australia), and SMUD. Allows curtailment of charging load for up to three hours per day, fifteen days per year. Impacts were modeled for both home charging and workplace charging programs.

- **Timed water heating:** The heating element of electric resistance water heaters can be set to heat water during off-peak hours of the day. The thermal storage capabilities of the water tank provide sufficient hot water during peak hours without needing to activate the heating element.

- **Smart water heating:** Offers improved flexibility and functionality in the control of the heating element in the water heater. The thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. Modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

- **Ice-based thermal storage:** Commercial customers shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day.

- **C&I Auto-DR:** Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting (both luminaire and zonal lighting options).

## DR Benefits

This study accounts for value streams that are commonly included in assessments of DR potential:

- **Avoided generation capacity costs:** The need for new peaking capacity can be reduced by lowering system peak demand. Important considerations when estimating the equivalence of DR and a peaking generation unit are discussed later in this section of the report.

- **Reduced peak energy costs:** Reducing load during high priced hours leads to a reduction in energy costs. Our analysis estimates net avoided energy costs, accounting for costs associated with the increase in energy consumption during lower cost hours due to "load building." The energy benefit accounts for avoided average line losses. Our analysis likely includes a conservative estimate of this value, as peak line losses are greater than off-peak line losses. Our analysis does not include the effect of any potential change in energy market prices that may result from changes in load patterns (sometimes referred to as the "demand response induced price effect," or DRIPE). It is simply a calculation of reduced resource costs.

- **System-wide deferral of transmission and distribution (T&D) capacity costs.** System-wide reductions in peak demand can, on average, contribute to the reduced need for peak-driven upgrades in T&D capacity. We account for this potential value using methods that were established in a recent Minnesota PUC proceeding.[7]

This study also accounts for value streams that can be captured through more advanced DR programs:

- **Geo-targeted distribution capacity investment deferral:** DR participants may be recruited in locations on the distribution system where load reductions would defer the need for capacity upgrades. NSP's 5-year distribution plan was used to identify candidate deferral projects, and qualifying DR programs were evaluated based on their ability to contribute to the deferral.[8]

- **Ancillary services:** The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service (albeit with limited system need).

- **Load building / valley filling:** Load can be shifted to off-peak hours to reduce wind curtailments or take advantage of low or negatively priced hours. DR was dispatched against hourly energy price series to capture the economic incentive that energy prices provide for this service.

Figure 2 summarizes the ways in which this assessment of DR potential extends the scope of prior studies in Minnesota and other jurisdictions. In the figure, "X" indicates the value streams that each DR program is assumed to provide.

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7 Minnesota PUC Docket No. E999/CIP-16-541.

8 The distribution plan was in-development at the time of our analysis. Distribution data was provided to Brattle in March 2018.

**Figure 2: Options for Expanding the Existing DR Portfolio**

1 Increase enrollment in the conventional portfolio

2 Extend DR value streams

3 Include non-traditional DR options

| | Generation capacity avoidance | Reduced peak energy costs | System peak related T&D deferral | Targeted distribution capacity deferral | Valley filling/ Load building | Ancillary services |
|---|---|---|---|---|---|---|
| Direct load control (DLC) | X | X | X | | | |
| Interruptible tariff | X | X | X | | | |
| Demand bidding | X | X | X | | X | |
| Smart thermostat | X | X | X | | | |
| Time-of-use (TOU) rates | X | X | X | | | |
| Dynamic pricing | X | X | X | | | |
| Behavioral DR | X | X | X | | | |
| EV managed charging | X | X | X | X | X | |
| Smart water heating | X | X | X | | X | X |
| Timed water heating | X | X | X | | X | |
| Ice-based thermal storage | X | X | X | X | X | |
| C&I Auto-DR | X | X | X | X | X | X |

Notes: "X" indicates the value streams that each DR option is assumed to be able to provide.

# Defining DR Potential

We use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to determine the cost-effectiveness of the incremental DR portfolio. The UCT determines whether a given DR program will increase or decrease the utility's revenue requirement. This is the same perspective that utilities take when deciding whether or not to invest in a supply-side resource (e.g., a combustion turbine) through the IRP process.[9] Since the purpose of this DR potential study is to determine the amount of DR that should be included in the IRP, the UCT was determined to be the appropriate perspective. Major categories of benefits and costs included in the UCT are summarized Table 1.

[9] According to the National Action Plan for Energy Efficiency: "The UCT is the appropriate cost test from a utility resource planning perspective, which typically aims to minimize a utility's lifecycle revenue requirements."

**Table 1: Categories of Benefits and Costs included in the Utility Cost Test**

| Benefits | Costs |
|---|---|
| Avoided generation capacity | Incentive payments |
| Avoided peak energy costs | Utility equipment & installation |
| Avoided transmission capacity | Administration/overhead |
| Avoided distribution capacity | Marketing/promotion |
| Ancillary services | |

Throughout this study, we quantify DR potential in two different ways:

**Technical Potential:** Represents achievable potential without consideration for cost-effectiveness. In other words, this is a measure of DR capability that could be achieved from anticipated enrollment associated with a moderate participation incentive payment, regardless of whether or not the incentive payment and other program costs exceed the program benefits. As it is used here, the term "technical potential" differs from its use in energy efficiency studies. Technical potential in energy efficiency studies assumes 100% participation, whereas we assume an achievable level of participation in this assessment of DR potential.

**Cost-effective Potential:** Represents the portion of technical potential that can be obtained at cost-effective incentive payment levels. For each program, the assumed participation incentive payment level is set such that the benefit-cost ratio is equal to 1.0. Participation rates are estimated to align with this incentive payment level. When non-incentive costs (e.g., equipment and installation costs) are found to outweigh the benefits alone, the benefit-cost ratio is less than 1.0 and there is no opportunity to offer a cost-effective participation incentive payment. In that case, the program is considered to have no cost-effective potential.

## The Load*Flex* Model

The Brattle Group's Load*Flex* model was used to estimate DR potential in this study. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to NSP's experience with DR programs where available (e.g., impacts from existing DLC programs or dynamic pricing pilots).

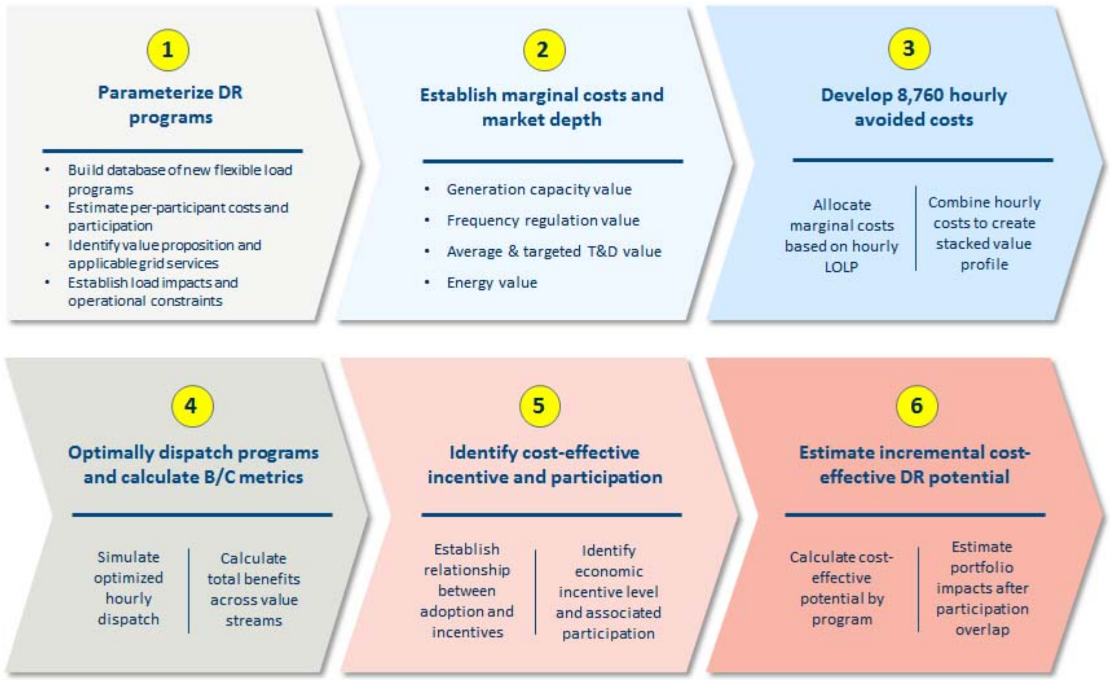
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local transmission or distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies of load flexibility value have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* modeling framework is organized around six steps, as summarized in Figure 3. Appendix A provides detail on the methodology behind each of these steps.

**Figure 3: The Load*Flex* Modeling Framework**




# Modeling Scenarios

The value that DR will provide depends on the underlying conditions of the utility system in which it is deployed. Generation capacity costs, the anticipated need for new transmission and distribution (T&D) assets, and energy price volatility are a few of the factors that will determine DR value and potential. To account for uncertainty in NSP's future system conditions, we considered two modeling scenarios: A "Base Case" and a "High Sensitivity Case."

The **Base Case** most closely aligns with NSP's expectations for future conditions on its system, as defined in its IRP. The Base Case represents a continuation of recent market trends, combined with information about known or planned developments during the planning horizon.

The **High Sensitivity Case** was developed to illustrate how the value of DR can change under alternative future market conditions. The High Sensitivity Case is defined by assumptions about the future state of the NSP system and MISO market that are more favorable to DR program economics. The High Sensitivity Case is not intended to be the most likely future state of the NSP system. Relative to the Base Case, the High Sensitivity Case consists of a higher assumed generation capacity cost, more volatile energy prices due to greater market penetration of renewable generation, a significant reduction in emerging DR technology costs, and an increase in the need for frequency regulation.

Defining features of the two cases are summarized in Table 2. Appendix A includes more detail on assumptions and data sources behind the two cases.

**Table 2: Defining Features of Base Case and High Sensitivity Case**

| | Base Case | High Sensitivity Case |
|---|---|---|
| **Generation capacity (Net CONE)** | $64/kW-yr (2018 NSP IRP) | $93/kW-yr (2018 EIA Annual Energy Outlook) |
| **Hourly energy price** | Based on MISO MTEP "Continued Fleet Change" case (15% wind+solar by 2032) | Based on MISO MTEP "Accelerated Fleet Change" case (30% wind+solar by 2032) |
| **Frequency regulation** | Price varies, 25 MW average need by 2030 | Price same as Base Case, 50 MW average need by 2030 |
| **System average T&D deferral** | Transmission: $3.6/kW-yr, Distribution: $9.5/kW-yr (2017 NSP Avoided T&D Study) | Same as Base Case |
| **Geo-targeted T&D deferral** | Value varies by distribution project, 90 MW eligible for deferral by 2030 | Same as Base Case |
| **DR technology cost** | 10% reduction from current levels by 2030 (in real terms) | 30% reduction from current levels by 2030 (in real terms) |

Notes: Unless otherwise specified, values shown are for year 2030 and in nominal dollars.

Modeling results are summarized for the years 2023 and 2030. 2023 is the year by which NSP must procure additional DR capability according to the Minnesota PUC's Order in Docket No. E-002/RP-15-21. The 2030 snapshot captures the potential for significant future changes in system conditions and their implications for DR value, and is consistent with the longer-term perspective of NSP's IRP study horizon. A summary of annual results, including intermediate years, is provided in Appendix D.

# Data

To develop participation, cost, and load impact assumptions for this study, we relied on a broad range of resources. Where applicable, we relied directly upon information from NSP's experience with DR programs in its service territory. We also utilized the results of primary market research that was conducted directly with customers in NSP's service territory in order to better understand their preferences for various DR program options. Where NSP-specific information was unavailable, we reviewed national data on DR programs, DR potential studies from other jurisdictions, and DR program impact evaluations. A complete list of resources is provided in the References section and described further in Appendix A.

In an assessment of emerging DR opportunities, it is important to recognize that data availability varies significantly by DR program type. Conventional DR programs, such as air-conditioning load control, have decades of experience as full-scale deployments around the US and internationally. By contrast, emerging DR programs like EV charging load control have only recently begun to be explored, largely through pilot projects. Figure 4 summarizes data availability for each of the DR program types analyzed in this study.

**Figure 4: Data Availability by DR Program Type**

| | Participation | Costs | Peak Impacts | Advanced Impacts |
|---|---|---|---|---|
| **Residential** | | | | |
| Air-conditioning DLC | ● | ● | ● | N/A |
| Smart thermostat | ● | ● | ● | N/A |
| TOU rate | ● | ● | ◑ | N/A |
| CPP rate | ● | ● | ◑ | N/A |
| Behavioral DR | ◑ | ◑ | ◑ | N/A |
| Smart water heating | ◔ | ◔ | ◑ | ◔ |
| Timed water heating | ◔ | ◔ | ◑ | ◔ |
| EV managed charging (home) | ○ | ○ | ◔ | N/A |
| EV charging TOU (home) | ○ | ○ | ◔ | N/A |
| **C&I** | | | | |
| Interruptible tariff | ● | ● | ● | N/A |
| Demand bidding | ● | ● | ● | N/A |
| TOU rate | ● | ● | ◑ | N/A |
| CPP rate | ● | ● | ◑ | N/A |
| Ice-based thermal storage | ◔ | ◔ | ◔ | ◔ |
| EV workplace charging | ○ | ○ | ◔ | N/A |
| Automated DR | ○ | ◔ | ◔ | ○ |

Notes:

● NSP-specific data, including market research, pilot programs, and full-scale deployments

◑ Signficant program experience in other jurisdictions

◔ Some pilot or demonstration project experience in other jurisdictions

○ Speculative, estimated from theoretical studies and calibrated to NSP conditions

"Advanced impacts" refers to load flexibilty capability beyond conventional peak period reductions (e.g., frequency regulation)

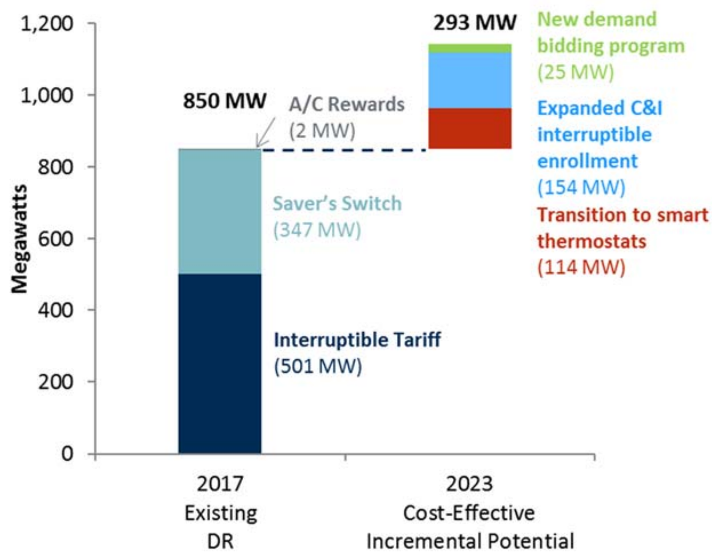
# III. Conventional DR Potential in 2023

As an initial step in the assessment of NSP's cost-effective DR potential, we analyzed the potential if NSP were to deploy a portfolio of conventional DR programs. As defined for this study, conventional programs include interruptible tariffs, air-conditioning DLC, smart thermostats, and demand bidding. These program types are currently offered by NSP, with the exception of demand bidding. Therefore, the assessment of conventional programs is largely an assessment of the potential to grow the current DR portfolio through options such as new marketing initiatives or targeted marketing toward specific customer segments. We initially focus on the year 2023, as that is the year by which the Minnesota PUC has required NSP to procure additional DR capability.[10]

Figure 5 summarizes the cost-effective potential in a conventional DR portfolio in 2023. There is 293 MW of cost-effective incremental potential. Drivers of this potential include the expanded enrollment in NSP's interruptible tariff program, greater per-participant impacts that will be achieved as NSP continues to transition from a switch-based air-conditioning DLC program to a smart thermostat-based program, overall growth in NSP's customer base between 2017 and 2023, and a modest amount of potential in a new demand bidding program.

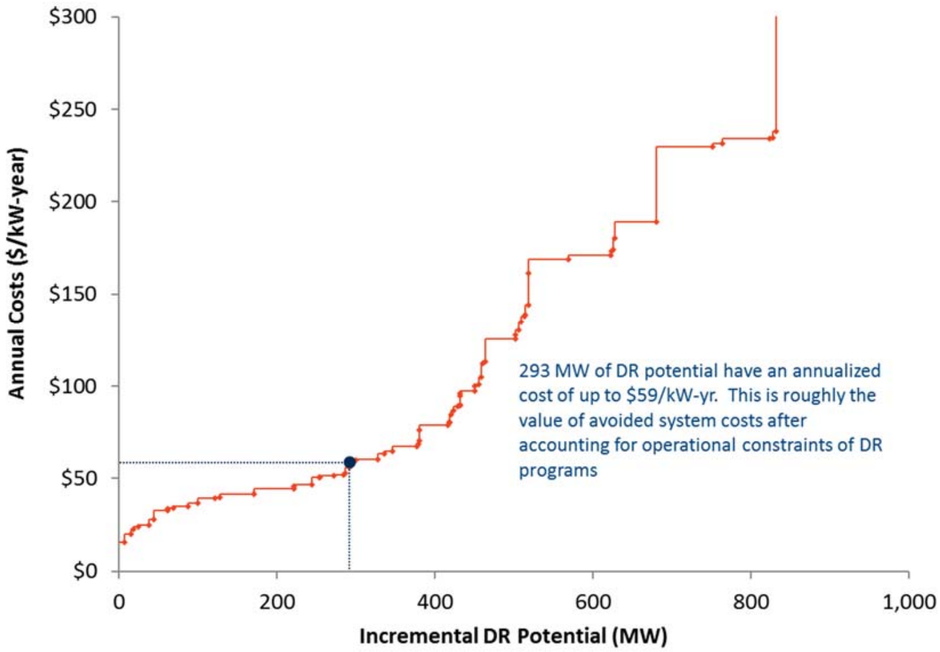
[10] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

**Figure 5: Total DR Potential in 2023 (Conventional Portfolio)**




The incremental potential in conventional DR programs can be expressed as a "supply curve." Figure 6 illustrates the costs associated with achieving increasing levels of DR capability. The upward slope of the curve illustrates how DR capability (i.e., enrollment) increases as incentive payments increase. The curve also captures the different costs and potential associated with each conventional DR program and applicable customer segment. Cost-effective DR capability is identified with the blue dotted line. There is roughly 293 MW of incremental DR potential available at a cost of less than $59/kW-year. That cost equates to the value of avoided system costs after accounting for the operational constraints of DR programs.

**Figure 6: NSP's Incremental DR Supply Curve in 2023 (Conventional Portfolio)**




Note: Supply curve shows conventional DR potential without accounting for cost-effectiveness. Potential estimates if the DR options were offered simultaneously as part of a portfolio at each price point (i.e. accounts for overlap). Program costs presented in nominal terms.

As discussed previously in this report, the Minnesota PUC has established a DR procurement requirement of 400 MW by 2023. It is important to clarify whether this 400 MW is a capacity-equivalent value, a generator-level value, or a meter-level value. Specifically, 1 MW of load reduction at the meter (or customer premise) avoids more than 1 MW at the generator level due to line losses between the generator and the customer. Further, 1 MW of load reduction at the generator level provides more than 1 MW of full capacity-equivalent value, as the load reduction would also avoid the additional capacity associated with NSP's obligation to meet the planning reserve requirement. Based on NSP's calculations, which account for line losses and the reserve requirement, 1 MW of load reduction at the meter level equates to 1.08 MW of load reduction at the generator level and 1.11 MW of capacity-equivalent value.

NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR. This equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses. These values are summarized in Table 3. Throughout this report, DR values are reported at the generator level. Thus, for consistency, we refer to the procurement requirement as a 391 MW generator-level value unless otherwise specified.

**Table 3: NSP's 2023 DR Procurement Requirement**

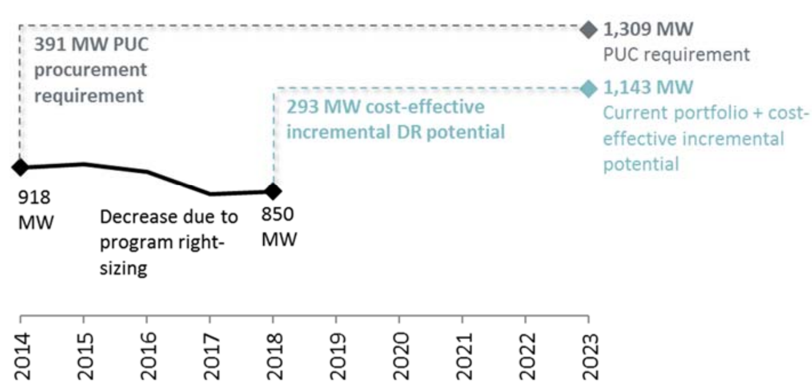
| | Requirement (MW) | Notes |
|---|---|---|
| Meter level | 361.7 | Premise-level |
| Generator level | 390.7 | Grossed up for 8% line losses |
| Capacity equivalent | 400.0 | Grossed up for line losses and reserve requirement |

Source: Calculations provided by NSP.

Our interpretation of the PUC's Order is that the required DR procurement is incremental to NSP's DR capability as it existed in 2014.[11] NSP had 918 MW of DR capability in 2014, leading to a total DR capability requirement of 1,309 MW in 2023. NSP's DR capability decreased between 2014 and 2017 largely due to an effort to ensure that enrolled load would be available for curtailment when called upon, thus leading to an incremental DR requirement that is larger than 391 MW (at the generator level).[12]

Combined with current capability of 850 MW, the incremental cost-effective DR potential in 2023 would result in a total portfolio of 1,143 MW. This estimate of cost-effective potential is 166 MW short of the PUC's DR procurement requirement. Figure 7 illustrates the gap between NSP's conventional DR potential and the DR procurement requirement.

**Figure 7: NSP DR Capability (Conventional Portfolio)**




Note: Chart is scaled such that vertical axis does not start at zero. 391 MW procurement requirement is expressed at the generator level and is equivalent to 400 MW of DR capacity.

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11 2014 is the year of NSP's prior DR potential study, which was used to inform the Minnesota PUC's establishment of the DR procurement requirement.

12 For instance, some customers did not realize that they were participating in the program and dropped out when notified, or otherwise elected to reduce their enrolled load level.

# IV. Expanded DR Potential in 2023

Given the shortfall of the conventional DR portfolio relative to the 2023 procurement target, it is relevant to consider if an expanded portfolio of DR options could mitigate the shortfall. We analyzed eight additional emerging DR programs that could be offered to up to four different customer segments (if applicable). As described in Section II, these emerging DR options include both price based programs (e.g., TOU and CPP rate designs) and technology-based programs (e.g., Auto-DR and smart water heating).

## Base Case

Among the individual measures with the most *technical potential* in 2023 are HVAC Auto-DR for Medium C&I customers and thermal storage for commercial customers. Each of these programs has technical potential in excess of 100 MW.

Pricing programs and lighting Auto-DR for C&I customers, timed water heating programs, and behavioral DR compose the next tier of opportunities, with technical potential in each ranging between 50 and 100 MW. These programs generally have the potential to reach significant levels of enrollment or, alternatively, to provide deep load reductions among a smaller share of customers.

The Small C&I segment accounts for many of the DR programs with the lowest technical potential, as there is a relatively small share of load in this segment and these customers have historically demonstrated a lower willingness to participate in DR programs.

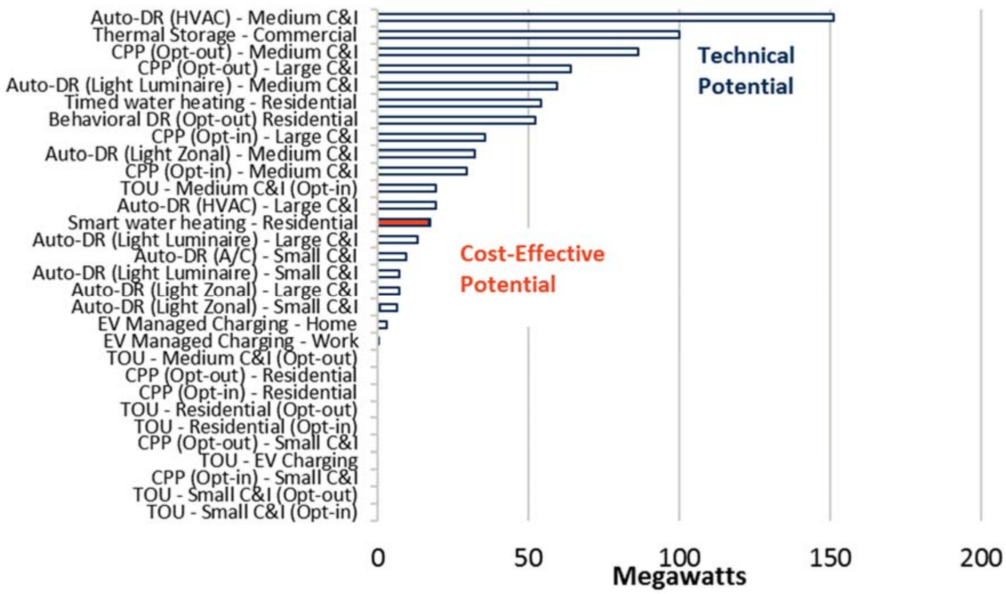
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

Pricing programs (i.e., TOU, CPP) cannot be offered on a full scale basis in 2023 to residential and small C&I customers, as AMI will not yet be fully deployed. Therefore, pricing programs have not been included in the potential estimates for 2023. Rollout of the programs is assumed to begin in 2024, upon NSP's projected completion of the AMI rollout.

Programs with significant *technical potential* do not necessarily have significant *cost-effective potential*. After accounting for cost-effectiveness under Base Case market conditions as well as technical constraints, the potential in DR programs is limited in 2023. Individually, only smart water heating and a modest amount of automated load control for C&I customers pass the cost-effectiveness screen. These programs pass the cost-effectiveness screen largely because they are capable of providing an expanded array of value streams, such as frequency regulation and geo-targeted T&D deferral.

Figure 8 summarizes the technical and cost-effective potential in each of the new DR program options. Potential is first shown for DR programs as if they were each offered in isolation.

**Figure 8: New DR Program Potential in 2023 (Base Case)**

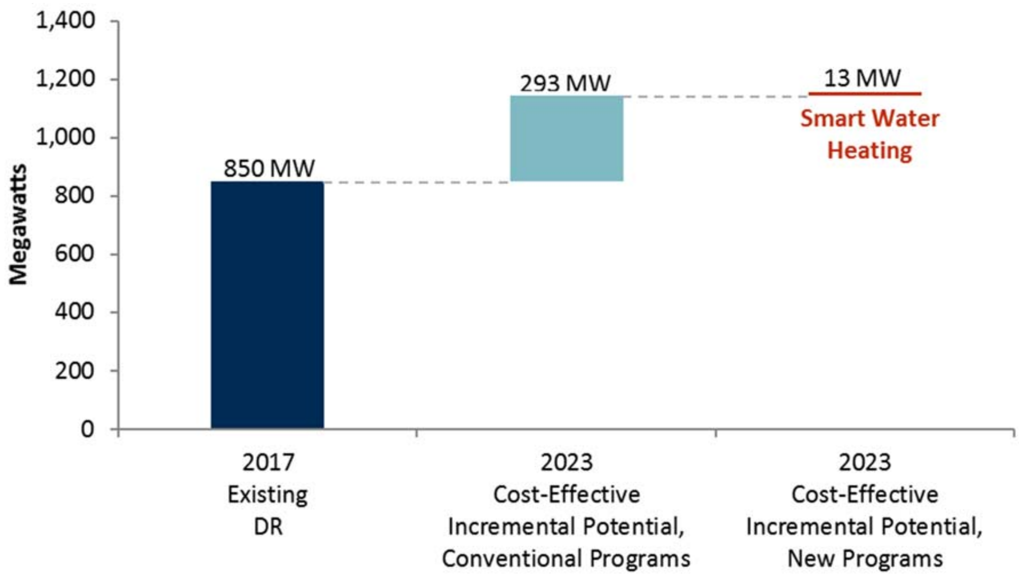



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The program-level DR impacts shown above cannot be added together to arrive at the potential capability of a DR portfolio. Adjustments must be made to account for double-counting of impacts when customers are enrolled in more than one program, and for limits on the need for certain value streams such as frequency regulation. Thus, combining the cost-effective programs into a portfolio can result in lower total potential DR capability than if the individual impacts shown above were simply summed.

In the 2023 scenario described above, the smart water heating program alone could satisfy NSP's need for frequency regulation. With that value stream no longer available to the Auto-DR program, the Auto-DR program fails the cost-effectiveness screen. **With the addition of the smart water heating program, NSP's cost-effective DR portfolio would increase by 13 MW. Achievement of all cost-effective DR potential would amount to total system-wide DR capability of 1,156 MW, but would still fall short of the PUC's procurement target by 154 MW.** The expanded capability in 2023 is illustrated in Figure 9.

**Figure 9: Total DR Potential in 2023 (Expanded Portfolio)**




## Near-term Limitations on DR Value

The value of DR is very dependent on the characteristics of the system in which it is deployed. Several factors limit NSP's cost-effective DR in 2023, relative to other jurisdictions.

- **Low capacity prices:** NSP has access to low-cost peaking capacity, primarily due to the presence of brownfield sites that significantly reduce development costs. For instance, the all-in cost of a new combustion turbine in NSP's IRP is $63/kW-year, which is 23 percent lower than the cost of a CT assumed by the U.S. Energy Information Administration (EIA) in its Annual Energy Outlook (AEO). Similarly, a recent study approved by the Minnesota PUC determined that the average value of T&D capacity deferral achieved through reductions in customer consumption is approximately $11/kW-year in NSP's service territory.[13] This value, which was determined through a detailed bottom-up engineering assessment, is significantly lower than that of T&D deferral benefits observed in other studies, which can commonly reach values of $30/kW-year.[14] The value of T&D deferral is dependent on characteristics of the utility system and drivers of the investment need, and therefore varies significantly across utilities.

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13 Xcel Energy, "Minnesota Transmission and Distribution Avoided Cost Study," submitted to the Minnesota Department of Commerce, Division of Energy Resources (Department), July 31, 2017

14 Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

- **Metering technology limitations:** NSP has not yet deployed AMI, with an estimated forecast that system-wide AMI installation will be completed in 2024. AMI-based DR programs, such as time-varying rates and behavioral DR, cannot be offered to customers until deployment is complete. This effectively excludes the possibility of introducing any AMI-based programs in the year 2023.

- **High DR technology costs:** Some emerging DR programs depend on new technologies that have not yet experienced the cost declines that could be achieved at scale. While these technology costs could decrease over time, those reductions are not achieved in the early years of the study horizon.

- **Limited need for additional DR value streams:** While certain DR value streams potentially can be very valuable, these value streams can also be limited in need. For instance, our analysis of NSP's five-year distribution plan identified only 38 MW of projects that were potential candidates for geo-targeted capacity investment deferral. Those projects accounted for roughly 10 percent of the total value of NSP's plan. To qualify, projects need to satisfy criteria such as being driven by growth in demand and being of a certain size.[15] Similarly, while frequency regulation is often a highly-valued ancillary service and can be provided by certain types of DR, the need for frequency regulation across most markets is significantly less than one percent of system peak demand. This limits the amount of that value stream that can be provided by DR.

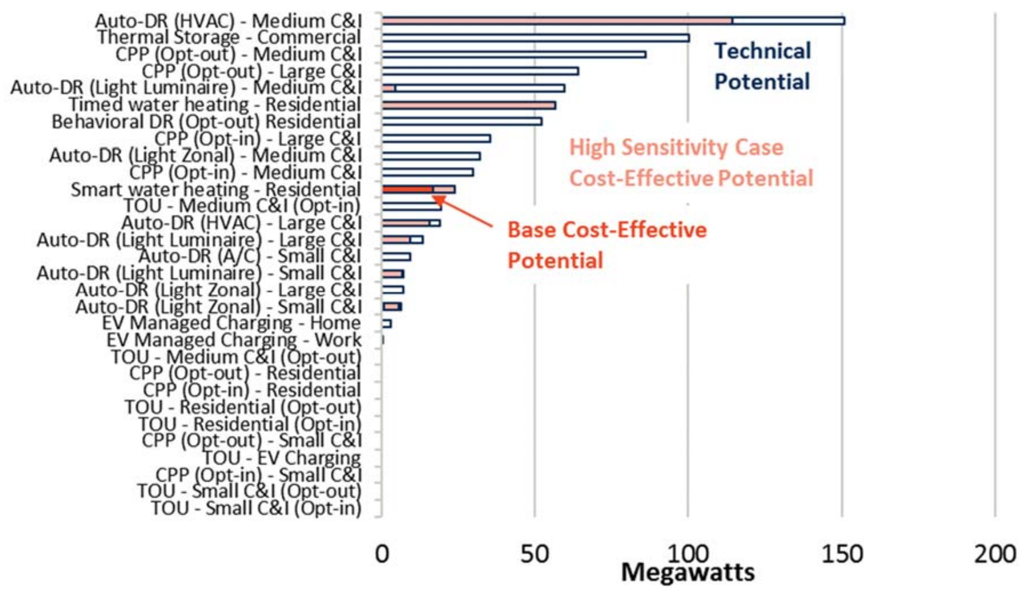
## High Sensitivity Case

The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. As discussed earlier in this report, assumptions behind the High Sensitivity Case are not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative High Sensitivity Case assumptions, cost-effective DR potential increases significantly. Several programs that were not previously passing the cost-effectiveness screen, such as medium C&I HVAC-based Auto DR, residential timed water heating, and a small amount of lighting-based Auto-DR do pass the screen under the more favorable assumptions in this case. Figure 10 summarizes the increase in cost-effective potential at the individual program level.

[15] Details of the geo-targeted T&D deferral analysis are included in Appendix A.

**Figure 10: New DR Program Potential in 2023 (High Sensitivity Case)**




Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

A DR portfolio constructed from cost-effective programs in the High Sensitivity Case would produce total incremental DR potential of 484 MW in 2023. Under the illustrative assumptions in this case, the cost-effective incremental portfolio would consist of 393 MW of conventional DR programs, and 91 MW of new DR programs. The portfolio of new DR programs includes residential smart water heating[16] (24 MW) and C&I HVAC-based Auto-DR (67 MW). Achievement of all cost-effective DR potential under the High Sensitivity Case would amount to total system-wide DR capability of 1,334 MW.

[16] Smart water heating has lower cost-effective potential in 2023 than timed water heating. However, the smart water heating program provides more value and more significant per-participant impacts as participation ramps up in the later years of the study horizon, so it is the water heating program that was included in the portfolio.

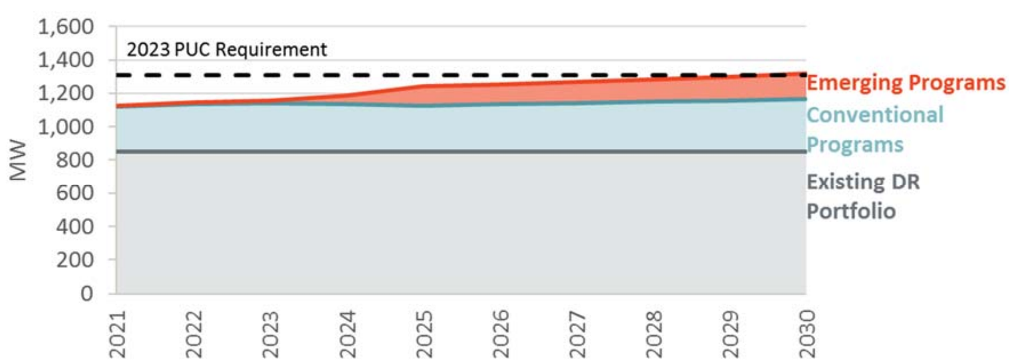
# V. Expanded DR Potential in 2030

## Base Case

Opportunities to expand cost-effective DR portfolio will grow beyond 2023. Most significantly, time-varying rates (such as TOU and CPP rates) can be offered to customers following completion of the AMI rollout in 2024. Additionally, the customer base is projected to grow over the study horizon, expanding the population of customers eligible to participation in DR programs. Growth in the market penetration of renewable generation will likely lead to more volatility in energy costs, further creating opportunities for DR to provide value. Additionally, current participants in the Savers Switch program are expected to transition to the smart thermostat-based A/C Reward program over time. Smart thermostats provide a greater per-participant demand reduction than the technology in the Savers Switch program, therefore further increasing DR potential.

Figure 11 summarizes growth in DR potential under Base Case assumptions for the portfolio of cost-effective DR programs. The majority of the post-2023 growth comes from the introduction of time-varying pricing programs.

**Figure 11: Cost-Effective DR Potential, Base Case**




Under Base Case conditions, benefits of the DR program are primarily driven by avoided generation capacity costs. Avoided generation capacity costs account for $51 million of the $66 million (77 percent) in total annual benefits from the DR programs in the year 2030. This is because the relatively low avoided costs in the Base Case scenario tend to favor conventional DR programs which are primarily constrained to reducing the system peak, but have lower costs as a result of this somewhat limited functionality. Table 4 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the Base Case.

**Table 4: Annual Avoided Costs from 2030 DR Portfolio, Base Case ($ million/year)**

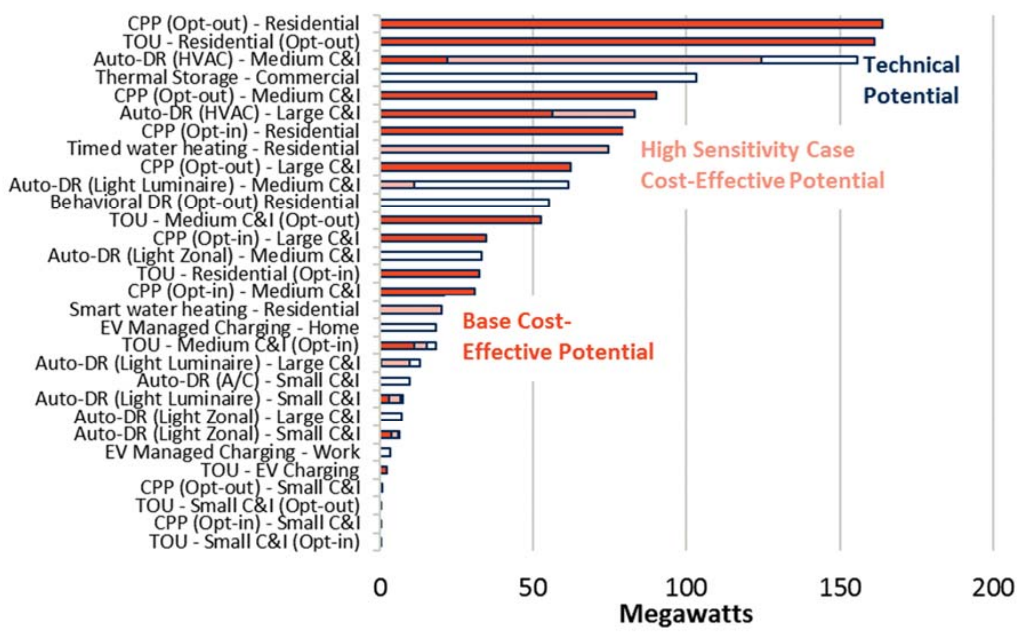
| | Energy | Generation Capacity | System Average T&D Deferral | Geotargeted Distribution Deferral | Frequency Regulation | Total |
|---|---|---|---|---|---|---|
| Conventional Programs | $5.0 | $43.6 | $2.8 | $0.0 | $0.0 | $51.4 |
| Emerging Programs | $5.7 | $7.4 | $0.4 | $0.0 | $1.2 | $14.7 |
| Total | $10.7 | $50.9 | $3.2 | $0.0 | $1.2 | $66.1 |

*Notes:* Benefits shown in 2023 dollars.

# High Sensitivity Case

Drivers of growth over time under the illustrative High Sensitivity Case conditions are similar to growth drivers under Base Case conditions, with AMI-enabled time-varying rates accounting for the majority of new opportunities after 2023. Figure 12 summarizes the 2030 incremental measure-level potential for both the Base Case and the High Sensitivity Case.

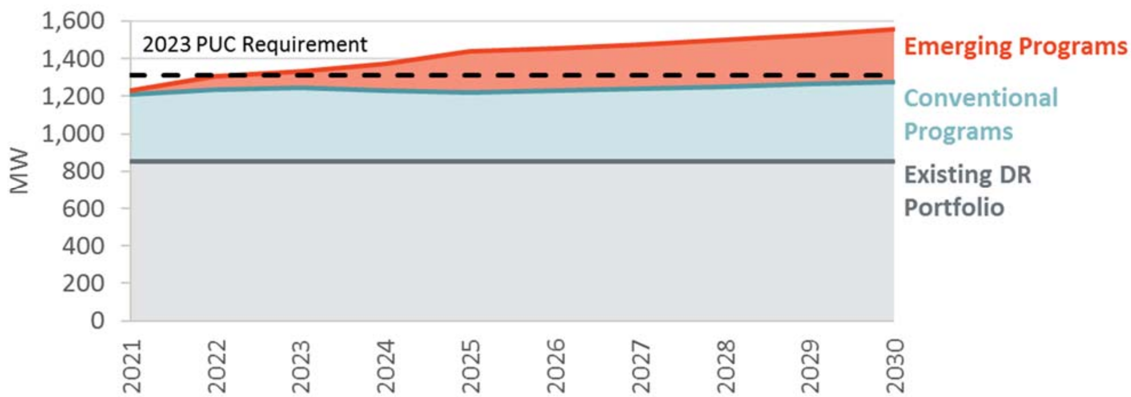
**Figure 12: New DR Program Potential in 2030**




Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The capability of the cost-effective DR portfolio for the High Sensitivity Case is summarized in Figure 13.

**Figure 13: Cost-Effective DR Potential, High Sensitivity Case**




Over the longer-term, new policies could potentially drive down DR costs and therefore increase cost-effective potential. One initiative that has garnered some attention is the development of a technology standard known as "CTA-2045." CTA-2045 is a communications interface which would allow various control technologies to connect to appliances through a standard port or socket. While widespread adoption of this standard is not considered to be imminent, it could potentially have positive implications for DR adoption in the longer term. See the Sidebar at the end of this section for further discussion of the outlook for CTA-2045.

The benefits of DR under the High Sensitivity Case assumptions continue to be driven primarily by avoided generation capacity costs. However, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Table 5 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the High Sensitivity Case.

**Table 5: Annual Avoided Costs from 2030 DR Portfolio, High Sensitivity Case ($ million/year)**

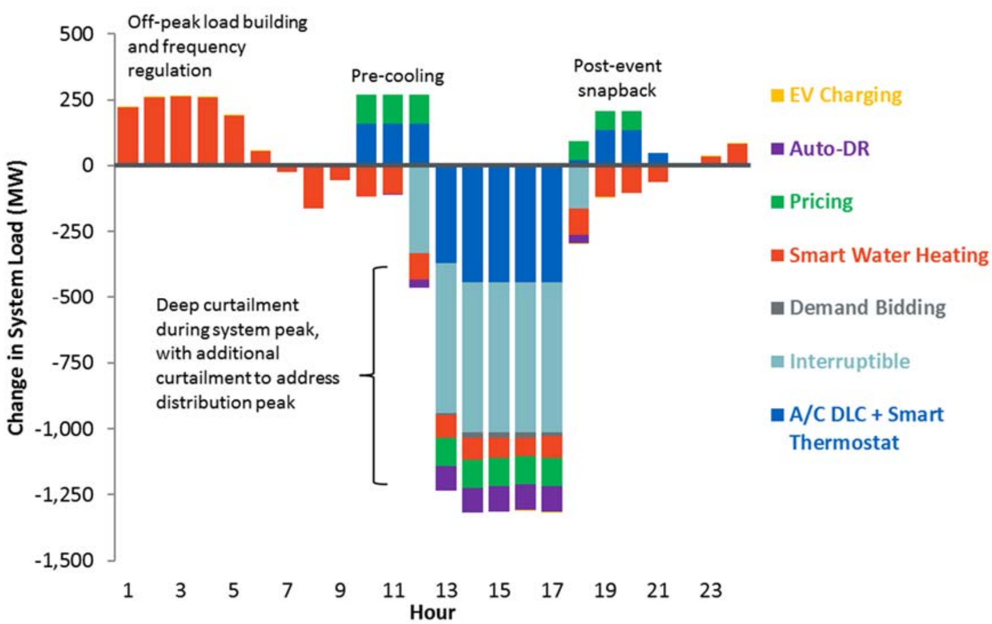
| | Energy | Generation Capacity | System Average T&D Deferral | Geotargeted Distribution Deferral | Frequency Regulation | Total |
|---|---|---|---|---|---|---|
| Conventional Programs | $8.6 | $69.7 | $3.3 | $0.0 | $0.0 | $81.5 |
| Emerging Programs | $19.6 | $19.5 | $0.8 | $0.7 | $4.6 | $45.2 |
| Total | $28.2 | $89.2 | $4.0 | $0.7 | $4.6 | $126.8 |

*Notes:* Benefits shown in 2023 dollars.

# DR Portfolio Operation

The addition of emerging programs to NSP's DR portfolio will improve operational flexibility across NSP's system. Figure 14 illustrates how the cost-effective DR portfolio from the High Sensitivity Case could operate on an hourly basis during the days of the year with the highest system peak demand. The profile shown maximizes avoided costs relative to the system cost assumptions used in this study.

**Figure 14: Average Load Impacts of the 2030 Cost-Effective DR Portfolio on Top 10 Load Days (High Sensitivity Case)**



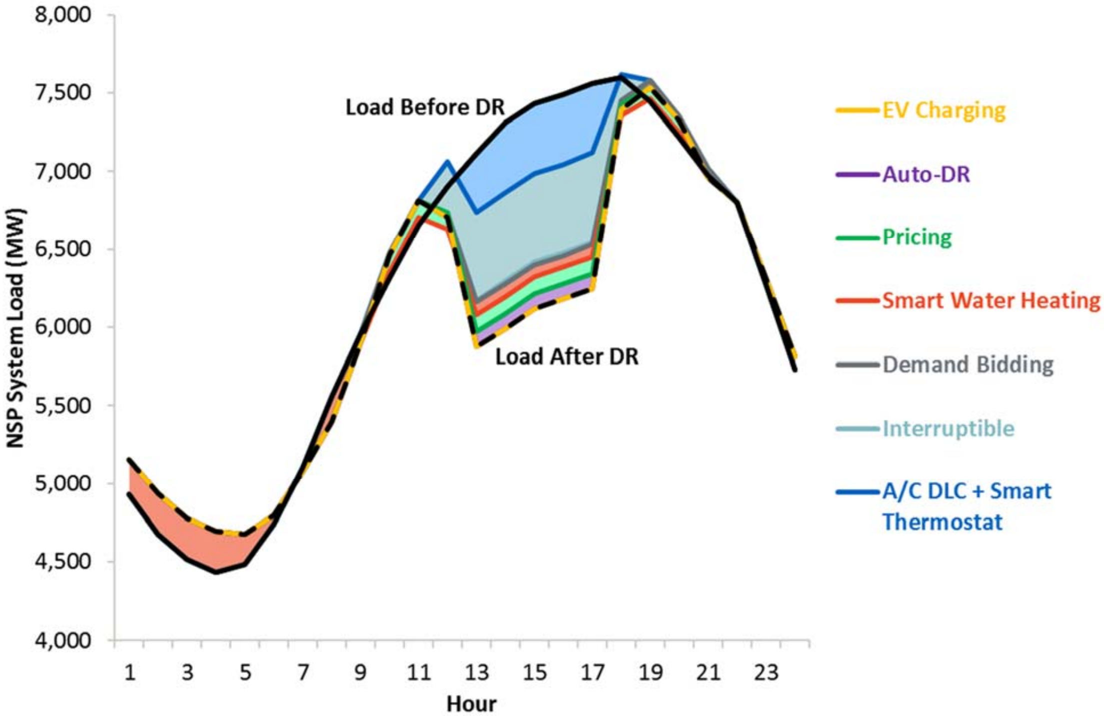

Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

A deep curtailment of load during system peak hours is utilized to capture significant generation and T&D capacity deferral benefits. These also tend to be hours when energy costs are highest, leading to additional energy value. The duration of the peak load curtailment spans a fairly broad period of time – seven hours – in order to account for the lack of coincidence of the system and local peak demand that drive capacity needs. Load curtailment can be staggered across DR programs – and across participants in a given DR program – in order to achieve this duration of demand reduction.

Load increases are observed immediately before and after the peak load reduction. This is driven mostly by the need to maintain and restore building temperatures to desired levels around DR events. The smart water heating program builds load during nighttime hours, shifting heating load to the lowest cost hours and potentially reducing the curtailment of renewable generation.

Figure 15 illustrates how NSP's system load shape changes as a result of the impacts shown in Figure 14 above. The figure shows a steep reduction in load during hours of the MISO system peak, while NSP's later peak is only modestly reduced. This is primarily due to NSP's planning needs being driven by MISO coincident peak demand. If the MISO peak shifts later in the day due to solar PV adoption, or if NSP transitions to an increased focus on its own peak demand in planning activities, then the dispatch of the DR programs would need to be modified accordingly. In particular, it may become necessary to stagger the utilization of DR programs across a broader window of hours in order to "flatten" peak demand across the hours of the day.

**Figure 15: Average Impacts of the 2030 Cost-Effective DR Portfolio on NSP System Load (High Sensitivity Case)**




Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

## Sidebar: The Outlook for CTA-2045

CTA-2045 is a standard which specifies a low-cost communications "socket" that would be embedded in electric appliances and other consumer products. If consumers wished to make an appliance capable of participating in a demand response program, they could simply plug a communications receiver into the socket, thus allowing the appliance to be controlled by themselves or a third party. CTA-2045 has the potential to establish a low-cost option for two-way communications capability in appliances, thus reducing the cost and hassle of consumer enrollment in DR programs that would otherwise require on-site installation of more costly equipment.

Development of CTA-2045 began in 2011, through work by the Consumer Technology Association (CTA) and the Electric Power Research Institute (EPRI). Refinements to the standard are ongoing. To assess the outlook for CTA-2045 and its potential implications for future DR efforts, we conducted phone and email interviews with subject matter experts from utilities, appliance manufacturers, and DR software platforms.

There is a shared view that CTA-2045 is facing a chicken-and-egg problem. Manufacturers have been hesitant to incorporate the standard into their products, because there is a cost associated with doing so and they have not yet observed demand in the market for the communications functionality. At the same time, a barrier preventing increased adoption of DR technologies could be some of the costs and installation challenges that CTA-2045 would ultimately address.

Products with CTA-2045 functionality have not yet been deployed at scale, and where available are sold at a price premium that is significantly higher than the unit costs that could ultimately be achieved at scale. The relative lack of enthusiasm among manufacturers for rolling out CTA-2045 compliant products has led to a slow pace of development of the standard itself. Progress is being made incrementally, though technical issues still remain to be resolved.

Looking forward, some in the industry feel that the mandating CTA-2045 through a new state appliance standard could be the catalyst that is needed for adoption to become broadly widespread. Aggressive support for CTA-2045 by large utilities is also considered to be the type of activity that would facilitate adoption.

If compliance with CTA-2045 ultimately were to accelerate through activities like those described above, electric water heaters are poised to become the first such commercial application, as they have been the most common test case for proving the technical concept and are an attractive source of load flexibility. Particularly in the context of water heaters, CTA-2045 would help to overcome the challenge of enrolling customers in a DR program during the very narrow window of time during which their existing water heater expires and must be replaced. Other controllable end-uses, such as thermostats or even electric vehicle chargers could be candidates for the standard, though these technologies sometimes already come pre-equipped with communications capabilities.

# VI. Conclusions and Recommendations

NSP's sizeable existing DR portfolio has the potential to be expanded by tapping into latent demand for existing programs and also by rolling out a new portfolio of emerging DR programs. Specific recommendations for acting on the findings of this study including the following:

**Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program.** NSP's relatively low avoided costs mean that lower cost, established DR programs are the most economically attractive options in the near term. Smart thermostats and a Medium C&I interruptible program present the largest incremental opportunity and the least amount of uncertainty/risk.

**Pilot and deploy a smart water heating program.** There is significant experience with advanced water heating load control in the Upper Midwest, and the technology is rapidly advancing. The thermal storage capabilities of water heaters provide a high degree of load flexibility that can be adapted to a range of system needs.

**As a complementary activity to the development of a smart water heating program, also evaluate the economics and environmental impacts of switching from gas to electric heating**, factoring in the grid reliability benefits associated with this flexible source of load. Doing so would require revisiting existing state policies that prohibit utility-incentivized fuel switching.

**Build the foundation for a robust offering of time-varying rates.** As a first step, prepare a strategy for rolling out innovative rates soon after AMI is deployed. This should include exploring rate offerings that could be deployed to customers on a default (opt-out) basis, as default rate offerings maximize the overall economic benefit for the program.

**Develop measurement & verification (M&V) 2.0 protocols** to ensure that the impacts of the program are dependable and can be integrated meaningfully into resource planning efforts. Included in this initiative could be the development of a data collection plan to enhance the quality of future market potential studies. Further, detailed customer segmentation and geographically granular load data at the distribution system level will provide an improved base from which to develop a cost-effective DR strategy.

**Design programs with peak period flexibility.** From a planning standpoint, the timing of the peak period could change for a variety of reasons (e.g., DR flattens the peak, solar PV shifts the net peak, or the planning emphasis shifts from a focus on the MISO peak to a focus on more local peaks). DR programs will need to be designed with the flexibility to adjust the timing of curtailments in response to these changes.

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# Appendix A: Load*Flex* Modeling Methodology and Assumptions

## The Load*Flex* Model

The Brattle Group's Load*Flex* model was developed to quantify the potential impacts, costs, and benefits of demand response (DR) programs. The Load*Flex* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging "DR 2.0" programs which not only reduce system peak demand, but also provide around-the-clock load management opportunities.

The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to the utility's experience with DR programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).

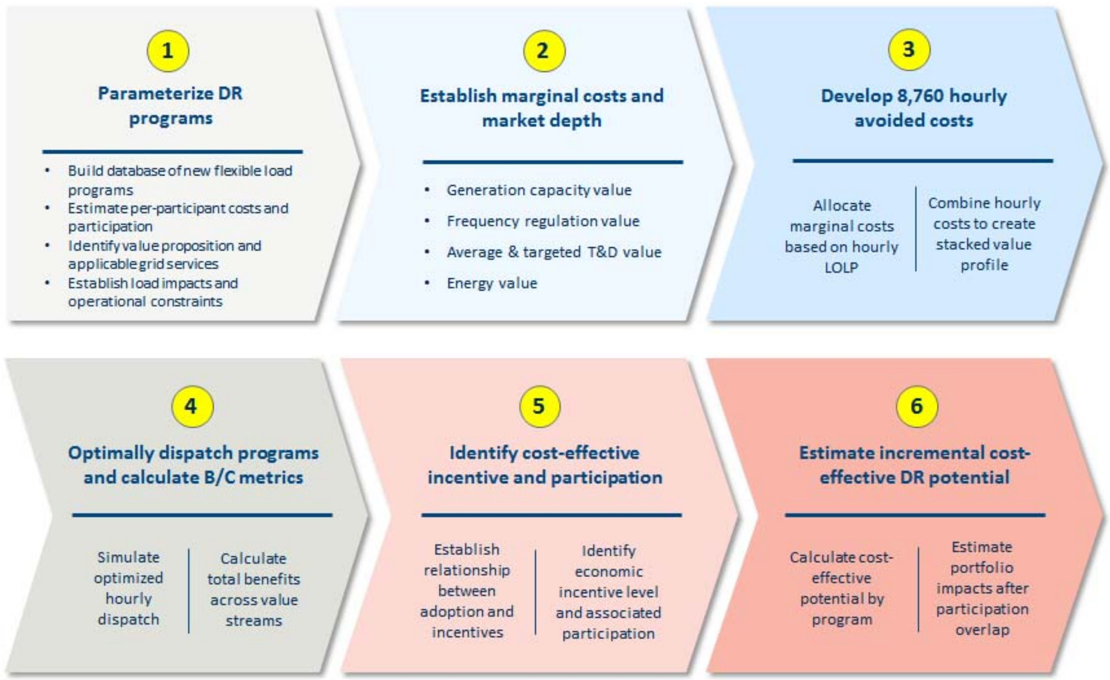
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of the utility's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* methodology is organized around six steps, as summarized in Figure 16. The remainder of this appendix describes each of the six steps in further detail, documenting methodology, assumptions, and data sources.

**Figure 16: The Load*Flex* Modeling Framework**




## Step 1: Parameterize the DR programs

Each DR program is represented according to two broad categories of characteristics: Performance characteristics and cost characteristics.

### Program Performance Characteristics

The performance characteristics of each DR program are represented in detail in Load*Flex* to accurately estimate the ability of the DR programs to provide system value. The following are key aspects of each program's performance capability.

**Load impact profiles**

Each DR program is represented with 24-hour average daily profiles of load reduction and load increase capability. These 24-hour impact profiles are differentiated by season (summer, winter, shoulder) and day type (weekday, weekend). For instance, air-conditioning load curtailment capability is highest during daytime hours in the summer, lower during nighttime summer hours, and non-existent during all hours in the winter.

Whenever possible, load impacts are derived directly from NSP's experience with its existing DR programs and pilots. NSP's experience directly informed the impact estimates for direct load control, smart thermostat, and interruptible rates programs. For emerging non-pricing DR programs, impacts are based on a review of experience and studies in other jurisdictions and tailored to NSP's customer mix and climate. Methods used to develop impact profile estimates for emerging non-pricing DR programs include the following:

- *C&I Auto-DR:* The potential for C&I customers to provide around-the-clock load flexibility was primarily derived from data supporting a 2017 statewide assessment of DR potential in California[17], a 2013 LBNL study of DR capability[18], and electricity load patterns representative of C&I buildings in Minneapolis developed by the Department of Energy.[19] Customer segment-specific estimates from these studies were combined to produce a composite load impact profile for the NSP service territory based on assumptions about NSP's mix of C&I customers. Impacts were scaled as necessary for consistency with NSP's prior experience with C&I DR programs.

- *Water heating load control:* Assumptions for the water heating load control programs – both grid interactive water heating and static timed water heating - are derived from a 2016 study on the value of various water heating load control strategies.[20] The program definition assumes that only customers with existing electric resistance water heaters will be eligible for participating in the water heating programs.

- *Behavioral DR:* Impacts are derived from a review of the findings of behavioral DR pilot studies conducted around the US, including for Baltimore Gas & Electric, Consumers Energy, Green Mountain Power, Glendale Water and Power, Portland Gas Electric, and Pacific Gas and Electric. Most behavioral DR pilot studies have been conducted by Oracle (OPower) and have generally found that programs with a limited number of short curtailment events (4-10 events for 3-5 afternoon/evening hours) can achieve 2% to 3% load reduction across enrolled customers.[21] Based on these findings, we assumed that a

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17 Peter Alstone et al., Lawrence Berkeley National Laboratory, "Final Report on Phase 2 Results: 2025 California Demand Response Potential Study." March 2017.

18 Daniel J. Olsen, Nance Matson, Michael D. Sohn, Cody Rose, Junqiao Dudley, Sasank Goli, and Sila Kiliccote (Lawrence Berkeley National Oaboratory), Marissa Hummon, David Palchak, Paul Denholm, and Jennie Jorgenson (National Renewable Energy Laboratory), and Ookie Ma (U.S. Department of Energy), "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.

19 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

20 Ryan Hledik, Judy Chang, and Roger Lueken. "The Hidden Battery: Opportunities in Electric Water Heating." January 2016. Posted at: http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

21 For example, see Jonathan Cook et al., "Behavioral Demand Response Study – Load Impact Evaluation Report", January 11, 2016, prepared for Pacific Gas & Electric Company, available at: http://www.oracle.com/us/industries/utilities/behavioral-demand-response-3628982.pdf, and OPower,

Continued on next page

behavioral DR program called 10 times per year between 3 pm and 6 pm would achieve a 2.5% load reduction.

- *EV managed charging:* Estimates of load curtailment capability are based on projections of aggregate EV charging load shapes provided by Xcel Energy. The ability to curtail this charging load is based on a review of recent utility EV charging DR pilots, including managed charging programs at several California utilities (PG&E, SDG&E, SCE, and SMUD) and United Energy in Australia.[22]

- *Ice-based thermal energy storage:* Estimates of load curtailment capability are estimated based on charging and discharging (freezing and cooling) information from Ice Bear[23] and adapted to mirror building use patterns in Minnesota based on load profiles from the U.S. Department of Energy.[24]

For impacts from pricing programs, we relied on Brattle's database of time-varying pricing offerings. The database includes the results of more than 300 experimental and non-experimental pricing treatments across over 60 pilot programs.[25] It includes published results from Xcel Energy's various pricing pilots during this time period. The results of the pilots in the database are used to establish a relationship between the peak-to-off-peak price ratio of the rates and the average load reduction per participant, in order to simulate price response associated with any given rate design. This relationship between load reduction and price ratio is illustrated in Figure 17.

Continued from previous page

"Transform Every Customer into a Demand Response Resource: How Utilities Can Unlock the Full Potential of Residential Demand Response", 2014, available at: https://go.oracle.com/LP=42838?elqCampaignId=74613.

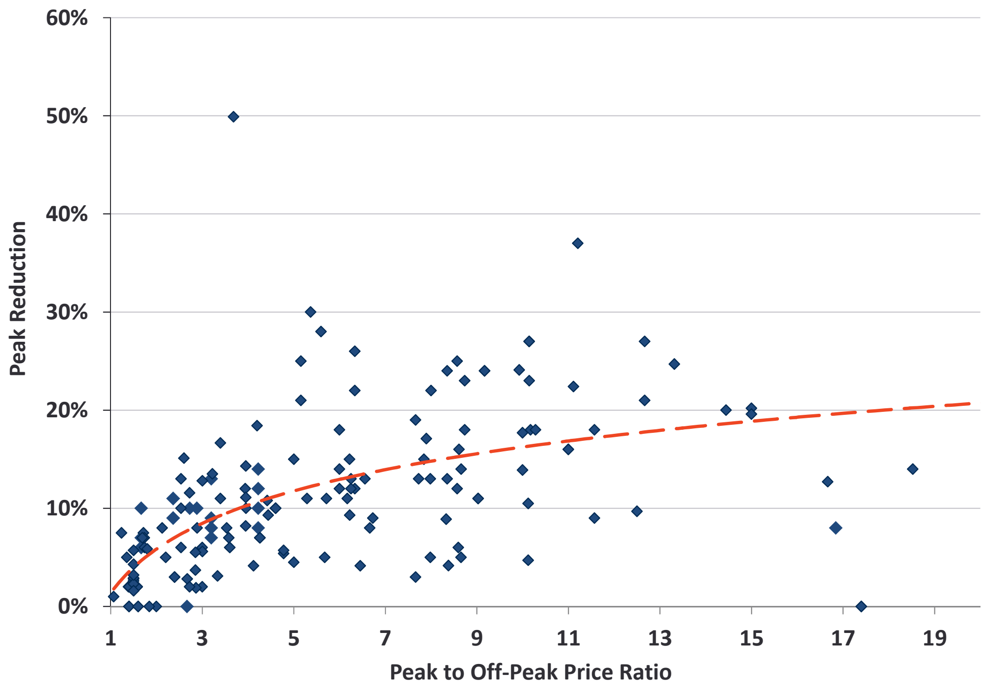
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

23 Ice Energy, "Ice Bear 20 Case Study," November 2016. Available: https://www.ice-energy.com/wp-content/uploads/2016/12/SantaYnez_CaseStudy_Nov2016.pdf

24 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

25 Ahmad Faruqui, Sanem Sergici, and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal*, 2017.

**Figure 17: Relationship between Price Ratio and Price Response in Residential Pricing Pilots**




Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

**Daily relationship between load reduction and load increase**

Some DR programs will require a load increase to offset or partially offset the load that is reduced during a curtailment event. In Load*Flex*, each program definition includes a parameter that represents the percent of curtailed load that must be offset by increased load on the same day, including the timing of when the load increase must occur. For instance, in a water heating load control program, any reduction in water heating load is assumed to be offset by an equal increase in water heating load on the same day in order to meet the customer's water heating needs. Alternatively, a reduction in air-conditioning load may only be offset partially by an increase in consumption, but it would immediately follow the curtailment.

Where data is available, these load building assumptions are based on the same data sources described above. Otherwise, these impacts are derived from assumptions that were developed for FERC's 2009 *A National Assessment of Demand Response Potential*.

**Tariff-related operational constraints**

Most DR programs will have administrator-defined limits on the operation of the program. This includes the maximum number of hours per day that the program can be curtailed, whether or not those curtailment hours must be contiguous, and the maximum number of days per year with allowed curtailment. Assumed operational constraints are based on Xcel Energy's program definitions and a review of common limitations from programs offered in other jurisdictions.

**Ancillary services availability**

If a DR program has the advanced control and communications technology necessary to provide ancillary services, Load*Flex* accounts for the capacity that is available to provide fast-response load increases or decreases in response to real-time fluctuations in supply and demand. In this study, smart water heating and Auto-DR are assumed to be able to offer ancillary services. Specifically, we model frequency regulation as it is the most valuable ancillary services product. Capability is based on the same data sources described above.

Table 6 summarizes the performance characteristics for each DR program in this study. In the table, "load shifting capability" identifies whether or not a program is capable of shifting energy usage from peak periods to off-peak periods on a daily basis.

**Table 6: DR Program Performance Characteristics**

| Segment | Program | Peak-coincident curtailment capability (kW/participant) | Hours of Curtailment (hours) | Average regulation up provided (kW/participant) | Average regulation down provided (kW/participant) | Load shifting capability? |
|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0.62 | 75 | 0.00 | 0.00 | No |
| Residential | Behavioral DR (Opt-out) | 0.06 | 40 | 0.00 | 0.00 | No |
| Residential | CPP (Opt-in) | 0.34 | 75 | 0.00 | 0.00 | No |
| Residential | CPP (Opt-out) | 0.17 | 75 | 0.00 | 0.00 | No |
| Residential | EV Managed Charging - Home | 0.46 | 45 | 0.00 | 0.00 | Yes |
| Residential | EV Managed Charging - Work | 0.09 | 45 | 0.00 | 0.00 | Yes |
| Residential | Smart thermostat - MDU | 0.86 | 75 | 0.00 | 0.00 | No |
| Residential | Smart thermostat - SFH | 1.15 | 75 | 0.00 | 0.00 | No |
| Residential | Smart water heating | 0.46 | 4,745 | 0.37 | 0.38 | Yes |
| Residential | Timed water heating | 0.43 | 1,825 | 0.00 | 0.00 | Yes |
| Residential | TOU - EV Charging (Opt-in) | 0.05 | 1,460 | 0.00 | 0.00 | Yes |
| Residential | TOU (Opt-in) | 0.17 | 1,284 | 0.00 | 0.00 | No |
| Residential | TOU (Opt-out) | 0.08 | 1,284 | 0.00 | 0.00 | No |
| Small C&I | A/C DLC | 1.93 | 75 | 0.00 | 0.00 | No |
| Small C&I | Auto-DR (A/C) | 1.37 | 200 | 0.37 | 0.49 | Yes |
| Small C&I | Auto-DR (Light Luminaire) | 1.07 | 300 | 0.52 | 0.57 | Yes |
| Small C&I | Auto-DR (Light Zonal) | 0.92 | 300 | 0.44 | 0.49 | Yes |
| Small C&I | CPP (Opt-in) | 0.02 | 75 | 0.00 | 0.00 | No |
| Small C&I | CPP (Opt-out) | 0.01 | 75 | 0.00 | 0.00 | No |
| Small C&I | Demand Bidding | 0.02 | 200 | 0.00 | 0.00 | No |
| Small C&I | Interruptible | 1.98 | 90 | 0.00 | 0.00 | No |
| Small C&I | TOU (Opt-in) | 0.01 | 1,281 | 0.00 | 0.00 | No |
| Small C&I | TOU (Opt-out) | 0.00 | 1,281 | 0.00 | 0.00 | No |
| Medium C&I | A/C DLC | 3.92 | 75 | 0.00 | 0.00 | No |
| Medium C&I | Auto-DR (HVAC) | 46.17 | 430 | 14.61 | 14.09 | Yes |
| Medium C&I | Auto-DR (Light Luminaire) | 18.22 | 300 | 8.62 | 8.83 | Yes |
| Medium C&I | Auto-DR (Light Zonal) | 9.81 | 300 | 5.47 | 5.78 | Yes |
| Medium C&I | CPP (Opt-in) | 4.83 | 75 | 0.00 | 0.00 | No |
| Medium C&I | CPP (Opt-out) | 2.42 | 75 | 0.00 | 0.00 | No |
| Medium C&I | Demand Bidding | 4.43 | 200 | 0.00 | 0.00 | No |
| Medium C&I | Interruptible | 27.45 | 90 | 0.00 | 0.00 | No |
| Medium C&I | Thermal Storage | 50.97 | 644 | 0.00 | 0.00 | Yes |
| Medium C&I | TOU (Opt-in) | 2.31 | 1,281 | 0.00 | 0.00 | No |
| Medium C&I | TOU (Opt-out) | 1.39 | 1,281 | 0.00 | 0.00 | No |
| Large C&I | Auto-DR (HVAC) | 592.09 | 430 | 151.57 | 207.60 | Yes |
| Large C&I | Auto-DR (Light Luminaire) | 416.95 | 120 | 191.67 | 200.74 | Yes |
| Large C&I | Auto-DR (Light Zonal) | 224.51 | 120 | 103.21 | 108.09 | Yes |
| Large C&I | CPP (Opt-in) | 283.92 | 75 | 0.00 | 0.00 | No |
| Large C&I | CPP (Opt-out) | 141.67 | 75 | 0.00 | 0.00 | No |
| Large C&I | Demand Bidding | 260.28 | 200 | 0.00 | 0.00 | No |
| Large C&I | Interruptible | 483.62 | 90 | 0.00 | 0.00 | No |

*Notes:*
Program impacts shown reflect impacts for new participants. Impacts shown assume each program is offered independently.

## Program Cost Characteristics

The costs of each program include startup costs, marketing and customer recruitment, the utility's share of equipment and installation costs, program administration and overhead, churn costs (i.e., the annual cost of replacing participants that leave the program), and participation incentives.[26]

[26] The Utility Cost Test (UCT) is the cost-effectiveness screen used in this study, which calls for including incentive payments as a cost.

Cost assumptions are based on NSP's current program costs, where applicable. Otherwise, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors, and are tailored for consistency with NSP's current program costs. Notable assumptions in developing the cost estimates include the following:

- Water heating technology costs include the cost of the load control and communications equipment and the *incremental* cost of replacing the existing water heater (50-gallon average) with a larger water heater (80-gallon) when the existing water heater expires. The full cost of a new water heater is not assigned to the program.

- Similarly, EV charging load control equipment costs include the incremental cost of load control and communications technology, but not the full cost of a charging unit.

- The cost of AMI is not counted against any of the DR programs, as it is treated as a sunk cost that is likely to be justified by a broad range of benefits that the new digital infrastructure will provides to customers and to NSP. However, a rough estimate of the cost of IT and billing system upgrades specifically associated with offering time-varying pricing programs are included in the costs for those programs.

- The cost of advanced lighting control systems is not counted against DR programs as these control systems are typically installed for non-energy benefits.

Table 7 summarizes Base Case cost assumptions for 2023 and Table 8 summarizes High Sensitivity Case cost assumptions for 2030. The 2030 assumptions reflect an assumed 25% reduction in the cost (in real terms) of emerging technologies. Costs in both tables are shown in nominal dollars. As discussed later in this appendix, the "base" incentive levels are derived from commonly observed payments both by NSP and in other jurisdictions. They do not reflect the cost-effective incentive payment levels that are ultimately established through the modeling.

## Table 7: 2023 Base Case Program Cost Assumptions

| Segment | Program | One-Time Costs: Fixed Cost ($) | One-Time Costs: Variable Equipment Cost ($/participant) | One-Time Costs: Other Initial Costs ($/participant) | Recurring Costs: Fixed Admin & Other ($/year) | Recurring Costs: Variable Admin & Other ($/participant-year) | Recurring Costs: Base Annual Incentive Level ($/participant-year) | Economic Life (years) |
|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | $0 | $172 | $92 | $0 | $13 | $59 | 15 |
| Residential | Behavioral DR (Opt-out) | $0 | $0 | $0 | $0 | $4 | $0 | 15 |
| Residential | CPP (Opt-in) | $223,208 | $0 | $80 | $83,703 | $2 | $0 | 15 |
| Residential | CPP (Opt-out) | $223,208 | $0 | $40 | $83,703 | $2 | $0 | 15 |
| Residential | EV Managed Charging - Home | $0 | $229 | $0 | $0 | $17 | $45 | 15 |
| Residential | EV Managed Charging - Work | $0 | $229 | $0 | $0 | $17 | $45 | 15 |
| Residential | Smart thermostat - MDU | $0 | $126 | $92 | $0 | $11 | $28 | 10 |
| Residential | Smart thermostat - SFH | $0 | $126 | $92 | $0 | $11 | $28 | 10 |
| Residential | Smart water heating | $0 | $686 | $34 | $0 | $0 | $28 | 10 |
| Residential | Timed water heating | $0 | $458 | $34 | $0 | $0 | $11 | 10 |
| Residential | TOU - EV Charging (Opt-in) | $0 | $0 | $0 | $83,703 | $0 | $0 | 15 |
| Residential | TOU (Opt-in) | $223,208 | $0 | $57 | $83,703 | $1 | $0 | 15 |
| Residential | TOU (Opt-out) | $223,208 | $0 | $29 | $83,703 | $0 | $0 | 15 |
| Small C&I | A/C DLC | $0 | $172 | $92 | $0 | $13 | $237 | 15 |
| Small C&I | Auto-DR (A/C) | $0 | $0 | $2,218 | $0 | $22 | $112 | 15 |
| Small C&I | Auto-DR (Light Luminaire) | $0 | $0 | $1,328 | $0 | $22 | $112 | 15 |
| Small C&I | Auto-DR (Light Zonal) | $0 | $0 | $1,001 | $0 | $22 | $112 | 15 |
| Small C&I | CPP (Opt-in) | $74,403 | $0 | $80 | $27,901 | $0 | $0 | 15 |
| Small C&I | CPP (Opt-out) | $74,403 | $0 | $40 | $27,901 | $0 | $0 | 15 |
| Small C&I | Demand Bidding | $0 | $0 | $0 | $691,944 | $0 | $1 | 15 |
| Small C&I | Interruptible | $0 | $0 | $0 | $280,126 | $0 | $259 | 15 |
| Small C&I | TOU (Opt-in) | $74,403 | $0 | $57 | $20,926 | $0 | $0 | 15 |
| Small C&I | TOU (Opt-out) | $74,403 | $0 | $29 | $20,926 | $0 | $0 | 15 |
| Medium C&I | A/C DLC | $0 | $343 | $92 | $0 | $13 | $481 | 15 |
| Medium C&I | Auto-DR (HVAC) | $0 | $0 | $26,820 | $0 | $22 | $9,444 | 12 |
| Medium C&I | Auto-DR (Light Luminaire) | $0 | $0 | $33,220 | $0 | $22 | $4,351 | 15 |
| Medium C&I | Auto-DR (Light Zonal) | $0 | $0 | $24,719 | $0 | $22 | $4,351 | 15 |
| Medium C&I | CPP (Opt-in) | $74,403 | $0 | $1,144 | $27,901 | $22 | $0 | 15 |
| Medium C&I | CPP (Opt-out) | $74,403 | $0 | $572 | $27,901 | $22 | $0 | 15 |
| Medium C&I | Demand Bidding | $0 | $0 | $0 | $280,126 | $0 | $249 | 15 |
| Medium C&I | Interruptible | $0 | $0 | $0 | $280,126 | $0 | $5,627 | 15 |
| Medium C&I | Thermal Storage | $0 | $120,114 | $34 | $0 | $382 | $0 | 20 |
| Medium C&I | TOU (Opt-in) | $74,403 | $0 | $1,144 | $20,926 | $22 | $0 | 15 |
| Medium C&I | TOU (Opt-out) | $74,403 | $0 | $572 | $20,926 | $22 | $0 | 15 |
| Large C&I | Auto-DR (HVAC) | $0 | $0 | $306,980 | $0 | $22 | $108,307 | 12 |
| Large C&I | Auto-DR (Light Luminaire) | $0 | $0 | $495,047 | $0 | $22 | $86,691 | 15 |
| Large C&I | Auto-DR (Light Zonal) | $0 | $0 | $367,510 | $0 | $22 | $86,691 | 15 |
| Large C&I | CPP (Opt-in) | $74,403 | $0 | $1,144 | $27,901 | $22 | $0 | 15 |
| Large C&I | CPP (Opt-out) | $74,403 | $0 | $572 | $27,901 | $22 | $0 | 15 |
| Large C&I | Demand Bidding | $0 | $0 | $0 | $315,839 | $0 | $14,651 | 15 |
| Large C&I | Interruptible | $0 | $0 | $0 | $315,839 | $0 | $90,997 | 15 |

*Notes:*

All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

**Table 8: 2030 High Sensitivity Case Program Cost Assumptions**

| | | One-Time Costs | | | Recurring Costs | | | |
|---|---|---|---|---|---|---|---|---|
| Segment | Program | Fixed Cost ($) | Variable Equipment Cost ($/participant) | Other Initial Costs ($/participant) | Fixed Admin & Other ($/year) | Variable Admin & Other ($/participant-year) | Base Annual Incentive Level ($/part.-yr) | Economic Life (years) |
| Residential | A/C DLC - SFH | $0 | $140 | $75 | $0 | $16 | $69 | 15 |
| Residential | Behavioral DR (Opt-out) | $0 | $0 | $0 | $0 | $5 | $0 | 15 |
| Residential | CPP (Opt-in) | $182,204 | $0 | $65 | $97,609 | $2 | $0 | 15 |
| Residential | CPP (Opt-out) | $182,204 | $0 | $33 | $97,609 | $2 | $0 | 15 |
| Residential | EV Managed Charging - Home | $0 | $187 | $0 | $0 | $20 | $52 | 15 |
| Residential | EV Managed Charging - Work | $0 | $187 | $0 | $0 | $20 | $52 | 15 |
| Residential | Smart thermostat - MDU | $0 | $103 | $75 | $0 | $13 | $33 | 10 |
| Residential | Smart thermostat - SFH | $0 | $103 | $75 | $0 | $13 | $33 | 10 |
| Residential | Smart water heating | $0 | $560 | $28 | $0 | $0 | $33 | 10 |
| Residential | Timed water heating | $0 | $374 | $28 | $0 | $0 | $13 | 10 |
| Residential | TOU - EV Charging (Opt-in) | $0 | $0 | $0 | $97,609 | $0 | $0 | 15 |
| Residential | TOU (Opt-in) | $182,204 | $0 | $47 | $97,609 | $1 | $0 | 15 |
| Residential | TOU (Opt-out) | $182,204 | $0 | $23 | $97,609 | $1 | $0 | 15 |
| Small C&I | A/C DLC | $0 | $140 | $75 | $0 | $16 | $277 | 15 |
| Small C&I | Auto-DR (A/C) | $0 | $0 | $1,810 | $0 | $26 | $130 | 15 |
| Small C&I | Auto-DR (Light Luminaire) | $0 | $0 | $1,084 | $0 | $26 | $130 | 15 |
| Small C&I | Auto-DR (Light Zonal) | $0 | $0 | $817 | $0 | $26 | $130 | 15 |
| Small C&I | CPP (Opt-in) | $60,735 | $0 | $65 | $32,536 | $0 | $0 | 15 |
| Small C&I | CPP (Opt-out) | $60,735 | $0 | $33 | $32,536 | $0 | $0 | 15 |
| Small C&I | Demand Bidding | $0 | $0 | $0 | $806,905 | $0 | $1 | 15 |
| Small C&I | Interruptible | $0 | $0 | $0 | $326,666 | $0 | $302 | 15 |
| Small C&I | TOU (Opt-in) | $60,735 | $0 | $47 | $24,402 | $0 | $0 | 15 |
| Small C&I | TOU (Opt-out) | $60,735 | $0 | $23 | $24,402 | $0 | $0 | 15 |
| Medium C&I | A/C DLC | $0 | $280 | $75 | $0 | $16 | $561 | 15 |
| Medium C&I | Auto-DR (HVAC) | $0 | $0 | $21,893 | $0 | $26 | $11,013 | 12 |
| Medium C&I | Auto-DR (Light Luminaire) | $0 | $0 | $27,117 | $0 | $26 | $5,074 | 15 |
| Medium C&I | Auto-DR (Light Zonal) | $0 | $0 | $20,178 | $0 | $26 | $5,074 | 15 |
| Medium C&I | CPP (Opt-in) | $60,735 | $0 | $934 | $32,536 | $26 | $0 | 15 |
| Medium C&I | CPP (Opt-out) | $60,735 | $0 | $467 | $32,536 | $26 | $0 | 15 |
| Medium C&I | Demand Bidding | $0 | $0 | $0 | $326,666 | $0 | $291 | 15 |
| Medium C&I | Interruptible | $0 | $0 | $0 | $326,666 | $0 | $6,562 | 15 |
| Medium C&I | Thermal Storage | $0 | $98,049 | $28 | $0 | $445 | $0 | 20 |
| Medium C&I | TOU (Opt-in) | $60,735 | $0 | $934 | $24,402 | $26 | $0 | 15 |
| Medium C&I | TOU (Opt-out) | $60,735 | $0 | $467 | $24,402 | $26 | $0 | 15 |
| Large C&I | Auto-DR (HVAC) | $0 | $0 | $250,588 | $0 | $26 | $126,301 | 12 |
| Large C&I | Auto-DR (Light Luminaire) | $0 | $0 | $404,107 | $0 | $26 | $101,093 | 15 |
| Large C&I | Auto-DR (Light Zonal) | $0 | $0 | $299,998 | $0 | $26 | $101,093 | 15 |
| Large C&I | CPP (Opt-in) | $60,735 | $0 | $934 | $32,536 | $26 | $0 | 15 |
| Large C&I | CPP (Opt-out) | $60,735 | $0 | $467 | $32,536 | $26 | $0 | 15 |
| Large C&I | Demand Bidding | $0 | $0 | $0 | $368,313 | $0 | $17,085 | 15 |
| Large C&I | Interruptible | $0 | $0 | $0 | $368,313 | $0 | $106,116 | 15 |

*Notes:*

2030 one-time costs assumed to be 30% lower than 2023 one-time costs (in real terms), reflecting assumed declines in technology costs. All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

# Step 2: Establish system marginal costs and quantity of system need

Load*Flex* was used to quantify a broad range of value streams that could be provided by DR. These include avoided generation capacity costs, avoided system-wide T&D costs, additional avoided distribution costs from geo-targeted deployment of the DR programs, frequency regulation, and net avoided marginal energy costs.

The system costs that could be avoided through DR deployment are estimated based on market data that is specific to NSP's service territory. Assumptions used in developing each marginal (i.e., avoidable) cost estimate are described in more detail below, for both the Base Case and the High Sensitivity Case.

**Avoided generation capacity costs**

DR programs are most appropriately recognized as substitutes for new combustion turbine (CT) capacity. CTs are "peaking" units with relatively low up-front installation costs and high variable costs. As a result, they typically only run up to a few hundred hours of the year, when electricity demand is very high and/or there are system reliability concerns. Similarly, use of DR programs in the U.S. is typically limited to less than 100 hours per year. This constraint is either written into the DR program tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs.

In contrast, new intermediate or baseload capacity (e.g., gas-fired combined cycle) has a higher capital cost and lower variable cost than a CT, and therefore could run for thousands of hours per year. The DR programs considered in this study cannot feasibly avoid the need for new intermediate or baseload capacity, because they cannot be called during a sufficient number of hours of the year. Energy efficiency is a more comparable demand-side alternative to these resource types since it is a permanent load reduction that applies to a much broader range of hours.

In the Base Case, the installed cost of new CT capacity is based on data provided directly by NSP and consistent with the assumptions in NSP's 2019 IRP for a brownfield CT. The total cost amounts to $60.60/kW-year; this is sometimes referred to the gross cost of new entry (CONE). The gross CONE value is adjusted downward to account for the energy and ancillary services value that would otherwise be provided by that unit. Based on simulated unit profit data provided by NSP, we have estimated the annual energy and ancillary services value to be roughly $5.50/kW-year. The resulting net CONE value is $55.20/kW-year. This calculation is described further in Table 9 below.

This same approach is used to establish the capacity cost for the High Sensitivity Case. Rather than using the CT cost from NSP's IRP, we relied on the U.S. Energy Information Administration's (EIA's) estimate of the installed cost of an Advanced CT from the 2018 Annual Energy Outlook. For the Midwest Reliability Organization West region, this amounts to a gross CONE of $76.80/kW-year. Reducing this value by the same energy and ancillary services value described above leads to a net CONE of $71.40/kW-year.

**Table 9: Combustion Turbine Cost of New Entry Calculation**

| Variable | | NSP 2019 IRP Brownfield CT | NSP 2019 IRP Greenfield CT | AEO 2018 Advanced CT |
|---|---|---|---|---|
| Overnight Capital Cost ($/kW) | [1] | $467 | $617 | $698 |
| Effective Charge Rate (%) | [2] | 10% | 10% | 10% |
| Levelized Capital Cost ($/kW-yr) | [3]=[1]x[2] | $46.7 | $61.7 | $69.8 |
| Annual Fixed Costs ($/kW-yr) | [4] | $13.9 | $13.9 | $7.0 |
| Gross Cost of New Entry ($/kW-yr) | [5]=[3]+[4] | $60.6 | $75.6 | $76.8 |
| E&AS Margins ($/kW-yr) | [6] | $5.5 | $5.5 | $5.5 |
| Net Cost of New Entry ($/kW-yr) | [7]=[5]-[6] | $55.2 | $70.2 | $71.4 |

*Notes:* All costs shown in 2018 dollars. Assumes that overnight capital costs are recovered at 10% effective charge rate. AEO 2018 advanced CT costs shown for the Midwest Reliability Organization West region. Capacity costs are held constant in real terms throughout the period of study.

DR produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of 8% percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise.[27] When estimating the avoided capacity cost of DR, the avoided cost is grossed up to account for this factor. For this study, Xcel Energy provided load data at the generator level, thus already accounting for line loss gross-up.

Similarly, NSP incorporates a planning reserve margin of 2.4% percent into its capacity investment decisions.[28] This effectively means NSP will plan to have enough capacity available to meet its projected peak demand plus 2.4% percent of that value. In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.024 kW of capacity. Including the 2.4% reserve margin adjustment increases the net CONE value described above from $55.2 and $71.4/kW-year to $56.5 and $73.1/kW-year, for the Base and High Sensitivity Cases respectively. This is the generation capacity value that could be provided by DR if it were to operate exactly like a CT.

**Avoided transmission capacity costs**

Reductions in system peak demand may also reduce the need for transmission upgrades. A portion of transmission investment is driven by the need to have enough capacity available to

27 8% represents an average line loss across NSP territories and customer segments. Actual line losses range from 2 to 10%.

28 NSP's planning reserve margin target is 7.8% of load during the MISO peak, which translates into a margin of 2.4% during its own system peak.

move electricity to where it is needed during peak times while maintaining a sufficient level of reliability. Other transmission investments will not be peak related, but rather are intended to extend the grid to remotely located sources of generation, or to address constraints during mid- or off-peak periods. Based on the findings of NSP's 2017 T&D Avoided Cost Study for energy efficiency programs, we have assumed an avoidable transmission cost of $3.10/kW-year in 2023, rising to $3.60/kW-year in 2030.[29]

**Avoided system-wide distribution capacity costs**

Similar to transmission value, there may be long-term distribution capacity investment avoidance value associated with reductions in peak demand across the NSP system. For programs that do not provide the higher-value distribution benefits from geo-targeted deployment, as described below, we have assumed that peak demand reductions can produce avoided distribution costs of $8.10/kW-year in 2023, rising to $9.50/kW-year in 2030, based on NSP's 2017 T&D Avoided Cost Study.

**Geo-targeted distribution capacity costs**

DR participants may be recruited in locations on the distribution system where load reductions would defer the need for local capacity upgrades. This local deployment of the DR program can be targeted at specifically locations where distribution upgrades are expected to be costly.

DR cannot serve as a substitute for distribution upgrades in all cases, such as adding new circuit breakers, telemetry upgrades, or adding distribution lines to connect new customers. However, in many cases, system upgrades are needed to meet anticipated gradual load growth in a local area. At times, system planners must over-size distribution investments relative to the immediate needs to meet local load to allow for future load growth or utilize equipment (such as transformers) that only comes in certain standard sizes. To the extent that DR can be used to reduce local peak loads, the loading on the distribution system is reduced, which means otherwise necessary distribution upgrades may be deferred. Such deferrals are especially valuable if load growth is relatively slow and predictable such that the upgraded system would not be fully utilized for many years.

To quantify geo-targeted distribution capacity deferral value in Load*Flex*, we began with a list of all distribution capacity projects in NSP's five-year plan. Brattle worked with NSP staff to reduce this list to a subset of projects that are likely candidates for deferral through DR. Four criteria were applied to identify the list of candidate deferral projects:

[29] Xcel Energy, Minnesota Power, Otter Tail Power Company, Mendota Group & Environmental Economics, "Minnesota Transmission and Distribution Avoided Cost Study," July 31, 2017.

1. The need for the distribution project must be driven by load growth. DR could not be used to avoid the need to simply replace aging equipment, for example.

2. The project must have a meaningful overall cost on a per-kilowatt basis. In our analysis, we required that the cost of the project equate to a value of at least $100,000 per megawatt of reduced demand in order to be considered.[30] This is the equivalent of roughly $7/kW-year on an annualized basis. Projects below this cost threshold were excluded from the geo-targeted deferral analysis.

3. There must be sufficient local customer load in order for the upgrade to be deferrable through the use of DR. For instance, if a 20 MW load reduction would be needed to avoid a specific distribution upgrade, and there was only 25 MW of total load at that location in the system, then DR would not be a useful candidate because it is unlikely that DR could consistently and reliably produce an 80% load reduction. In establishing this criterion, projects with more than 6 MVA of "load at risk"[31] were excluded, as 6 MVA represents about half of the load on a typical feeder.

4. The project should not be needed to simultaneously address many risks across feeders. In some cases, distribution upgrades are needed to mitigate a number of different contingencies. There are significant operational challenges associated with using DR in a similar manner. Projects were screened out based on the number and severity of risks that they were intended to address.

After applying the above criteria, up to roughly 10% of the cost of NSP's 5-year plan remained as potentially deferrable through the use of DR. We have assumed linear growth in NSP's distribution capacity needs, meaning the geo-targeted distribution deferral opportunity increases by this amount every five years over the forecast horizon. Figure 17 summarizes the process for identifying geo-targeted distribution deferral opportunities.

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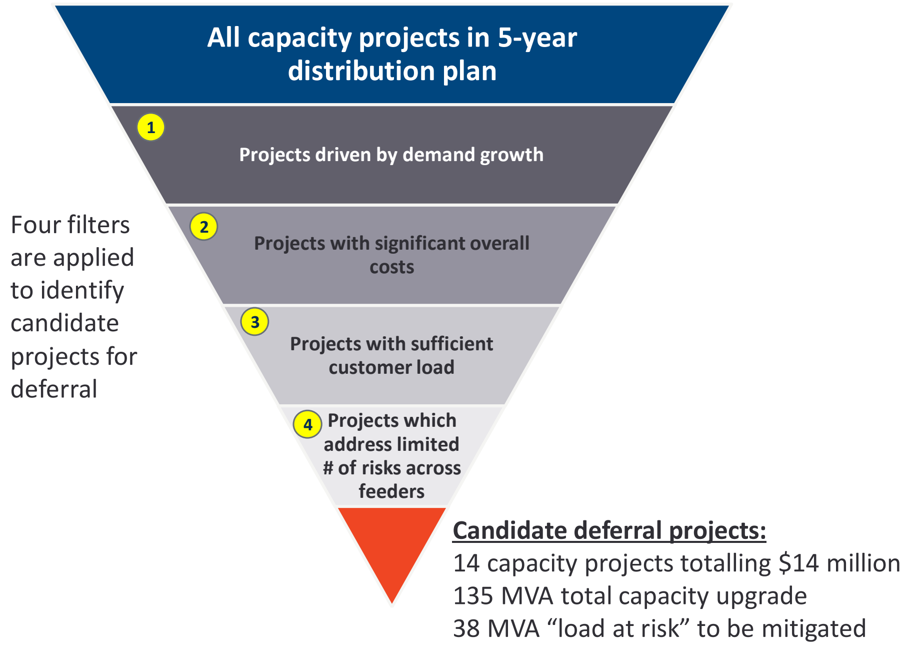
30 For simplicity, we assumed 1 MVA = 1 MW.

31 "Load at risk" effectively represents the load reduction that would need to be achieved to defer the capacity upgrade.

**Figure 18: Identification of Candidates for Geo-targeted Distribution Investment Deferral**




### Avoided energy costs

Load can be shifted from hours with higher energy costs to hours with lower energy costs, thus producing net energy cost savings across the system.[32] Hourly energy costs in this study are based on the 2018 MISO Transmission Expansion Plan (MTEP18) modeled day-ahead prices for the NSP hub. These modeled prices were used to capture evolving future system conditions that would not be reflected in historical prices. MTEP18 presents four "futures" that represent broadly different long-term views of MISO energy system, enabling the evaluation of the avoided energy value of DR under different market conditions.

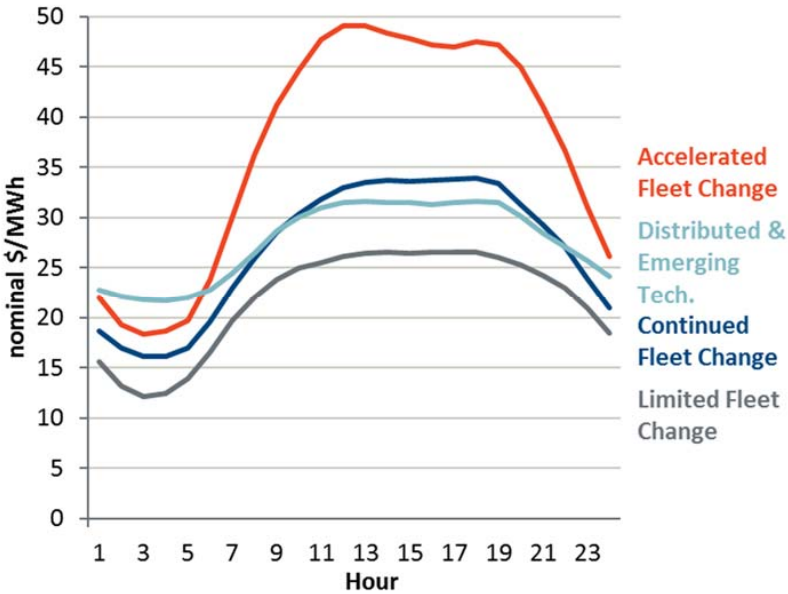
For the Base Case, we relied on prices from MTEP18's Continued Fleet Change (CFC) future. This future assumes a continuation of trends in the MISO market from the past decade: persistent low gas prices, limited demand growth, continued economic coal retirements, and gradual growth in renewables above state requirements.[33] Figure 19 below shows that 2022 energy prices

32 Energy savings refer to reduced fuel and O&M costs. In this study, we do not model the impact that DR would have on MISO wholesale energy prices. This is sometimes referred to as the demand response induced price effect (DRIPE). It represents a benefit to consumers and an offsetting cost to producers, with no net change in costs across the system as a whole.

33 See MISO, "MTEP 18 Futures – Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results." for additional details on MTEP18 scenarios.

under the CFC future lie somewhere in the middle of the four MTEP scenarios (energy prices in other years follow the same relative pattern across scenarios).

**Figure 19: Average Energy Price by Hour of Day in 2022 MTEP Scenarios for NSP Hub**




For the High Sensitivity Case, we relied on prices from the Accelerated Fleet Change (AFC) future. The AFC case has twice the amount of renewable generation capacity additions as the CFC future. However, increased load growth, accelerated coal retirements, and higher gas prices lead to overall higher energy prices, particularly in daytime hours. For our analysis years (2023, 2025 and 2030), we relied on prices from the nearest MTEP modeling year (2022, 2027, and 2032, respectively) and adjusted them accordingly for inflation (assumed to be 2.2% per year).

**Ancillary services**

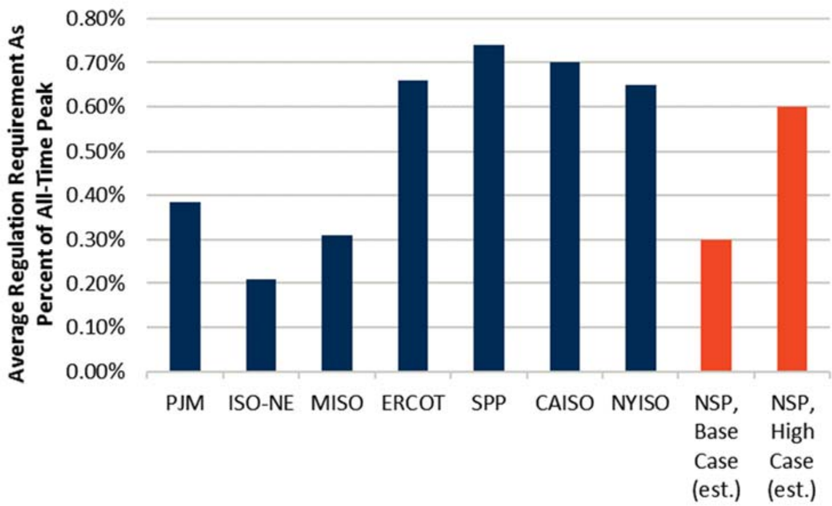
The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service.

Frequency regulation is a high value resource with a very limited need. Across most markets, the need for frequency regulation capacity is less than 1% of the system peak. We assume that the frequency regulation needs in the NSP system across all analysis years are 25 MW (0.3% of annual peak) in the Base Case, and 50 MW in the High Sensitivity Case (0.6% of annual peak).[34] Figure 20 summarizes frequency regulation needs across various U.S. markets, demonstrating

[34] Calculated assuming an annual peak of 8,335 MW after line losses.

that the quantities of frequency regulation assumed in this study are consistent with experience elsewhere.

**Figure 20: Frequency Regulation Requirements Across Wholesale Markets**




*Sources and Notes:* Values for wholesale markets extracted from PJM, "RTO/ISO Regulation Market Comparison", April 13, 2016. Orange bars for NSP assume that NSP's all-time peak is 8,335 MW at the customer level, based on three years of provided peak load data and assumed 8% line losses. Frequency regulation values for all markets are average levels as of 2016.

Because regulation prices were not available from the 2018 MTEP, we utilized 2017 hourly generation regulation prices for the MISO system adjusted for inflation.

Table 10 summarizes the potential value of each DR benefit. Values shown are the maximum achievable value. Operational constraints of the DR resources (e.g., limits on number of load curtailments per year) often result in realized benefits estimates that are lower than the values shown.

**Table 10: Summary of Avoided Costs/Value Streams in 2023**

| Value Stream | Quantity of Need | | Avoided Cost | | Description |
|---|---|---|---|---|---|
| | Base Case | High Case | Base Case | High Case | |
| **Avoided Generation Capacity** | Unconstrained | Unconstrained | $63.0/kW-year | $81.5/kW-year | Base: Xcel's Brownfield CT costs minus estimated CT energy revenues from 2018 IRP, plus 2.4% reserve margin gross-up. |
| **Avoided Transmission Capacity** | Unconstrained | Unconstrained | $3.1/kW-year | $3.1/kW-year | 72% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study. |
| **Avoided Distribution Capacity** | Unconstrained | Unconstrained | $8.0/kW-year | $8.0/kW-year | 28% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study. |
| **Geo-targeted Distribution Capacity** | 38 MW | 38 MW | $25.8/kW-year | $25.8/kW-year | Total value of 14 projects identified as eligible for distribution capacity deferral by demand response. |
| **Frequency Regulation** | 25 MW | 50 MW | Avg: $12.4/MWh | Avg: $12.4/MWh | 2017 MISO regulation prices. Assumes that NSP's share of regulation need is 25 MW in 2023 and 50 MW in 2030. |
| **Avoided Energy** | Unconstrained | Unconstrained | Avg: $27.5/MWh | Avg: $27.5/MWh | Hourly MISO MTEP18 modeled energy prices for NSP HUB. 2023 used prices from the CFC 2022 scenario, and 2030 used prices from the AFC 2032 scenario. |
| Top 10% Average | | | $50.5/MWh | $71.3/MWh | |
| Bottom 10% Average | | | $8.1/MWh | $8.6/MWh | |

*Notes:*
All values shown in nominal dollars. 2030 avoided costs are similar, rising at inflation.

# Step 3: Develop 8,760 hourly profile of marginal costs

Each of the annual avoided cost estimates established in Step 2 is converted into a chronological profile of hourly costs for all 8,760 hours of the year. In each hour, these estimates are added together across all value streams to establish the total "stacked" value that is obtainable through a reduction in load in that hour (or, conversely, the total cost associated with an increase in load in that hour).

Capacity costs are allocated to hours of the year proportional to the likelihood that those hours will drive the need for new capacity. In other words, the greater the risk of a capacity shortage in a given hour, the larger the share the marginal capacity cost that is allocated to that hour.

Capacity costs are allocated across the top 100 load hours of the year. The allocation is roughly proportional to each hour's share of total load in the hours. This means more capacity value is allocated to the top load hour than the 100th load hour.

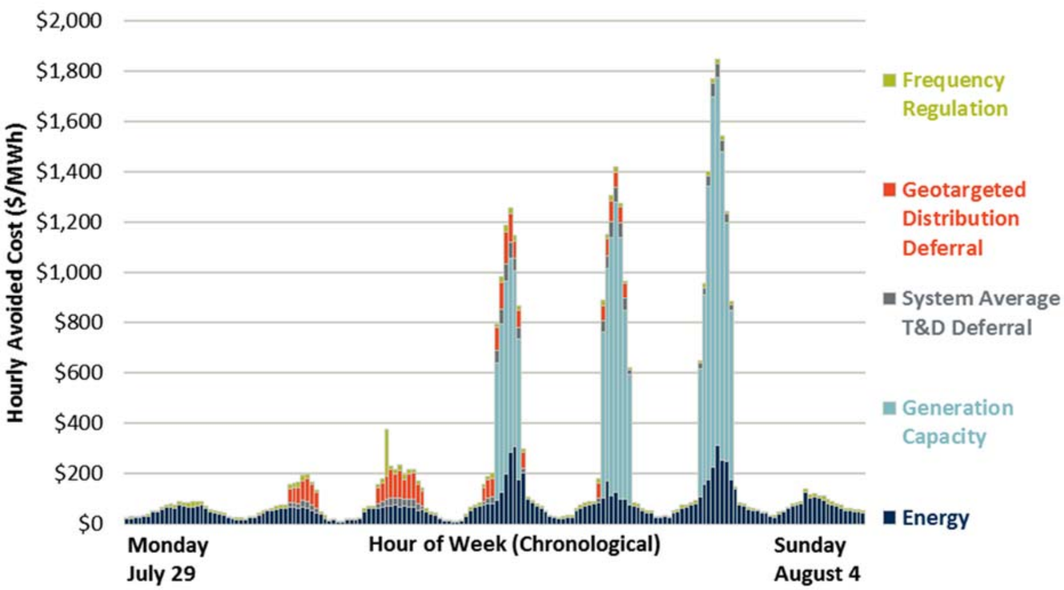
Different allocators are used to allocate generation, transmission, and distribution capacity costs. Generation and transmission capacity costs are allocated based on 2017 hourly MISO system gross load.[35] Distribution capacity costs are allocated based on hourly feeder load data provided by NSP. Both generic distribution capacity deferral and geo-targeted distribution capacity deferral value are allocated over a larger number of peak hours (roughly 330 hours, rather than 100 hours), representing that a single distribution project will address multiple feeders with load profiles that are only partially coincident.

A conceptually similar approach to quantifying capacity value is used in the California Energy Commission's time-dependent valuation (TDV) methodology for quantifying the value of energy efficiency, and also in the CPUC's demand response cost-effectiveness evaluation protocols. This hourly allocation-based approach effectively derates the value of distributed resources relative to the avoided cost of new peaking capacity by accounting for constraints that may exist on the operator's ability to predict and respond to resource adequacy needs. These constraints could result in DR utilization patterns that reflect a willingness to bypass some generation capacity value in order to provide distribution deferral value, for instance. The approach is effectively a theoretical construct intended to quantify long-term capacity value, rather than reflecting the way resource adequacy payments would be monetized by a DR operator in a wholesale market.

Figure 21 illustrates the "stacked" marginal costs associated with each value stream for a single week in the study period. The figure shows that certain hours present a significantly larger opportunity to reduce costs through load reduction – namely, those hours to which capacity costs are allocated.

[35] Capacity value was allocated proportional to MISO gross load because NSP is required to use its MISO-coincident peak for resource adequacy planning decisions.

**Figure 21: Chronological Allocation of Marginal Costs (Illustration for Week of July 29)**



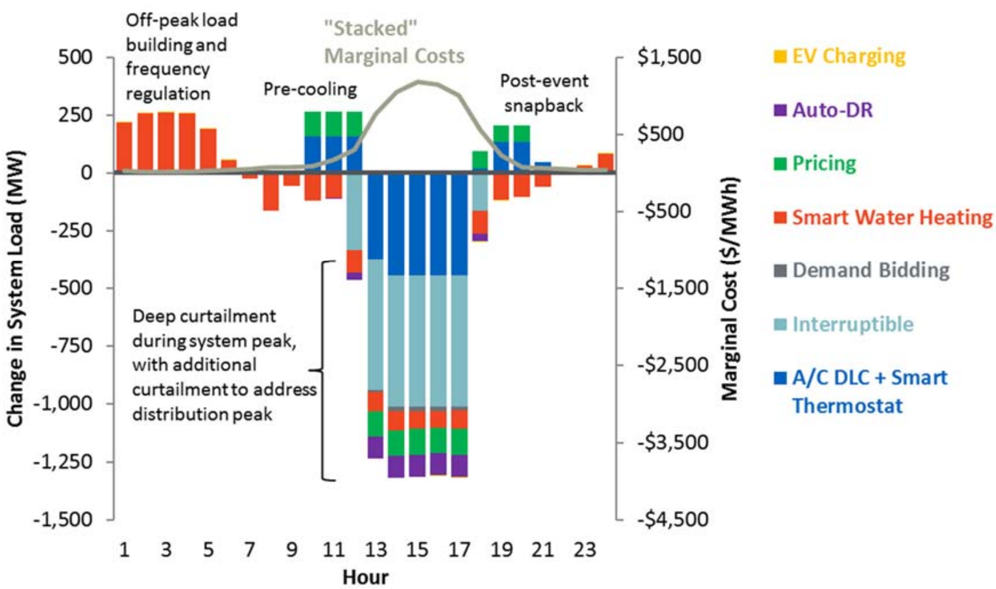

*Notes:* Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

## Step 4: Optimally dispatch programs and calculate benefit-cost metrics

As discussed above, using DR to pursue one value stream may require forgoing opportunities to pursue other "competing" sources of value. While the value streams quantified in this study can be estimated individually, those estimates are not purely additive. A DR operator must choose how to operate the program in order to maximize its value. Accurately estimating the total value of DR programs requires accounting for tradeoffs across the value streams.

Load*Flex* employs an algorithm that "co-optimizes" the dispatch of a DR program across the hourly marginal cost series from Step 3, subject to the operational constraints defined in Step 1, such that overall system value produced by the program is maximized. In other words, the programs are operated to reduce load during hours when the total cost is highest and build load during hours when the total cost is lowest, without violating any of the established conditions around their use. Figure 22 illustrates how the dispatch of the High Sensitivity Case portfolio in this study compares to the hourly cost profile on those same days.

**Figure 22: Illustrative Program Operations Relative to "Stacked" Marginal Costs**




Through an iterative process, Load*Flex* determines when the need for a given value stream has been fully satisfied by DR in each hour, and excludes that value stream from that hour for incremental additions of DR. This ensures that DR is not over-supplying certain resources and being incorrectly credited for services that do not provide additional value to the system.

## Step 5: Identify cost-effective incentive and participation levels

A unique feature of Load*Flex* is the ability to identify participation levels that are consistent with the incentive payments that are economically justified for each DR program. This ensures that each program's economic potential estimate is based on an incentive payment level that produces a benefit-cost ratio of 1.0. Without this functionality, the analysis would under-represent the potential for a given DR program, or could even exclude it from the analysis entirely based on inaccurate assumptions about uneconomic incentive payments levels.

As a starting point, participation estimates for each DR program are established to represent the maximum enrollment that is likely to be achieved when offered in NSP's service territory at a "typical" incentive payment level. The estimates are tailored to NSP's customer base using data on current program enrollment, as well as survey-based market research conducted directly with

NSP's customers.[36] For DR programs not included in the market research study, we developed participation assumptions based on experience with similar programs in other jurisdictions and applied judgement to make the participation rates consistent with available evidence that is specific to NSP's customer base.

Table 11 summarizes these "base" participation rates for conventional DR programs. In all cases, participation is expressed as a percent of the eligible customer base. For instance, the population of customers eligible for the smart thermostat program is limited to those customers with central air-conditioning.

The 2017 values represent current participation levels. Values in future years reflect participation rates if the programs were offered as part of an expanded DR portfolio. This accounts for the fact that a single customer could not simultaneously participate in two different programs.

Residential air-conditioning load control participation assumptions reflect a transition from compressor switch-based direct load control program to a smart thermostat-based program. These programs are currently marketed by NSP as "Savers Switch" and "AC Rewards", respectively. Based on the aforementioned primary market research conducted in NSP's service territory, we estimate that a 66% participation rate among eligible customers is achievable at the medium incentive level for these programs collectively. In 2017, participation in air-conditioning load control programs reached 52% of eligible residential customers, mostly through the Savers Switch program. In the future, NSP will increase its marketing emphasis on the AC Rewards program as its primary air-conditioning load control program. Therefore, we assume that achievable incremental participation in residential air-conditioning load control transitions from an equal split between AC Rewards and Savers Switch in 2018 to a 75/25 split in favor of AC Rewards by 2023. Additionally, NSP will focus on transitioning customers from Savers Switch to AC Rewards as compressor switches reach the end of their useful life. Based on information about the age of deployed switches and conversations with NSP, we assume that the number of switches replaced by smart thermostats grows from around 6,600/year in 2018 to 10,000/year in 2023 and onwards.

It is important to note that the participation rates shown are consistent with a participation incentive payment level that is representative of common offerings across the U.S. Participation rates are shown for all programs at these incentive levels, regardless of whether or not the programs are cost-effective at those incentive levels.[37] Later in this section of the appendix, we describe adjustments that are made to these "base" incentive levels to reflect enrollment that could be achieved at cost-effective incentive levels.

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[36] Ahmad Faruqui, Ryan Hledik, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," April 2014.

[37] This is the basis for our estimate of "technical potential".

**Table 11: Participation Assumptions for Conventional DR Programs**

*Participation as a percentage of eligible customers*

| Segment | Program | 2017 | 2023 | 2030 |
|---|---|---|---|---|
| Residential | A/C DLC - SFH | 52% | 50% | 39% |
| Residential | Smart thermostat - SFH | 0% | 16% | 24% |
| Residential | Smart thermostat - MDU | 0% | 35% | 32% |
| Small C&I | A/C DLC | 0% | 30% | 30% |
| Small C&I | Interruptible | 0% | 14% | 12% |
| Small C&I | Demand Bidding | 0% | 2% | 1% |
| Medium C&I | A/C DLC | 73% | 64% | 64% |
| Medium C&I | Interruptible | 3% | 13% | 11% |
| Medium C&I | Demand Bidding | 0% | 6% | 5% |
| Large C&I | Interruptible | 12% | 44% | 43% |
| Large C&I | Demand Bidding | 0% | 5% | 4% |

*Notes:*
Participation rates shown for programs at the portfolio level (i.e. accounts for program overlap). Lower participation rates for some programs in 2030 relative to 2023 result from customers switching to an opt-in CPP rate (for which participation estimates are shown separately). High Medium C&I participation in A/C DLC is relative to a small portion of the customer segment that is eligible for enrollment.

Table 12 illustrates the potential participation rates for each new DR program analyzed in the study. As noted above, these enrollment rates are consistent with "base" incentive payment levels and do not reflect enrollment associated with cost-effective payment levels. **Here, participation in each program is shown as if the program were offered in isolation.** In other words, it is the achievable participation level in the absence of other programs being offered. In our assessment of expanded DR portfolios that include multiple new DR programs, restrictions on participation in multiple programs are accounted for and the participation rates are derated accordingly.

**Table 12: Participation Assumptions for New DR Programs**

*Participation as a percentage of eligible customers*

| Segment | Program | 2017 | 2023 | 2030 |
|---|---|---|---|---|
| Residential | Behavioral DR (Opt-out) | 0% | 80% | 80% |
| Residential | CPP (Opt-in) | 0% | 0% | 20% |
| Residential | CPP (Opt-out) | 0% | 0% | 80% |
| Residential | EV Managed Charging - Home | 0% | 20% | 20% |
| Residential | EV Managed Charging - Work | 0% | 20% | 20% |
| Residential | Smart water heating | 0% | 15% | 50% |
| Residential | Timed water heating | 0% | 50% | 50% |
| Residential | TOU - EV Charging (Opt-in) | 0% | 0% | 20% |
| Residential | TOU (Opt-in) | 1% | 0% | 16% |
| Residential | TOU (Opt-out) | 0% | 0% | 80% |
| Small C&I | Auto-DR (A/C) | 0% | 5% | 5% |
| Small C&I | Auto-DR (Light Luminaire) | 0% | 5% | 5% |
| Small C&I | Auto-DR (Light Zonal) | 0% | 5% | 5% |
| Small C&I | CPP (Opt-in) | 0% | 0% | 20% |
| Small C&I | CPP (Opt-out) | 0% | 0% | 80% |
| Small C&I | TOU (Opt-in) | 3% | 0% | 10% |
| Small C&I | TOU (Opt-out) | 0% | 0% | 80% |
| Medium C&I | Auto-DR (HVAC) | 0% | 5% | 5% |
| Medium C&I | Auto-DR (Light Luminaire) | 0% | 5% | 5% |
| Medium C&I | Auto-DR (Light Zonal) | 0% | 5% | 5% |
| Medium C&I | CPP (Opt-in) | 0% | 14% | 14% |
| Medium C&I | CPP (Opt-out) | 0% | 79% | 79% |
| Medium C&I | Thermal Storage | 0% | 3% | 3% |
| Medium C&I | TOU (Opt-in) | 21% | 19% | 19% |
| Medium C&I | TOU (Opt-out) | 0% | 0% | 80% |
| Large C&I | Auto-DR (HVAC) | 0% | 5% | 5% |
| Large C&I | Auto-DR (Light Luminaire) | 0% | 5% | 5% |
| Large C&I | Auto-DR (Light Zonal) | 0% | 5% | 5% |
| Large C&I | CPP (Opt-in) | 0% | 22% | 22% |
| Large C&I | CPP (Opt-out) | 0% | 81% | 81% |
| Large C&I | TOU (Opt-in) | 100% | 100% | 100% |

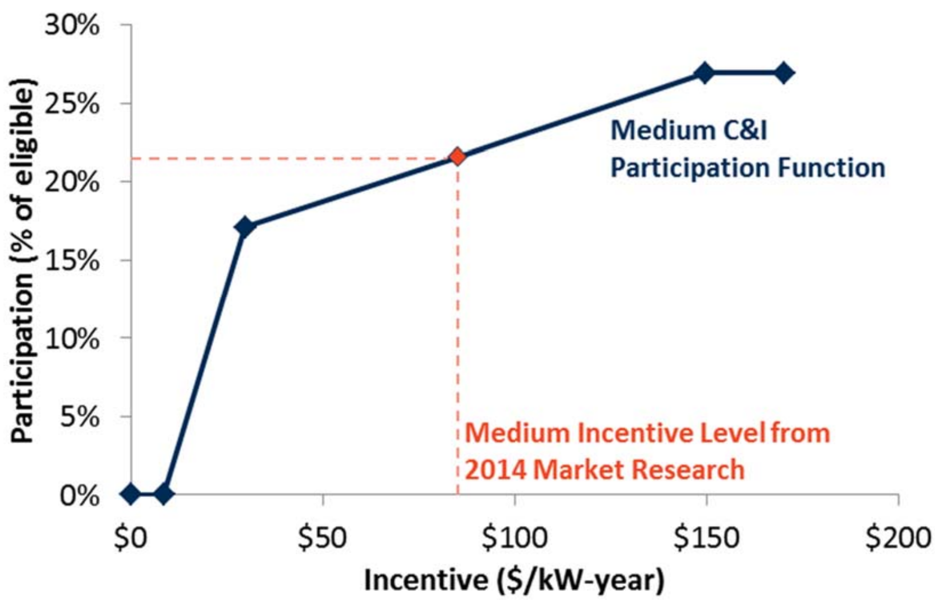
*Notes:*
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

As discussed above, the cost-effectiveness screening process in many DR potential studies often treats programs as an all-or-nothing proposition. In other words, the studies commonly assume a base incentive level and then simply evaluate the cost-effectiveness of the programs relative to that incentive level. However, in reality, the incentives can be decreased or increased to accommodate lower or higher thresholds for cost effectiveness. For instance, in a region with lower avoided cost, a lower incentive payment could be offered, and vice versa. Program participation will vary according to these changes in the incentive payment level.

In Load*Flex* model, participation is expressed as a function of the assumed incentive level. The incentive level that produces a benefit-cost ratio of 1.0 is quantified, thus defining the maximum potential cost-effective participation for the program.[38] The DR adoption function for each program is derived from the results of the aforementioned 2014 market research study, which tested customer willingness to participate in DR programs at various incentive levels.

An illustration of the participation function for the Medium C&I Interruptible program is provided in Figure 23. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis). At an incentive level of around $85/kW-yr, slightly more than 20% of eligible customers would participate in the program. If the economics of the program could only justify an incentive payment less than this (e.g., due to low avoided capacity costs), participation would decrease according to the blue line in the chart, and vice versa. Below an incentive payment level of around $25/kW-yr, customer willingness to enroll in the program quickly drops off.

**Figure 23: Medium C&I Interruptible Tariff Adoption Function**




## Step 6: Estimate cost-effective DR potential

After the cost-effective potential of each individual DR program is estimated, the programs are combined into a portfolio. Constructing the portfolio is not as simple as adding up the potential estimates of each individual program. In some cases, two programs may be targeting the same end-use (e.g., timed water heating and smart water heating), so their impacts are not additive.

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38 In some cases, the non-incentive costs (e.g., equipment costs) outweigh the benefits, in which case the program does not pass the cost-effectiveness screen.

In instances where two cost-effective programs target the exact same end-use, we have assumed that the portfolio would only include the program that produces the larger impact by the end of the study horizon. In the water heating example, this means that the smart water heating program was included and the timed water heating program was not.

In other cases, two "competing" programs would likely be offered simultaneously to customers as mutually exclusive options. For instance, it is possible that C&I customers would only be allowed to enroll in either an interruptible tariff program or a CPP rate. Simultaneous enrollment in both could result in customer being compensated twice for the same load reduction – once through the incentive payment in the interruptible tariff, and a second time through avoiding the higher peak price of the CPP rate. In these cases, we relied on the results of the aforementioned 2014 market research study, which used surveys to determine relative customer preferences for these options when offered simultaneously. Participation rates were reduced in the portfolio to account for this overlap.

In cases where two programs would be offered simultaneously to the same customer segment, but would target entirely different end-uses (e.g., a smart thermostat program and an EV charging load control program), no adjustments to the participation rates were deemed necessary.

# Appendix B: NSP's Proposed Portfolio

At a stakeholder meeting on August 8, 2018, NSP presented a draft portfolio of proposed DR programs. The DR portfolio that NSP is considering consists of the programs and deployment years summarized in Table 13.

**Table 13: NSP's Draft Portfolio of DR Programs**

| Program | First Year of Rollout |
|---|---|
| Saver's Switch | Existing |
| A/C Rewards | Existing |
| EV home charging control | 2020 |
| Med/large C&I Auto-DR | 2021 |
| Med/large C&I interruptible tariff (program expansion) | 2021 |
| Med/large C&I Opt-in CPP | 2022 |
| Residential smart water heating | 2023 |
| Residential behavioral DR | 2023 |
| Residential opt-out TOU | 2024 |

The potential for this portfolio was quantified under the Base and High Sensitivity cases for years 2023 and 2030. Results are summarized in Table 14. In the table, the values in the row labeled "All Proposed Programs" indicate the incremental technical potential in each of the programs that have been proposed by NSP. The values in the row "Cost-Effective Proposed programs" indicate the amount of incremental DR in the proposed programs that can be achieved at cost-effective incentive payment levels. In both cases, DR potential is shown at the portfolio level, accounting for overlap in participation when multiple programs are offered simultaneously.

**Table 14: Incremental Potential in NSP's Draft Portfolio of DR Programs (MW)**

| | Base Case | | High Sensitivity Case | |
|---|---|---|---|---|
| | 2023 | 2030 | 2023 | 2030 |
| **All Proposed Programs** | 642 | 907 | 658 | 927 |
| **Cost-Effective Proposed Programs** | 262 | 461 | 411 | 677 |

Note: Values shown are incremental to the existing 850 MW portfolio.

# Appendix C: Base Case with Alternative Capacity Costs

For its 2019 IRP, NSP has developed cost assumptions for new CT capacity at brownfield and greenfield sites. Our Base Case assumptions rely on brownfield CT costs as the avoided generation cost estimate, as this is the lowest cost option available to NSP for future peaking generation development. To test the sensitivity of our findings to that assumption, we modeled an alternative case in which the avoided capacity cost in the Base Case is based on a greenfield CT rather than a brownfield CT.[39] Other Base Case assumptions remained unchanged.

The greenfield CT capacity cost is higher than the brownfield CT cost, which increases the benefits of DR programs due to higher avoided generation costs. Relative to the Base Case, the cost-effective incremental potential in the DR portfolio increases by 73 MW in 2023 and by 119 MW in 2030. Nearly all of this increase in potential is attributable to a further expansion of participation in programs that were already cost-effective in the Base Case. The additional potential is mostly in the smart thermostat program, increases from 112 MW to 148 MW in 2023 and from 169 MW to 220 MW in 2030. Other programs that were economic in the Base Case (residential smart water heating, additional C&I interruptible, and demand bidding) also have small increases in cost-effective potential.

The only program that was initially uneconomic under Base assumptions but becomes economic under the greenfield CT capacity cost assumption is HVAC-based Auto-DR: 3 MW of Large C&I Auto-DR becomes cost-effective in 2023, growing to 6 MW in 2030 (in addition to 32 MW of Medium C&I Auto-DR). Together, these programs account for 4% of additional potential in 2023, but over 30% of additional potential in 2030.

Table 15 compares the portfolio-level incremental DR potential for the Base Case with brownfield CT costs to the alternative case with greenfield CT costs. Annual program-level potential estimates are provided in Appendix D.

[39] Table 9 of this report summarizes the greenfield, brownfield and AEO 2018 CT costs used in this analysis.

**Table 15: Incremental Cost-Effective Potential in Portfolio of DR Programs with Alternative CT Costs (MW)**

| | 2023 | 2030 |
|---|---|---|
| **Base Case (Brownfield CT Cost)** | 306 | 468 |
| **Alternative Case (Greenfield CT Cost)** | 378 | 587 |
| **Difference (Alternative - Base)** | 73 | 119 |

Note: Values shown are incremental to the existing 850 MW portfolio.

# Appendix D: Annual Results Summary

## Base Case, All Programs

### Technical Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 52 | 52 | 52 | 53 | 53 | 54 | 54 | 54 | 55 | 55 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 15 | 62 | 65 | 69 | 73 | 76 | 80 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 157 | 157 | 159 | 160 | 161 | 163 | 164 |
| Residential | EV Managed Charging - Home | 1 | 2 | 3 | 5 | 7 | 9 | 12 | 14 | 16 | 18 |
| Residential | EV Managed Charging - Work | 0 | 0 | 1 | 1 | 1 | 2 | 2 | 3 | 3 | 3 |
| Residential | Smart thermostat - MDU | 3 | 13 | 16 | 16 | 16 | 16 | 16 | 16 | 17 | 17 |
| Residential | Smart thermostat - SFH | 161 | 161 | 161 | 175 | 190 | 204 | 219 | 233 | 248 | 262 |
| Residential | Smart water heating | 6 | 11 | 17 | 23 | 29 | 30 | 34 | 40 | 49 | 60 |
| Residential | Timed water heating | 11 | 43 | 54 | 55 | 55 | 55 | 55 | 56 | 56 | 56 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 6 | 23 | 25 | 26 | 28 | 29 | 31 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 155 | 155 | 156 | 157 | 159 | 160 | 161 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 2 | 2 | 2 |
| Small C&I | A/C DLC | 44 | 44 | 44 | 44 | 44 | 44 | 45 | 45 | 45 | 45 |
| Small C&I | Auto-DR (A/C) | 2 | 8 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 10 |
| Small C&I | Auto-DR (Light Luminaire) | 1 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 |
| Small C&I | Auto-DR (Light Zonal) | 1 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 65 | 65 | 65 | 65 | 66 | 66 | 66 | 67 | 67 | 67 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 |
| Medium C&I | A/C DLC | 3 | 3 | 3 | 4 | 4 | 4 | 5 | 5 | 5 | 6 |
| Medium C&I | Auto-DR (HVAC) | 30 | 121 | 151 | 152 | 152 | 153 | 154 | 154 | 155 | 156 |
| Medium C&I | Auto-DR (Light Luminaire) | 12 | 48 | 60 | 60 | 60 | 60 | 61 | 61 | 61 | 62 |
| Medium C&I | Auto-DR (Light Zonal) | 6 | 26 | 32 | 32 | 32 | 33 | 33 | 33 | 33 | 33 |
| Medium C&I | CPP (Opt-in) | 6 | 24 | 30 | 30 | 30 | 30 | 30 | 31 | 31 | 31 |
| Medium C&I | CPP (Opt-out) | 86 | 86 | 86 | 87 | 87 | 88 | 89 | 89 | 90 | 90 |
| Medium C&I | Demand Bidding | 4 | 16 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Medium C&I | Interruptible | 310 | 310 | 310 | 313 | 316 | 318 | 321 | 324 | 326 | 329 |
| Medium C&I | Thermal Storage | 20 | 80 | 100 | 101 | 101 | 101 | 102 | 102 | 103 | 103 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 51 | 51 | 51 | 51 | 52 | 52 | 52 |
| Large C&I | Auto-DR (HVAC) | 4 | 15 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 18 |
| Large C&I | Auto-DR (Light Luminaire) | 3 | 11 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Large C&I | Auto-DR (Light Zonal) | 1 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Large C&I | CPP (Opt-in) | 7 | 28 | 36 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| Large C&I | CPP (Opt-out) | 64 | 64 | 64 | 64 | 64 | 63 | 63 | 63 | 63 | 62 |
| Large C&I | Demand Bidding | 2 | 6 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Large C&I | Interruptible | 85 | 85 | 85 | 84 | 83 | 82 | 81 | 80 | 79 | 78 |

**Notes:**
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## Base Case, All Programs

### Cost-Effective Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 11 | 44 | 46 | 49 | 52 | 54 | 57 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Home | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Work | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - MDU | 0 | 1 | 1 | 4 | 6 | 6 | 6 | 6 | 7 | 7 |
| Residential | Smart thermostat - SFH | 112 | 112 | 112 | 122 | 131 | 139 | 146 | 154 | 162 | 169 |
| Residential | Smart water heating | 4 | 9 | 13 | 17 | 22 | 23 | 25 | 29 | 35 | 42 |
| Residential | Timed water heating | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 2 | 2 |
| Small C&I | A/C DLC | 19 | 19 | 19 | 21 | 22 | 22 | 22 | 22 | 22 | 22 |
| Small C&I | Auto-DR (A/C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 32 | 32 | 32 | 31 | 30 | 30 | 30 | 30 | 30 | 30 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | A/C DLC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (HVAC) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | CPP (Opt-in) | 0 | 0 | 0 | 10 | 19 | 19 | 19 | 20 | 20 | 20 |
| Medium C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Demand Bidding | 4 | 14 | 18 | 16 | 15 | 15 | 15 | 15 | 15 | 15 |
| Medium C&I | Interruptible | 45 | 45 | 45 | 31 | 16 | 17 | 18 | 19 | 20 | 22 |
| Medium C&I | Thermal Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (HVAC) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | CPP (Opt-in) | 0 | 0 | 0 | 16 | 32 | 32 | 32 | 32 | 32 | 31 |
| Large C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Demand Bidding | 1 | 6 | 7 | 6 | 5 | 5 | 5 | 5 | 5 | 5 |
| Large C&I | Interruptible | 58 | 58 | 58 | 55 | 51 | 51 | 50 | 49 | 48 | 47 |
| **Portfolio-Level Total** | | **276** | **296** | **306** | **338** | **393** | **405** | **418** | **433** | **450** | **468** |

**Notes:**

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## Alternative Base Case with Greenfield CT Costs, All Programs

### Technical Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 52 | 52 | 52 | 53 | 53 | 54 | 54 | 54 | 55 | 55 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 15 | 62 | 65 | 69 | 73 | 76 | 80 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 157 | 157 | 159 | 160 | 161 | 163 | 164 |
| Residential | EV Managed Charging - Home | 1 | 2 | 3 | 5 | 7 | 9 | 12 | 14 | 16 | 18 |
| Residential | EV Managed Charging - Work | 0 | 0 | 1 | 1 | 1 | 2 | 2 | 3 | 3 | 3 |
| Residential | Smart thermostat - MDU | 3 | 13 | 16 | 16 | 16 | 16 | 16 | 16 | 17 | 17 |
| Residential | Smart thermostat - SFH | 180 | 180 | 180 | 204 | 227 | 245 | 262 | 280 | 298 | 315 |
| Residential | Smart water heating | 6 | 13 | 19 | 26 | 33 | 34 | 38 | 44 | 53 | 65 |
| Residential | Timed water heating | 11 | 43 | 54 | 55 | 55 | 55 | 55 | 56 | 56 | 56 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 6 | 23 | 25 | 26 | 28 | 29 | 31 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 155 | 155 | 156 | 157 | 159 | 160 | 161 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 2 | 2 | 2 |
| Small C&I | A/C DLC | 44 | 44 | 44 | 44 | 44 | 44 | 45 | 45 | 45 | 45 |
| Small C&I | Auto-DR (A/C) | 2 | 8 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 10 |
| Small C&I | Auto-DR (Light Luminaire) | 1 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 |
| Small C&I | Auto-DR (Light Zonal) | 1 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 65 | 65 | 65 | 65 | 66 | 66 | 66 | 67 | 67 | 67 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 |
| Medium C&I | A/C DLC | 3 | 3 | 3 | 4 | 4 | 4 | 5 | 5 | 5 | 6 |
| Medium C&I | Auto-DR (HVAC) | 30 | 121 | 151 | 152 | 152 | 153 | 154 | 154 | 155 | 156 |
| Medium C&I | Auto-DR (Light Luminaire) | 12 | 48 | 60 | 60 | 60 | 60 | 61 | 61 | 61 | 62 |
| Medium C&I | Auto-DR (Light Zonal) | 6 | 26 | 32 | 32 | 32 | 33 | 33 | 33 | 33 | 33 |
| Medium C&I | CPP (Opt-in) | 6 | 24 | 30 | 30 | 30 | 30 | 30 | 31 | 31 | 31 |
| Medium C&I | CPP (Opt-out) | 86 | 86 | 86 | 87 | 87 | 88 | 89 | 89 | 90 | 90 |
| Medium C&I | Demand Bidding | 4 | 16 | 20 | 21 | 21 | 21 | 21 | 22 | 22 | 22 |
| Medium C&I | Interruptible | 310 | 310 | 310 | 313 | 316 | 318 | 321 | 324 | 326 | 329 |
| Medium C&I | Thermal Storage | 20 | 80 | 100 | 101 | 101 | 101 | 102 | 102 | 103 | 103 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 51 | 51 | 51 | 51 | 52 | 52 | 52 |
| Large C&I | Auto-DR (HVAC) | 4 | 15 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| Large C&I | Auto-DR (Light Luminaire) | 3 | 11 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Large C&I | Auto-DR (Light Zonal) | 1 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Large C&I | CPP (Opt-in) | 7 | 28 | 36 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| Large C&I | CPP (Opt-out) | 64 | 64 | 64 | 64 | 64 | 63 | 63 | 63 | 63 | 62 |
| Large C&I | Demand Bidding | 2 | 6 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Large C&I | Interruptible | 85 | 85 | 85 | 84 | 83 | 82 | 81 | 80 | 79 | 78 |

**Notes:**
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## Alternative Base Case with Greenfield CT Costs, All Programs

### Cost-Effective Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 11 | 44 | 46 | 49 | 52 | 54 | 57 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Home | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Work | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - MDU | 2 | 10 | 12 | 12 | 12 | 12 | 12 | 12 | 13 | 13 |
| Residential | Smart thermostat - SFH | 148 | 148 | 148 | 159 | 170 | 180 | 190 | 200 | 210 | 220 |
| Residential | Smart water heating | 5 | 10 | 15 | 21 | 26 | 27 | 30 | 35 | 42 | 51 |
| Residential | Timed water heating | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 2 | 2 |
| Small C&I | A/C DLC | 31 | 31 | 31 | 31 | 32 | 32 | 32 | 32 | 32 | 32 |
| Small C&I | Auto-DR (A/C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 34 | 34 | 34 | 32 | 31 | 31 | 31 | 31 | 31 | 31 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | A/C DLC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (HVAC) | 0 | 0 | 0 | 9 | 18 | 20 | 23 | 26 | 29 | 32 |
| Medium C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | CPP (Opt-in) | 0 | 0 | 0 | 10 | 19 | 19 | 19 | 20 | 20 | 20 |
| Medium C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Demand Bidding | 4 | 16 | 19 | 18 | 16 | 16 | 16 | 16 | 16 | 16 |
| Medium C&I | Interruptible | 47 | 47 | 47 | 32 | 17 | 18 | 19 | 20 | 21 | 23 |
| Medium C&I | Thermal Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (HVAC) | 1 | 2 | 3 | 4 | 5 | 5 | 5 | 5 | 6 | 6 |
| Large C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | CPP (Opt-in) | 0 | 0 | 0 | 16 | 32 | 32 | 32 | 32 | 32 | 31 |
| Large C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Demand Bidding | 2 | 6 | 8 | 6 | 5 | 5 | 5 | 5 | 5 | 5 |
| Large C&I | Interruptible | 61 | 61 | 61 | 58 | 54 | 53 | 52 | 51 | 50 | 49 |
| **Portfolio-Level Total** | | **335** | **365** | **378** | **418** | **480** | **498** | **517** | **538** | **562** | **587** |

**Notes:**

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## High Sensitivity Case, All Programs

### Technical Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 52 | 52 | 52 | 53 | 53 | 54 | 54 | 54 | 55 | 55 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 15 | 62 | 65 | 69 | 73 | 76 | 80 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 157 | 157 | 159 | 160 | 161 | 163 | 164 |
| Residential | EV Managed Charging - Home | 1 | 2 | 3 | 5 | 7 | 9 | 12 | 14 | 16 | 18 |
| Residential | EV Managed Charging - Work | 0 | 0 | 1 | 1 | 1 | 2 | 2 | 3 | 3 | 3 |
| Residential | Smart thermostat - MDU | 3 | 13 | 16 | 17 | 17 | 17 | 17 | 17 | 17 | 17 |
| Residential | Smart thermostat - SFH | 213 | 213 | 213 | 238 | 263 | 283 | 302 | 321 | 341 | 360 |
| Residential | Smart water heating | 8 | 16 | 24 | 32 | 40 | 42 | 47 | 56 | 68 | 83 |
| Residential | Timed water heating | 11 | 45 | 57 | 66 | 76 | 76 | 75 | 75 | 75 | 74 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 6 | 23 | 25 | 26 | 28 | 29 | 31 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 155 | 155 | 156 | 157 | 159 | 160 | 161 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 2 | 2 | 2 |
| Small C&I | A/C DLC | 44 | 44 | 44 | 44 | 44 | 44 | 45 | 45 | 45 | 45 |
| Small C&I | Auto-DR (A/C) | 2 | 8 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 10 |
| Small C&I | Auto-DR (Light Luminaire) | 1 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 |
| Small C&I | Auto-DR (Light Zonal) | 1 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 65 | 65 | 65 | 65 | 66 | 66 | 66 | 67 | 67 | 67 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 |
| Medium C&I | A/C DLC | 3 | 3 | 3 | 4 | 4 | 4 | 5 | 5 | 5 | 6 |
| Medium C&I | Auto-DR (HVAC) | 30 | 121 | 151 | 152 | 152 | 153 | 154 | 154 | 155 | 156 |
| Medium C&I | Auto-DR (Light Luminaire) | 12 | 48 | 60 | 60 | 60 | 60 | 61 | 61 | 61 | 62 |
| Medium C&I | Auto-DR (Light Zonal) | 6 | 26 | 32 | 32 | 32 | 33 | 33 | 33 | 33 | 33 |
| Medium C&I | CPP (Opt-in) | 6 | 24 | 30 | 30 | 30 | 30 | 30 | 31 | 31 | 31 |
| Medium C&I | CPP (Opt-out) | 86 | 86 | 86 | 87 | 87 | 88 | 89 | 89 | 90 | 90 |
| Medium C&I | Demand Bidding | 4 | 17 | 21 | 21 | 22 | 22 | 22 | 22 | 22 | 22 |
| Medium C&I | Interruptible | 310 | 310 | 310 | 313 | 316 | 318 | 321 | 324 | 326 | 329 |
| Medium C&I | Thermal Storage | 20 | 80 | 100 | 101 | 101 | 101 | 102 | 102 | 103 | 103 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 51 | 51 | 51 | 51 | 52 | 52 | 52 |
| Large C&I | Auto-DR (HVAC) | 4 | 15 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 18 |
| Large C&I | Auto-DR (Light Luminaire) | 3 | 11 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Large C&I | Auto-DR (Light Zonal) | 1 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Large C&I | CPP (Opt-in) | 7 | 28 | 36 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| Large C&I | CPP (Opt-out) | 64 | 64 | 64 | 64 | 64 | 63 | 63 | 63 | 63 | 62 |
| Large C&I | Demand Bidding | 2 | 6 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Large C&I | Interruptible | 85 | 85 | 85 | 84 | 83 | 82 | 81 | 80 | 79 | 78 |

**Notes:**
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## High Sensitivity Case, All Programs

### Cost-Effective Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 11 | 44 | 46 | 49 | 52 | 54 | 57 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Home | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Work | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - MDU | 3 | 12 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| Residential | Smart thermostat - SFH | 176 | 176 | 176 | 186 | 197 | 208 | 219 | 230 | 241 | 252 |
| Residential | Smart water heating | 8 | 16 | 24 | 32 | 40 | 42 | 47 | 56 | 68 | 83 |
| Residential | Timed water heating | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 2 | 2 |
| Small C&I | A/C DLC | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 33 | 33 | 33 |
| Small C&I | Auto-DR (A/C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 34 | 34 | 34 | 32 | 31 | 31 | 31 | 31 | 31 | 31 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | A/C DLC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (HVAC) | 11 | 45 | 56 | 64 | 72 | 72 | 73 | 74 | 75 | 76 |
| Medium C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | CPP (Opt-in) | 0 | 0 | 0 | 10 | 19 | 19 | 19 | 20 | 20 | 20 |
| Medium C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Demand Bidding | 4 | 16 | 20 | 18 | 16 | 16 | 16 | 16 | 16 | 16 |
| Medium C&I | Interruptible | 47 | 47 | 47 | 32 | 17 | 18 | 19 | 20 | 22 | 23 |
| Medium C&I | Thermal Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (HVAC) | 2 | 8 | 10 | 11 | 12 | 12 | 11 | 11 | 11 | 11 |
| Large C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | CPP (Opt-in) | 0 | 0 | 0 | 16 | 32 | 32 | 32 | 32 | 32 | 31 |
| Large C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Demand Bidding | 2 | 6 | 8 | 7 | 5 | 5 | 5 | 5 | 5 | 5 |
| Large C&I | Interruptible | 62 | 62 | 62 | 58 | 55 | 54 | 53 | 52 | 51 | 50 |
| **Portfolio-Level Total** | | **380** | **454** | **484** | **524** | **586** | **603** | **623** | **647** | **674** | **705** |

**Notes:**

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## Base Case, NSP Proposed Portfolio

### Technical Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 0 | 0 | 52 | 53 | 53 | 54 | 54 | 54 | 55 | 55 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Home | 2 | 3 | 3 | 5 | 7 | 9 | 12 | 14 | 16 | 18 |
| Residential | EV Managed Charging - Work | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - MDU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - SFH | 161 | 161 | 161 | 175 | 190 | 204 | 219 | 233 | 248 | 262 |
| Residential | Smart water heating | 0 | 0 | 8 | 15 | 22 | 23 | 26 | 31 | 39 | 48 |
| Residential | Timed water heating | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 155 | 155 | 156 | 157 | 159 | 160 | 161 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | A/C DLC | 44 | 44 | 44 | 44 | 44 | 44 | 45 | 45 | 45 | 45 |
| Small C&I | Auto-DR (A/C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 53 | 53 | 53 | 53 | 54 | 54 | 54 | 54 | 54 | 55 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 |
| Medium C&I | A/C DLC | 3 | 3 | 3 | 4 | 4 | 4 | 5 | 5 | 5 | 6 |
| Medium C&I | Auto-DR (HVAC) | 30 | 121 | 151 | 152 | 152 | 153 | 154 | 154 | 155 | 156 |
| Medium C&I | Auto-DR (Light Luminaire) | 12 | 48 | 60 | 60 | 60 | 60 | 61 | 61 | 61 | 62 |
| Medium C&I | Auto-DR (Light Zonal) | 6 | 26 | 32 | 32 | 32 | 33 | 33 | 33 | 33 | 33 |
| Medium C&I | CPP (Opt-in) | 0 | 6 | 24 | 30 | 30 | 30 | 30 | 31 | 31 | 31 |
| Medium C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Interruptible | 310 | 310 | 310 | 313 | 316 | 318 | 321 | 324 | 326 | 329 |
| Medium C&I | Thermal Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (HVAC) | 4 | 15 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 18 |
| Large C&I | Auto-DR (Light Luminaire) | 3 | 11 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Large C&I | Auto-DR (Light Zonal) | 1 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Large C&I | CPP (Opt-in) | 0 | 7 | 28 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| Large C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Interruptible | 85 | 85 | 85 | 84 | 83 | 82 | 81 | 80 | 79 | 78 |

**Notes:**
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## Base Case, NSP Proposed Portfolio

### Cost-Effective Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Home | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Work | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - MDU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - SFH | 112 | 112 | 112 | 122 | 131 | 139 | 146 | 154 | 162 | 169 |
| Residential | Smart water heating | 0 | 0 | 8 | 13 | 18 | 19 | 21 | 25 | 30 | 36 |
| Residential | Timed water heating | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 95 | 95 | 96 | 96 | 97 | 98 | 99 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | A/C DLC | 21 | 21 | 21 | 22 | 23 | 23 | 23 | 23 | 22 | 22 |
| Small C&I | Auto-DR (A/C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 14 | 14 | 14 | 14 | 15 | 15 | 15 | 15 | 15 | 15 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | A/C DLC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (HVAC) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | CPP (Opt-in) | 0 | 4 | 15 | 19 | 19 | 19 | 19 | 20 | 20 | 20 |
| Medium C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Interruptible | 13 | 13 | 13 | 15 | 16 | 17 | 18 | 19 | 20 | 22 |
| Medium C&I | Thermal Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (HVAC) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | CPP (Opt-in) | 0 | 6 | 26 | 32 | 32 | 32 | 32 | 32 | 32 | 31 |
| Large C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Interruptible | 52 | 52 | 52 | 52 | 51 | 51 | 50 | 49 | 48 | 47 |
| **Portfolio-Level Total** | | **213** | **223** | **262** | **384** | **400** | **410** | **420** | **433** | **446** | **461** |

**Notes:**
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## High Sensitivity Case, NSP Proposed Portfolio

### Technical Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 0 | 0 | 52 | 53 | 53 | 54 | 54 | 54 | 55 | 55 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Home | 2 | 3 | 3 | 5 | 7 | 9 | 12 | 14 | 16 | 18 |
| Residential | EV Managed Charging - Work | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - MDU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - SFH | 213 | 213 | 213 | 238 | 263 | 283 | 302 | 321 | 341 | 360 |
| Residential | Smart water heating | 0 | 0 | 8 | 16 | 24 | 26 | 31 | 39 | 51 | 66 |
| Residential | Timed water heating | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 155 | 155 | 156 | 157 | 159 | 160 | 161 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | A/C DLC | 44 | 44 | 44 | 44 | 44 | 44 | 45 | 45 | 45 | 45 |
| Small C&I | Auto-DR (A/C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 53 | 53 | 53 | 53 | 54 | 54 | 54 | 54 | 54 | 55 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 |
| Medium C&I | A/C DLC | 3 | 3 | 3 | 4 | 4 | 4 | 5 | 5 | 5 | 6 |
| Medium C&I | Auto-DR (HVAC) | 30 | 121 | 151 | 152 | 152 | 153 | 154 | 154 | 155 | 156 |
| Medium C&I | Auto-DR (Light Luminaire) | 12 | 48 | 60 | 60 | 60 | 60 | 61 | 61 | 61 | 62 |
| Medium C&I | Auto-DR (Light Zonal) | 6 | 26 | 32 | 32 | 32 | 33 | 33 | 33 | 33 | 33 |
| Medium C&I | CPP (Opt-in) | 0 | 6 | 24 | 30 | 30 | 30 | 30 | 31 | 31 | 31 |
| Medium C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Interruptible | 310 | 310 | 310 | 313 | 316 | 318 | 321 | 324 | 326 | 329 |
| Medium C&I | Thermal Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (HVAC) | 4 | 15 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 18 |
| Large C&I | Auto-DR (Light Luminaire) | 3 | 11 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Large C&I | Auto-DR (Light Zonal) | 1 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| Large C&I | CPP (Opt-in) | 0 | 7 | 28 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| Large C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Interruptible | 85 | 85 | 85 | 84 | 83 | 82 | 81 | 80 | 79 | 78 |

**Notes:**
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

## High Sensitivity Case, NSP Proposed Portfolio

### Cost-Effective Potential (MW, at generator-level)

| Segment | Program | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | A/C DLC - SFH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Behavioral DR (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Home | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | EV Managed Charging - Work | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - MDU | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | Smart thermostat - SFH | 176 | 176 | 176 | 186 | 197 | 208 | 219 | 230 | 241 | 252 |
| Residential | Smart water heating | 0 | 0 | 8 | 16 | 24 | 26 | 31 | 39 | 51 | 66 |
| Residential | Timed water heating | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residential | TOU (Opt-out) | 0 | 0 | 0 | 95 | 95 | 96 | 96 | 97 | 98 | 99 |
| Residential | TOU - EV Charging (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | A/C DLC | 36 | 36 | 36 | 34 | 33 | 33 | 34 | 34 | 34 | 34 |
| Small C&I | Auto-DR (A/C) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | Interruptible | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| Small C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | A/C DLC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (HVAC) | 11 | 45 | 56 | 64 | 72 | 72 | 73 | 74 | 75 | 76 |
| Medium C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | CPP (Opt-in) | 0 | 4 | 15 | 19 | 19 | 19 | 19 | 20 | 20 | 20 |
| Medium C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | Interruptible | 14 | 14 | 14 | 15 | 17 | 18 | 19 | 20 | 22 | 23 |
| Medium C&I | Thermal Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-in) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Medium C&I | TOU (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (HVAC) | 2 | 8 | 10 | 11 | 12 | 12 | 11 | 11 | 11 | 11 |
| Large C&I | Auto-DR (Light Luminaire) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Auto-DR (Light Zonal) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | CPP (Opt-in) | 0 | 6 | 26 | 32 | 32 | 32 | 32 | 32 | 32 | 31 |
| Large C&I | CPP (Opt-out) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Demand Bidding | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Large C&I | Interruptible | 56 | 56 | 56 | 55 | 55 | 54 | 53 | 52 | 51 | 50 |
| **Portfolio-Level Total** | | **309** | **359** | **411** | **543** | **570** | **585** | **603** | **624** | **649** | **677** |

**Notes:**
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

BOSTON
NEW YORK
SAN FRANCISCO
WASHINGTON
TORONTO
LONDON
MADRID
ROME
SYDNEY

THE Brattle GROUP

IVVO 1.25%

***NSPM -AMI- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **446** |
| O&M Benefits | 53 |
| Other Benefits | 203 |
| CAP Benefits | 190 |
| **Costs** | **(539)** |
| O&M Expense | (179) |
| Change in Revenue Requirements | (359) |
| **Benefit/Cost Ratio** | **0.83** |

**FLISR**

| | |
|---|---|
| **Benefits** | **103** |
| O&M Benefits | 0 |
| Customer Benefits | 103 |
| **Costs** | **(79)** |
| O&M Expense | (5) |
| Change in Revenue Requirements | (74) |
| **Benefit/Cost Ratio** | **1.31** |

**IVVO**

| | |
|---|---|
| Benefits | 22 |
| Other Benefits | 19 |
| CAP Benefits | 3 |
| Costs | (39) |
| O&M Expense | (2) |
| Change in Capital Revenue Requirement | (37) |
| Benefit/Cost Ratio | **0.57** |

***NSPM -AMI,FLISR, IVVOS- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **571** |
| O&M Benefits | 53 |
| Other Benefits | 222 |
| Customer Benefits | 103 |
| CAP Benefits | 193 |
| **Costs** | **(657)** |
| O&M Expense | (186) |
| Change in Revenue Requirement | (470) |
| **Benefit/Cost Ratio** | **0.87** |

IVVO 1.25% - No Contingency



***NSPM -AMI- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **446** |
| O&M Benefits | 53 |
| Other Benefits | 203 |
| CAP Benefits | 190 |
| **Costs** | **(452)** |
| O&M Expense | (146) |
| Change in Revenue Requirements | (306) |
| **Benefit/Cost Ratio** | **0.99** |

**FLISR**

| | |
|---|---|
| **Benefits** | **103** |
| O&M Benefits | 0 |
| Customer Benefits | 103 |
| **Costs** | **(67)** |
| O&M Expense | (4) |
| Change in Revenue Requirements | (63) |
| **Benefit/Cost Ratio** | **1.53** |

**IVVO**

| | |
|---|---|
| Benefits | 22 |
| Other Benefits | 19 |
| CAP Benefits | 3 |
| Costs | (37) |
| O&M Expense | (2) |
| Change in Capital Revenue Requirement | (34) |
| Benefit/Cost Ratio | **0.61** |

***NSPM -AMI,FLISR, IVVOS- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **571** |
| O&M Benefits | 53 |
| Other Benefits | 222 |
| Customer Benefits | 103 |
| CAP Benefits | 193 |
| **Costs** | **(556)** |
| O&M Expense | (152) |
| Change in Revenue Requirement | (404) |
| **Benefit/Cost Ratio** | **1.03** |

IVVO 1%

***NSPM -AMI- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **446** |
| O&M Benefits | 53 |
| Other Benefits | 203 |
| CAP Benefits | 190 |
| **Costs** | **(539)** |
| O&M Expense | (179) |
| Change in Revenue Requirements | (359) |
| **Benefit/Cost Ratio** | **0.83** |

**FLISR**

| | |
|---|---|
| **Benefits** | **103** |
| O&M Benefits | 0 |
| Customer Benefits | 103 |
| **Costs** | **(79)** |
| O&M Expense | (5) |
| Change in Revenue Requirements | (74) |
| **Benefit/Cost Ratio** | **1.31** |

**IVVO**

| | |
|---|---|
| Benefits | 18 |
| Other Benefits | 15 |
| CAP Benefits | 3 |
| Costs | (39) |
| O&M Expense | (2) |
| Change in Capital Revenue Requirement | (37) |
| Benefit/Cost Ratio | **0.46** |

***NSPM -AMI,FLISR, IVVOS- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **567** |
| O&M Benefits | 53 |
| Other Benefits | 219 |
| Customer Benefits | 103 |
| CAP Benefits | 193 |
| **Costs** | **(657)** |
| O&M Expense | (186) |
| Change in Revenue Requirement | (470) |
| **Benefit/Cost Ratio** | **0.86** |

# IVVO 1% - No Contingency

***NSPM -AMI-*** ***NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **446** |
| O&M Benefits | 53 |
| Other Benefits | 203 |
| CAP Benefits | 190 |
| **Costs** | **(452)** |
| O&M Expense | (146) |
| Change in Revenue Requirements | (306) |
| **Benefit/Cost Ratio** | **0.99** |

**FLISR**

| | |
|---|---|
| **Benefits** | **103** |
| O&M Benefits | 0 |
| Customer Benefits | 103 |
| **Costs** | **(67)** |
| O&M Expense | (4) |
| Change in Revenue Requirements | (63) |
| **Benefit/Cost Ratio** | **1.53** |

**IVVO**

| | |
|---|---|
| Benefits | 18 |
| Other Benefits | 15 |
| CAP Benefits | 3 |
| Costs | (37) |
| O&M Expense | (2) |
| Change in Capital Revenue Requirement | (34) |
| Benefit/Cost Ratio | **0.49** |

***NSPM -AMI,FLISR, IVVOS-*** ***NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **567** |
| O&M Benefits | 53 |
| Other Benefits | 219 |
| Customer Benefits | 103 |
| CAP Benefits | 193 |
| **Costs** | **(556)** |
| O&M Expense | (152) |
| Change in Revenue Requirement | (404) |
| **Benefit/Cost Ratio** | **1.02** |

IVVO 1.5%



**NSPM -AMI- NPV**

| | Total ($MM) |
|---|---|
| **Benefits** | **446** |
| O&M Benefits | 53 |
| Other Benefits | 203 |
| CAP Benefits | 190 |
| **Costs** | **(539)** |
| O&M Expense | (179) |
| Change in Revenue Requirements | (359) |
| **Benefit/Cost Ratio** | **0.83** |

**FLISR**

| | |
|---|---|
| **Benefits** | **103** |
| O&M Benefits | 0 |
| Customer Benefits | 103 |
| **Costs** | **(79)** |
| O&M Expense | (5) |
| Change in Revenue Requirements | (74) |
| **Benefit/Cost Ratio** | **1.31** |

**IVVO**

| | |
|---|---|
| Benefits | 27 |
| Other Benefits | 23 |
| CAP Benefits | 4 |
| Costs | (39) |
| O&M Expense | (2) |
| Change in Capital Revenue Requirement | (37) |
| Benefit/Cost Ratio | **0.67** |

**NSPM -AMI,FLISR, IVVOS- NPV**

| | Total ($MM) |
|---|---|
| **Benefits** | **575** |
| O&M Benefits | 53 |
| Other Benefits | 226 |
| Customer Benefits | 103 |
| CAP Benefits | 194 |
| **Costs** | **(657)** |
| O&M Expense | (186) |
| Change in Revenue Requirement | (470) |
| **Benefit/Cost Ratio** | **0.88** |

## IVVO 1.5% - No Contingency

***NSPM -AMI- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **446** |
| O&M Benefits | 53 |
| Other Benefits | 203 |
| CAP Benefits | 190 |
| **Costs** | **(452)** |
| O&M Expense | (146) |
| Change in Revenue Requirements | (306) |
| **Benefit/Cost Ratio** | **0.99** |

**FLISR**

| | |
|---|---|
| **Benefits** | **103** |
| O&M Benefits | 0 |
| Customer Benefits | 103 |
| **Costs** | **(67)** |
| O&M Expense | (4) |
| Change in Revenue Requirements | (63) |
| **Benefit/Cost Ratio** | **1.53** |

**IVVO**

| | |
|---|---|
| Benefits | 27 |
| Other Benefits | 23 |
| CAP Benefits | 4 |
| Costs | (37) |
| O&M Expense | (2) |
| Change in Capital Revenue Requirement | (34) |
| Benefit/Cost Ratio | **0.72** |

***NSPM -AMI,FLISR, IVVOS- NPV***

| | Total ($MM) |
|---|---|
| **Benefits** | **575** |
| O&M Benefits | 53 |
| Other Benefits | 226 |
| Customer Benefits | 103 |
| CAP Benefits | 194 |
| **Costs** | **(556)** |
| O&M Expense | (152) |
| Change in Revenue Requirement | (404) |
| **Benefit/Cost Ratio** | **1.03** |

# The Commonwealth of Massachusetts

## DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 12-76-C November 5, 2014

Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid.

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Exhibit 5

TABLE OF CONTENTS

# I. INTRODUCTION AND SUMMARY OF PROCEEDINGS

On October 2, 2012, the Department of Public Utilities ("Department") issued a Notice of Investigation ("NOI") into the modernization of the electric grid. Modernization of the Electric Grid, D.P.U. 12-76 (2012). The Department hosted a workshop, attended by over 125 stakeholders, and subsequently created a stakeholder working group to inform the Department's approach to grid modernization and provide input on the sequence and pace of grid modernization infrastructure investments. From November 2012 through June 2013, stakeholders discussed a full range of issues relating to modernization of the grid, and on July 2, 2013, submitted a report to the Department that contained information, principles, and recommendations on a wide array of grid modernization issues: "Report to the Department of Public Utilities from the Steering Committee," D.P.U. 12-76 ("Report"). The Department solicited comments on the Report and, on December 23, 2013, issued an Order setting forth a proposal for achieving grid modernization, Modernization of the Electric Grid, D.P.U. 12-76-A (2013) ("Straw Proposal"). In Section V.B.4.b. of that Order, the Department proposed that grid modernization plans include a benefit-cost analysis, using a "business case" approach that "assesses all costs and benefits, including those that are difficult to quantify, and provides its underlying assumptions." On February 21, 2014, the Department initiated a working group to further develop and finalize the parameters of the business case and benefit-cost analysis model.

On June 12, 2014, the Department issued an Order requiring each Massachusetts electric distribution company[1] ("company" or collectively "companies") to submit a grid modernization plan ("GMP"), and outlining the requirements of those filings. Modernization of the Electric Grid, D.P.U. 12-76-B (June 12, 2014). In that Order, the Department affirmed that the companies must include a business case analysis within their GMPs, and noted that the deliberations of the working group regarding the business case and benefit-cost analysis were ongoing. D.P.U. 12-76-B at 18.

The Department held working group meetings on March 25, April 23, and May 19, 2014. Additionally, between working group meetings, the Department sought written input from participants on certain topics. On July 30, 2014, the Department issued draft Grid Modernization Business Case Filing Requirements ("Draft Filing Requirements") and a draft Business Case Summary Template ("Draft Template"), along with briefing questions, to the working group participants ("participants") for comment and proposed revisions.[2] On August 22, 2014, the following participants filed comments: (1) the Massachusetts Department of Energy Resources ("DOER"); (2) Environment Northeast ("ENE"); (3) Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"); (4) Gary Fauth ("Fauth"); (5) Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid ("National Grid"); and (6) NSTAR Electric Company ("NSTAR Electric") and Western Massachusetts

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1 Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, NSTAR Electric Company, and Western Massachusetts Electric Company.

2 The Department requested that participants submit proposed revisions to the Draft Filing Requirements in redline/strikeout in addition to comments.

Electric Company ("WMECo") (collectively "Northeast Utilities")[3]; with joint comments filed by the Office of the Attorney General ("Attorney General"), the Low Income Network ("LEAN"), the Associated Industries of Massachusetts ("AIM"), and the National Consumer Law Center ("NCLC") ("Joint Commenters").

In this Order, the Department establishes the final Grid Modernization Business Case Filing Requirements ("Filing Requirements") and the final Business Case Summary Template ("Template"), both attached to this Order.

## II. BUSINESS CASE FILING REQUIREMENTS AND TEMPLATE

### A. Introduction

The Filing Requirements are designed to provide guidance on the business case that the companies must file as part of their GMPs (Draft Filing Requirements at 1). See D.P.U. 12-76-B at 15-17. In the Draft Filing Requirements, the Department proposed to require each company's short-term investment plan ("STIP")[4] to include one composite business case that illustrates how the STIP investments will achieve measurable progress towards the Department's four grid modernization objectives, including achieving advanced metering functionality (Draft Filing Requirements at 1-2). See D.P.U. 12-76-B at 10-13. The business case will serve as the vehicle by which the Department and other parties will evaluate whether the benefits, both quantified and unquantified, justify the costs of the proposed STIP

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3 NSTAR Electric and WMECo are affiliated companies within the holding company system of their parent company, Northeast Utilities. NSTAR Electric Company/Northeast Utilities Merger, D.P.U. 10-170-B at 1, 15-16 (2012).

4 The STIP will address the capital investments a company proposes to make over the first five years of the GMP. D.P.U. 12-76-B at 17.

investments (Draft Filing Requirements at 1).[5] The Draft Filing Requirements set forth four primary components for the business case: (1) goals, scope and scale, and drivers for investments; (2) detailed descriptions of the proposed investments, as well as identification and quantification of all quantifiable benefits and costs associated with the STIP; (3) identification of all difficult to quantify/unquantifiable benefits and costs; and (4) a stranded cost analysis (Draft Filing Requirements at 2). Additionally, under the Draft Filing Requirements, each company must present an overall assessment of whether its business case justifies the proposed investments (Draft Filing Requirements at 2).

The Draft Template consisted of tabs the companies must fill out, and included summary information and analysis regarding quantifiable and unquantifiable benefits and costs as well as an analysis of stranded costs (Draft Filing Requirements at 2). The Department developed the Draft Template in order to assist the Department and other parties in the review of each company's business case.

The Department has given careful consideration to all of the comments submitted by the participants in this proceeding. We have adopted a number of the recommendations in developing the final versions of the Filing Requirements and Template. We conclude that a number of arguments raised in the comments warrant specific discussion in this Order. As such, in the sections that follow we will address the following issues: (1) composite business case; (2) business case components; (3) STIP investments and incremental STIP investments; (4) alternative and least-cost investments; (5) common assumptions; (6) common analysis

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5 As discussed in D.P.U. 12-76-B, a company may also propose an alternative STIP with a corresponding business case if the benefits of implementing advanced metering functionality within five years do not justify the costs. D.P.U. 12-76-B at 17.

methods; (7) unquantifiable benefits; (8) stranded cost analysis; (9) bill impact analysis; (10) template structure; (11) allocation of benefits; (12) preventing double counting; and (13) granularity of data.

## B. Composite Business Case

### 1. Introduction and Summary of Comments

The Draft Filing Requirements provided that each STIP must include one composite business case to justify the STIP investments (Draft Filing Requirements at 1). National Grid supports the use of a composite business case to review all STIP investments as a single package (National Grid Comments at 3). Other participants recommend that the Department instead require that each individual STIP investment be supported by a separate business case (Joint Redline at 2; Northeast Utilities Comments at 9-11; Northeast Utilities Redline at 2). Northeast Utilities argues that aggregating grid modernization investments under one umbrella business case would result in investments that might not be justified by their own individual business cases (Northeast Utilities Comments at 9). Northeast Utilities further asserts that a composite business case also may make it difficult to parse out cost and benefit information for a specific investment (Northeast Utilities Comments at 10).[6] Unitil does not oppose the composite business case, but states that it expects that each proposed STIP investment also will be justified based on a standalone business case (Unitil Redline at 1).

6 Northeast Utilities also suggests that companies undertake a business case analysis, including a benefit-cost component, for all investments in the GMP (i.e., for all proposed investments over the ten-year GMP timeframe) (Northeast Utilities Comments at 7-9). The Department declines to expand the business case analysis beyond STIP investments given that cost and investment planning over such a large timeline will be speculative and prone to changes due to the rapidly evolving nature of technology.

2. Analysis and Conclusions

After consideration of the arguments raised by participants to require a separate business case for each STIP investment, the Department is not persuaded to revise its requirement that companies provide a composite business case for all STIP investments. Rather, we conclude that a composite business case will provide a more comprehensive view of the proposed STIP by examining the costs and benefits of the full package of grid modernization investments.

The Department has previously found that seemingly stand-alone capital projects may be interrelated to such an extent that these projects are more appropriately examined as part of a single analysis. See, e.g., Massachusetts-American Water Company, D.P.U. 95-118, at 56 (1996). As discussed in the Report at 11-21, many technologies that are required to enable grid modernization functionalities can be leveraged to achieve improvement in multiple objectives. For instance, a company's investment in a communications system for a distribution automation project may not provide a positive business case when evaluated as a single project; however, evaluating this system based on the technologies that it enables, (e.g., advanced metering, distribution automation, and voltage regulation), which will lead to measureable progress in multiple objectives, may produce a positive business case.

With respect to the argument that a composite business case will prevent the appropriate evaluation of individual investments, the Department concludes that the level of data and documentation required as part of the STIP, including the Template, will enable sufficient review of proposed investments, both on a combined basis and for individual projects. Therefore, we affirm that when evaluating a STIP, the Department will look to the company's business case as the primary lens for evaluation, and requires that all capital investments in the STIP be supported by one comprehensive business case.

### C. Business Case Filing Requirements

#### 1. Business Case Components

##### a. Introduction and Summary of Comments

Under the Draft Filing Requirements, the business case would be organized into four primary parts: (1) goals, scope and scale, and drivers for investments; (2) detailed descriptions of the proposed investments, and identification and quantification of all quantifiable benefits and costs associated with the STIP; (3) identification of all difficult to quantify/unquantifiable benefits and costs; and (4) a stranded cost analysis (Draft Filing Requirements at 2).

ENE proposes an alternative organization based on five components, including the addition of an analysis of how the STIP will enable the achievement of metrics and state policy goals and an overall justification of the STIP (ENE Comments at 6-7). Specifically, ENE recommends structuring the business case on the following five primary components: (1) descriptions of technologies; (2) description of investment scenarios including baseline, proposed STIP, and other alternatives; (3) costs and benefits; (4) achievement of metrics and state policy goals; and (5) overall justification of the STIP (ENE Comments at 6-7; ENE Redline at 2). Additionally, participants suggest the addition of: (1) a revenue requirements analysis; and (2) bill impact analyses (Joint Comments at 6-9; ENE Comments at 7; Fauth Redline at 2; National Grid Comments at 4).

b. Analysis and Conclusions

Upon review, we have adjusted the components of the business case in a number of ways. First, we adopt ENE's proposal to add a separate section to the business case analysis to demonstrate how the proposed STIP will impact performance metrics and state policy goals. Additionally, while the Draft Filing Requirements required each company to present an overall assessment of whether its business case justifies the proposed investments, we adopt ENE's proposal to include this overall justification of the STIP as a separate component of the business case.

The overall justification section will provide a summary of the costs and benefits of the STIP, while weighing other information that will influence the justification for the business case. The stranded cost analysis, a separate component under the Draft Filing Requirements, will now be included within the overall justification section. In addition, as proposed by participants, the Department finds that it is appropriate to include an analysis of how the companies' STIPs will affect customers' bills as part of the overall justification of the STIP. Therefore, as detailed in the Filing Requirements, the Department requires each business case to include the following components: (1) goals and drivers for investments; (2) technology/project descriptions; (3) costs and benefits, including both quantifiable and unquantifiable costs and benefits; (4) achievement of performance metrics and state policy goals; and (5) an overall assessment of the STIP.

2. STIP Investments and Incremental STIP Investments

a. Introduction and Summary of Comments

In the Draft Filing Requirements, the Department directed companies to include within their business cases the benefits and costs of their STIP investments (Draft Filing Requirements at 1, 3, 4, 6-7). The Joint Commenters assert that, in order to prevent double counting and to establish a clear and traceable understanding of STIP benefits and costs, the Department should require each company to identify a baseline against which the STIP-specific incremental impacts of costs and benefits may be tracked as distinct from historic practice or other current and future programs (Joint Comments at 10-12 & n.17, 17-18, 24; Joint Redline at 4-6, 8-10). ENE proposes incorporating a forward-looking baseline scenario into the Filing Requirements (ENE Comments at 6; ENE Redline at 2-3). Specifically regarding a prospective transition to advanced metering functionality through the widespread installation of advanced metering infrastructure ("AMI"), Northeast Utilities argues that companies must analyze only those benefits provided by AMI in excess of a baseline level of automatic meter reading ("AMR") benefits (Northeast Utilities Comments at 5).

b. Analysis and Conclusions

In D.P.U. 12-76-B at 15-18, the Department stated that each company's STIP will include all new grid modernization investments to be made over the next five years, including those that are not incremental to current practice. Consequently, all benefits and the costs associated with new grid modernization investments will be included in the business case.

In terms of capital costs, a company must include all direct capital costs and capitalized overhead costs, and must only include those benefits that it projects will accrue from the new STIP investments and not from any prior investments. See Filing Requirements at 1. In terms of non-capitalized O&M costs that are integral to the STIP and achievements of its benefits, a company must include only the change in projected O&M expenses attributed to STIP investments; any increase in expenses should be counted as a cost and any decrease should be counted as a benefit. See Filing Requirements at 1, Template Key Terms tab. In addition, we direct companies to include as a benefit the avoided costs of replacing current technologies with like technologies for those investments that will reach the ends of their useful lives within the benefit-cost analysis time horizon ("BCA time horizon").

In terms of a baseline, the companies must clearly present and support any baseline information that they use to calculate the costs and benefits of proposed STIP investments. Beyond this, however, the Department declines to require the companies to develop a comprehensive investment baseline to show that proposed benefits and costs are incremental to historic or future investment practices, as proposed by some participants.

In D.P.U. 12-76-B, the Department distinguished between incremental and non-incremental grid modernization investments for the purposes of cost recovery. In particular, we determined that only capital expenditures included in the STIP that are incremental to current practice are eligible for targeted cost recovery through a capital expenditure tracker mechanism. D.P.U. 12-76-B at 22-23. Further, we found that only technologies that are either new types of technology or with respect to which there is an increase in the level of investment a company proposes relative to its current investment practices will qualify as incremental. D.P.U. 12-76-B at 19-20. We require that incremental investments: (1) be addressed in a separate table and narrative (see Filing Requirements at 3); (2) be identified in the Costs tab in the Template; and (3) be used in the bill impacts analysis, as discussed in Section II.C.9. For any technologies that a company identifies as incremental in the Template, the company must provide evidence that the technology meets our definition of incremental, including a comparison of current investment with proposed investments.

3. Alternative and Least-Cost Investments

a. Introduction and Summary of Comments

The Draft Filing Requirements proposed that each company include a clear statement of its reasoning and rationale for its proposed STIP investments, including a discussion of any alternative investments considered and the rationale for choosing the proposed suite of investments (Draft Filing Requirements at 2).

Several participants suggest that the Department require the companies to provide an analysis of alternative investments considered as part of their STIP business case (DOER Redline at 2; ENE Comments at 6-7; ENE Redline at 2). National Grid argues that any mandate to discuss alternative investments be limited to a company's planning framework (i.e., investments considered, evaluation process and decision criteria) rather than a requirement to discuss each alternative technology considered (National Grid Comments at 4). The Joint Commenters assert that companies should propose least-cost investments within their business cases and explain the rationale for deviating from a least-cost investment approach (Joint Comments at 3, 24; Joint Redline at 3).

b. Analysis and Conclusions

After consideration of the arguments raised by the participants, the Department concludes that a discussion of alternative investments in the business case should be limited in scope to a company's distribution planning framework process. Our intention in requiring companies to discuss alternative investments is to provide a high level analysis of the range of investments a company considered and its evaluation criteria for these proposed STIP investments. We do not seek a detailed comparative analysis of proposed STIP investments to the universe of all other potential investments. Accordingly, we have amended the Filing Requirements to reflect this intent.

In addition, the Department declines to adopt the recommendation that companies be required to justify all proposed investments against a benchmark of least-cost alternatives. As discussed in D.P.U. 12-76-B at 16, the business case will be the primary lens to assess the STIP. Central to this business case framework is that the benefits of proposed investments must justify the costs. Given the range of possible grid modernization proposals and investment options, it would be infeasible to require that such proposals be benchmarked against least-cost alternatives.

4. Costs and Benefits

a. Introduction and Summary of Comments

The Draft Filing Requirements proposed requiring each company to evaluate the full suite of costs and benefits that result from its investment plan, including an itemization and analysis of all quantifiable costs and benefits, as well an assessment of difficult to quantify or unquantifiable benefits (Draft Filing Requirements at 3-7). The companies request that costs and benefits for proposed investments be presented in a range, rather than as a single figure (Northeast Utilities Response to Briefing Question 4; National Grid Comments at 1; Unitil Response to Briefing Question 4). In addition to a range estimate, Unitil proposes application of a sensitivity analysis to address expectations of uncertainty in estimates (Unitil Response to Briefing Question 4).

b. Analysis and Conclusions

The Department declines to adopt the companies' proposal to provide a range of estimates for costs and benefits for a company's proposed grid modernization investments. We direct companies to include a single dollar value for the present value of each monetized cost and benefit in the Template. Instead of providing a range of estimates, the Department directs companies to perform sensitivity analyses, if estimates are uncertain.

Although we recognize that cost and benefit estimates may need to be revised and refined during the development and implementation of a company's GMP, the Department directs each company to include its best estimates of costs and benefits at the time its STIP is submitted to the Department. The Department directs the companies to attempt to monetize all costs and benefits to the extent possible using vendor quotes, estimates from in-state pilot projects, and data from relevant case studies in other jurisdictions. To the extent that costs and benefits cannot be monetized, the Department directs companies to attempt to quantify them to the extent possible.

5. Common Assumptions

a. Introduction and Summary of Comments

In calculating quantifiable benefits and costs, the Draft Filing Requirements identified seven common assumptions and values for the companies to jointly develop: (1) rate of inflation; (2) energy forecast; (3) demand forecast; (4) forecast of energy prices; (5) forecast of capacity prices; (6) forecast of demand reduction induced price effects (also referred to as "market price suppression"); and (7) forecast of renewable energy certificate ("REC") costs (Draft Filing Requirements at 3-4). Additionally, the Department issued a briefing question about the possibility of leveraging data from studies in other Department proceedings to develop values for common assumptions (Briefing Question 3).

Several participants assert that forecasts of energy, demand, and demand-induced reduction price effects should be company-specific, rather than common assumptions (Unitil

Redline at 5; ENE Comments at 6; ENE Redline at 4). Other participants propose additional common assumptions relative to: (1) greenhouse gas compliance costs, (2) avoided SOx, NOx, PM-10 compliance costs, and (3) other fuel prices (DOER Redline at 4; ENE Comments at 6, ENE Redline at 4).

In response to the Department's briefing question, several participants suggest that the Department may be able to use studies and work from other Department dockets as a starting point in establishing some of the common assumptions (National Grid Comments at 20-21; DOER Comments at 3; ENE Comments at 4-5). However, participants also caution that if the Department seeks to rely on studies such as Avoided Energy Supply Costs in New England ("2013 AESC")[7] for demand-induced price effects, the assumptions in that study would need to be updated to apply to grid modernization (National Grid Comments at 20-21; ENE Comments at 4-5; Northeast Utilities Comments at 19). DOER suggests that to calculate the costs of greenhouse gas emissions reduction, the Department may be able to incorporate work from Method for Calculating Avoided Costs of Complying with Global Warming Solutions Act, D.P.U. 14-86 (DOER Comments at 3).

The Joint Commenters object to the use of studies from other proceedings to develop common assumptions because they assert that: (1) the use of studies from other dockets would deprive parties of their due process rights to evaluate those studies; (2) the applicability of those studies to grid modernization has not been evaluated; and (3) the timing of those studies

7 The most recent version of this study is the Avoided Energy Supply Costs in New England: 2013 Report (July 12, 2013), available at http://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england.

relative to GMP filings might render any cost and benefit data from those studies outdated (Joint Comments at 18-20).

Several participants request that the Department create a stakeholder process and commission new studies to establish the values for the common assumptions before the companies file their GMPs (Northeast Utilities Comments at 11-13; Unitil Redline at 4-5). These participants argue that establishing the common assumptions before companies file GMPs will faciliate the review process and reduce delays implementing GMPs that may result from modification or changes in the assumptions (Northeast Utilities Comments at 11-13; Unitil Redline at 4-5).

b. Analysis and Conclusions

After consideration of the comments, we adopt some of the recommended changes and provide additional guidance on establishing the common assumptions. First, we agree that each company's demand and energy forecasts are more appropriate as company-specific assumptions because each company has significant experience in this area given the unique demographics and economic conditions of its service territory. Accordingly, we have removed these two from the list of common assumptions for companies to jointly develop.

As the companies develop their common forecasts for energy prices, capacity prices, demand reduction induced price effects, and renewable energy portfolio standard ("RPS") compliance costs, they should leverage similar studies, such as those conducted for the review of long-term contracts for renewable energy procured under Section 83A, and the AESC, to the extent that assumptions across the studies are comparable and the timing of such studies are applicable to that of the GMPs. See, e.g., Fitchburg Gas and Electric Light Company et al., D.P.U. 13-146/13-147/13-148/13-149, at 46-48 (February 26, 2014). Embedded in any forecast will be projections of future prices of fuels such as natural gas, oil, and gasoline, as well as compliance costs for environmental regulations limiting pollutants such as SOx, NOx, and PM-10, and to some degree, greenhouse gas emissions (i.e., through the Regional Greenhouse Gas Initiative). All assumptions must be well documented in a transparent manner that is easily reviewable by the Department and other stakeholders. We also note that a company's use of data or forecasts, as well as any underlying assumptions, from other proceedings will not preclude parties to the GMP proceedings from fully investigating those inputs within the GMP proceedings.

In terms of compliance costs for reducing greenhouse gas emissions, we expect that any jointly developed forecast of electricity prices will include compliance with the Global Warming Solutions Act ("GWSA")[8], either as an embedded cost within the electricity price forecast or through a method similar to that contemplated in D.P.U. 14-86, pending the outcome of that proceeding. If the companies are not able to monetize the benefits of avoided GWSA compliance costs, we direct the companies to include qualitative assessments of the contribution their STIP proposals will provide to this benefit in their analyses of difficult to quantify benefits. We include compliance with the GWSA as an additional common assumption.

In addition, the Department declines to create a stakeholder process to establish the values for the common assumptions before the companies file their GMPs. We expect that the companies will be able to jointly develop appropriate common assumptions. The Department

[8] St.2008, c. 298.

and other stakeholders will have the ability to assess any common assumptions, and their underlying methods, during the adjudication of GMPs.

6. Common Analysis Methods

a. Introduction

The Draft Filing Requirements identified four common analysis methods for the companies to use in calculating quantifiable benefits and costs in their business cases: (1) treatment of stranded costs, (2) discount rate, (3) benefit-cost analysis time horizon ("BCA time horizon"), and (4) sensitivity analyses (Draft Filing Requirements at 4-5). Additionally, the Department issued a briefing question regarding whether the weighted average cost of capital ("WACC") or the 20-year Treasury bond rate was the most appropriate discount rate for evaluating benefits and costs of GMP investments in the STIP proposals (Briefing Question 1).

In addition, in finalizing the Filing Requirements, we add a common analysis method regarding customer response to time varying rates. We address the discount rate, BCA time horizon, time varying rates, and sensitivity analyses, below. We address the treatment of stranded costs in Section II.C.8.

b. Discount Rate

i. Introduction and Summary of Comments

In the Draft Filing Requirements, the Department proposed that companies employ a discount rate of the WACC and/or the 20-year Treasury bond rate, as appropriate (Draft Filing Requirements at 5). Several participants supported the WACC as the appropriate discount rate for grid modernization investments rather than the 20-year Treasury bond rate (Northeast Utilities Comments at 18; National Grid Comments at 15-16; Unitil Response to Briefing

Question 1; Joint Comments at 13-15). These participants argue that using the WACC is consistent with best practices of utilities and regulators in other jurisdictions evaluating advanced metering and smart grid investments, as well as with the rate the companies use to analyze investments (National Grid Comments at 16-18; Northeast Utilities Comments at 18; Unitil Response to Briefing Question 1; Joint Comments at 15). Fauth suggests that the WACC is the appropriate rate to apply to discount utility costs, while the 20-year Treasury bond rate might be appropriate to apply to customer costs and benefits[9] (Fauth Comments at 1).

DOER and ENE propose that the Department adopt the 20-year Treasury bond rate as the discount rate, asserting that STIP investments constitute a lower risk profile than continuing with business-as-usual distribution investments and based on the argument that such STIP investments are backed by legislation (DOER Comments at 3; ENE Comments at 3-4). National Grid and ENE suggest a requirement that companies conduct a sensitivity analysis for the discount rate to illustrate alternative perspectives (National Grid Comments at 18-19; ENE Comments at 3-4).

ii. Analysis and Conclusions

The Department is persuaded by the comments from participants that the company-specific WACC is the appropriate discount rate for companies to use in their business cases. While we view the risk profile for those STIP grid modernization investments eligible for preferential cost recovery to be lower than the risks associated with other distribution-related investments, this observation does not necessarily lead to the conclusion

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9 Fauth suggests that because the Treasury bill rate is such a low rate, it may be more appropriate to create a customer discount rate for benefits based on a weighted average of the common consumer borrowing costs (Fauth Comments at 2).

that 20-year Treasury bond rates represents a reasonable or appropriate discount rate. In view of prevailing practices and the companies' reliance on the WACC to evaluate non-grid modernization investments, we find that the WACC represents the appropriate discount rate. However, as a means to illustrate how the value of the benefit streams may be influenced by an alternative discount rate, we direct companies to conduct a sensitivity analysis that uses the 20-year Treasury bond rate as the discount rate for all benefits accruing directly to customers, as designated in the Template.

c. Benefit-Cost Analysis Time Horizon

i. Introduction and Summary of Comments

In the Draft Filing Requirements the Department proposed a common approach to a BCA time horizon of projecting out costs and benefits to the end of the depreciable life of the technology or asset in question (Draft Filing Requirements at 5). Unitil and Northeast Utilities assert that because each company may deploy different technologies with a unique lifespan a common analysis method for the BCA time horizon may not be appropriate (Unitil Redline at 5; Northeast Utilities Comments at 14). National Grid proposes a 15-year BCA time horizon for the evaluation of all STIP investments, a period of time that is aligned with the economic life of advanced meters, and long enough to capture STIP investment costs while realizing projected benefits (National Grid Comments at 10).

ii. Analysis and Conclusions

The Department agrees with National Grid's proposal to adopt a fixed time horizon for the benefit-cost analysis. To simplify and standardize the review process of the business cases, the Department directs the companies to use 15 years as the time horizon to discount costs and benefits for all STIP investments. The Department also directs companies to conduct a sensitivity analysis for the BCA time horizon, using 20 years to permit an analysis of how the overall values of benefits and costs will vary based on changes in this assumption.

d. Time Varying Rates

i. Introduction

In Time Varying Rates, D.P.U. 14-04-C (November 5, 2014), the Department adopted a policy framework for the implementation of time varying rates for basic service. In particular, the default basic service offering will be a time of use rate, with a critical peak pricing component. Customers may opt out of the time of use rate and into a flat rate with a peak time rebate ("PTR") component. D.P.U. 14-04-C at 2, 20. The Department finds it appropriate to add an additional common analysis method applicable to each company's assessment of time varying rates.

ii. Analysis and Conclusions

The Department requires the companies to include in their business case analyses the implementation of the time varying rates framework established in D.P.U. 14-04-C. At a minimum, such analyses must include an estimate of the benefits and costs associated with customer peak load response to time varying rates.[10] A number of key variables will affect the impact and, therefore, the benefits of the time varying rate framework. These variables include: (1) customer peak load reduction in response to time varying rates; (2) the percentage of customers that opt out of advanced metering functionality technology (e.g., advanced meters); (3) the percentage of customers that opt out of the default basic service rate offering

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10 The companies also should include, as applicable, the benefits of time varying rates related to: (1) overall conservation; (2) off-peak charging of electric vehicles; (3) energy storage; and (4) solar energy resources. See D.P.U. 14-04-C at 3.

and receive service under a flat rate with a PTR component; (4) the persistence over time of the level of customer response; and (5) the percentage of customers served by competitive suppliers who opt to receive flat rate service.

The key assumption in this analysis will be the level of customer peak load reduction in response to time varying rates. To develop company-specific values for this assumption, the companies should use a common analysis method to estimate the peak period response of customers that corresponds to the critical peak, peak, and off-peak electricity price ratios, based on the companies' forecasts. This method should use the common forecast of energy and capacity prices to calculate electricity price ratios and consider evidence from industry pilots and deployments of time varying rates to estimate the corresponding peak load reductions and energy savings by customers.[11] We expect that this common method will provide each company with discretion in estimating a load response that appropriately reflects the unique characteristics of its service territory while taking into account the energy price

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11 See, e.g., Ahmad Faruqui and Jenny Palmer, The Discovery of Price Responsiveness: A Survey of Experiments Involving Dynamic Pricing of Electricity, EDI Quarterly, 4(1), at 15-18 (2012) available at http://www.energydelta.org/uploads/bestanden/f5ef3dfc-81ee-41f1-9ffd-2faa24bd1c2f; NSTAR Electric Company, D.P.U. 09-33, NSTAR Smart Grid Pilot Final Technical Report (June 30, 2014); Ahmad Faruqui and Sanem Sergici, Impact Evaluation of CL&P's Plan-it Wise Energy Program: Final Results, The Brattle Group, at 16 (November 2, 2009) available at http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/PlanItWiseAppendix/$File/Plan-it%20Wise%20Pilot%20Results%20Appendix.pdf; Sacramento Municipal Utility District, SmartPricing Options Final Evaluation at 4, 74-75, 83 (September 5, 2014) available at https://www.smartgrid.gov/document/smartpricing_options_final_evaluation; Global Energy Partners, OG&E Smart Study Together Impact Results: Auxiliary Final Report – Summer 2011 (April 23, 2012) available at https://smartgrid.gov/sites/default/files/doc/files/Chapter_4_Load_Impact_Results_2011.pdf

forecast. In developing its estimate of customer response, we expect each company also will take into account other factors affecting this value, including climatic conditions, appliance saturation rates, customer education and awareness of rate structures, and other relevant customer demographic information.

In addition, we direct the companies to use common analysis methods for: (1) the percentage of customers that opt out of advanced metering functionality technology (e.g., advanced meters); (2) the percentage of customers that opt out of the default basic service rate offering and receive service under a flat rate with a PTR component; (3) the persistence over time of the level of customer response; and (4) the percentage of customers served by competitive suppliers who opt to receive flat rate service. These common analysis methods should lead to reasonable estimates, based on available studies and evidence from pilots and deployments in the Commonwealth and in other jurisdictions.

We conclude that this common analysis approach is an appropriate way to incorporate our time varying rates framework into the companies' business case analyses. However, we acknowledge that there is uncertainty in estimating these variables. Therefore, we expect each company to present at least two additional scenarios that evaluate a lower and higher estimate of the customer response rate to assess the sensitivity of its business case results to varying customer response rates. These lower and higher estimates should be in line with low and high impact results from pilots and deployments. Further, we direct the companies to conduct an additional scenario based on the assumption that all distribution customers are subject to a time of use rate with a critical peak pricing component, akin to the Department's framework for time varying rates for basic service.[12]

e. Other Sensitivity Analyses

i. Introduction and Summary of Comments

The Draft Filing Requirements proposed requiring each company to include sensitivity analyses for a limited set of variables, to be determined by the company, to arrive at a reasonable range of quantifiable benefits and/or costs (Draft Filing Requirements at 5). Northeast Utilities states that the variables a company selects for a sensitivity analysis may differ as they will be specific to the types of investments a company selects (Northeast Utilities Comments at 13-14).

ii. Analysis and Conclusions

In the final Filing Requirements, the Department amends the table of required sensitivity analyses to include the sensitivity analyses related to the discount rate, BCA time horizon, and time varying rates, as discussed above. In addition to these required sensitivity analyses, we agree that other sensitivity analyses may differ by company depending on the investment profile. We expect that each company will conduct other company-specific sensitivity analyses based on the criteria laid out in the Filing Requirements.

12 This assumption reflects the perspective that time varying rate products will become the new norm for electricity supply. This perspective reflects the assumptions that: (1) achievement of advanced metering functionality will allow broad deployment of time varying rates; (2) retail competitive suppliers will build off marketing and education efforts by distribution companies and others in support of time varying rates; and (3) time varying rate structures will provide most customers with opportunities to shift load and save money.

7. Identification of Difficult to Quantify/Unquantifiable Benefits and Costs

a. Introduction and Summary of Comments

In the Draft Filing Requirements, the Department proposed directing the companies to provide a weight for all unquantifiable variables included in the Template and a narrative explanation of the weight assigned (Draft Filing Requirements at 5-6). Additionally, the Department issued a briefing question soliciting feedback from participants on what additional guidance the companies seek from the Department in assessing and ranking unquantifiable benefits (Briefing Question 5). Several participants request further guidance on evaluating unquantifiable benefits, as well as on the role that unquantifiable benefits will have for cost recovery purposes (ENE Comments at 5; DOER Comments at 3; Joint Comments at 21-23; Unitil Redline at 6; Northeast Utilities Comments at 20). ENE suggests that the Department determine which categories of benefits should be (1) quantifiable and monetized, (2) quantifiable but not monetized, and (3) unquantifiable (ENE Comments at 5). DOER recommends adoption of an explicit formulaic treatment of the weights for unquantifiable benefits (DOER Comments at 3). The Joint Commenters maintain that while the Department cannot rely on qualitative or unquantifiable benefits as part of the cost effectiveness analysis in the business case, it may allow these benefits to be qualitatively described in the business case (Joint Comments at 21-23). Fauth suggests that the Department should consider requiring companies to quantify some benefits that the Department acknowledges may be difficult to quantify, such as reliability (Fauth Comments at 3).

b. Analysis and Conclusions

In response to participants' requests for guidance on how to categorize both quantifiable and unquantifiable benefits, we have revised the Template to require companies to identify those benefits that are: (1) quantified and monetized; (2) quantified but not possible to monetize; and (3) not quantifiable (Template, Benefits Tab 3). Each company must include full descriptions of unquantifiable benefits in the Template. The Filing Requirements direct companies to provide in their business case narratives an explanation of the contribution of the unquantifiable benefits to state policy goals and Department mandates, including the weights companies give to these benefits in the overall business case analysis. As part of the GMP review process, all parties will have the opportunity to evaluate and suggest alternatives to a company's determination of the value of the unquantifiable benefits to its STIP.

Several participants requested guidance on the criteria companies will use to weigh the unquantifiable benefits and suggested that the Department establish weights to standardize company analysis of the unquantifiable benefits. We acknowledge that in the first iteration of the GMPs, companies and stakeholders may have difficulty in evaluating unquantifiable benefits across companies. Nonetheless, the Department will not prescribe standard weights at this time. However, the Department and other stakeholders will assess how each company weighed unquantifiable benefits within its STIP as part of the GMP review.

8. Stranded Costs

a. Introduction and Summary of Comments

In the Draft Filing Requirements, the Department proposed requiring that companies exclude the undepreciated value of existing assets from their presentations of costs and benefits (Draft Filing Requirements at 5, 7-8). However, the Department recognized that the magnitude of stranded costs may inform a company's business case and the timing of proposed investments (Draft Filing Requirements at 5, 7-8). As a result, the Department proposed requiring the companies to submit separate accountings of estimated stranded costs associated with existing capital equipment that they propose to replace as a result of the proposed STIP investments, as well as a narrative regarding the expected impact of these costs on the company's overall business case (Draft Filing Requirements at 5, 7-8).

National Grid suggests that the Stranded Costs tab of the Department's Template should include a time dimension to show the difference between date of retirement and the end of useful life for stranded assets (National Grid Comments at 11). Further, National Grid proposes that companies provide amortization schedules and carrying charges for the undepreciated portion of stranded assets in order to facilitate Department rulings on cost recovery for stranded assets at the same time as issuing a STIP decision (National Grid Comments at 11). According to National Grid, companies must be allowed to recover the undepreciated value and appropriate carrying charges of used and useful assets that are stranded as a result of grid modernization within a certain timeframe, and this approval should be provided as part of the Department's approval of the STIP and GMP (National Grid Comments at 8-9, 11).

Northeast Utilities asserts that the Department's decision to exclude stranded costs from the benefit-cost analysis of the business case is contrary to the Department's own cost recovery prudency standards and is an attempt to manipulate the business case analysis to force a positive outcome for AMI (Northeast Utilities Comments at 4, 6-7). Northeast Utilities further argues that stranded costs associated with the removal of existing capital equipment (such as AMR meters) that would not be retired but for grid modernization should be included in a company's cost benefit analysis as part of the STIP investment business case, and that without the inclusion of stranded costs, a business case will not reflect the true cost of the investment (Northeast Utilities Comments at 4-6).

Unitil proposes including a sensitivity analysis of stranded costs to determine the effect of stranded costs and overall impact on customers flowing from investment decisions within the business case (Unitil Redline at 5, 8). Unitil maintains that the outcome of the sensitivity analysis should dictate whether stranded costs are properly includable in the decision-making process, and that the Department should allow depreciation and stranded costs within a company's economic evaluation (Unitil Redline at 5,7-8).

b. Analysis and Conclusions

The Department has considered the various arguments raised by participants and reaffirms the approach to stranded costs proposed in the Draft Filing Requirements. As discussed in Section II.C.2., above, the benefit and cost analysis portion of a company's STIP business case will be forward-looking and, therefore, only the costs of new investments and the benefits that flow from those investments are appropriate for inclusion.[13] However, as discussed in the Filing Requirements at 8-9, we have included an analysis of stranded costs as a component within the overall justification section of the business case. We expect each company to assess the magnitude of potential stranded costs when determining the timing of

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[13] This finding is consistent with the principle that an analysis of benefits and costs used to assess a forward-looking investment should not include previously expended costs (i.e., sunk costs). See, e.g., N. GREGORY MANKIW, PRINCIPLES OF ECONOMICS 286-287 (Cengage Learning, 7th ed., 2014); PAUL KRUGMAN ET AL., ESSENTIALS OF ECONOMICS 210 (Worth Publishers, 2d ed. 2010); OFFICE OF MGMT. & BUDGET, EXECUTIVE OFFICE OF THE PRESIDENT, OMB CIRCULAR A-94. MEMORANDUM FOR HEADS OF EXECUTIVE DEPARTMENTS AND ESTABLISHMENTS: GUIDELINES AND DISCOUNT RATES FOR BENEFIT-COST ANALYSIS OF FEDERAL PROGRAMS 6.a (1992), available at http://www.whitehouse.gov/omb/circulars_a094#6.

proposed STIP investments and explain how stranded costs affect the business case. In addition, the companies must provide the remaining depreciable life of these assets in the Stranded Costs tab of the Template.

Regarding National Grid's proposal to review stranded cost recovery proposals as part of GMP review, we note that the Department has a significant body of precedent regarding the ratemaking treatment of stranded costs.[14] The companies may file proposals for the treatment of retired plant as an extraordinary loss consistent with the Uniform System of Accounts for Electric Companies ("USOA") and the Department's ratemaking practice within their GMPs (see Filing Requirements at 9, n.8).

9. Bill Impact Analysis

a. Introduction and Summary of Comments

As discussed above, the Department amends the Filing Requirements to include a bill impact analysis as proposed by some participants. The Joint Commenters suggest that companies file two distinct types of bill impact analyses: (1) a bill impact analysis of the STIP; and (2) bill impact analyses of all known rate changes that will occur during the STIP cost recovery period (Joint Comments at 6-9).

14 See, e.g., Milford Water Company, D.P.U. 12-86, at 29-77 (2013) (water treatment plant); Bay State Gas Company, D.T.E. 05-27, at 197-200 (2005) (meter reading technology); Boston Gas Company, D.P.U. 93-60, at 41-44 (1993) (SNG plant); Boston Edison Company, D.P.U. 18515, at 10-11 (1976) (pollution control devices); Fitchburg Gas and Electric Light Company, D.P.U. 18031-A at n.1 (1975) (generating plant); Western Massachusetts Electric Company, D.P.U. 558, at 39-41 (1982) (gas-fired turbines); Worcester Gas Light Company, D.P.U. 16316, at 8 (1970) (manufactured gas facilities).

b. Analysis and Conclusions

A bill impact analysis is generally used to show the impact on bills of a specific and discrete change in the rates customers will face from a specific charge (or credit). In their STIPs, the companies must include two types of grid modernization investments, those that are non-incremental to current practice and incremental investments. Recovery of the costs of non-incremental investments will be addressed in the future through traditional ratemaking means (e.g., rate cases). Therefore, we exclude such investments from the bill impact analysis. The Department determines that the appropriate bill impact analysis will capture the bill impacts of the incremental investment in new technologies or new levels of investment resulting from grid modernization, those that the company would likely not make but for our grid modernization proceeding. Therefore, the Department concludes that the most appropriate bill impact analysis is of costs the companies project to recover through their capital expenditure trackers. We direct the companies to include a bill impact analysis for each year of the STIP (e.g., five years) that includes the investments a company proposes to recover through the capital expenditure tracker.[15]

We emphasize, however, that a bill impact analysis must not be examined in isolation, as STIP investments also will result in lower customer bills relative to what they otherwise would have been through reduced utility costs, and other benefits that accrue to customers. Therefore, a bill impact analysis is appropriately viewed as one component of the larger

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15 A traditional bill impact analysis shows: (1) the existing charges; (2) the proposed charges; (3) the percentage change in the charges; (4) the total dollar change in total monthly bill at various consumption levels; and (5) the percentage change in the total bill per month at various consumption levels. See 220 C.M.R. §§ 5.03, 5.06.

business case necessary to assess the short-term rate impacts of the STIP and in context of the full benefits of grid modernization investments identified elsewhere in the business case.

Finally, we decline to require companies to provide an analysis of all known rate changes that will occur during the STIP cost recovery period. As discussed above, a bill impact analysis will allow the Department to examine near-term rate impacts as a result of the proposed STIP investments. Including other rate changes over the STIP planning horizon would involve numerous assumptions and uncertainty, making it difficult, if not impossible, to draw any conclusions from such an analysis.

D. Business Case Summary Template

1. Introduction

The Department developed and proposed the Draft Template for the companies to provide summary information and analysis regarding quantifiable and unquantifiable benefits and costs as well as an analysis of stranded costs (Draft Filing Requirements at 2). By requiring the use of the Template, the Department seeks to promote a level of transparency, uniformity, and granularity in the data and analyses underlying each company's business case.

In their GMP filings, the companies will itemize and quantify each cost and benefit associated with their proposed grid modernization technology investments. To facilitate this task, in the Draft Template the Department provided reference lists of costs and benefits, as well as functional and technology categories commonly associated with grid modernization investments. The Department also instructed each company to add categories of costs, benefits, functions, and technologies that were not already included in the Draft Template, as needed, to accurately reflect each company's proposed STIP investments.

2. Structure of Template

a. Introduction and Summary of Comments

The Draft Template was designed to provide a snapshot of each company's benefits and costs associated with its proposed STIP investments. The Draft Template was organized into three main data entry tabs: (1) Benefits; (2) Costs; and (3) Stranded Costs, and six main reference tabs: (1) Overview; (2) Instructions; (3) Key Definitions; (4) List of Benefits; (5) List of Costs; and (6) Glossary. Using the reference lists as a guide, the companies would enter information about their portfolio of selected technologies and corresponding functions, and then identify and assign values to the benefits and costs associated with those investments.

Participants state that building some degree of flexibility into the structure of the Template is necessary to account for changes in costs, benefits, and assumptions over time (e.g., changes introduced by emerging technologies, or best practices from other jurisdictions) (DOER Comments at 2; National Grid Comments at 2-3, 12). Participants assert that the Department should allow the companies to: (1) modify the structure of the Template as they develop their STIP proposals (National Grid Comments at 2, 3-4); (2) use the Template as a guide in organizing costs, benefits, and functions, without requiring the mandatory application of a pre-defined template (National Grid Comments at 2, 11); or (3) add new items to the Template, as needed (DOER Comments at 2; ENE Comments at 3; Joint Comments at 9; National Grid Comments at 3). Unitil asserts that the Department should not require companies to investigate the costs and benefits of every technology, system, or device listed in the Template (Unitil Redline at 2).

Several participants propose adding: (1) new categories of benefits for distributed energy resources ("DER"), resiliency, safety, and transmission capital savings (DOER

Comments at 2; ENE Comments at 8; National Grid Comments at 14); (2) new categories of costs related to DERs, customer contacts, cyber security, and storage capacity (Joint Comments at 23, 24); (3) new and/or expanded definitions for key terms (ENE Comments at 3, 8; National Grid Comments at 12, 15); (4) summary tables of overall costs and benefits by category (ENE Comments at 3); and (5) a results tab, which compares quantifiable benefits to costs, and provides an overview of the score on the unquantifiable benefits, resulting in a conclusion (DOER Comments at 3; DOER Redline at 2, 3, 5).

National Grid proposes that the Department restructure the Benefits tab of the Template, so that the logic of the worksheet flows in the opposite direction (i.e., benefit → function → technology) (National Grid Comments at 3). National Grid argues that the consideration of benefits in the business case analysis would more logically focus on a particular benefit and then define the functions and technologies that would enable that benefit (National Grid Comments at 3).

b. Analysis and Conclusions

After careful consideration of the arguments raised, the Department adopts some of the participants' suggestions, but retains the general structure of the Draft Template. In addition, based on the comments, the Department clarifies and refines certain aspects of the Draft Template.

The Department acknowledges that building some degree of flexibility into the structure of the Template is necessary to account for variations in each company's proposed STIP investments. Accordingly, the Department encourages each company to make additions to the Template as needed, including adding new categories of benefits, costs, functions, and technologies, to ensure that all the costs and benefits associated with its proposed STIP investments are reflected in the business case analysis. However, the companies may not modify the structure of the Template, other than to add new categories to the Benefits and Costs tabs. Further, the purpose of the lists included in the Template is to provide a comprehensive reference list of the type of investments a company could make, but not require an investigation of every technology, device, or system included in the Template. Accordingly, a company need not enter information into categories that do not apply to its proposed set of grid modernization investments.

The Department agrees that the addition of summary tables will benefit the Department and other stakeholders in evaluating whether the benefits justify the proposed STIP investments in a company's business case. Accordingly, the Department has added to the Template a new tab, "Summary – Benefits and Costs" which will include summary tables that display: (1) monetized costs aggregated by cost category and benefits aggregated by function; (2) a list of all quantified but non-monetized benefits, the function associated with each benefit and the quantified value; and (3) a list of all unquantified benefits and the function associated with each benefit.

The Department declines to adopt the proposal to restructure the Benefits tab in the Template so that the worksheet flows in the opposite direction (i.e., benefit → function → technology). The Department structured the flow of the Template based on the assumption that the company will complete the Template after it has selected the technologies for its proposed STIP investments. Therefore, the selected technologies and functions will define the benefits. Accordingly, we will maintain the flow of the Template, from technology to function to benefit.

Although the Department retains the basic structure of the Draft Template, we simplify it by: (1) removing the "Action/ Impact" column from both the Benefits and Costs tabs; and (2) removing the "Function" column from the Costs tab. Finally, we adopt National Grid's proposal to add a new column to the Costs tab of the Template to indicate which costs the company proposes including within the capital expenditure tracker.

3. Allocation of Benefits

a. Introduction and Summary of Comments

In the Draft Template, the Department proposed instructing each company to apportion the benefits associated with its proposed STIP investments in a clear and consistent manner across the Template.[16] Several participants assert that it will be difficult to fully allocate or compartmentalize the elements of each company's STIP investments in the Template (Fauth Comments at 2; National Grid Comments at 13). Some argue that the Draft Template appears to be based on an assumption that there are simple one-to-one or one-to-many correspondences between grid modernization objectives, actions/impacts, functions, technologies, and benefits (National Grid Comments at 13; ENE Comments at 7-8). Participants identify challenges in demonstrating how benefits are allocated in the Draft Template, such as when: (1) a particular benefit is realized as a result of several grid modernization investments and new O&M activities working together in concert, and the company is not able to clearly apportion the benefit across the different technologies (National Grid Comments at 13); (2) an enabling technology (e.g., a backhaul communication system) does not produce any benefits of its own,

[16] In issuing the Draft Filing Requirements, the Department addressed the allocation of benefits and costs. Because participants did not raise cost allocation issues, we limit our analysis to benefits only.

but, instead, enables benefits via other technologies (e.g., advanced meters) (National Grid Comments at 13); and (3) a group of technologies deliver a function (e.g., conservation voltage reduction) that provides a particular benefit (e.g., reduced line losses) on its own, but when paired with other technologies (e.g., advanced meters) results in an increase of that same benefit (Fauth Comments at 2).

b. Analysis and Conclusions

The Department recognizes that the companies will need to address the challenge of appropriately allocating calculated benefits to specific technologies in the Template. We direct each company to identify a method that ensures that all benefits are allocated in a consistent manner throughout the Template. Each company must document how, where, and why benefits are allocated when it is not otherwise clear how the benefits should be allocated. In instances where a technology or network systems enabler[17] (e.g., a backhaul communications system), which may or may not produce any benefits on its own, enables benefits through other technologies (e.g., advanced meters), the Department recommends attributing the value of the benefit to the enabled technology and not trying to allocate any portion of the benefit back to specific enabling technologies.

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17 The term network systems enabler ("NSE") was used during the Grid Modernization Stakeholder Working Group meetings and in the Working Group Report (Report at 13). In the Template, the Department defines NSEs as "systems and software applications that underpin distribution company operations and support implementation of various grid modernization capabilities. For example, supervisory control and data acquisition ("SCADA") and a distribution management system ("DMS") are NSEs that are necessary to implement automated feeder reconfiguration."

4. Preventing Double Counting

a. Introduction and Summary of Comments

In the Draft Template, the Department proposed instructing each company to produce line items for each benefit and cost associated with its proposed STIP investments to avoid double counting. In addition, the Department asked a briefing question on the topic of preventing double counting of costs and benefits in the business case and requested that the participants address whether the Draft Template was adequate to prevent double counting. We also requested recommendations for how these materials could be modified to address potential concerns with double counting.

In response to the Department's briefing question, participants assert that there is sufficient guidance in the Draft Filing Requirements and Draft Template to prevent double counting, but recognize that the potential for double counting still exists due to: (1) arbitrary assignments of costs or benefits to functions or technologies (Fauth Comments at 2); (2) counting benefits that do not directly result from the achievement of grid modernization objectives (DOER Comments at 3); and (3) redundancies between broad common assumptions and specific estimates that may account for portions of the same costs/savings (Unitil Response to Briefing Question 2).

Some participants assert that the burden of proof is on companies to prove that their quantification of benefits and costs has not resulted in double counting (Joint Comments at 24; Northeast Utilities Comments at 18-19; National Grid Comments at 19).

b. Analysis and Conclusions

As noted by the participants, the companies bear the burden of demonstrating that they have not double counted in the quantification of costs and benefits. The Department encourages each company to develop its own method to ensure that all costs and benefits are treated in a consistent and non-duplicative manner throughout the Template. Similar to the Department's findings on the allocation of benefits in Section II.D.3., we expect that each company will describe its approach to avoiding double counting, how it consistently apportioned projected benefits and costs among multiple rows in the Template, and where such apportioning occurred in the Template.

5. Granularity of Data

a. Introduction and Summary of Comments

In the Draft Filing Requirements, the Department proposed that the business case include detailed descriptions of the proposed investments, as well as identification and quantification of costs and benefits (to the extent possible) associated with the STIP. In the Draft Template, the Department provided lists of technologies and functions commonly associated with grid modernization investments that companies would use to identify and quantify all costs and benefits of its proposed STIP investments. The Department also issued a briefing question requesting input on the level of granularity that would be appropriate for quantified costs and benefits.

Participants agree that the companies must provide sufficiently granular estimates for costs and benefits for the Department and stakeholders to evaluate the business case, but disagree on what constitutes a sufficient level of granularity (DOER Comments at 3, National Grid Comments at 21-22; Northeast Utilities Comments at 20). The Joint Commenters propose that companies provide costs on the unit of property level as found in the Department's USOA (Joint Comments at 20). In addition, the Joint Commenters and Fauth argue that the granularity of data underlying costs and benefits should reflect the geographic location of the proposed investment (Joint Comments at 20; Fauth Comments at 3).

Others expressed concerns with the trade-off between granularity and accuracy, with National Grid asserting that requiring a high degree of granularity in the business case is likely to suggest a false sense of precision for costs and benefits that are difficult to quantify, especially for benefits that depend on high-level assumptions and inputs, such as customer participation (National Grid Comments at 21; Unitil Response to Briefing Question 4).

b. Analysis and Conclusions

The companies must present costs and benefits at a level of granularity that strikes the appropriate balance between enabling review of their proposed STIP investments while reflecting the relatively high-level nature of the plans and the uncertainty inherent in planning estimates.

As a general matter, the Department agrees with the Joint Commenters that the companies should provide cost estimates on the unit of property level as found in the USOA, wherever possible. Providing cost estimates at this level of detail in the business case analysis will facilitate the identification of the retirement units associated with the grid modernization investments, which is necessary to determine their useful lives and, consequently, depreciation expense. See, e.g., Boston Gas Company, D.P.U. 88-67 (Phase One) at 131-132 (1988); Commonwealth Gas Company, D.P.U. 87-122, at 45 (1987). However, as discussed in Section II.D.2., individual costs should be grouped and summed by technology, while individual benefits should be grouped and summed by function in the Summary – Benefits and Costs tab in the Template.

While the Department recognizes that the estimates of costs and benefits of a proposed investment may vary depending on the geographic location of the investment, we decline to require that all investments include geographic information. However, where companies are proposing phased or partial technology deployments based on geography, we expect that they will provide their rationale for this proposal within the STIP.

## III. CONCLUSION

In this Order the Department establishes requirements for the business case component of the companies' GMP filings, and adopts the final Grid Modernization Business Case Filing Requirements and the final Business Case Summary Template, both attached to this Order.

## IV. ORDER

Accordingly, after notice, working group input, comment, and due consideration, it is

ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, NSTAR Electric Company, and Western Massachusetts Electric Company shall file grid modernization plans consistent with the directives in this Order; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, NSTAR Electric Company, and Western Massachusetts Electric Company shall comply with the directives contained in this Order.

By Order of the Department,

/s/
Ann G. Berwick, Chair

/s/
Jolette A. Westbrook, Commissioner

/s/
Kate McKeever, Commissioner

Unitil Corporation

# GMP BCA Model

**Draft - Version 8 - 8/18/2015**

Exhibit 6

# GMP BCA Model

## Sections, Sheets, & Descriptions

| Terms & Definitions | | |
|---|---|---|
| 29 | Cases | Short-Term Investment Plans (STIPs) |
| 30 | Objectives | Unitil Grid Modernization Objectives |
| 31 | Programs | Unitil Grid Modernization Programs |
| 32 | Initiatives | Unitil Grid Modernization Initiatives |
| 33 | Projects | Unitil Grid Modernization Projects |
| **Miscellaneous Sheets** | | |
| 34 | Validation List 1 | Validation List 1 - Programs |
| 35 | Validation List 2 | Validation List 2 - Initiatives |
| 36 | Validation List 3 | Validation List 3 - Projects |
| 37 | Validation List 4 | Validation List 4 - Miscellaneous |
| 38 | Chart Text | Chart Names & Titles |
| 39 | STIP Data 1-1 | STIP Data - STIP v2 7_8_15 - Programs |
| 40 | STIP Data 1-2 | STIP Data - STIP v2 7_8_15 - Initiatives |
| 41 | STIP Data 1-3 | STIP Data - STIP v2 7_8_15 - Projects |
| 42 | STIP Data 2-1 | STIP Data - TVR Opt-Out - Programs |
| 43 | STIP Data 2-2 | STIP Data - TVR Opt-Out - Initiatives |
| 44 | STIP Data 2-3 | STIP Data - TVR Opt-Out - Projects |
| 45 | Matrix Table | Relationships & Logic - Matrix Table |
| 46 | Import Data | Relationships & Logic - Import Data |
| 47 | Template Sheet | Blank Template Sheet |

# GMP BCA Model

## Unitil Grid Modernization Outline

| No. | Program | Initiative | Project |
|---|---|---|---|
| | **DER Enablement** | | |
| | DER Enablement | **DER Tariff & Pricing** | |
| 1 | DER Enablement | DER Tariff & Pricing | Customer-Owned DG Tariff |
| | DER Enablement | **DER Interconnection** | |
| 2 | DER Enablement | DER Interconnection | Circuit Capacity Study |
| 3 | DER Enablement | DER Interconnection | Customer-Focused DER Interconnection |
| | DER Enablement | **DER Management Platform** | |
| 4 | DER Enablement | DER Management Platform | DG Monitoring & Control Pilot |
| 5 | DER Enablement | DER Management Platform | Analytics & Visualiation System Platform |
| | DER Enablement | **DER Distribution Upgrades** | |
| 6 | DER Enablement | DER Distribution Upgrades | Substation 3V0 Protection |
| 7 | DER Enablement | DER Distribution Upgrades | Substation Voltage Regulation Control |
| | DER Enablement | **DER RD&D** | |
| 8 | DER Enablement | DER RD&D | DER RD&D |
| | **Grid Reliability** | | |
| | Grid Reliability | **Resiliency** | |
| 9 | Grid Reliability | Resiliency | SRP Cycle Reduction |
| 10 | Grid Reliability | Resiliency | Hazard Tree Enhancement |
| 11 | Grid Reliability | Resiliency | Jacketed Tree Wire & Spacer Cable |
| 12 | Grid Reliability | Resiliency | Breakaway Service Connector Pilot |
| | Grid Reliability | **Outage & Restoration Management** | |
| 13 | Grid Reliability | Outage & Restoration Management | Mobile Damage Assessment Tool |
| 14 | Grid Reliability | Outage & Restoration Management | AMI & OMS Integration |
| 15 | Grid Reliability | Outage & Restoration Management | OMS Resiliency & Hot Standby |
| | **Distributed Automation** | | |
| | Distributed Automation | **Automated Field Devices** | |
| 16 | Distributed Automation | Automated Field Devices | Automatic Throw-Over Switches |
| 17 | Distributed Automation | Automated Field Devices | Automated Cap Banks |
| 18 | Distributed Automation | Automated Field Devices | Automated Voltage Regulators |
| 19 | Distributed Automation | Automated Field Devices | Automated Transformer & Load Tap Changers |
| 20 | Distributed Automation | Automated Field Devices | Automated Sectionalizing & Restoration |

| | | | |
|---|---|---|---|
| | Distributed Automation | **Communications Network** | |
| 21 | Distributed Automation | Communications Network | Fitchburg SCADA Communications |
| 22 | Distributed Automation | Communications Network | Field Area Network |
| | Distributed Automation | **Automated Field Devices** | |
| 23 | Distributed Automation | Control Package / Software | ADMS |
| | Distributed Automation | **Energy Efficiency Tariff & Pricing** | |
| 24 | Distributed Automation | Energy Efficiency Tariff & Pricing | VVO Energy Efficiency Tariff |
| | **Customer Empowerment** | | |
| | Customer Empowerment | **Better Information & Communications** | |
| 25 | Customer Empowerment | Better Information & Communications | Customer Web Portal |
| 26 | Customer Empowerment | Better Information & Communications | Gamification Pilot |
| 27 | Customer Empowerment | Better Information & Communications | Customer Education |
| | Customer Empowerment | **New Service Options (Opt-In)** | |
| 28 | Customer Empowerment | New Service Options (Opt-In) | TVR & Demand Response |
| | Customer Empowerment | **Customer RD&D** | |
| 29 | Customer Empowerment | Customer RD&D | Customer RD&D |
| | **Workforce & Asset Management** | | |
| | Workforce & Asset Management | **Workforce Management** | |
| 30 | Workforce & Asset Management | Workforce Management | Mobility Platform & System |
| 31 | Workforce & Asset Management | Workforce Management | Work Management Automation & Integration |
| | Workforce & Asset Management | **Asset Management** | |
| 32 | Workforce & Asset Management | Asset Management | Condition-Base Maintenance |
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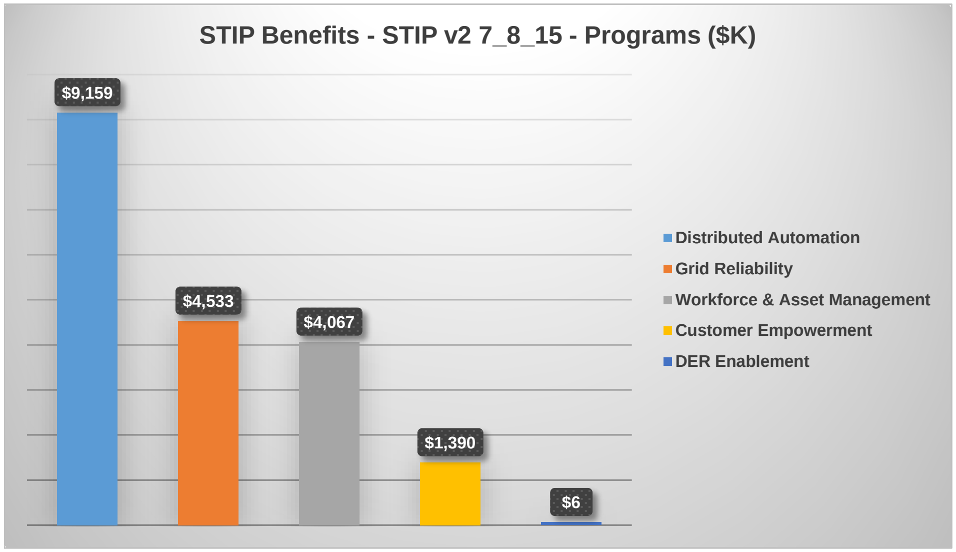
| **Total** | **5 Programs** | **16 Initiatives** | **32 Projects** |

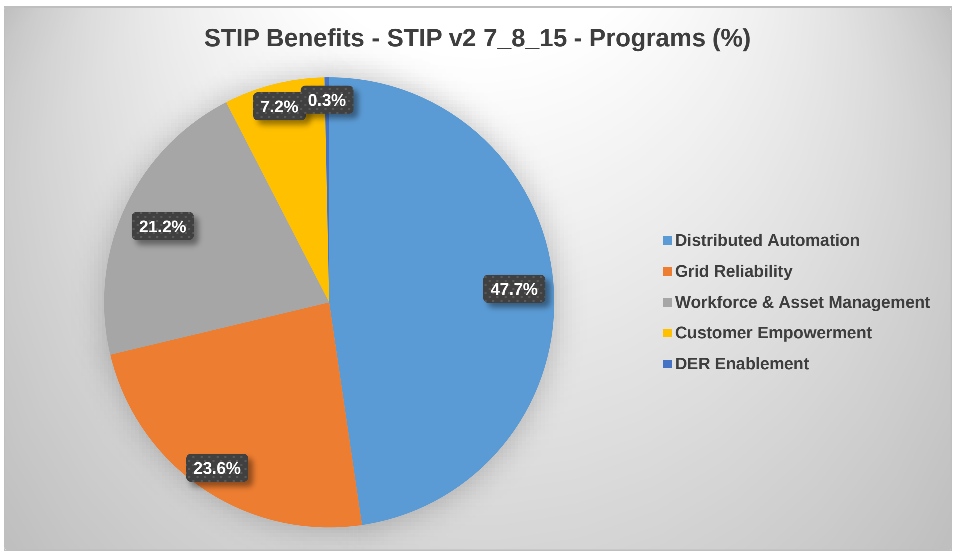
## STIP Totals - STIP v2 7_8_15 - Programs

| STIP Case 1 |
|---|
| STIP v2 7_8_15 |

| Program | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| All | $19,214 | $21,307 | 0.90 |



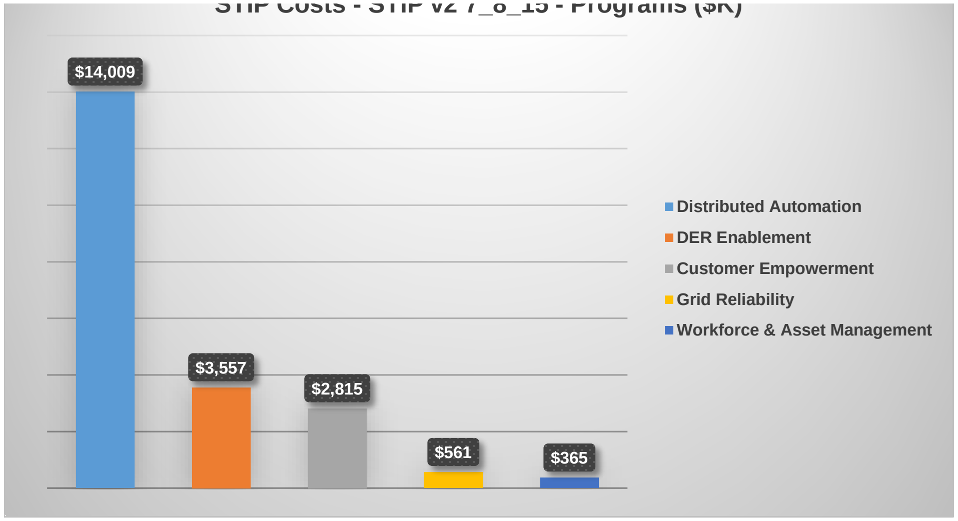

| Program | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Distributed Automation | $9,159 | $14,009 | 0.65 |
| Grid Reliability | $4,533 | $561 | 8.08 |
| Workforce & Asset Management | $4,067 | $365 | 11.14 |
| Customer Empowerment | $1,390 | $2,815 | 0.49 |
| DER Enablement | $64 | $3,557 | 0.02 |



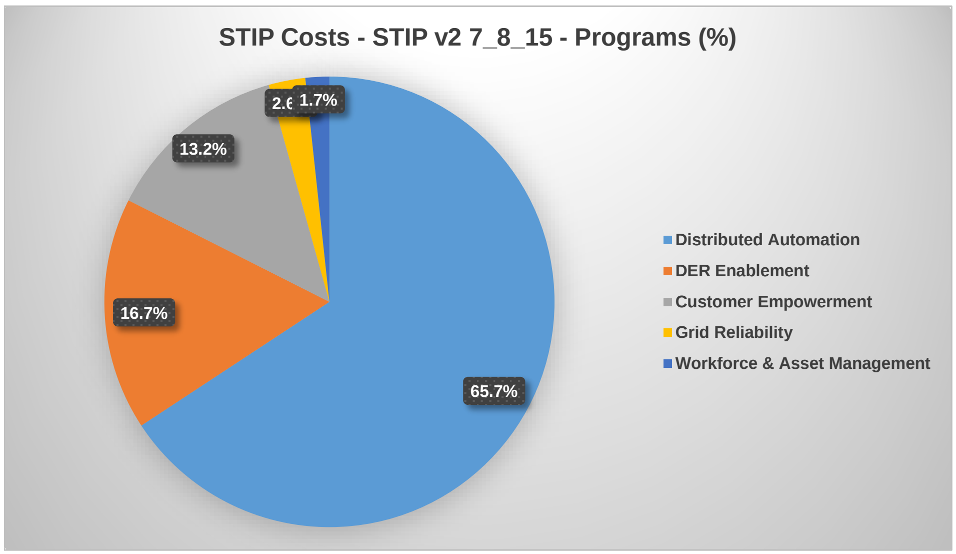

| Program | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Distributed Automation | 47.7% | 65.7% | 0.65 |
| Grid Reliability | 23.6% | 2.6% | 8.08 |
| Workforce & Asset Management | 21.2% | 1.7% | 11.14 |
| Customer Empowerment | 7.2% | 13.2% | 0.49 |
| DER Enablement | 0.3% | 16.7% | 0.02 |

STIP Costs - STIP v2 7_8_15 - Programs ($K)

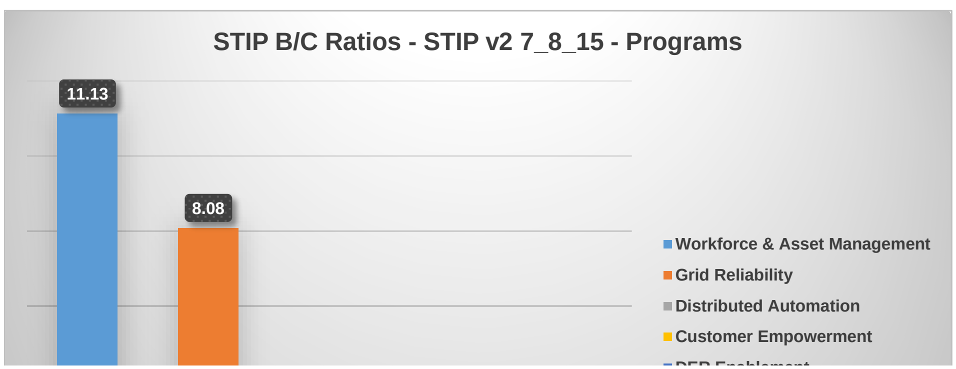
| Program | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|



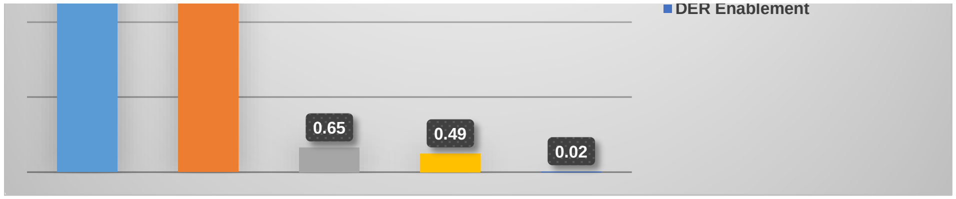

| | | | |
|---|---|---|---|
| Distributed Automation | $9,159 | $14,009 | 0.65 |
| DER Enablement | $64 | $3,557 | 0.02 |
| Customer Empowerment | $1,390 | $2,815 | 0.49 |
| Grid Reliability | $4,533 | $561 | 8.08 |
| Workforce & Asset Management | $4,067 | $365 | 11.14 |

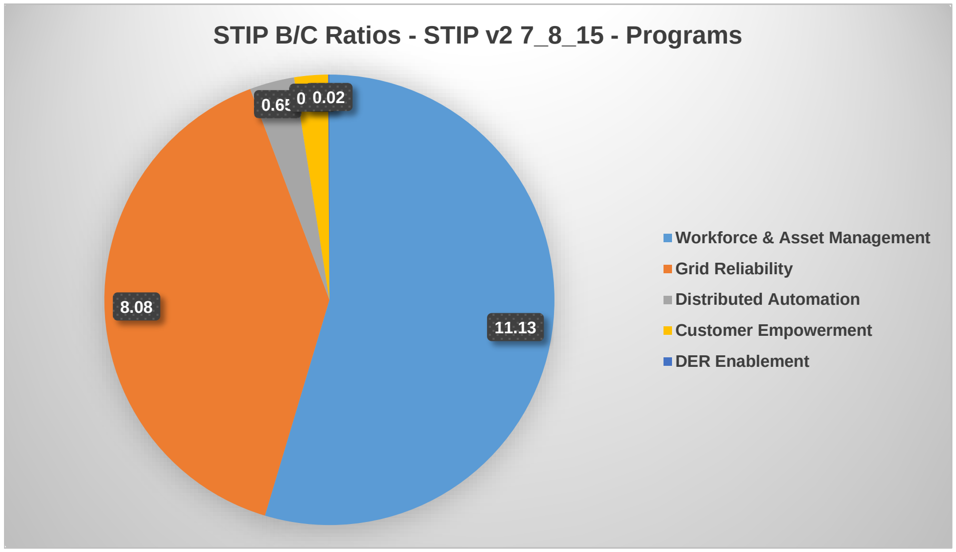



| Program | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Distributed Automation | 47.7% | 65.7% | 0.65 |
| DER Enablement | 0.3% | 16.7% | 0.02 |
| Customer Empowerment | 7.2% | 13.2% | 0.49 |
| Grid Reliability | 23.6% | 2.6% | 8.08 |
| Workforce & Asset Management | 21.2% | 1.7% | 11.14 |




| Program | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Workforce & Asset Management | $4,067 | $365 | 11.13 |
| Grid Reliability | $4,533 | $561 | 8.08 |
| Distributed Automation | $9,159 | $14,009 | 0.65 |
| Customer Empowerment | $1,390 | $2,815 | 0.49 |
| DER Enablement | $64 | $3,557 | 0.02 |



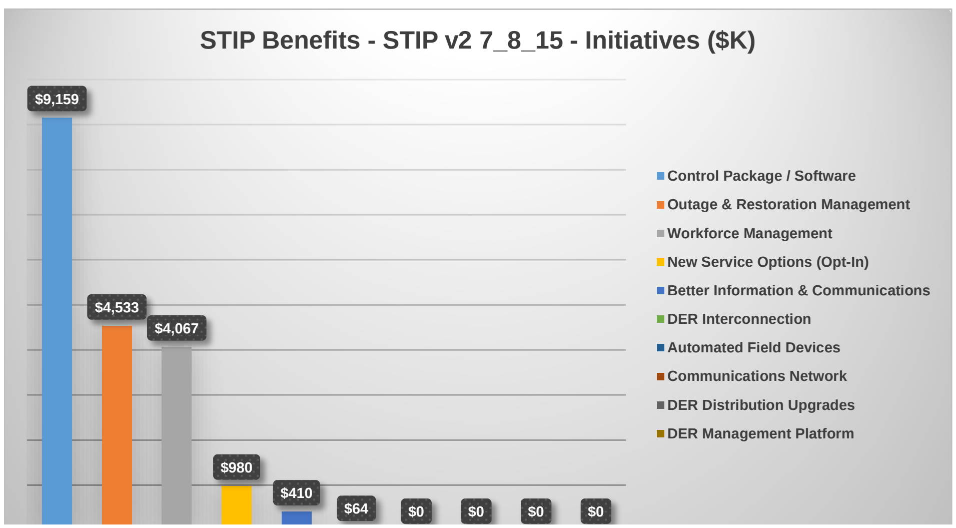
STIP B/C Ratios - STIP v2 7_8_15 - Programs

| Program | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Workforce & Asset Management | 21.2% | 1.7% | 11.13 |
| Grid Reliability | 23.6% | 2.6% | 8.08 |
| Distributed Automation | 47.7% | 65.7% | 0.65 |
| Customer Empowerment | 7.2% | 13.2% | 0.49 |
| DER Enablement | 0.3% | 16.7% | 0.02 |

## STIP Totals - STIP v2 7_8_15 - Initiatives

| STIP Case 1 |
|---|
| STIP v2 7_8_15 |

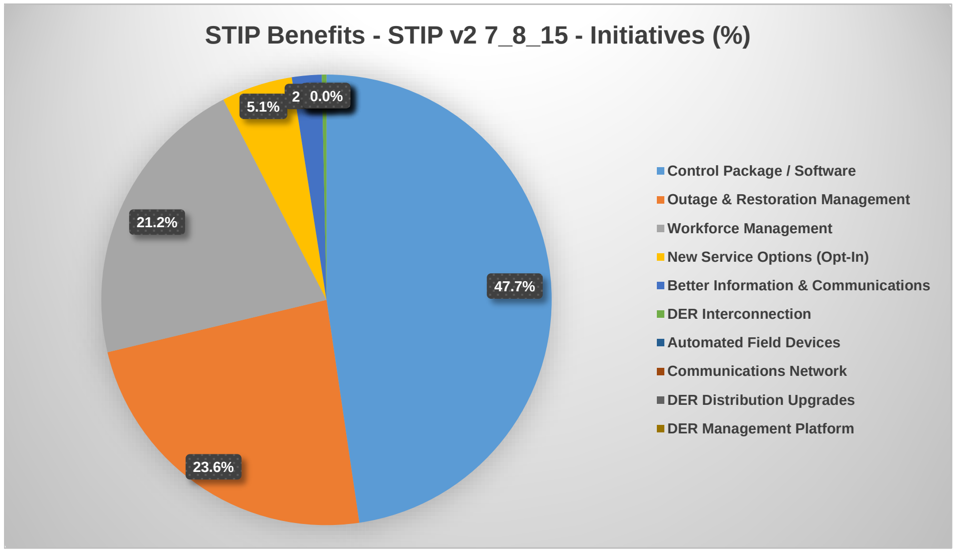
| Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| All | $19,214 | $21,307 | 0.90 |



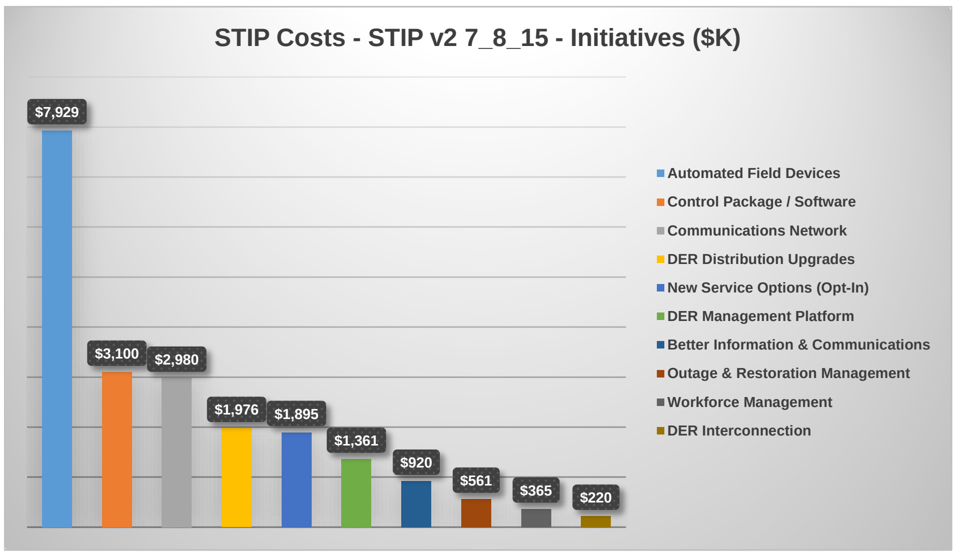
STIP Benefits - STIP v2 7_8_15 - Initiatives ($K)

| Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Control Package / Software | $9,159 | $3,100 | 2.95 |
| Outage & Restoration Management | $4,533 | $561 | 8.08 |
| Workforce Management | $4,067 | $365 | 11.14 |
| New Service Options (Opt-In) | $980 | $1,895 | 0.52 |
| Better Information & Communications | $410 | $920 | 0.45 |
| DER Interconnection | $64 | $220 | 0.29 |
| Automated Field Devices | $0 | $7,929 | 0.00 |
| Communications Network | $0 | $2,980 | 0.00 |
| DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| DER Management Platform | $0 | $1,361 | 0.00 |

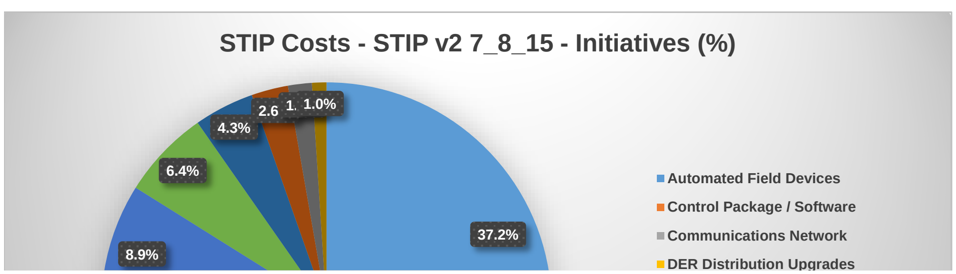
  



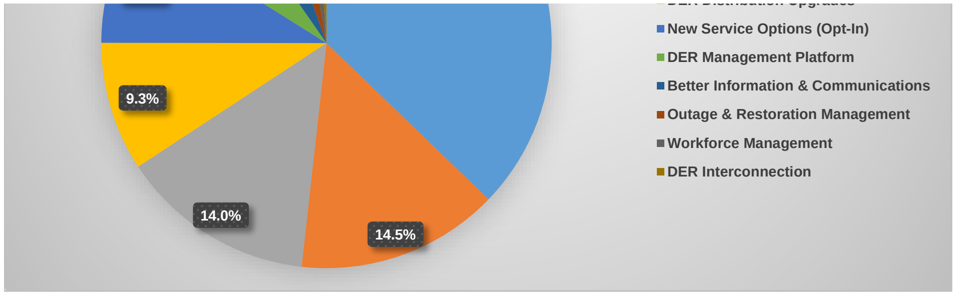

| Initiative | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Control Package / Software | 47.7% | 14.5% | 2.95 |
| Outage & Restoration Management | 23.6% | 2.6% | 8.08 |
| Workforce Management | 21.2% | 1.7% | 11.14 |
| New Service Options (Opt-In) | 5.1% | 8.9% | 0.52 |
| Better Information & Communications | 2.1% | 4.3% | 0.45 |
| DER Interconnection | 0.3% | 1.0% | 0.29 |
| Automated Field Devices | 0.0% | 37.2% | 0.00 |
| Communications Network | 0.0% | 14.0% | 0.00 |
| DER Distribution Upgrades | 0.0% | 9.3% | 0.00 |
| DER Management Platform | 0.0% | 6.4% | 0.00 |



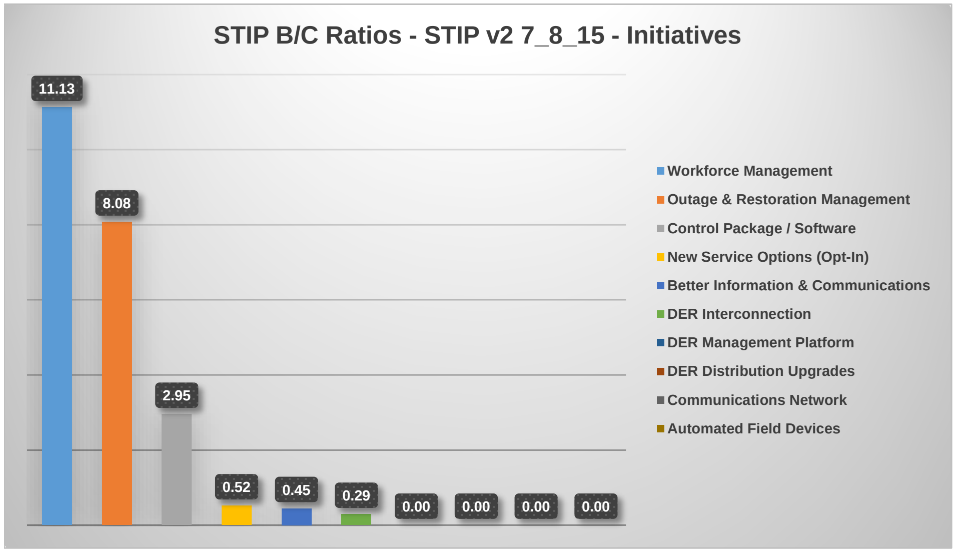

| Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Automated Field Devices | $0 | $7,929 | 0.00 |
| Control Package / Software | $9,159 | $3,100 | 2.95 |
| Communications Network | $0 | $2,980 | 0.00 |
| DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| New Service Options (Opt-In) | $980 | $1,895 | 0.52 |
| DER Management Platform | $0 | $1,361 | 0.00 |
| Better Information & Communications | $410 | $920 | 0.45 |
| Outage & Restoration Management | $4,533 | $561 | 8.08 |
| Workforce Management | $4,067 | $365 | 11.14 |
| DER Interconnection | $64 | $220 | 0.29 |



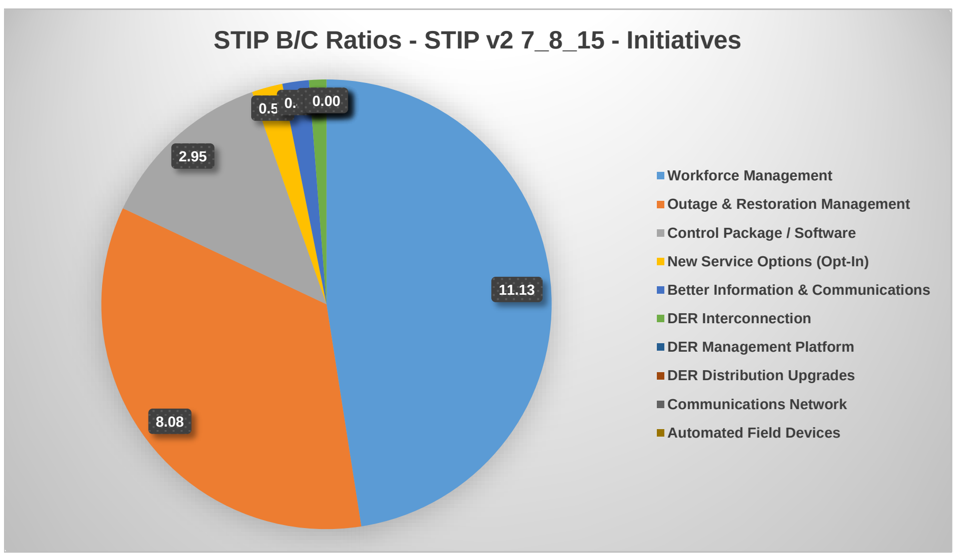

| Initiative | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Automated Field Devices | 0.0% | 37.2% | 0.00 |
| Control Package / Software | 47.7% | 14.5% | 2.95 |
| Communications Network | 0.0% | 14.0% | 0.00 |
| DER Distribution Upgrades | 0.0% | 9.3% | 0.00 |
| New Service Options (Opt-In) | 5.1% | 8.9% | 0.52 |
| DER Management Platform | 0.0% | 6.4% | 0.00 |
| Better Information & Communications | 2.1% | 4.3% | 0.45 |




| | | | |
|---|---|---|---|
| Outage & Restoration Management | 23.6% | 2.6% | 8.08 |
| Workforce Management | 21.2% | 1.7% | 11.14 |
| DER Interconnection | 0.3% | 1.0% | 0.29 |




| Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Workforce Management | $4,067 | $365 | 11.13 |
| Outage & Restoration Management | $4,533 | $561 | 8.08 |
| Control Package / Software | $9,159 | $3,100 | 2.95 |
| New Service Options (Opt-In) | $980 | $1,895 | 0.52 |
| Better Information & Communications | $410 | $920 | 0.45 |
| DER Interconnection | $64 | $220 | 0.29 |
| DER Management Platform | $0 | $1,361 | 0.00 |
| DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| Communications Network | $0 | $2,980 | 0.00 |
| Automated Field Devices | $0 | $7,929 | 0.00 |

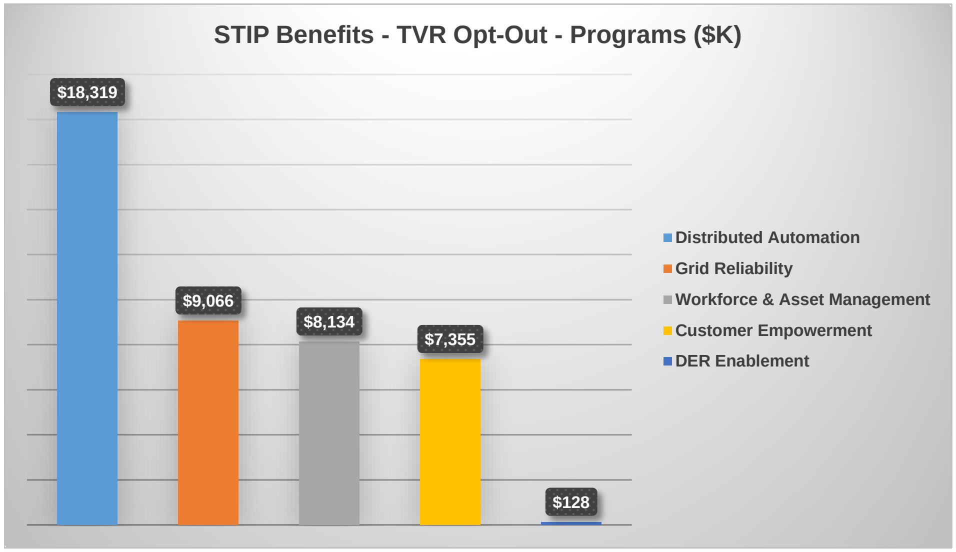



| Initiative | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Workforce Management | 21.2% | 1.7% | 11.13 |
| Outage & Restoration Management | 23.6% | 2.6% | 8.08 |
| Control Package / Software | 47.7% | 14.5% | 2.95 |
| New Service Options (Opt-In) | 5.1% | 8.9% | 0.52 |
| Better Information & Communications | 2.1% | 4.3% | 0.45 |
| DER Interconnection | 0.3% | 1.0% | 0.29 |
| DER Management Platform | 0.0% | 6.4% | 0.00 |
| DER Distribution Upgrades | 0.0% | 9.3% | 0.00 |
| Communications Network | 0.0% | 14.0% | 0.00 |
| Automated Field Devices | 0.0% | 37.2% | 0.00 |

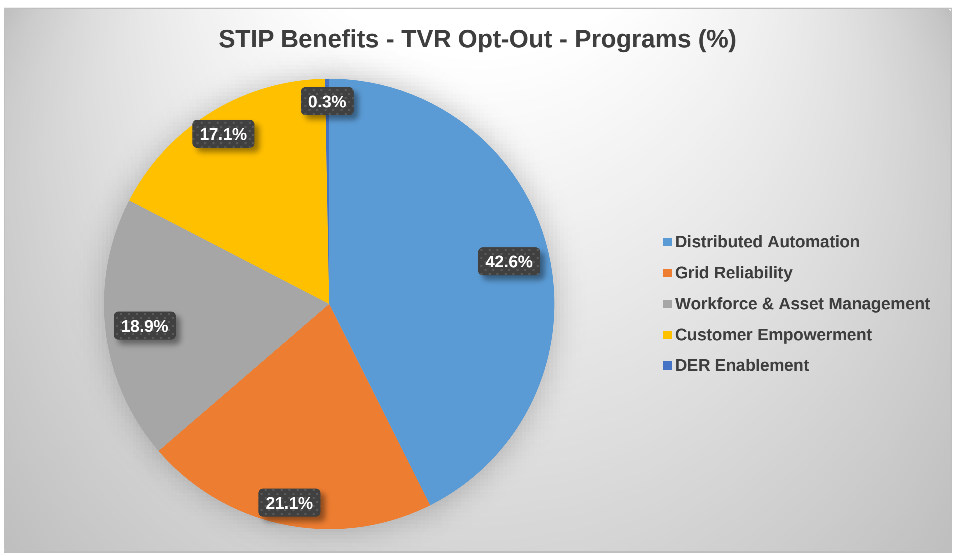
### STIP Totals - TVR Opt-Out - Programs

| STIP Case 2 |
|---|
| TVR Opt-Out |

| Program | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| All | $43,002 | $28,579 | 1.50 |

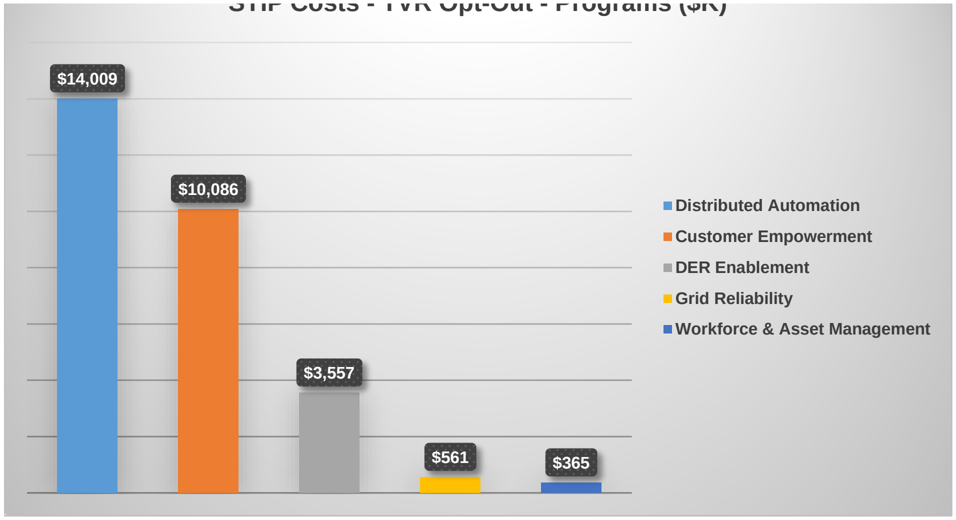



| Program | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Distributed Automation | $18,319 | $14,009 | 1.31 |
| Grid Reliability | $9,066 | $561 | 16.16 |
| Workforce & Asset Management | $8,134 | $365 | 22.28 |
| Customer Empowerment | $7,355 | $10,086 | 0.73 |
| DER Enablement | $128 | $3,557 | 0.04 |

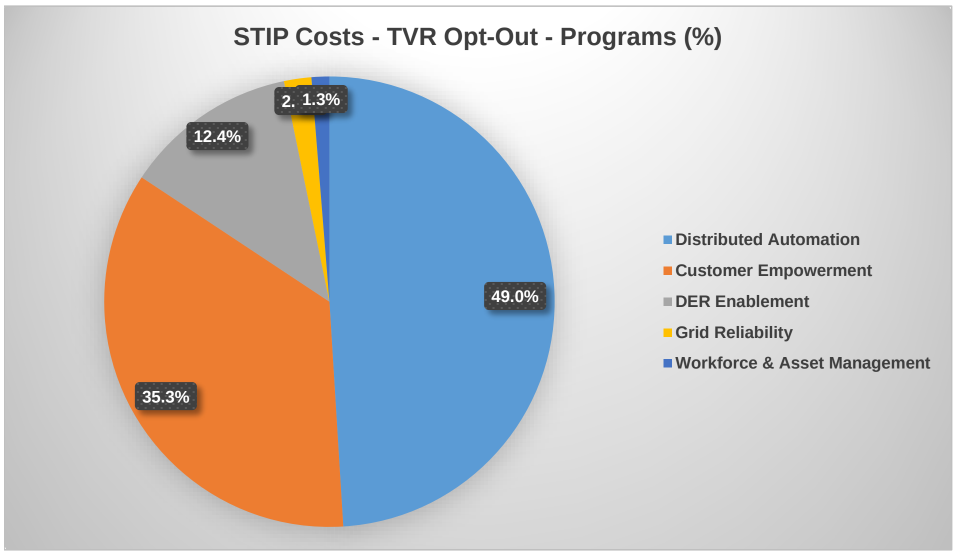



| Program | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Distributed Automation | 42.6% | 49.0% | 1.31 |
| Grid Reliability | 21.1% | 2.0% | 16.16 |
| Workforce & Asset Management | 18.9% | 1.3% | 22.28 |
| Customer Empowerment | 17.1% | 35.3% | 0.73 |
| DER Enablement | 0.3% | 12.4% | 0.04 |

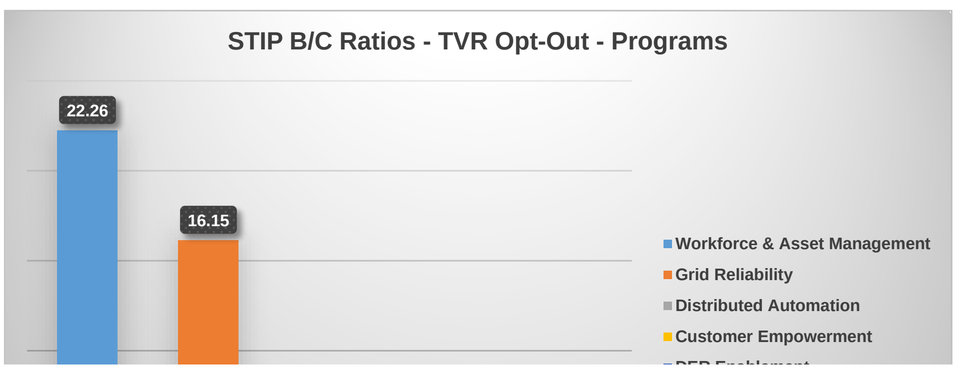

| Program | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|



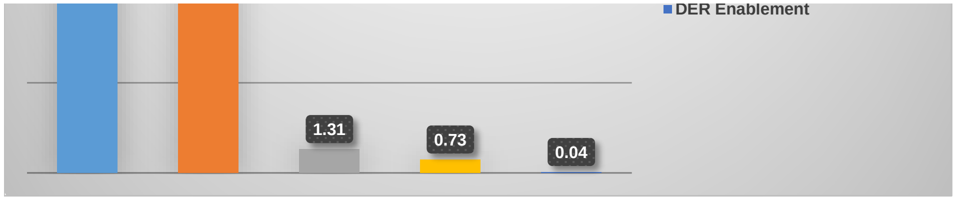

| | | | |
|---|---|---|---|
| Distributed Automation | $18,319 | $14,009 | 1.31 |
| Customer Empowerment | $7,355 | $10,086 | 0.73 |
| DER Enablement | $128 | $3,557 | 0.04 |
| Grid Reliability | $9,066 | $561 | 16.16 |
| Workforce & Asset Management | $8,134 | $365 | 22.28 |

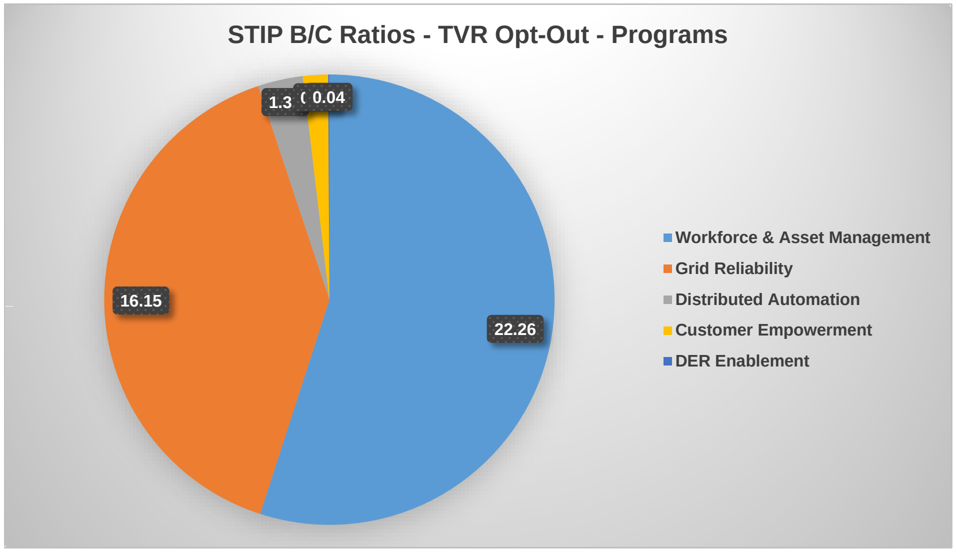



| Program | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Distributed Automation | 42.6% | 49.0% | 1.31 |
| Customer Empowerment | 17.1% | 35.3% | 0.73 |
| DER Enablement | 0.3% | 12.4% | 0.04 |
| Grid Reliability | 21.1% | 2.0% | 16.16 |
| Workforce & Asset Management | 18.9% | 1.3% | 22.28 |




| Program | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Workforce & Asset Management | $8,134 | $365 | 22.26 |
| Grid Reliability | $9,066 | $561 | 16.15 |
| Distributed Automation | $18,319 | $14,009 | 1.31 |
| Customer Empowerment | $7,355 | $10,086 | 0.73 |
| DER Enablement | $128 | $3,557 | 0.04 |



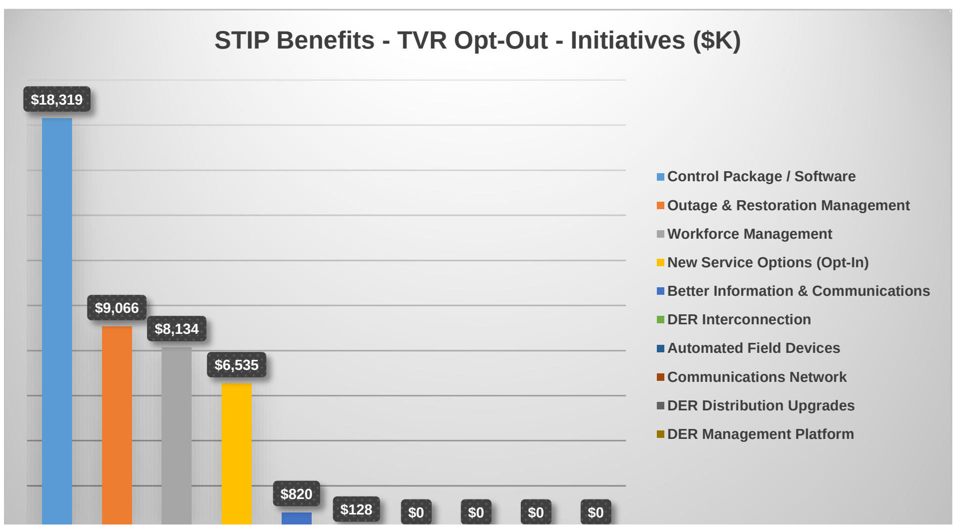




| Program | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Workforce & Asset Management | 18.9% | 1.3% | 22.26 |
| Grid Reliability | 21.1% | 2.0% | 16.15 |
| Distributed Automation | 42.6% | 49.0% | 1.31 |
| Customer Empowerment | 17.1% | 35.3% | 0.73 |
| DER Enablement | 0.3% | 12.4% | 0.04 |

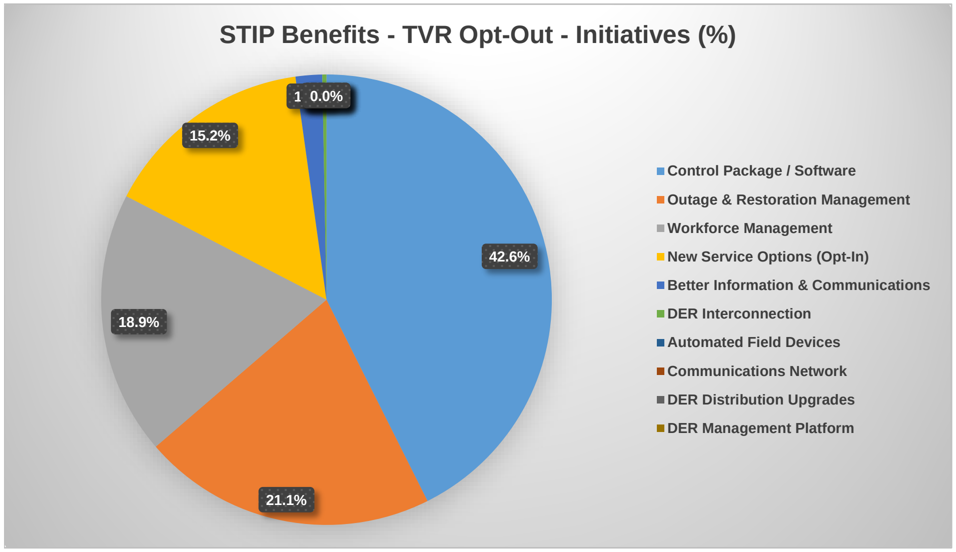
## STIP Totals - TVR Opt-Out - Initiatives

| STIP Case 2 |
|---|
| TVR Opt-Out |

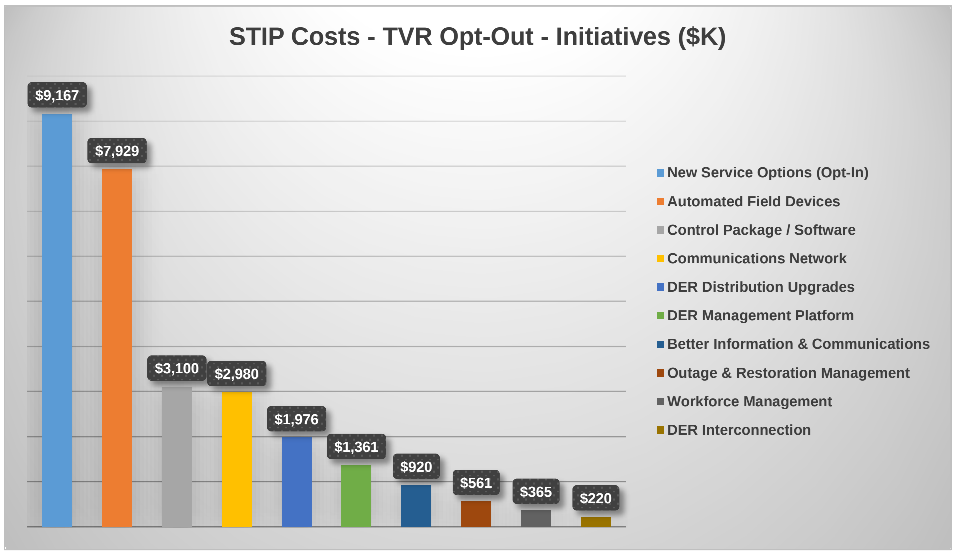
| Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| All | $43,002 | $28,579 | 1.50 |



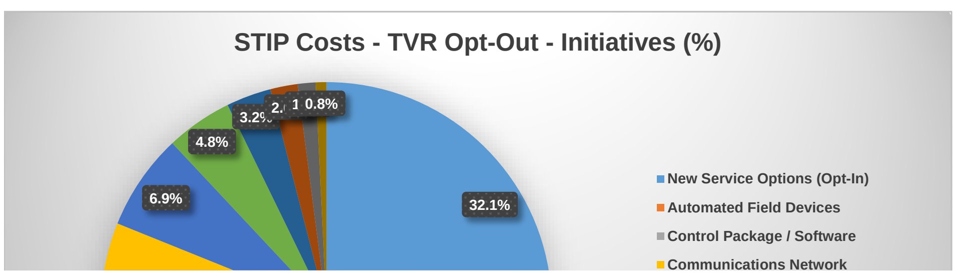

| Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Control Package / Software | $18,319 | $3,100 | 5.91 |
| Outage & Restoration Management | $9,066 | $561 | 16.16 |
| Workforce Management | $8,134 | $365 | 22.28 |
| New Service Options (Opt-In) | $6,535 | $9,167 | 0.71 |
| Better Information & Communications | $820 | $920 | 0.89 |
| DER Interconnection | $128 | $220 | 0.58 |
| Automated Field Devices | $0 | $7,929 | 0.00 |
| Communications Network | $0 | $2,980 | 0.00 |
| DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| DER Management Platform | $0 | $1,361 | 0.00 |



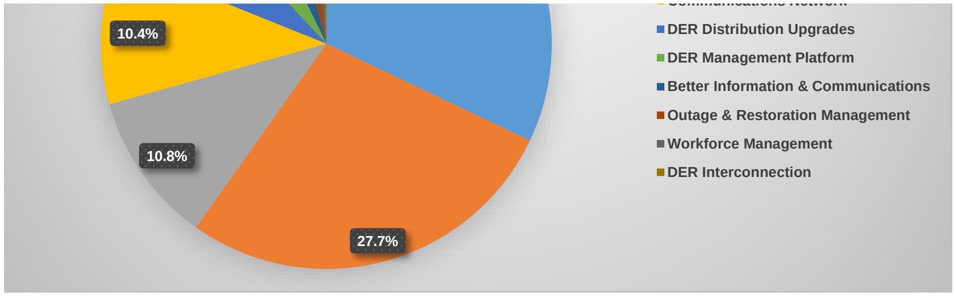

| Initiative | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Control Package / Software | 42.6% | 10.8% | 5.91 |
| Outage & Restoration Management | 21.1% | 2.0% | 16.16 |
| Workforce Management | 18.9% | 1.3% | 22.28 |
| New Service Options (Opt-In) | 15.2% | 32.1% | 0.71 |
| Better Information & Communications | 1.9% | 3.2% | 0.89 |
| DER Interconnection | 0.3% | 0.8% | 0.58 |
| Automated Field Devices | 0.0% | 27.7% | 0.00 |
| Communications Network | 0.0% | 10.4% | 0.00 |
| DER Distribution Upgrades | 0.0% | 6.9% | 0.00 |
| DER Management Platform | 0.0% | 4.8% | 0.00 |



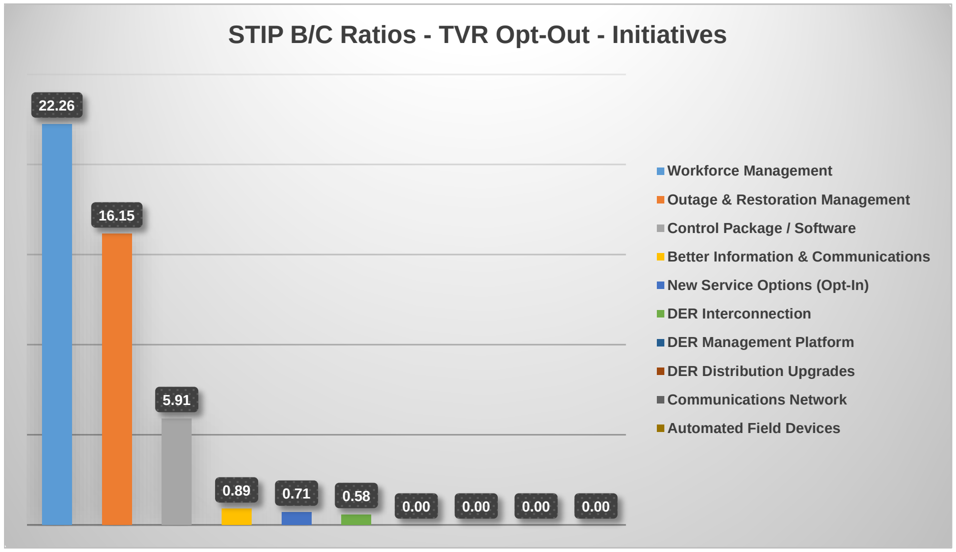

| Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| New Service Options (Opt-In) | $6,535 | $9,167 | 0.71 |
| Automated Field Devices | $0 | $7,929 | 0.00 |
| Control Package / Software | $18,319 | $3,100 | 5.91 |
| Communications Network | $0 | $2,980 | 0.00 |
| DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| DER Management Platform | $0 | $1,361 | 0.00 |
| Better Information & Communications | $820 | $920 | 0.89 |
| Outage & Restoration Management | $9,066 | $561 | 16.16 |
| Workforce Management | $8,134 | $365 | 22.28 |
| DER Interconnection | $128 | $220 | 0.58 |



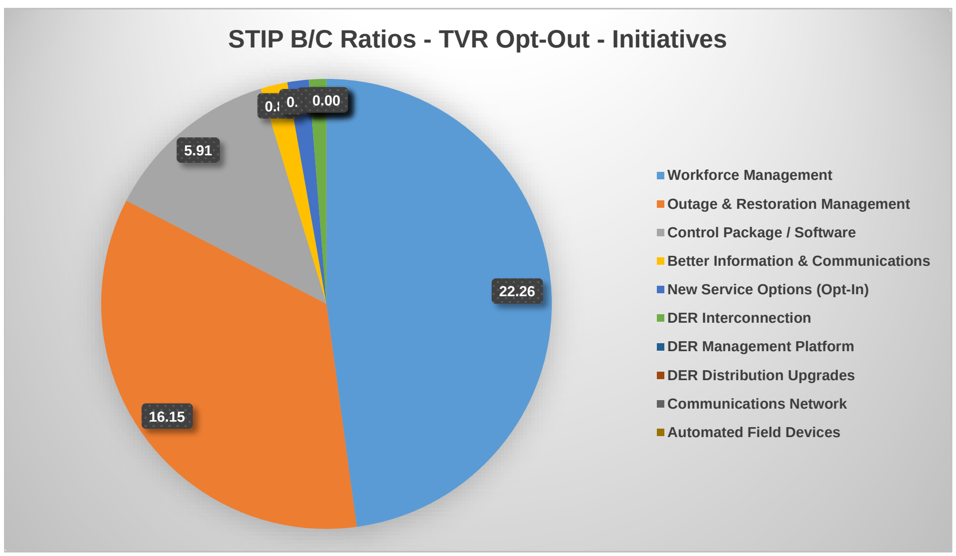

| Initiative | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| New Service Options (Opt-In) | 15.2% | 32.1% | 0.71 |
| Automated Field Devices | 0.0% | 27.7% | 0.00 |
| Control Package / Software | 42.6% | 10.8% | 5.91 |
| Communications Network | 0.0% | 10.4% | 0.00 |
| DER Distribution Upgrades | 0.0% | 6.9% | 0.00 |
| DER Management Platform | 0.0% | 4.8% | 0.00 |
| Better Information & Communications | 1.9% | 3.2% | 0.89 |




| | | | |
|---|---|---|---|
| Outage & Restoration Management | 21.1% | 2.0% | 16.16 |
| Workforce Management | 18.9% | 1.3% | 22.28 |
| DER Interconnection | 0.3% | 0.8% | 0.58 |




| Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| Workforce Management | $8,134 | $365 | 22.26 |
| Outage & Restoration Management | $9,066 | $561 | 16.15 |
| Control Package / Software | $18,319 | $3,100 | 5.91 |
| Better Information & Communications | $820 | $920 | 0.89 |
| New Service Options (Opt-In) | $6,535 | $9,167 | 0.71 |
| DER Interconnection | $128 | $220 | 0.58 |
| DER Management Platform | $0 | $1,361 | 0.00 |
| DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| Communications Network | $0 | $2,980 | 0.00 |
| Automated Field Devices | $0 | $7,929 | 0.00 |



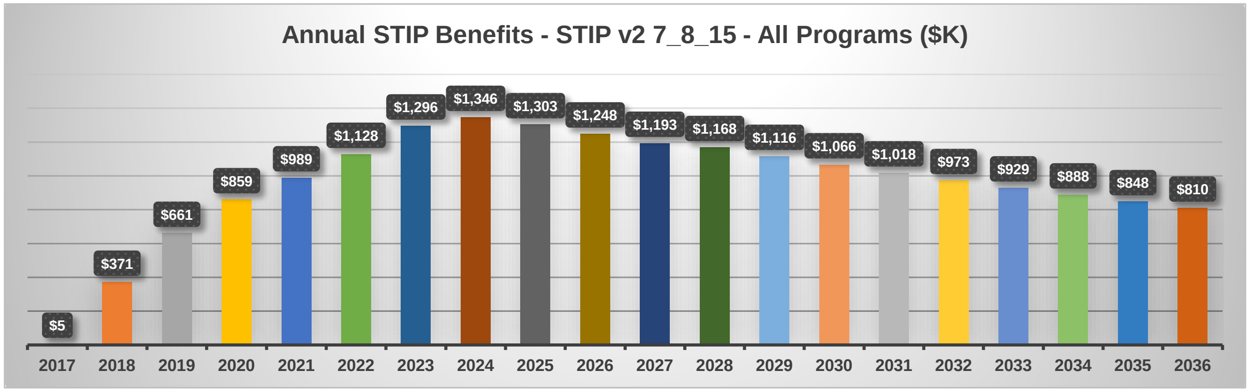

| Initiative | Benefits (%) | Costs (%) | B/C Ratio |
|---|---|---|---|
| Workforce Management | 18.9% | 1.3% | 22.26 |
| Outage & Restoration Management | 21.1% | 2.0% | 16.15 |
| Control Package / Software | 42.6% | 10.8% | 5.91 |
| Better Information & Communications | 1.9% | 3.2% | 0.89 |
| New Service Options (Opt-In) | 15.2% | 32.1% | 0.71 |
| DER Interconnection | 0.3% | 0.8% | 0.58 |
| DER Management Platform | 0.0% | 4.8% | 0.00 |
| DER Distribution Upgrades | 0.0% | 6.9% | 0.00 |
| Communications Network | 0.0% | 10.4% | 0.00 |
| Automated Field Devices | 0.0% | 27.7% | 0.00 |

## STIP Trends - STIP v2 7_8_15 - Programs

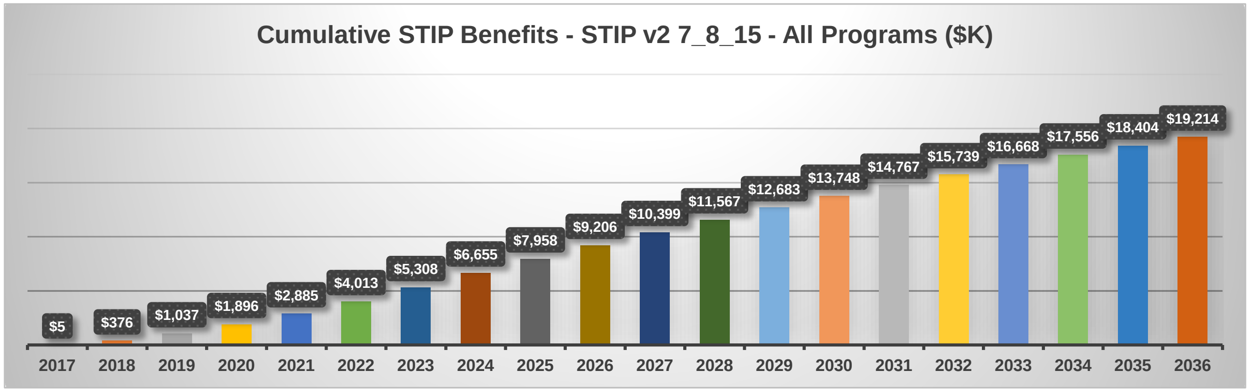
| Year | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| All | $19,214 | $21,307 | 0.90 |

| STIP Case 1 |
|---|
| STIP v2 7_8_15 |

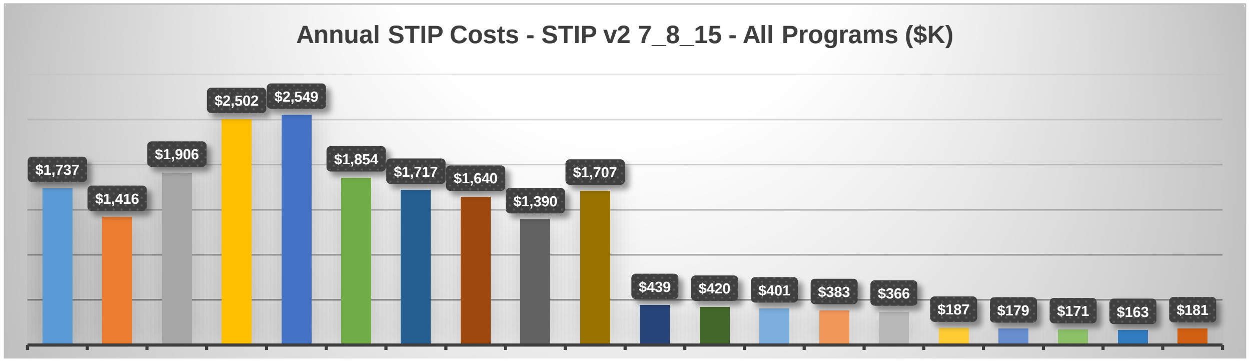
| Year | Benefits ($K) | Year | Benefits ($K) |
|---|---|---|---|
| 2017 | $5 | 2027 | $1,193 |
| 2018 | $371 | 2028 | $1,168 |
| 2019 | $661 | 2029 | $1,116 |
| 2020 | $859 | 2030 | $1,066 |
| 2021 | $989 | 2031 | $1,018 |
| 2022 | $1,128 | 2032 | $973 |
| 2023 | $1,296 | 2033 | $929 |
| 2024 | $1,346 | 2034 | $888 |
| 2025 | $1,303 | 2035 | $848 |
| 2026 | $1,248 | 2036 | $810 |
| Total | | | $19,214 |




| Year | Benefits ($K) | Year | Benefits ($K) |
|---|---|---|---|
| 2017 | $5 | 2027 | $10,399 |
| 2018 | $376 | 2028 | $11,567 |
| 2019 | $1,037 | 2029 | $12,683 |
| 2020 | $1,896 | 2030 | $13,748 |
| 2021 | $2,885 | 2031 | $14,767 |
| 2022 | $4,013 | 2032 | $15,739 |
| 2023 | $5,308 | 2033 | $16,668 |
| 2024 | $6,655 | 2034 | $17,556 |
| 2025 | $7,958 | 2035 | $18,404 |
| 2026 | $9,206 | 2036 | $19,214 |
| Total | | | $19,214 |

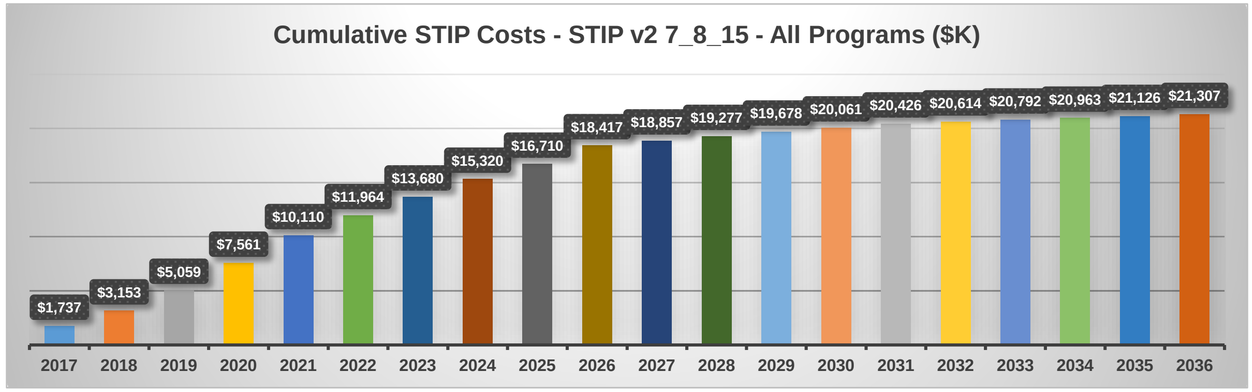



| Year | Costs ($K) | Year | Costs ($K) |
|---|---|---|---|
| 2017 | $1,737 | 2027 | $439 |
| 2018 | $1,416 | 2028 | $420 |
| 2019 | $1,906 | 2029 | $401 |
| 2020 | $2,502 | 2030 | $383 |
| 2021 | $2,549 | 2031 | $366 |
| 2022 | $1,854 | 2032 | $187 |
| 2023 | $1,717 | 2033 | $179 |
| 2024 | $1,640 | 2034 | $171 |
| 2025 | $1,390 | 2035 | $163 |
| 2026 | $1,707 | 2036 | $181 |

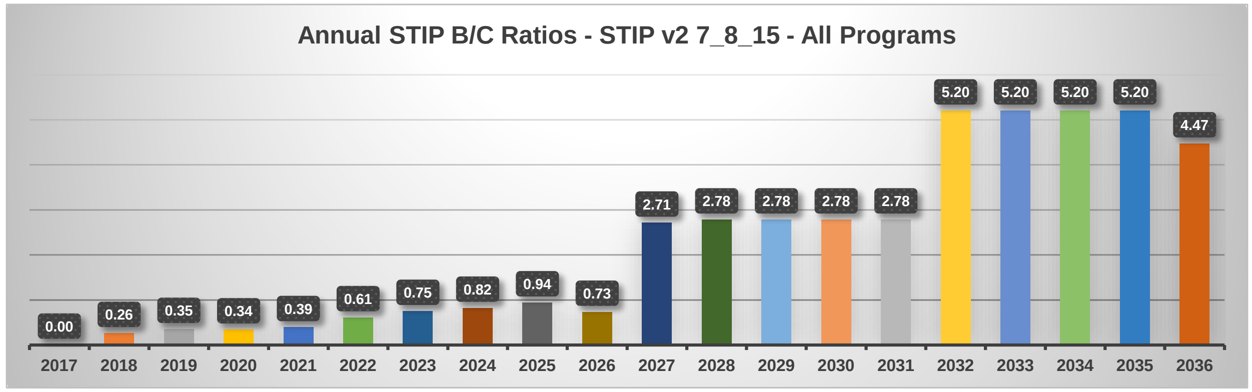


| Total | | | $21,307 |
|---|---|---|---|

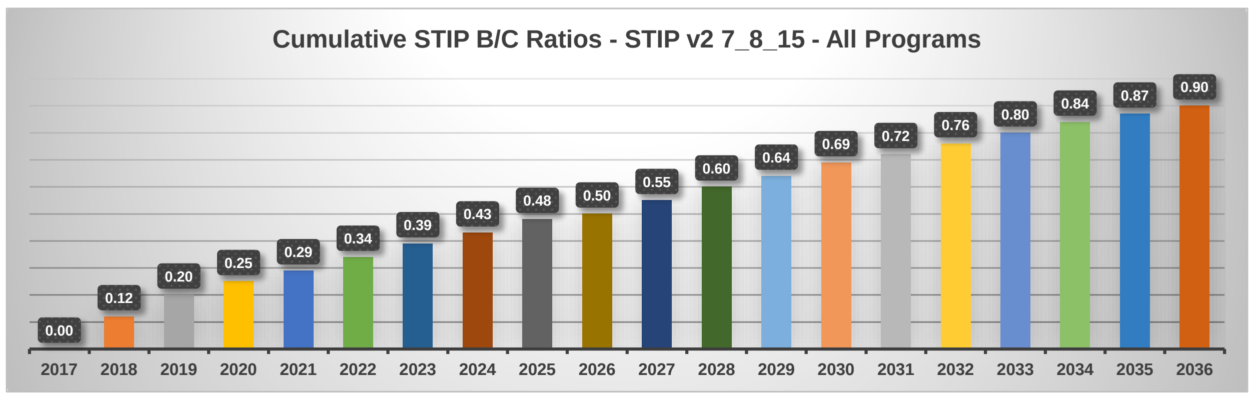

| Year | Costs ($K) | Year | Costs ($K) |
|---|---|---|---|
| 2017 | $1,737 | 2027 | $18,857 |
| 2018 | $3,153 | 2028 | $19,277 |
| 2019 | $5,059 | 2029 | $19,678 |
| 2020 | $7,561 | 2030 | $20,061 |
| 2021 | $10,110 | 2031 | $20,426 |
| 2022 | $11,964 | 2032 | $20,614 |
| 2023 | $13,680 | 2033 | $20,792 |
| 2024 | $15,320 | 2034 | $20,963 |
| 2025 | $16,710 | 2035 | $21,126 |
| 2026 | $18,417 | 2036 | $21,307 |
| Total | | | $21,307 |




| Year | B/C Ratio | Year | B/C Ratio |
|---|---|---|---|
| 2017 | 0.00 | 2027 | 2.71 |
| 2018 | 0.26 | 2028 | 2.78 |
| 2019 | 0.35 | 2029 | 2.78 |
| 2020 | 0.34 | 2030 | 2.78 |
| 2021 | 0.39 | 2031 | 2.78 |
| 2022 | 0.61 | 2032 | 5.20 |
| 2023 | 0.75 | 2033 | 5.20 |
| 2024 | 0.82 | 2034 | 5.20 |
| 2025 | 0.94 | 2035 | 5.20 |
| 2026 | 0.73 | 2036 | 4.47 |
| Total | | | 0.90 |




| Year | B/C Ratio | Year | B/C Ratio |
|---|---|---|---|
| 2017 | 0.00 | 2027 | 0.55 |
| 2018 | 0.12 | 2028 | 0.60 |
| 2019 | 0.20 | 2029 | 0.64 |
| 2020 | 0.25 | 2030 | 0.69 |
| 2021 | 0.29 | 2031 | 0.72 |
| 2022 | 0.34 | 2032 | 0.76 |
| 2023 | 0.39 | 2033 | 0.80 |
| 2024 | 0.43 | 2034 | 0.84 |
| 2025 | 0.48 | 2035 | 0.87 |
| 2026 | 0.50 | 2036 | 0.90 |
| Total | | | 0.90 |

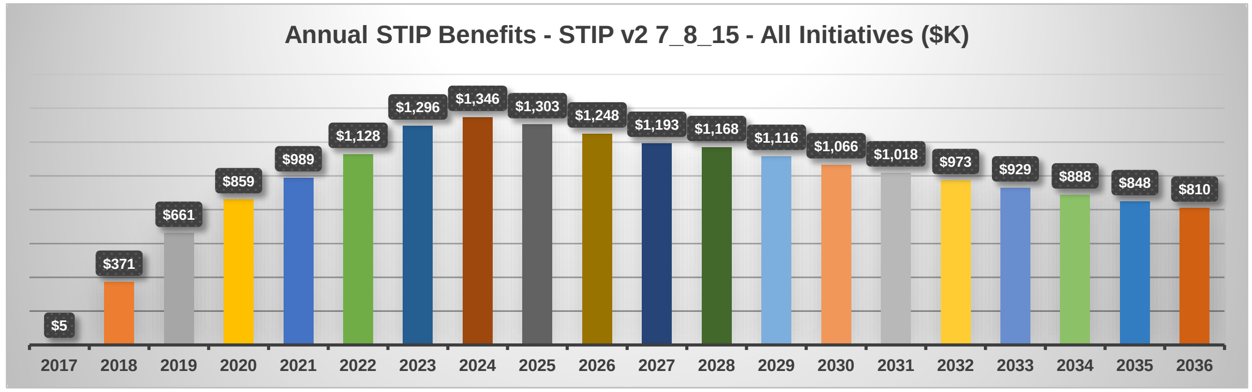



## STIP Trends - STIP v2 7_8_15 - Initiatives

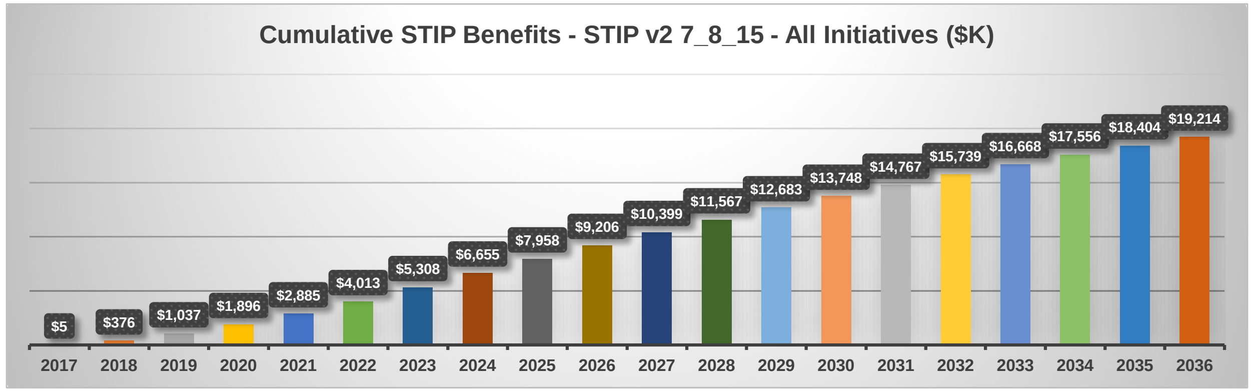
| Year | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| All | $19,214 | $21,307 | 0.90 |

| STIP Case 1 |
|---|
| STIP v2 7_8_15 |

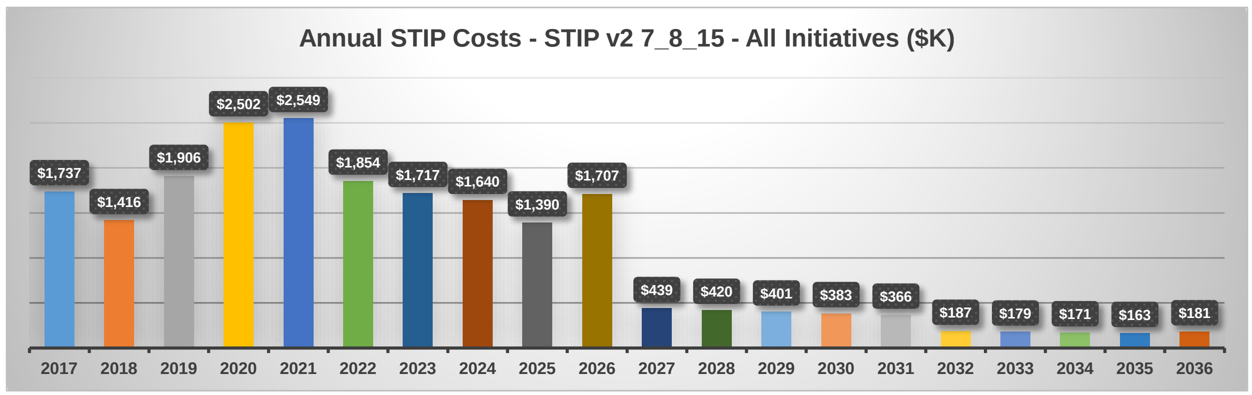
| Year | Benefits ($K) | Year | Benefits ($K) |
|---|---|---|---|
| 2017 | $5 | 2027 | $1,193 |
| 2018 | $371 | 2028 | $1,168 |
| 2019 | $661 | 2029 | $1,116 |
| 2020 | $859 | 2030 | $1,066 |
| 2021 | $989 | 2031 | $1,018 |
| 2022 | $1,128 | 2032 | $973 |
| 2023 | $1,296 | 2033 | $929 |
| 2024 | $1,346 | 2034 | $888 |
| 2025 | $1,303 | 2035 | $848 |
| 2026 | $1,248 | 2036 | $810 |
| **Total** | | | **$19,214** |



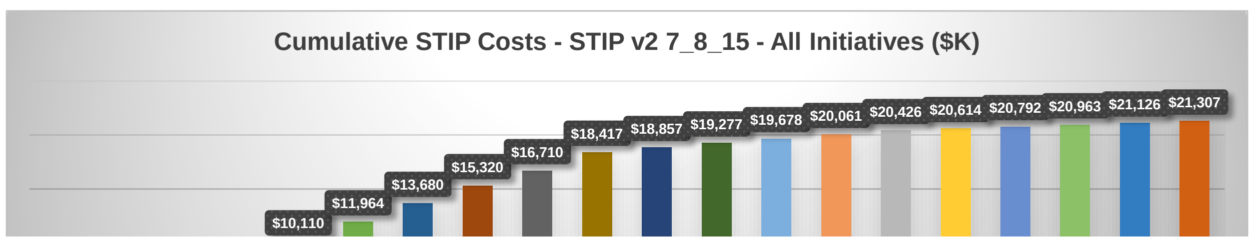

| Year | Benefits ($K) | Year | Benefits ($K) |
|---|---|---|---|
| 2017 | $5 | 2027 | $10,399 |
| 2018 | $376 | 2028 | $11,567 |
| 2019 | $1,037 | 2029 | $12,683 |
| 2020 | $1,896 | 2030 | $13,748 |
| 2021 | $2,885 | 2031 | $14,767 |
| 2022 | $4,013 | 2032 | $15,739 |
| 2023 | $5,308 | 2033 | $16,668 |
| 2024 | $6,655 | 2034 | $17,556 |
| 2025 | $7,958 | 2035 | $18,404 |
| 2026 | $9,206 | 2036 | $19,214 |
| **Total** | | | **$19,214** |



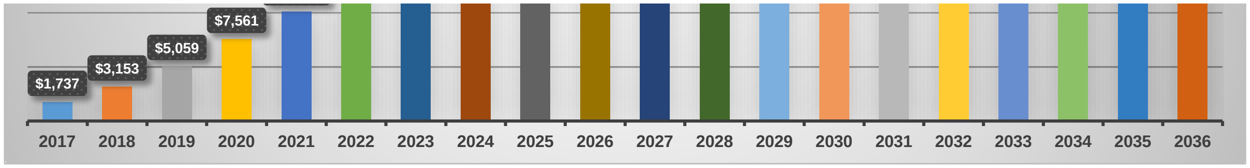

| Year | Costs ($K) | Year | Costs ($K) |
|---|---|---|---|
| 2017 | $1,737 | 2027 | $439 |
| 2018 | $1,416 | 2028 | $420 |
| 2019 | $1,906 | 2029 | $401 |
| 2020 | $2,502 | 2030 | $383 |
| 2021 | $2,549 | 2031 | $366 |
| 2022 | $1,854 | 2032 | $187 |
| 2023 | $1,717 | 2033 | $179 |
| 2024 | $1,640 | 2034 | $171 |
| 2025 | $1,390 | 2035 | $163 |
| 2026 | $1,707 | 2036 | $181 |
| **Total** | | | **$21,307** |



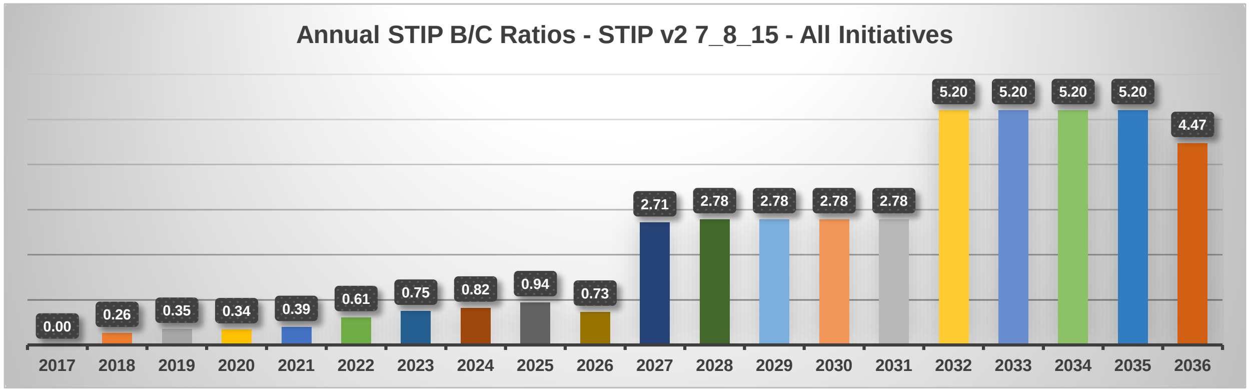

| Year | Costs ($K) | Year | Costs ($K) |
|---|---|---|---|
| 2017 | $1,737 | 2027 | $18,857 |
| 2018 | $3,153 | 2028 | $19,277 |
| 2019 | $5,059 | 2029 | $19,678 |
| 2020 | $7,561 | 2030 | $20,061 |
| 2021 | $10,110 | 2031 | $20,426 |
| 2022 | $11,964 | 2032 | $20,614 |



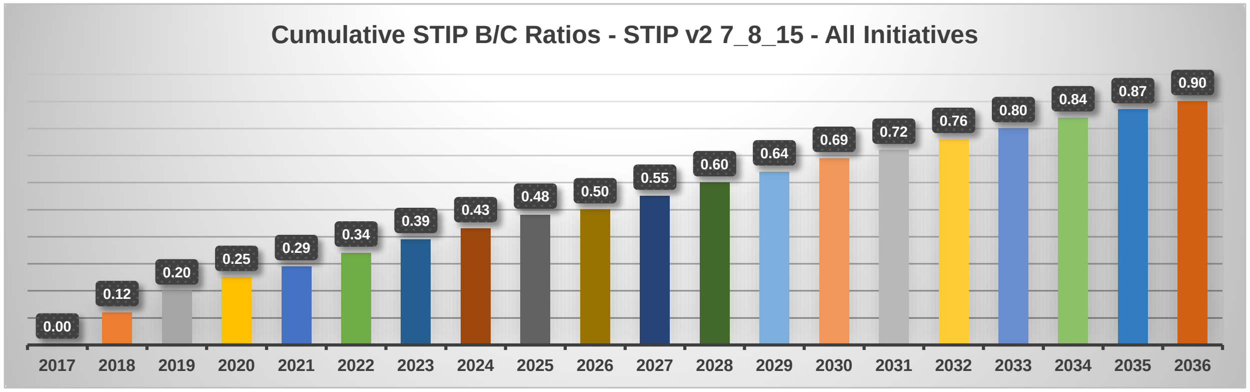
| | | | |
|---|---|---|---|
| 2023 | $13,680 | 2033 | $20,792 |
| 2024 | $15,320 | 2034 | $20,963 |
| 2025 | $16,710 | 2035 | $21,126 |
| 2026 | $18,417 | 2036 | $21,307 |
| **Total** | | | **$21,307** |




| Year | B/C Ratio | Year | B/C Ratio |
|---|---|---|---|
| 2017 | 0.00 | 2027 | 2.71 |
| 2018 | 0.26 | 2028 | 2.78 |
| 2019 | 0.35 | 2029 | 2.78 |
| 2020 | 0.34 | 2030 | 2.78 |
| 2021 | 0.39 | 2031 | 2.78 |
| 2022 | 0.61 | 2032 | 5.20 |
| 2023 | 0.75 | 2033 | 5.20 |
| 2024 | 0.82 | 2034 | 5.20 |
| 2025 | 0.94 | 2035 | 5.20 |
| 2026 | 0.73 | 2036 | 4.47 |
| **Total** | | | **0.90** |




| Year | B/C Ratio | Year | B/C Ratio |
|---|---|---|---|
| 2017 | 0.00 | 2027 | 0.55 |
| 2018 | 0.12 | 2028 | 0.60 |
| 2019 | 0.20 | 2029 | 0.64 |
| 2020 | 0.25 | 2030 | 0.69 |
| 2021 | 0.29 | 2031 | 0.72 |
| 2022 | 0.34 | 2032 | 0.76 |
| 2023 | 0.39 | 2033 | 0.80 |
| 2024 | 0.43 | 2034 | 0.84 |
| 2025 | 0.48 | 2035 | 0.87 |
| 2026 | 0.50 | 2036 | 0.90 |
| **Total** | | | **0.90** |



# GMP BCA Model

## STIP Trends - TVR Opt-Out

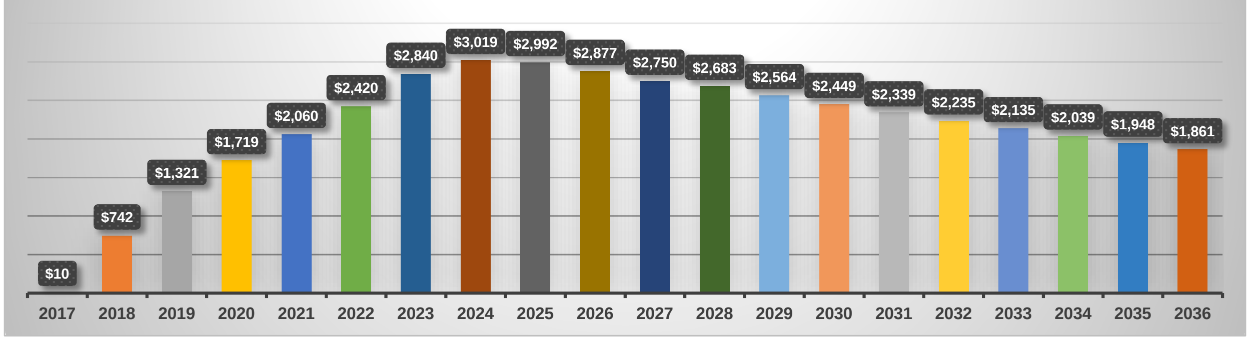
### STIP Trends - TVR Opt-Out - Programs

| Year | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| All | $43,002 | $28,579 | 1.50 |

| STIP Case 2 |
|---|
| TVR Opt-Out |

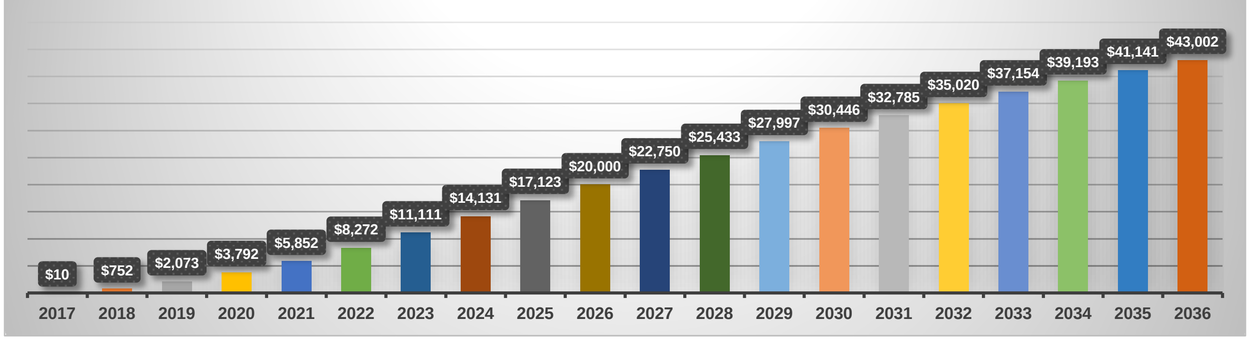
| Year | Benefits ($K) | Year | Benefits ($K) |
|---|---|---|---|
| 2017 | $10 | 2027 | $2,750 |
| 2018 | $742 | 2028 | $2,683 |
| 2019 | $1,321 | 2029 | $2,564 |
| 2020 | $1,719 | 2030 | $2,449 |
| 2021 | $2,060 | 2031 | $2,339 |
| 2022 | $2,420 | 2032 | $2,235 |
| 2023 | $2,840 | 2033 | $2,135 |
| 2024 | $3,019 | 2034 | $2,039 |
| 2025 | $2,992 | 2035 | $1,948 |
| 2026 | $2,877 | 2036 | $1,861 |
| **Total** | | | **$43,002** |

**Annual STIP Benefits - TVR Opt-Out - All Programs ($K)**



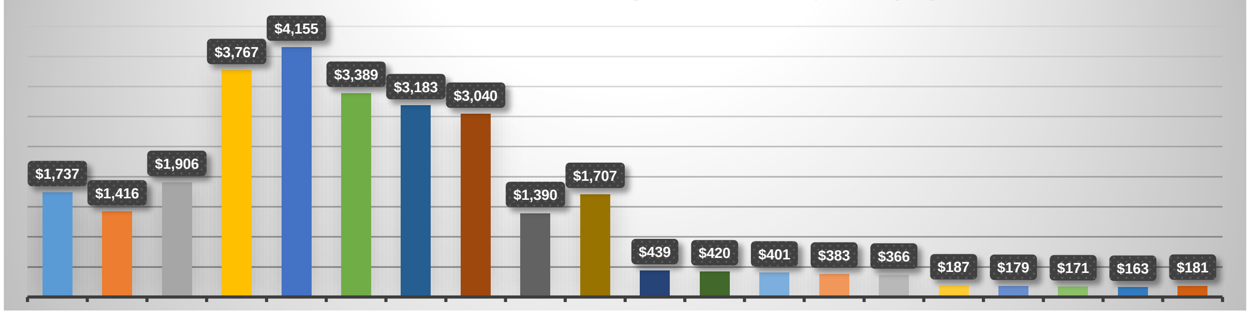

| Year | Benefits ($K) | Year | Benefits ($K) |
|---|---|---|---|
| 2017 | $10 | 2027 | $22,750 |
| 2018 | $752 | 2028 | $25,433 |
| 2019 | $2,073 | 2029 | $27,997 |
| 2020 | $3,792 | 2030 | $30,446 |
| 2021 | $5,852 | 2031 | $32,785 |
| 2022 | $8,272 | 2032 | $35,020 |
| 2023 | $11,111 | 2033 | $37,154 |
| 2024 | $14,131 | 2034 | $39,193 |
| 2025 | $17,123 | 2035 | $41,141 |
| 2026 | $20,000 | 2036 | $43,002 |
| **Total** | | | **$43,002** |

**Cumulative STIP Benefits - TVR Opt-Out - All Programs ($K)**



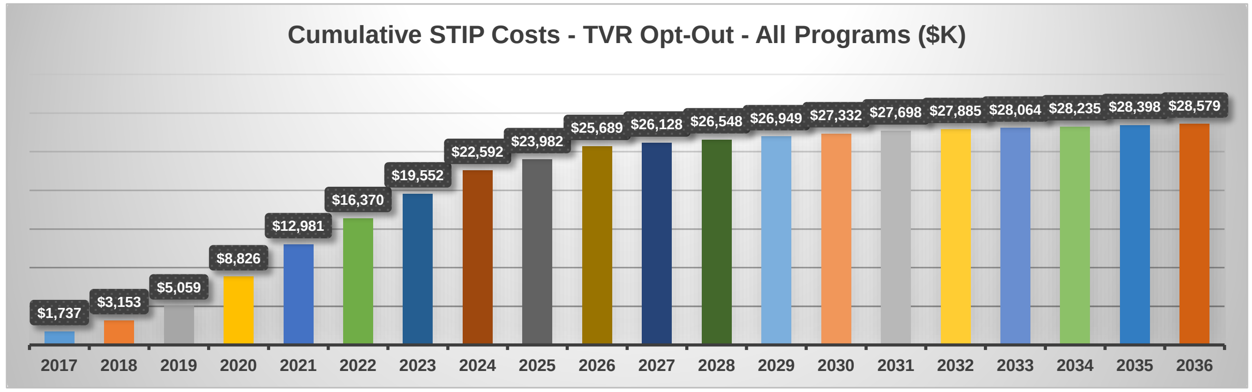

| Year | Costs ($K) | Year | Costs ($K) |
|---|---|---|---|
| 2017 | $1,737 | 2027 | $439 |
| 2018 | $1,416 | 2028 | $420 |
| 2019 | $1,906 | 2029 | $401 |
| 2020 | $3,767 | 2030 | $383 |
| 2021 | $4,155 | 2031 | $366 |
| 2022 | $3,389 | 2032 | $187 |
| 2023 | $3,183 | 2033 | $179 |
| 2024 | $3,040 | 2034 | $171 |
| 2025 | $1,390 | 2035 | $163 |
| 2026 | $1,707 | 2036 | $181 |

**Annual STIP Costs - TVR Opt-Out - All Programs ($K)**

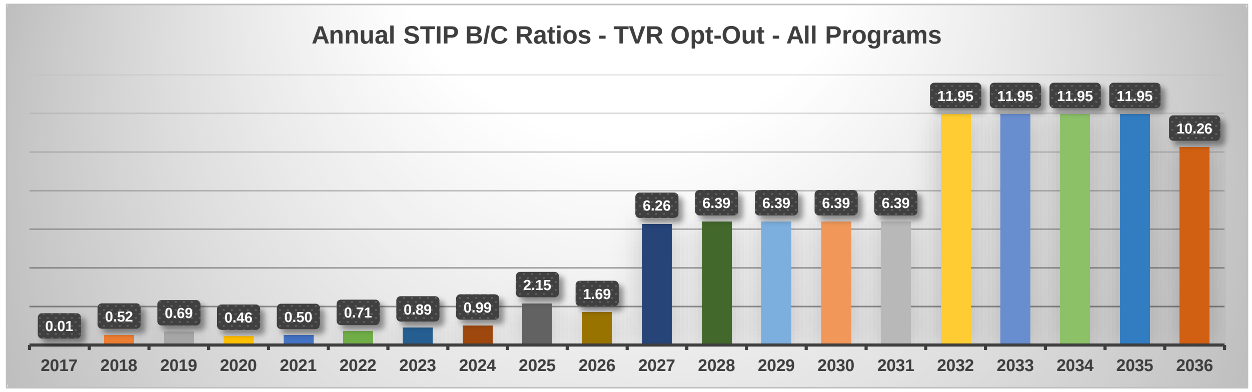


| Total | | | $28,579 |
|---|---|---|---|

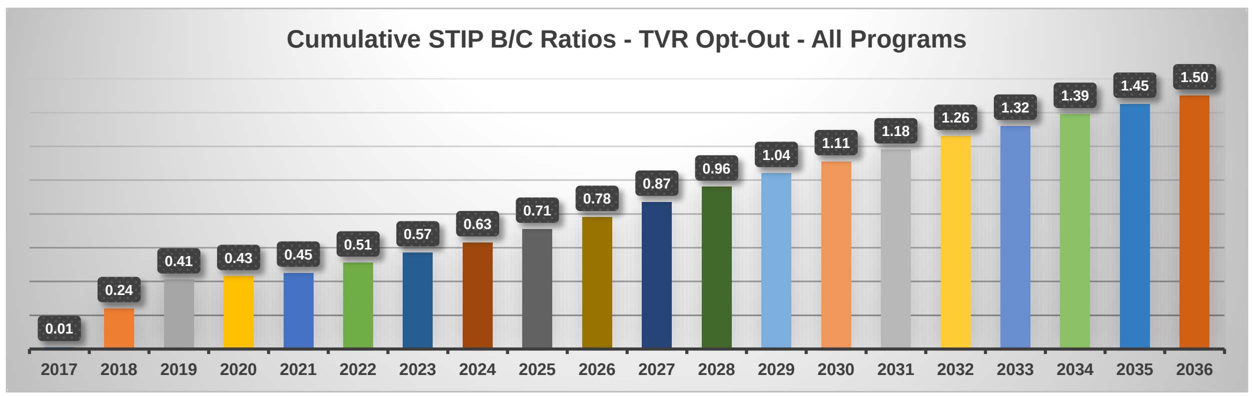

| Year | Costs ($K) | Year | Costs ($K) |
|---|---|---|---|
| 2017 | $1,737 | 2027 | $26,128 |
| 2018 | $3,153 | 2028 | $26,548 |
| 2019 | $5,059 | 2029 | $26,949 |
| 2020 | $8,826 | 2030 | $27,332 |
| 2021 | $12,981 | 2031 | $27,698 |
| 2022 | $16,370 | 2032 | $27,885 |
| 2023 | $19,552 | 2033 | $28,064 |
| 2024 | $22,592 | 2034 | $28,235 |
| 2025 | $23,982 | 2035 | $28,398 |
| 2026 | $25,689 | 2036 | $28,579 |
| Total | | | $28,579 |




| Year | B/C Ratio | Year | B/C Ratio |
|---|---|---|---|
| 2017 | 0.01 | 2027 | 6.26 |
| 2018 | 0.52 | 2028 | 6.39 |
| 2019 | 0.69 | 2029 | 6.39 |
| 2020 | 0.46 | 2030 | 6.39 |
| 2021 | 0.50 | 2031 | 6.39 |
| 2022 | 0.71 | 2032 | 11.95 |
| 2023 | 0.89 | 2033 | 11.95 |
| 2024 | 0.99 | 2034 | 11.95 |
| 2025 | 2.15 | 2035 | 11.95 |
| 2026 | 1.69 | 2036 | 10.26 |
| Total | | | 1.50 |




| Year | B/C Ratio | Year | B/C Ratio |
|---|---|---|---|
| 2017 | 0.01 | 2027 | 0.87 |
| 2018 | 0.24 | 2028 | 0.96 |
| 2019 | 0.41 | 2029 | 1.04 |
| 2020 | 0.43 | 2030 | 1.11 |
| 2021 | 0.45 | 2031 | 1.18 |
| 2022 | 0.51 | 2032 | 1.26 |
| 2023 | 0.57 | 2033 | 1.32 |
| 2024 | 0.63 | 2034 | 1.39 |
| 2025 | 0.71 | 2035 | 1.45 |
| 2026 | 0.78 | 2036 | 1.50 |
| Total | | | 1.50 |

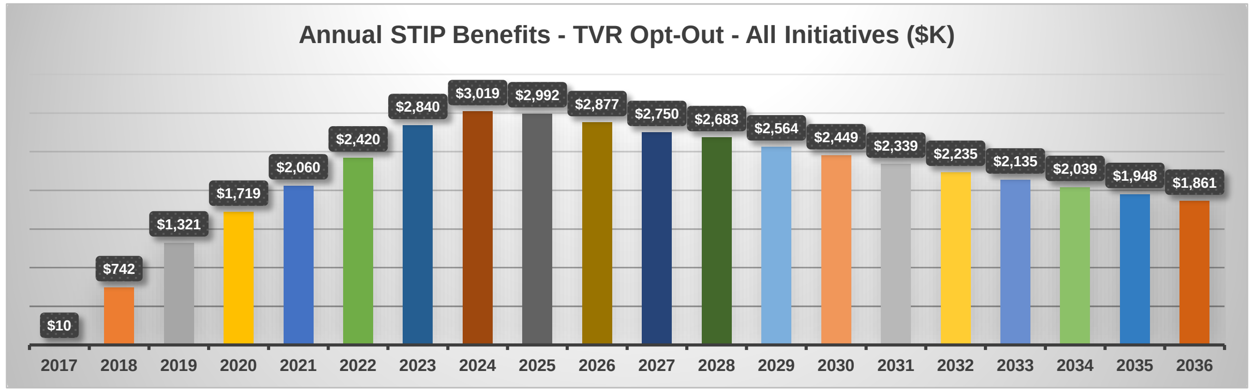



## STIP Trends - TVR Opt-Out - Initiatives

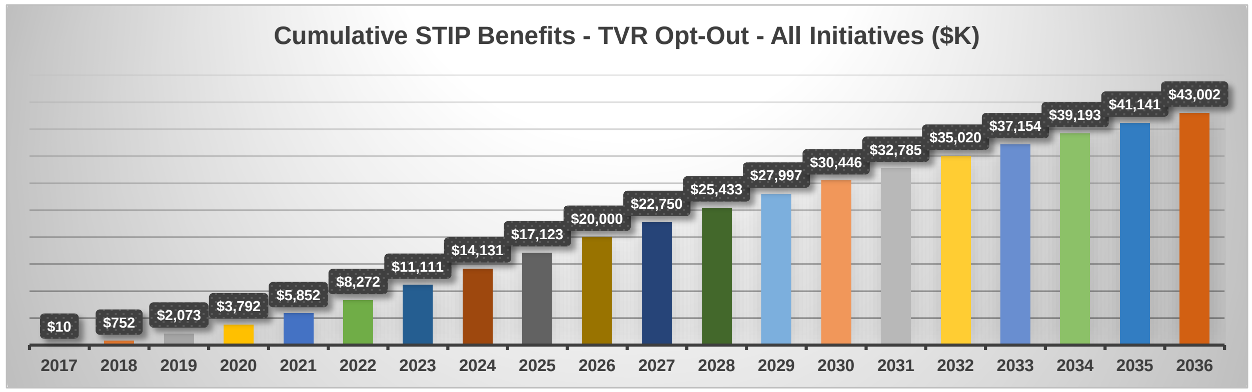
| Year | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|
| All | $43,002 | $28,579 | 1.50 |

| STIP Case 2 |
|---|
| TVR Opt-Out |

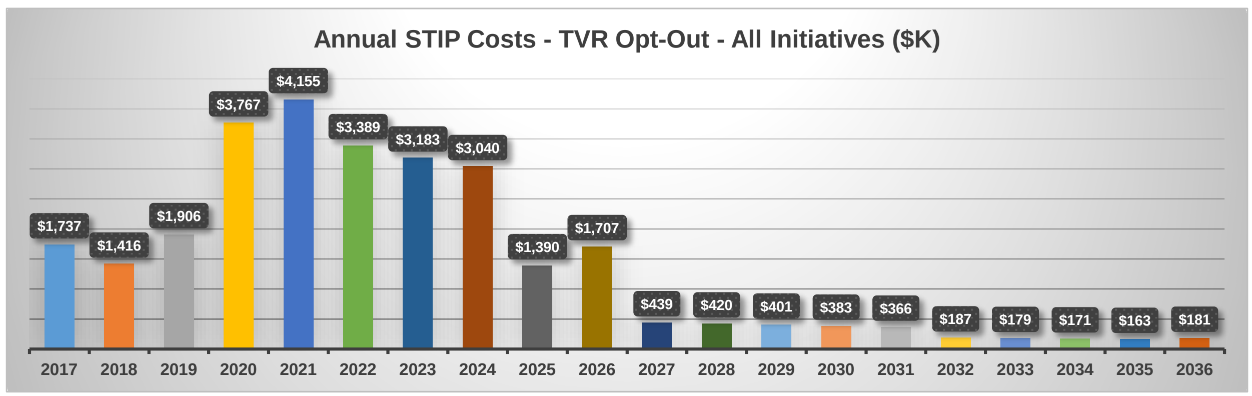
| Year | Benefits ($K) | Year | Benefits ($K) |
|---|---|---|---|
| 2017 | $10 | 2027 | $2,750 |
| 2018 | $742 | 2028 | $2,683 |
| 2019 | $1,321 | 2029 | $2,564 |
| 2020 | $1,719 | 2030 | $2,449 |
| 2021 | $2,060 | 2031 | $2,339 |
| 2022 | $2,420 | 2032 | $2,235 |
| 2023 | $2,840 | 2033 | $2,135 |
| 2024 | $3,019 | 2034 | $2,039 |
| 2025 | $2,992 | 2035 | $1,948 |
| 2026 | $2,877 | 2036 | $1,861 |
| **Total** | | | **$43,002** |



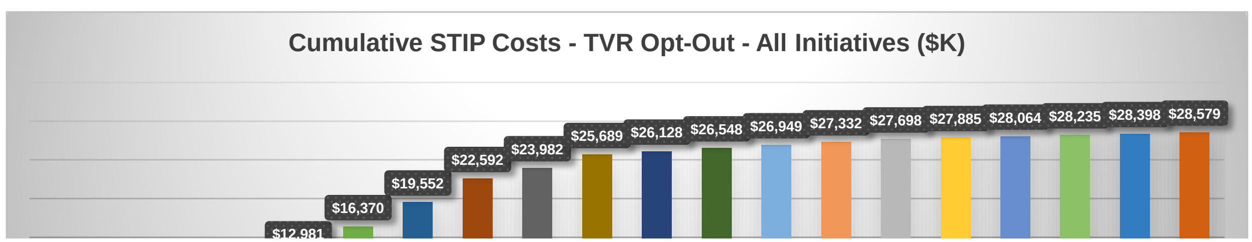

| Year | Benefits ($K) | Year | Benefits ($K) |
|---|---|---|---|
| 2017 | $10 | 2027 | $22,750 |
| 2018 | $752 | 2028 | $25,433 |
| 2019 | $2,073 | 2029 | $27,997 |
| 2020 | $3,792 | 2030 | $30,446 |
| 2021 | $5,852 | 2031 | $32,785 |
| 2022 | $8,272 | 2032 | $35,020 |
| 2023 | $11,111 | 2033 | $37,154 |
| 2024 | $14,131 | 2034 | $39,193 |
| 2025 | $17,123 | 2035 | $41,141 |
| 2026 | $20,000 | 2036 | $43,002 |
| **Total** | | | **$43,002** |



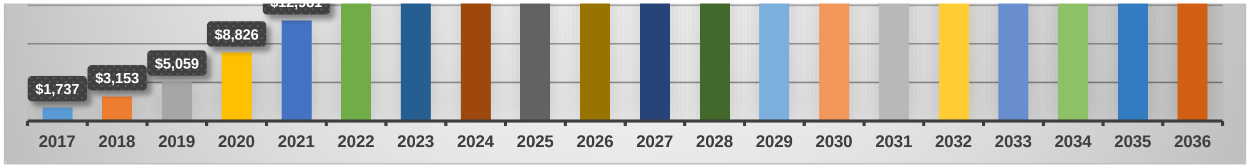

| Year | Costs ($K) | Year | Costs ($K) |
|---|---|---|---|
| 2017 | $1,737 | 2027 | $439 |
| 2018 | $1,416 | 2028 | $420 |
| 2019 | $1,906 | 2029 | $401 |
| 2020 | $3,767 | 2030 | $383 |
| 2021 | $4,155 | 2031 | $366 |
| 2022 | $3,389 | 2032 | $187 |
| 2023 | $3,183 | 2033 | $179 |
| 2024 | $3,040 | 2034 | $171 |
| 2025 | $1,390 | 2035 | $163 |
| 2026 | $1,707 | 2036 | $181 |
| **Total** | | | **$28,579** |



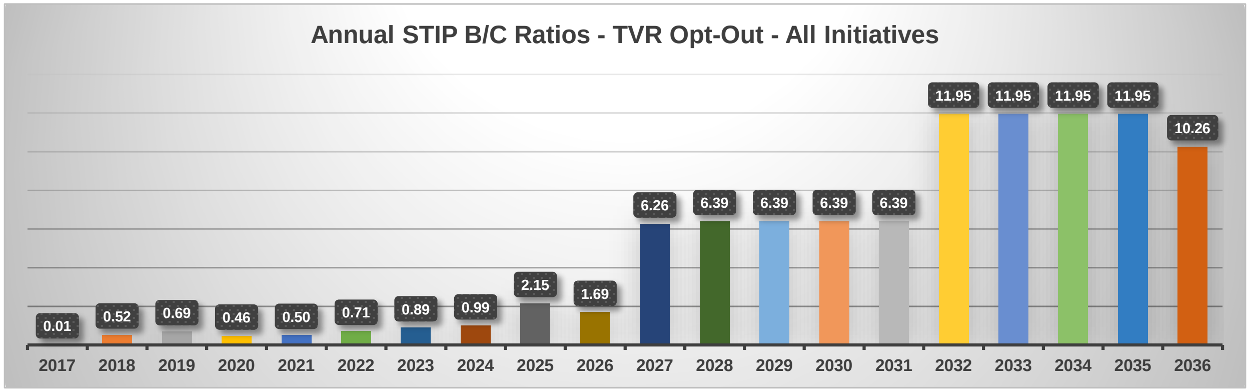

| Year | Costs ($K) | Year | Costs ($K) |
|---|---|---|---|
| 2017 | $1,737 | 2027 | $26,128 |
| 2018 | $3,153 | 2028 | $26,548 |
| 2019 | $5,059 | 2029 | $26,949 |
| 2020 | $8,826 | 2030 | $27,332 |
| 2021 | $12,981 | 2031 | $27,698 |
| 2022 | $16,370 | 2032 | $27,885 |



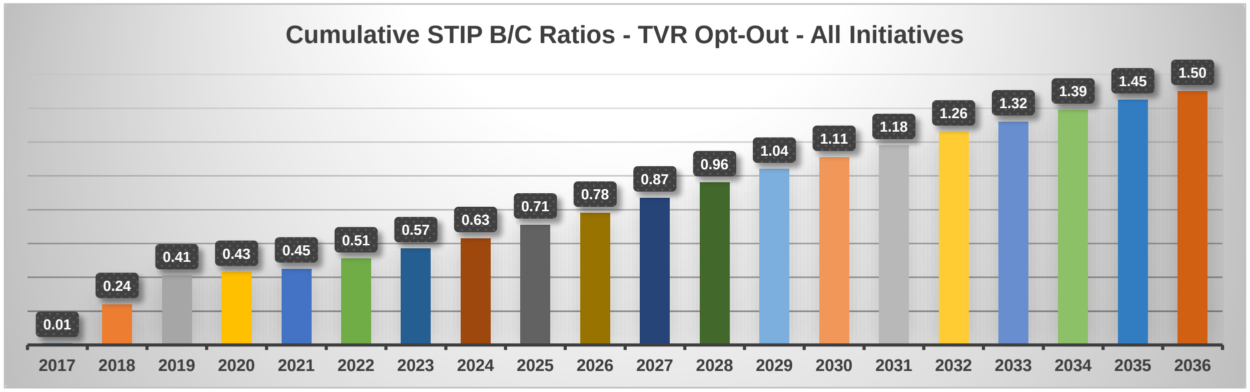
| | | | |
|---|---|---|---|
| 2023 | $19,552 | 2033 | $28,064 |
| 2024 | $22,592 | 2034 | $28,235 |
| 2025 | $23,982 | 2035 | $28,398 |
| 2026 | $25,689 | 2036 | $28,579 |
| **Total** | | | **$28,579** |




| Year | B/C Ratio | Year | B/C Ratio |
|---|---|---|---|
| 2017 | 0.01 | 2027 | 6.26 |
| 2018 | 0.52 | 2028 | 6.39 |
| 2019 | 0.69 | 2029 | 6.39 |
| 2020 | 0.46 | 2030 | 6.39 |
| 2021 | 0.50 | 2031 | 6.39 |
| 2022 | 0.71 | 2032 | 11.95 |
| 2023 | 0.89 | 2033 | 11.95 |
| 2024 | 0.99 | 2034 | 11.95 |
| 2025 | 2.15 | 2035 | 11.95 |
| 2026 | 1.69 | 2036 | 10.26 |
| **Total** | | | **1.50** |




| Year | B/C Ratio | Year | B/C Ratio |
|---|---|---|---|
| 2017 | 0.01 | 2027 | 0.87 |
| 2018 | 0.24 | 2028 | 0.96 |
| 2019 | 0.41 | 2029 | 1.04 |
| 2020 | 0.43 | 2030 | 1.11 |
| 2021 | 0.45 | 2031 | 1.18 |
| 2022 | 0.51 | 2032 | 1.26 |
| 2023 | 0.57 | 2033 | 1.32 |
| 2024 | 0.63 | 2034 | 1.39 |
| 2025 | 0.71 | 2035 | 1.45 |
| 2026 | 0.78 | 2036 | 1.50 |
| **Total** | | | **1.50** |



**GMP BCA Model**

**STIP Projects - STIP v2 7_8_15**

| Project Information | | Cumulative Totals ($K) | | | Annual Benefits ($K) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ID | Project | Benefits | Costs | Net Value | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
| A-2 | Circuit Capacity Study | $64 | $220 | -$156 | $5 | $5 | $4 | $4 | $4 | $4 | $4 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $2 | $2 | $2 | $2 | $2 |
| A-5 | Analytics & Visualiation System Platform | $0 | $1,361 | -$1,361 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| A-6 | Substation 3V0 Protection | $0 | $1,568 | -$1,568 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| A-7 | Substation Voltage Regulation Control | $0 | $408 | -$408 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| B-8 | Mobile Damage Assessment Tool | $3,840 | $502 | $3,338 | $0 | $0 | $306 | $292 | $279 | $267 | $255 | $243 | $233 | $222 | $212 | $203 | $194 | $185 | $177 | $169 | $161 | $154 | $147 | $141 |
| B-9 | AMI & OMS Integration | $693 | $60 | $634 | $0 | $53 | $51 | $49 | $47 | $44 | $42 | $41 | $39 | $37 | $35 | $34 | $32 | $31 | $29 | $28 | $27 | $26 | $25 | $23 |
| C-2 | Automated Cap Banks | $0 | $2,108 | -$2,108 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-3 | Automated Voltage Regulators | $0 | $5,293 | -$5,293 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-4 | Automated Transformer & Load Tap Changers | $0 | $528 | -$528 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-5 | Fitchburg SCADA Communications | $0 | $784 | -$784 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-6 | Field Area Network | $0 | $2,196 | -$2,196 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-7 | ADMS | $9,159 | $3,100 | $6,060 | $0 | $0 | $0 | $228 | $361 | $509 | $655 | $715 | $684 | $655 | $626 | $626 | $598 | $571 | $546 | $521 | $498 | $476 | $455 | $434 |
| D-1 | Customer Web Portal | $100 | $531 | -$431 | $0 | $0 | $0 | $0 | $8 | $8 | $8 | $7 | $7 | $7 | $7 | $6 | $6 | $6 | $6 | $5 | $5 | $5 | $5 | $5 |
| D-3 | Gamification Pilot | $310 | $389 | -$79 | $0 | $0 | $0 | $0 | $0 | $0 | $29 | $28 | $27 | $26 | $24 | $23 | $22 | $21 | $20 | $19 | $19 | $18 | $17 | $16 |
| D-6 | TVR & Demand Response | $980 | $1,895 | -$915 | $0 | $0 | $0 | $0 | $18 | $35 | $53 | $70 | $83 | $82 | $78 | $74 | $71 | $68 | $65 | $62 | $59 | $57 | $54 | $52 |
| E-1 | Mobility Platform & System | $4,067 | $365 | $3,702 | $0 | $313 | $299 | $286 | $273 | $261 | $249 | $238 | $227 | $217 | $207 | $198 | $189 | $181 | $173 | $165 | $158 | $151 | $144 | $137 |
| Total | 16 Projects | $19,214 | $21,307 | -$2,093 | $5 | $371 | $661 | $859 | $989 | $1,128 | $1,296 | $1,346 | $1,303 | $1,248 | $1,193 | $1,168 | $1,116 | $1,066 | $1,018 | $973 | $929 | $888 | $848 | $810 |

| Project Information | | Annual Costs ($K) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ID | Project | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
| A-2 | Circuit Capacity Study | $29 | $27 | $13 | $12 | $12 | $11 | $11 | $10 | $10 | $9 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 |
| A-5 | Analytics & Visualiation System Platform | $0 | $0 | $0 | $0 | $517 | $76 | $73 | $69 | $66 | $63 | $60 | $58 | $55 | $53 | $50 | $48 | $46 | $44 | $42 | $40 |
| A-6 | Substation 3V0 Protection | $191 | $183 | $174 | $167 | $159 | $152 | $145 | $139 | $132 | $127 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| A-7 | Substation Voltage Regulation Control | $50 | $47 | $45 | $43 | $41 | $40 | $38 | $36 | $34 | $33 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| B-8 | Mobile Damage Assessment Tool | $143 | $137 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $221 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| B-9 | AMI & OMS Integration | $48 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $0 | $0 | $0 |
| C-2 | Automated Cap Banks | $0 | $0 | $0 | $0 | $0 | $257 | $245 | $234 | $224 | $214 | $204 | $195 | $186 | $178 | $170 | $0 | $0 | $0 | $0 | $0 |
| C-3 | Automated Voltage Regulators | $645 | $616 | $588 | $562 | $537 | $513 | $490 | $468 | $447 | $427 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-4 | Automated Transformer & Load Tap Changers | $61 | $58 | $56 | $53 | $51 | $49 | $46 | $44 | $42 | $40 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $26 |
| C-5 | Fitchburg SCADA Communications | $96 | $91 | $87 | $83 | $80 | $76 | $73 | $69 | $66 | $63 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-6 | Field Area Network | $267 | $256 | $244 | $233 | $223 | $213 | $203 | $194 | $185 | $177 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-7 | ADMS | $0 | $0 | $610 | $583 | $557 | $122 | $116 | $111 | $106 | $101 | $97 | $92 | $88 | $84 | $81 | $77 | $73 | $70 | $67 | $64 |
| D-1 | Customer Web Portal | $0 | $0 | $87 | $83 | $40 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 | $19 | $18 | $17 | $17 | $16 | $15 |
| D-3 | Gamification Pilot | $0 | $0 | $0 | $42 | $80 | $76 | $18 | $17 | $17 | $16 | $15 | $14 | $14 | $13 | $13 | $12 | $11 | $11 | $10 | $10 |
| D-6 | TVR & Demand Response | $0 | $0 | $0 | $639 | $252 | $241 | $230 | $220 | $33 | $32 | $30 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 |
| E-1 | Mobility Platform & System | $207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $158 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | 16 Projects | $1,737 | $1,416 | $1,906 | $2,502 | $2,549 | $1,854 | $1,717 | $1,640 | $1,390 | $1,707 | $439 | $420 | $401 | $383 | $366 | $187 | $179 | $171 | $163 | $181 |

**GMP BCA Model**

**STIP Projects - TVR Opt-Out**

| Project Information | | Project Information | | |
|---|---|---|---|---|
| ID | Project | Benefits | Costs | Net Value |
| A-2 | Circuit Capacity Study | $128 | $220 | -$92 |
| A-5 | Analytics & Visualiation System Platform | $0 | $1,361 | -$1,361 |
| A-6 | Substation 3V0 Protection | $0 | $1,568 | -$1,568 |
| A-7 | Substation Voltage Regulation Control | $0 | $408 | -$408 |
| B-8 | Mobile Damage Assessment Tool | $7,679 | $502 | $7,178 |
| B-9 | AMI & OMS Integration | $1,387 | $60 | $1,327 |
| C-2 | Automated Cap Banks | $0 | $2,108 | -$2,108 |
| C-3 | Automated Voltage Regulators | $0 | $5,293 | -$5,293 |
| C-4 | Automated Transformer & Load Tap Changers | $0 | $528 | -$528 |
| C-5 | Fitchburg SCADA Communications | $0 | $784 | -$784 |
| C-6 | Field Area Network | $0 | $2,196 | -$2,196 |
| C-7 | ADMS | $18,319 | $3,100 | $15,219 |
| D-1 | Customer Web Portal | $200 | $531 | -$330 |
| D-3 | Gamification Pilot | $619 | $389 | $230 |
| D-6 | TVR & Demand Response | $6,535 | $9,167 | -$2,631 |
| E-1 | Mobility Platform & System | $8,134 | $365 | $7,769 |
| Total | 16 Projects | $43,002 | $28,579 | $14,423 |

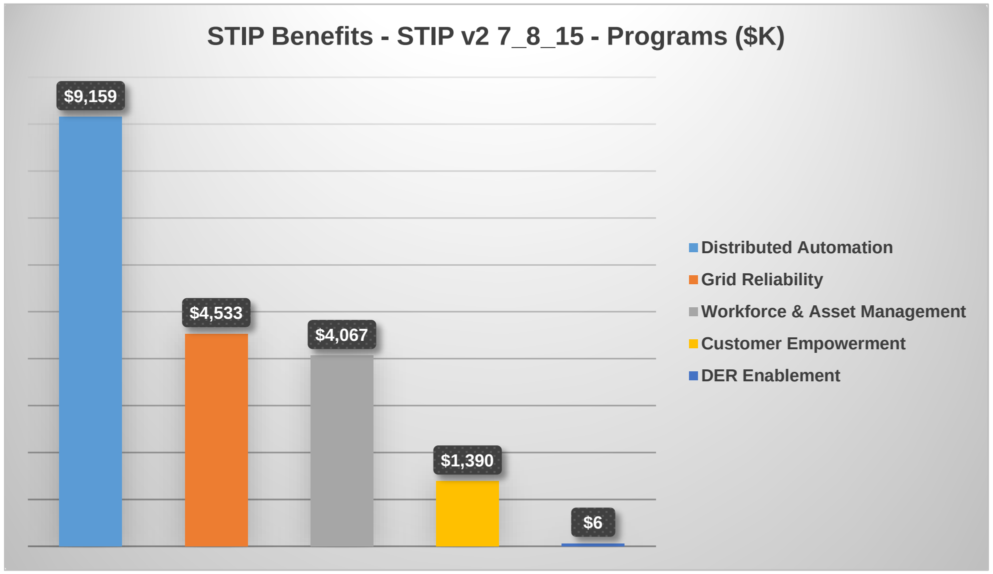
| | Annual Benefits ($K) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ID | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
| A-2 | $10 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | $6 | $6 | $5 | $5 | $5 | $5 | $4 | $4 | $4 |
| A-5 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| A-6 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| A-7 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| B-8 | $0 | $0 | $612 | $585 | $559 | $534 | $510 | $487 | $465 | $444 | $424 | $405 | $387 | $370 | $353 | $338 | $323 | $308 | $294 | $281 |
| B-9 | $0 | $107 | $102 | $97 | $93 | $89 | $85 | $81 | $78 | $74 | $71 | $68 | $65 | $62 | $59 | $56 | $54 | $51 | $49 | $47 |
| C-2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-5 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-6 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-7 | $0 | $0 | $0 | $456 | $721 | $1,017 | $1,311 | $1,431 | $1,369 | $1,309 | $1,252 | $1,252 | $1,196 | $1,143 | $1,092 | $1,043 | $996 | $952 | $909 | $868 |
| D-1 | $0 | $0 | $0 | $0 | $16 | $16 | $15 | $15 | $14 | $14 | $13 | $13 | $12 | $12 | $11 | $11 | $10 | $10 | $9 | $9 |
| D-3 | $0 | $0 | $0 | $0 | $0 | $0 | $59 | $56 | $53 | $51 | $49 | $47 | $45 | $43 | $41 | $39 | $37 | $35 | $34 | $32 |
| D-6 | $0 | $0 | $0 | $0 | $117 | $235 | $355 | $467 | $551 | $544 | $520 | $496 | $474 | $453 | $433 | $413 | $395 | $377 | $360 | $344 |
| E-1 | $0 | $626 | $598 | $572 | $546 | $522 | $498 | $476 | $455 | $434 | $415 | $396 | $379 | $362 | $346 | $330 | $315 | $301 | $288 | $275 |
| Total | $10 | $742 | $1,321 | $1,719 | $2,060 | $2,420 | $2,840 | $3,019 | $2,992 | $2,877 | $2,750 | $2,683 | $2,564 | $2,449 | $2,339 | $2,235 | $2,135 | $2,039 | $1,948 | $1,861 |

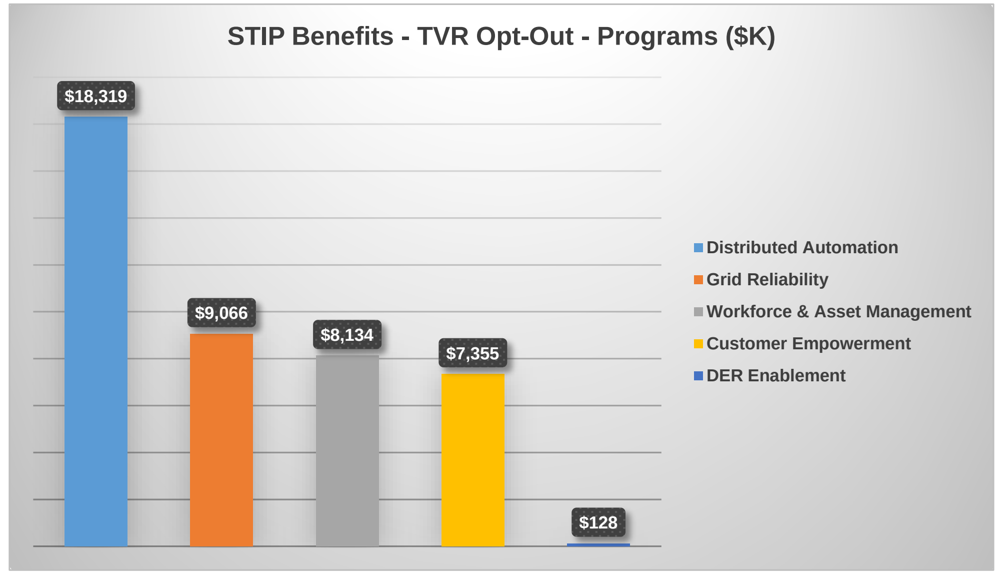
| | Annual Costs ($K) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ID | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
| A-2 | $29 | $27 | $13 | $12 | $12 | $11 | $11 | $10 | $10 | $9 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 |
| A-5 | $0 | $0 | $0 | $0 | $517 | $76 | $73 | $69 | $66 | $63 | $60 | $58 | $55 | $53 | $50 | $48 | $46 | $44 | $42 | $40 |
| A-6 | $191 | $183 | $174 | $167 | $159 | $152 | $145 | $139 | $132 | $127 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| A-7 | $50 | $47 | $45 | $43 | $41 | $40 | $38 | $36 | $34 | $33 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| B-8 | $143 | $137 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $221 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| B-9 | $48 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $0 | $0 | $0 |
| C-2 | $0 | $0 | $0 | $0 | $0 | $257 | $245 | $234 | $224 | $214 | $204 | $195 | $186 | $178 | $170 | $0 | $0 | $0 | $0 | $0 |
| C-3 | $645 | $616 | $588 | $562 | $537 | $513 | $490 | $468 | $447 | $427 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-4 | $61 | $58 | $56 | $53 | $51 | $49 | $46 | $44 | $42 | $40 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $26 |
| C-5 | $96 | $91 | $87 | $83 | $80 | $76 | $73 | $69 | $66 | $63 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-6 | $267 | $256 | $244 | $233 | $223 | $213 | $203 | $194 | $185 | $177 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-7 | $0 | $0 | $610 | $583 | $557 | $122 | $116 | $111 | $106 | $101 | $97 | $92 | $88 | $84 | $81 | $77 | $73 | $70 | $67 | $64 |
| D-1 | $0 | $0 | $87 | $83 | $40 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 | $19 | $18 | $17 | $17 | $16 | $15 |
| D-3 | $0 | $0 | $0 | $42 | $80 | $76 | $18 | $17 | $17 | $16 | $15 | $14 | $14 | $13 | $13 | $12 | $11 | $11 | $10 | $10 |
| D-6 | $0 | $0 | $0 | $1,904 | $1,858 | $1,775 | $1,696 | $1,620 | $33 | $32 | $30 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 |
| E-1 | $207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $158 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $1,737 | $1,416 | $1,906 | $3,767 | $4,155 | $3,389 | $3,183 | $3,040 | $1,390 | $1,707 | $439 | $420 | $401 | $383 | $366 | $187 | $179 | $171 | $163 | $181 |

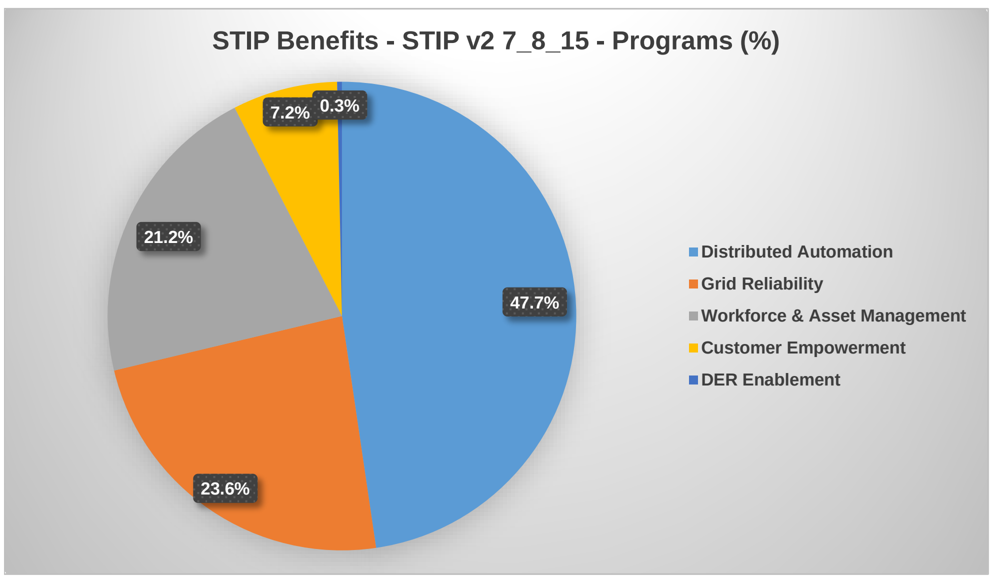
| ID | Outages | Demand | DG | Operations | Program (Technology) | Initiative (Function) | Project (Benefit Category) | Sub-Component (Benefit Sub-Category) | Primary Beneficiary | Monetizable | PV ($K) | Quantifiable | Quantifiable Benefits | Policies | GM Impact | Unquantifiable Benefits |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A-2 | | | X | | DER Enablement | DER Interconnection | Circuit Capacity Study | | Customer & Utility | Yes | $128 | Yes | Large DG developers will no longer need to submit multiple applications to | X | X | |
| A-5 | | X | X | | DER Enablement | DER Management Platform | Analytics & Visualiation System Platform | | Utility Only | No | $0 | Yes | None specified | X | | This will accommodate new installations of DER and support innovative |
| A-6 | | | X | | DER Enablement | DER Distribution Upgrades | Substation 3V0 Protection | | Utility Only | No | $0 | No | | X | X | Enables DG. |
| A-7 | | | X | | DER Enablement | DER Distribution Upgrades | Substation Voltage Regulation Control | | Utility Only | No | $0 | No | | X | X | |
| B-8 | X | | | X | Grid Reliability | Outage & Restoration Management | Mobile Damage Assessment Tool | | Customer & Utility | Yes | $7,679 | Yes | Reduced customer minutes interrupted (CMI) will have a financial benefit to | | | Customer satisfaction should improve with Unitil's improved ability to provide |
| B-9 | X | | | X | Grid Reliability | Outage & Restoration Management | AMI & OMS Integration | | Customer & Utility | Yes | $1,387 | Yes | Customers will benefit from AMI/OMS integration by experiencing, on | X | X | Unquantifiable customer benefits include satisfaction with utility company |
| C-2 | | X | | | Distributed Automation | Automated Field Devices | Automated Cap Banks | | Customer & Utility | No | $0 | No | | | X | |
| C-3 | | X | | | Distributed Automation | Automated Field Devices | Automated Voltage Regulators | | Customer & Utility | No | $0 | No | | | X | |
| C-4 | | X | | | Distributed Automation | Automated Field Devices | Automated Transformer & Load Tap Changers | | Customer & Utility | No | $0 | No | | | X | |
| C-5 | X | | X | | Distributed Automation | Communications Network | Fitchburg SCADA Communications | | Customer & Utility | No | $0 | Yes | Reduced outage time, for full quantification of benefits, see form C-7. | | X | Potentially better customer information on outage restoration |
| C-6 | X | X | X | X | Distributed Automation | Communications Network | Field Area Network | | Customer & Utility | No | $0 | Yes | No benefits directly related to FAN. This is an enabling technology. For full | X | X | No benefits directly related to FAN. This is an enabling technology. |
| C-7 | X | X | X | | Distributed Automation | Control Package / Software | ADMS | | Customer & Utility | Yes | $18,319 | Yes | Reduction in energy consumption | | X | Better outage information. |
| D-1 | | X | | | Customer Empowerment | Better Information & Communications | Customer Web Portal | | Customer & Utility | Yes | $200 | Yes | Real-time usage data enables customers to make informed energy usage | | | Enhanced customer engagement leads to an increase in customer |
| D-3 | | X | | | Customer Empowerment | Better Information & Communications | Gamification Pilot | | Customer & Utility | Yes | $619 | Yes | We anticipate energy and dollar savings resulting from changed behaviors | | | Increased customer satisfaction and engagement. |
| D-6 | | X | X | | Customer Empowerment | New Service Options (Opt-In) | TVR & Demand Response | | Customer & Utility | Yes | $6,535 | Yes | Customers will be able to reduce their electric bills by purchasing equipment | X | X | Achieve Energy Policy goals. Reducing peak and critical peak energy and |
| E-1 | X | | | X | Workforce & Asset Management | Workforce Management | Mobility Platform & System | | Customer & Utility | Yes | $8,134 | Yes | Customer benefits were estimated for a 15-minute savings per outage at | | | Customers will get better and more timely informaiton on estimated |

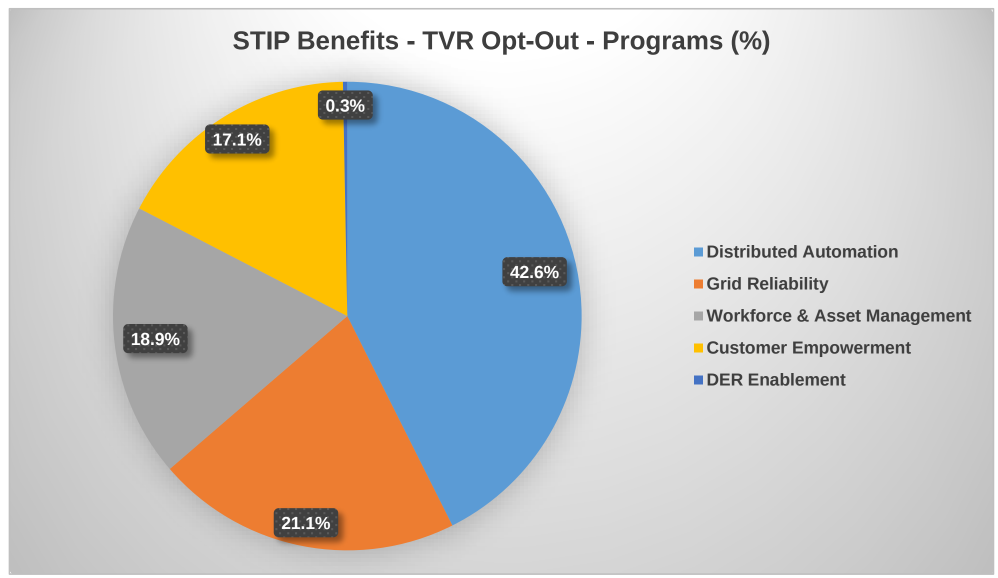
### Comparison Totals - Programs

| STIP Case 1 | STIP Case 2 |
|---|---|
| STIP v2 7_8_15 | TVR Opt-Out |

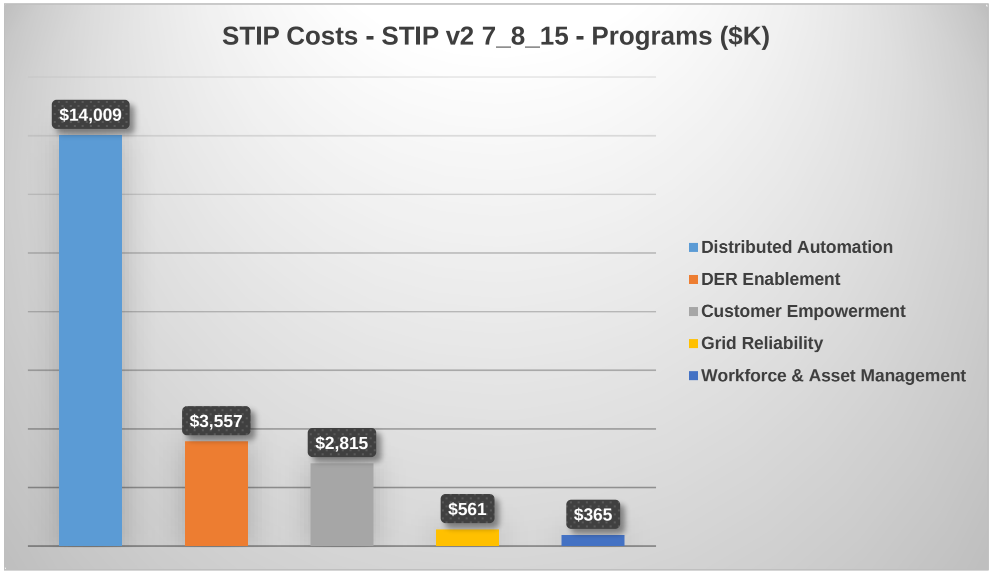


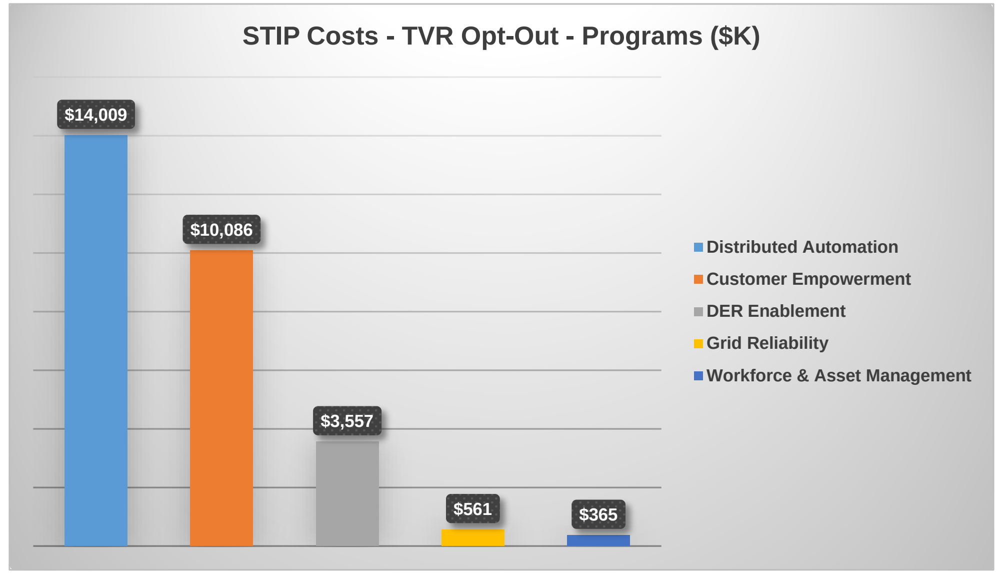



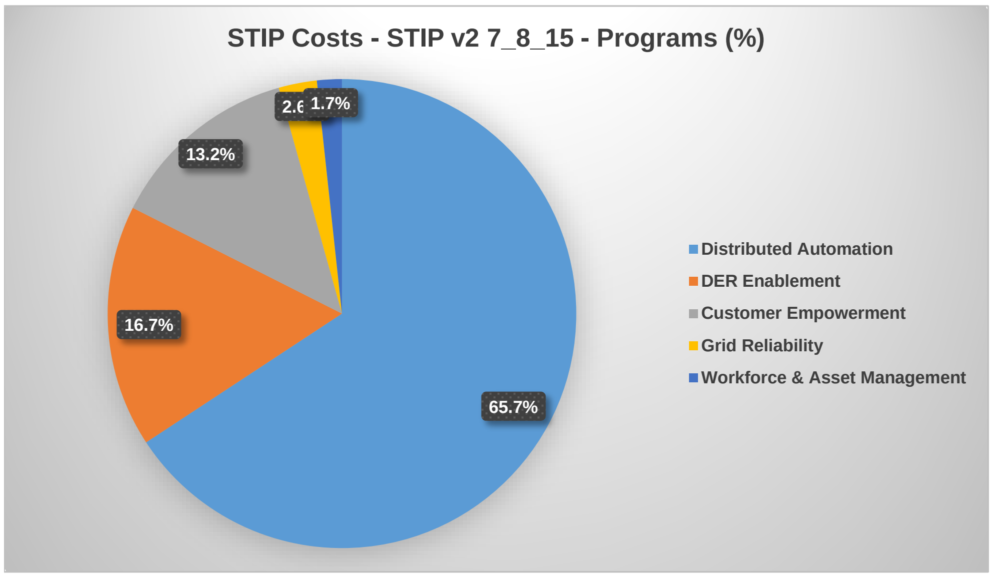



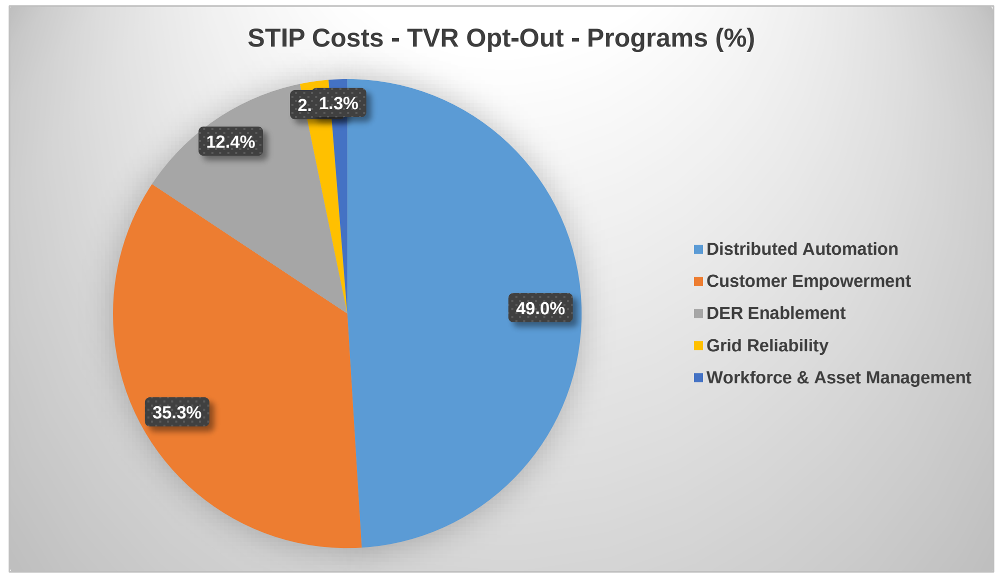



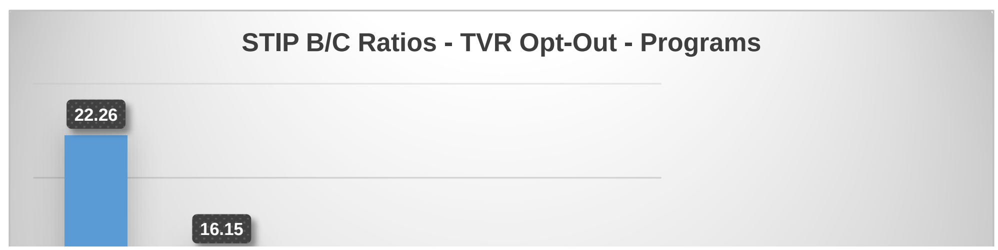

STIP Costs - STIP v2 7_8_15 - Programs ($K)
$14,009
$3,557
$2,815
$561
$365
Distributed Automation
DER Enablement
Customer Empowerment
Grid Reliability
Workforce & Asset Management

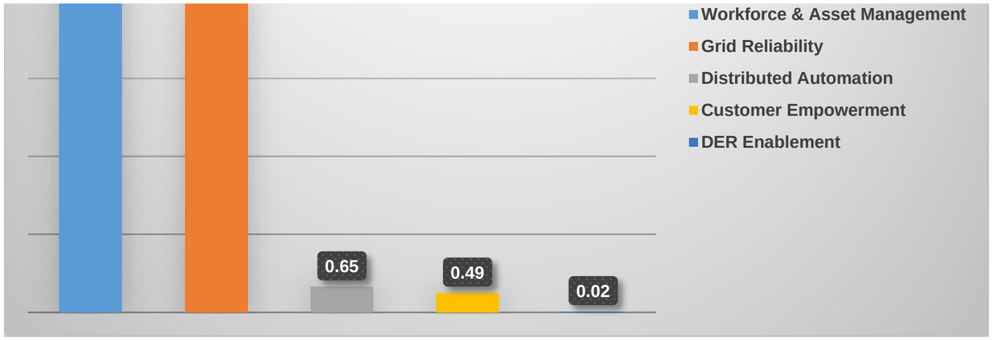

STIP Costs - TVR Opt-Out - Programs ($K)
$14,009
$10,086
$3,557
$561
$365
Distributed Automation
Customer Empowerment
DER Enablement
Grid Reliability
Workforce & Asset Management

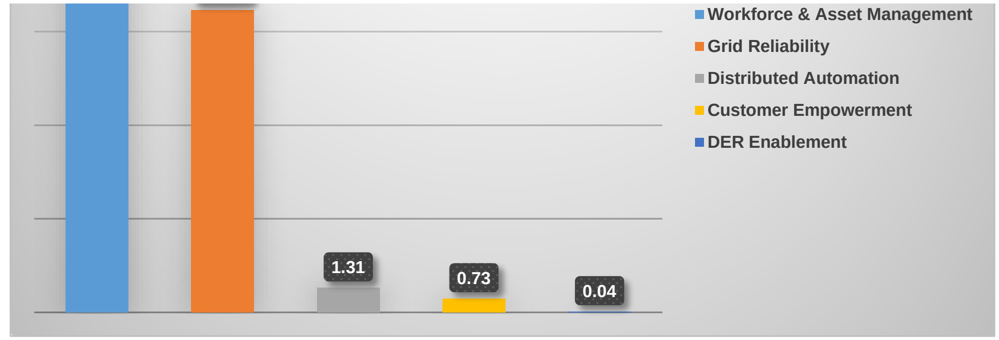

STIP Costs - STIP v2 7_8_15 - Programs (%)
1.7%
13.2%
16.7%
65.7%
Distributed Automation
DER Enablement
Customer Empowerment
Grid Reliability
Workforce & Asset Management

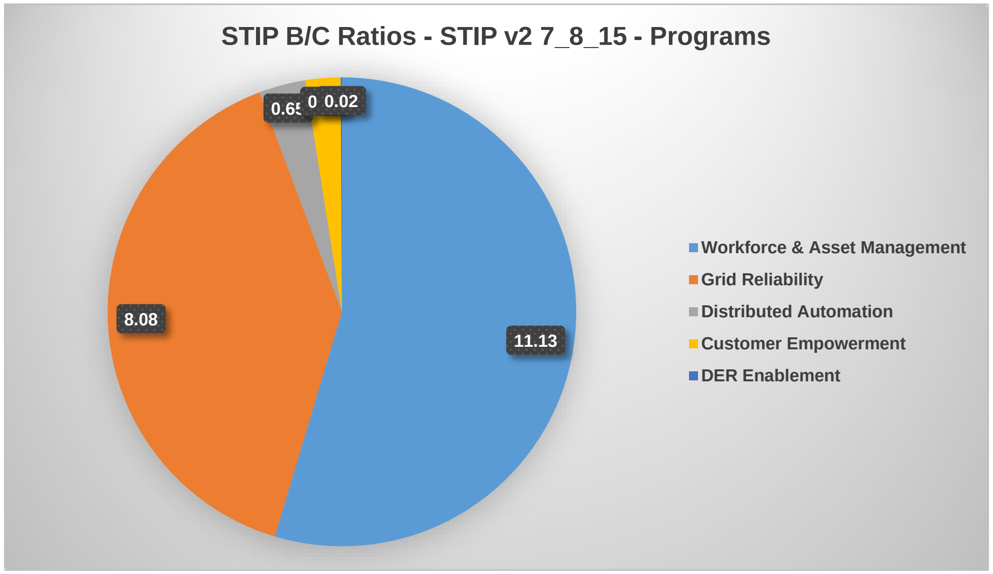

STIP Costs - TVR Opt-Out - Programs (%)
1.3%
12.4%
49.0%
35.3%
Distributed Automation
Customer Empowerment
DER Enablement
Grid Reliability
Workforce & Asset Management

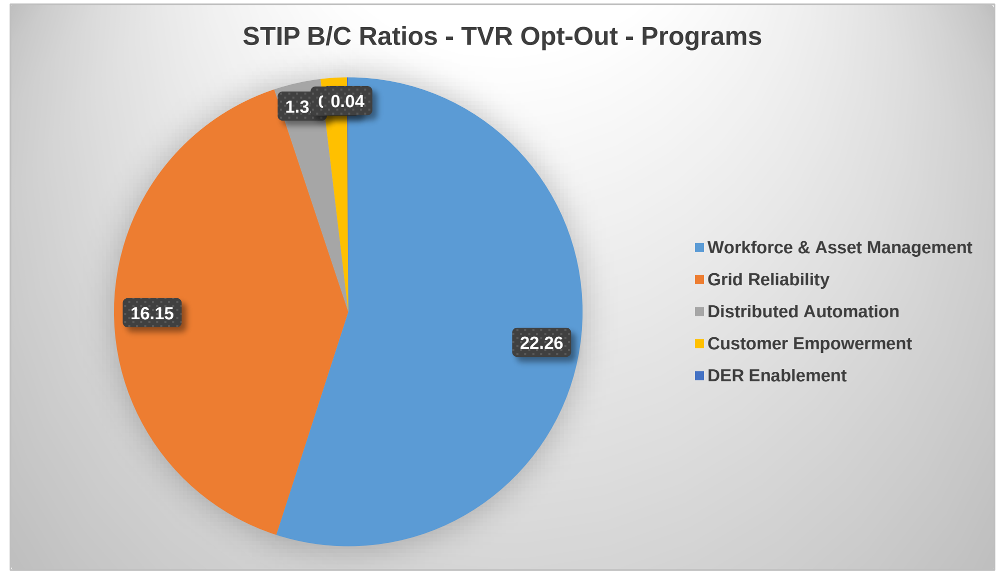

STIP B/C Ratios - STIP v2 7_8_15 - Programs
11.13
8.08


STIP B/C Ratios - TVR Opt-Out - Programs
22.26
16.15



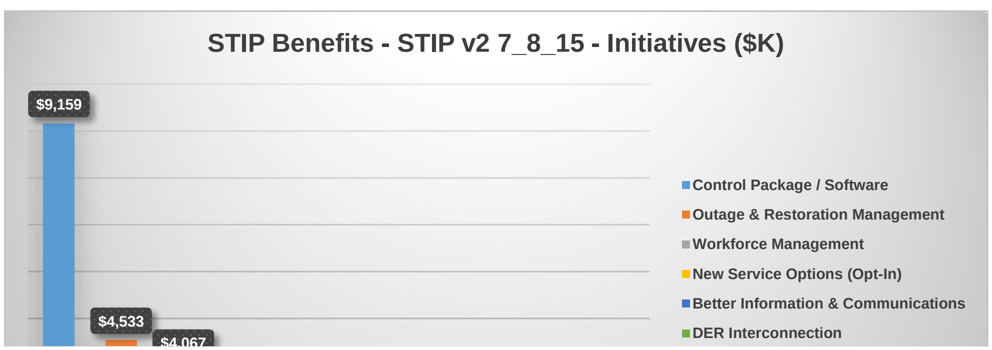



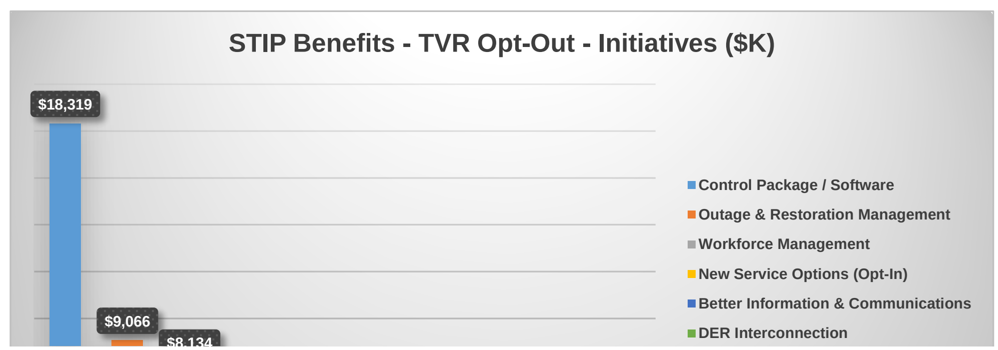




## Comparison Totals - Initiatives

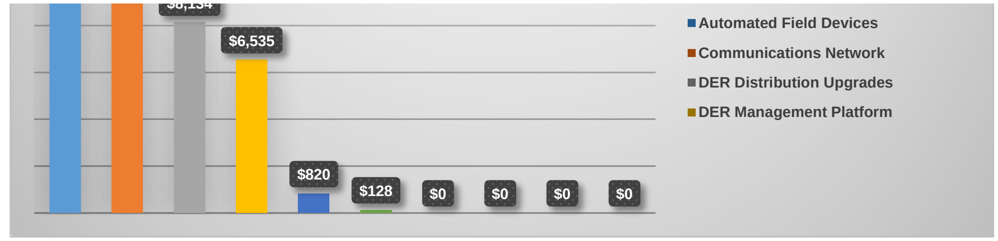
| STIP Case 1 |
|---|
| STIP v2 7_8_15 |

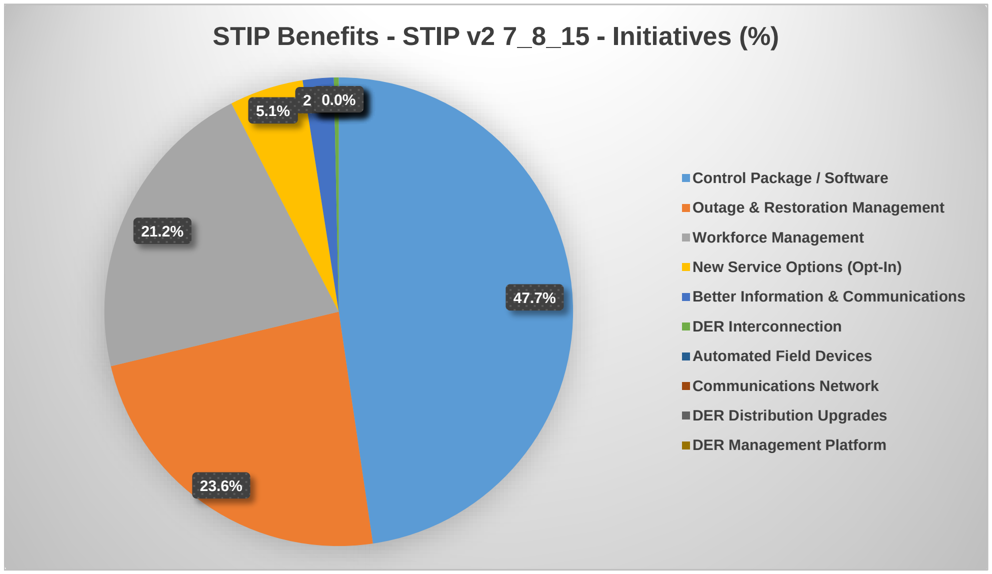
| STIP Case 2 |
|---|
| TVR Opt-Out |

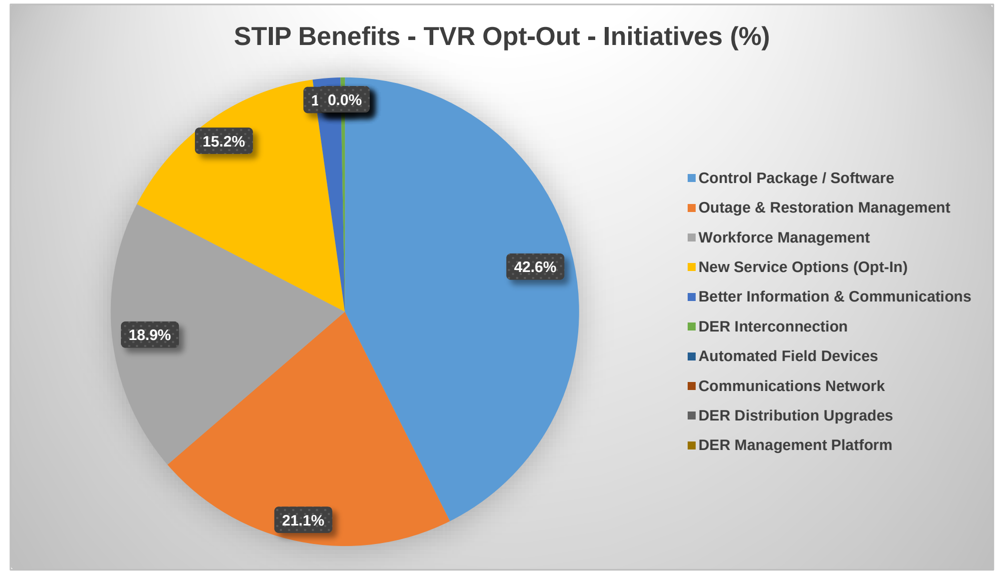


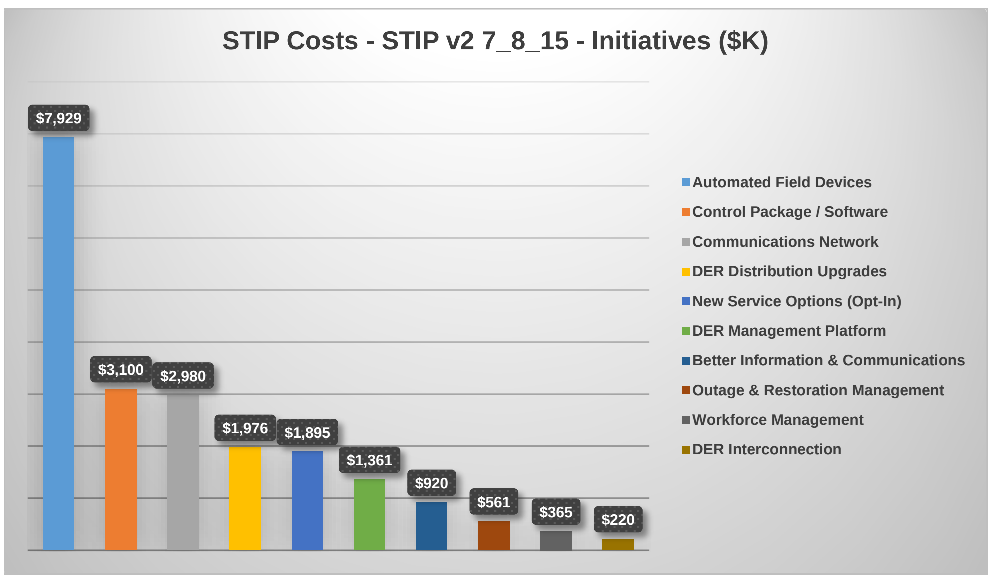



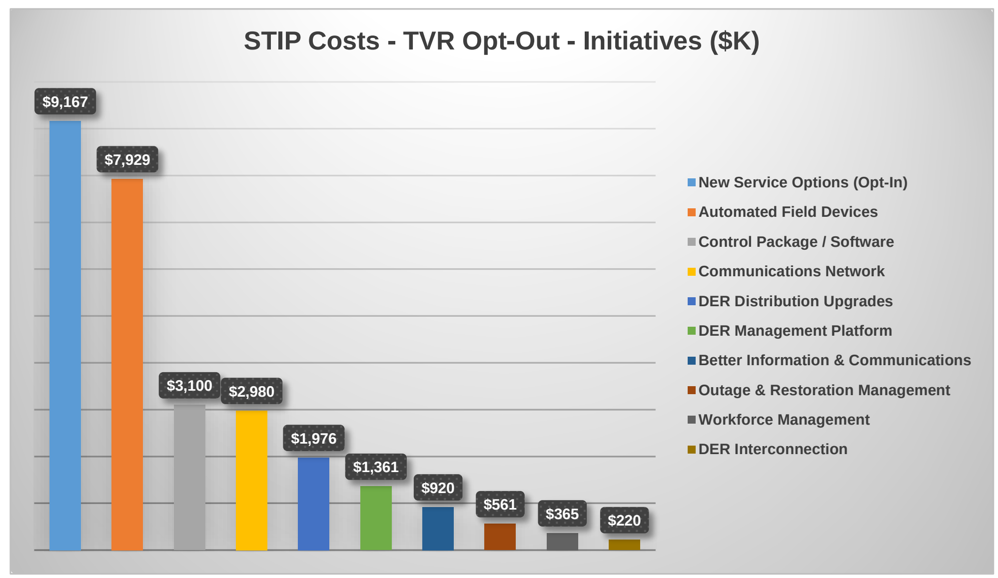

$980
$410
$64
$0
$0
$0
$0
Automated Field Devices
Communications Network
DER Distribution Upgrades
DER Management Platform

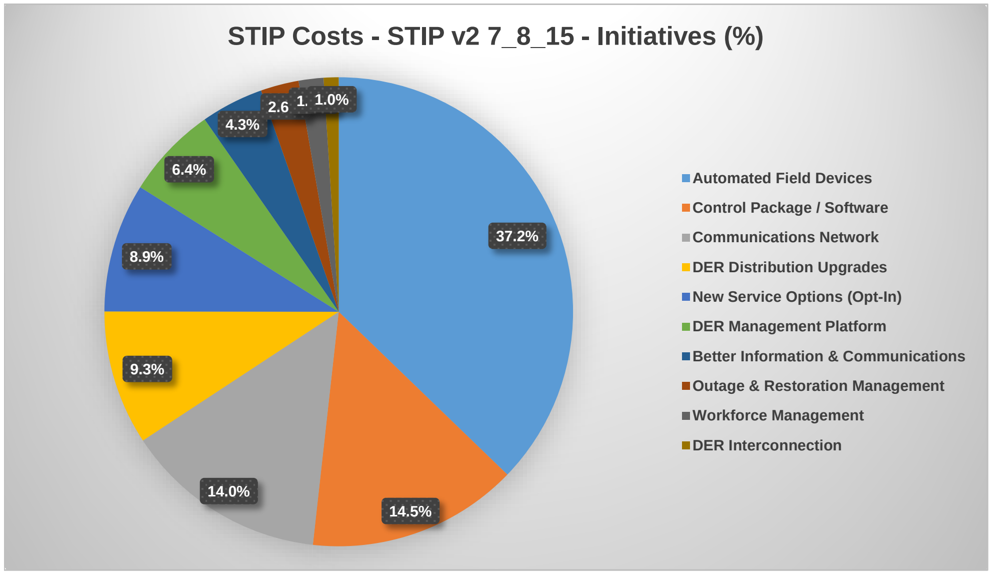

$6,535
$820
$128
$0
$0
$0
$0
Automated Field Devices
Communications Network
DER Distribution Upgrades
DER Management Platform

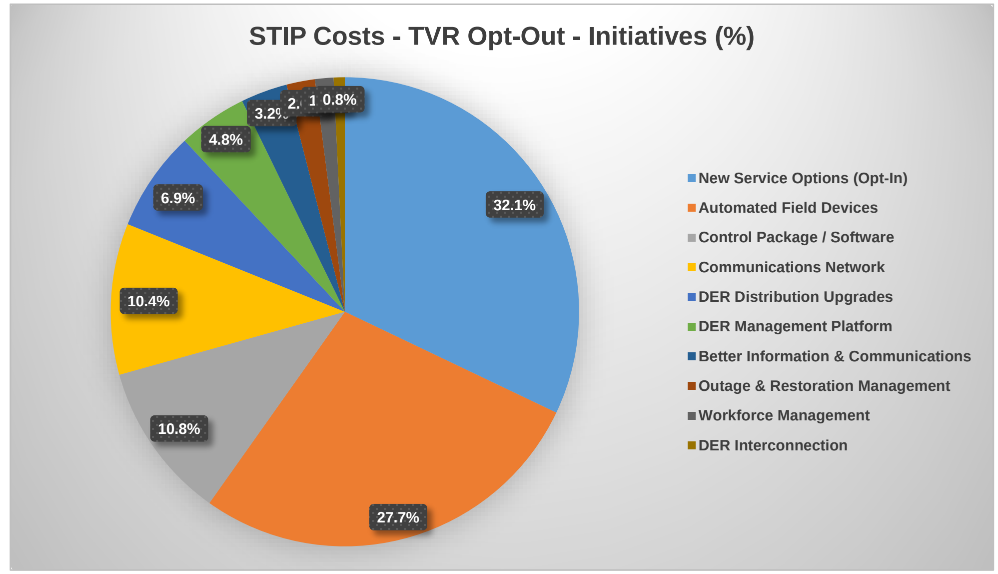

STIP Benefits - STIP v2 7_8_15 - Initiatives (%)
47.7%
23.6%
21.2%
5.1%
2
0.0%
Control Package / Software
Outage & Restoration Management
Workforce Management
New Service Options (Opt-In)
Better Information & Communications
DER Interconnection
Automated Field Devices
Communications Network
DER Distribution Upgrades
DER Management Platform

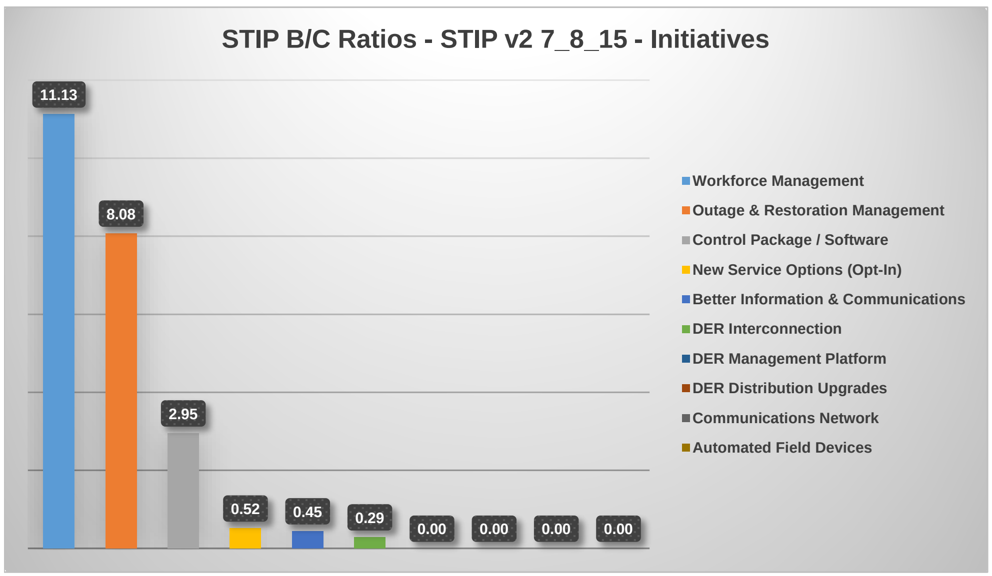

STIP Benefits - TVR Opt-Out - Initiatives (%)
42.6%
21.1%
18.9%
15.2%
1
0.0%
Control Package / Software
Outage & Restoration Management
Workforce Management
New Service Options (Opt-In)
Better Information & Communications
DER Interconnection
Automated Field Devices
Communications Network
DER Distribution Upgrades
DER Management Platform

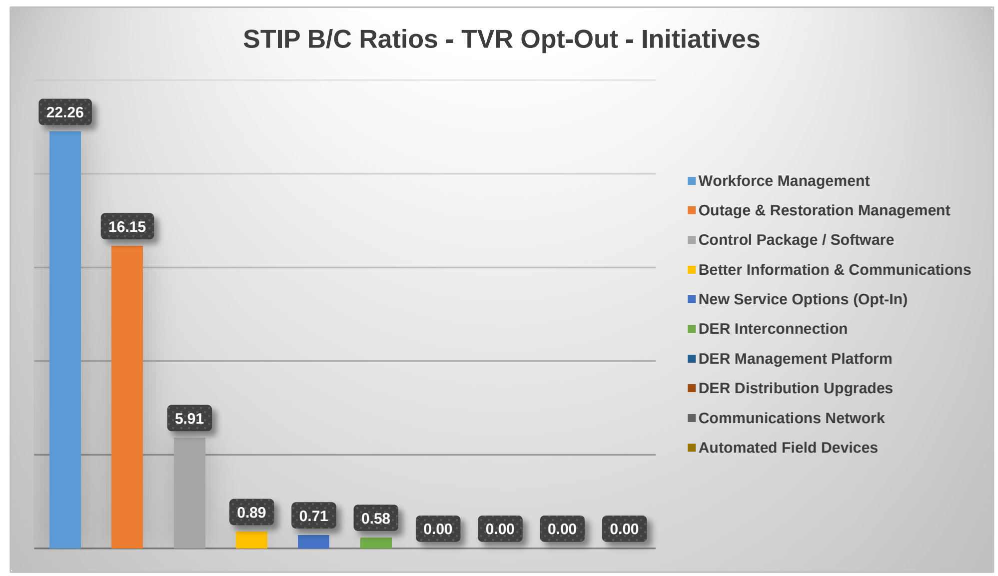

STIP Costs - STIP v2 7_8_15 - Initiatives ($K)
$7,929
$3,100
$2,980
$1,976
$1,895
$1,361
$920
$561
$365
$220
Automated Field Devices
Control Package / Software
Communications Network
DER Distribution Upgrades
New Service Options (Opt-In)
DER Management Platform
Better Information & Communications
Outage & Restoration Management
Workforce Management
DER Interconnection

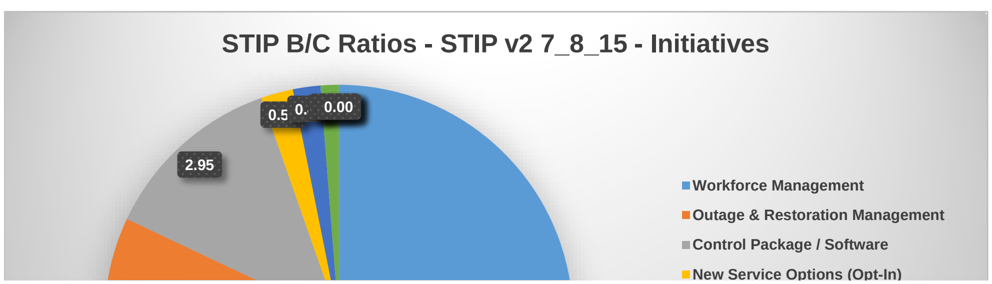

STIP Costs - TVR Opt-Out - Initiatives ($K)
$9,167
$7,929
$3,100
$2,980
$1,976
$1,361
$920
$561
$365
$220
New Service Options (Opt-In)
Automated Field Devices
Control Package / Software
Communications Network
DER Distribution Upgrades
DER Management Platform
Better Information & Communications
Outage & Restoration Management
Workforce Management
DER Interconnection

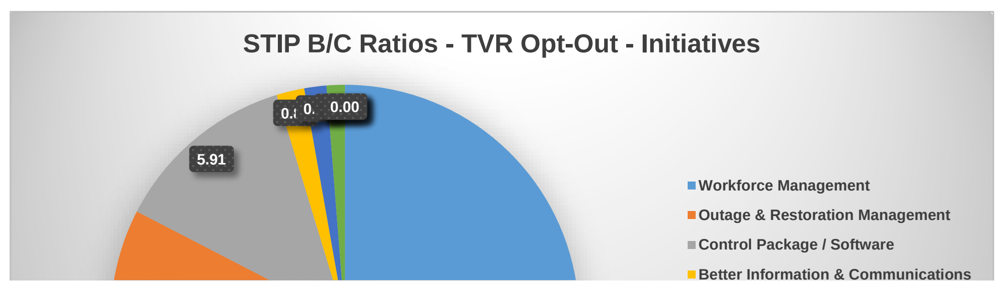

STIP Costs - STIP v2 7_8_15 - Initiatives (%)
37.2%
14.5%
14.0%
9.3%
8.9%
6.4%
4.3%
2.6
1.0%
Automated Field Devices
Control Package / Software
Communications Network
DER Distribution Upgrades
New Service Options (Opt-In)
DER Management Platform
Better Information & Communications
Outage & Restoration Management
Workforce Management
DER Interconnection

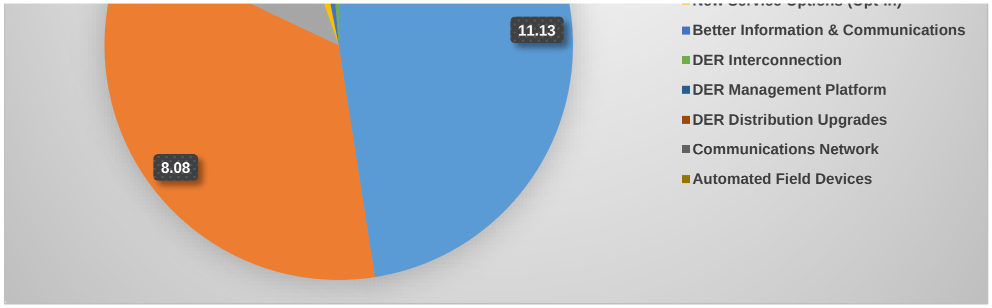
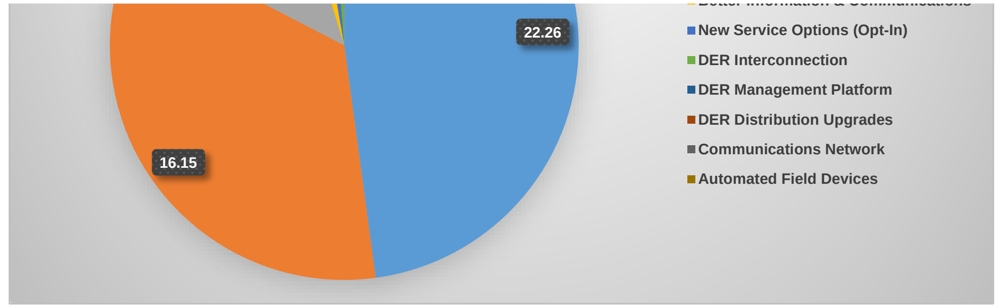

STIP Costs - TVR Opt-Out - Initiatives (%)
32.1%
27.7%
10.8%
10.4%
6.9%
4.8%
0.8%
New Service Options (Opt-In)
Automated Field Devices
Control Package / Software
Communications Network
DER Distribution Upgrades
DER Management Platform
Better Information & Communications
Outage & Restoration Management
Workforce Management
DER Interconnection


STIP B/C Ratios - STIP v2 7_8_15 - Initiatives
11.13
8.08
2.95
0.52
0.45
0.29
0.00
0.00
0.00
0.00
Workforce Management
Outage & Restoration Management
Control Package / Software
New Service Options (Opt-In)
Better Information & Communications
DER Interconnection
DER Management Platform
DER Distribution Upgrades
Communications Network
Automated Field Devices


STIP B/C Ratios - TVR Opt-Out - Initiatives
22.26
16.15
5.91
0.89
0.71
0.58
0.00
0.00
0.00
0.00
Workforce Management
Outage & Restoration Management
Control Package / Software
Better Information & Communications
New Service Options (Opt-In)
DER Interconnection
DER Management Platform
DER Distribution Upgrades
Communications Network
Automated Field Devices

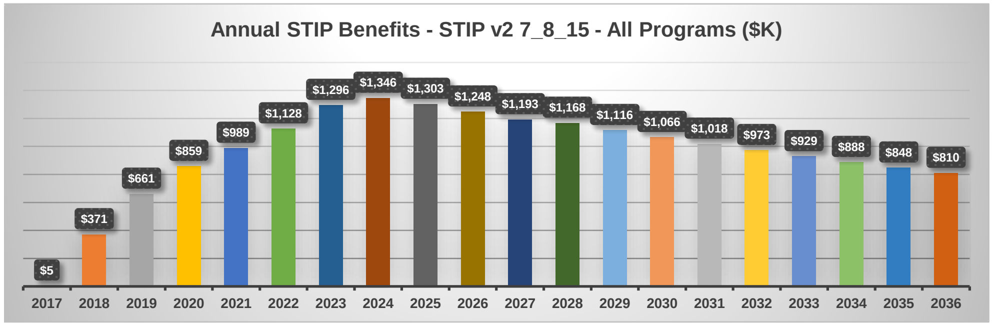

STIP B/C Ratios - STIP v2 7_8_15 - Initiatives
2.95
0.00
Workforce Management
Outage & Restoration Management
Control Package / Software
New Service Options (Opt-In)

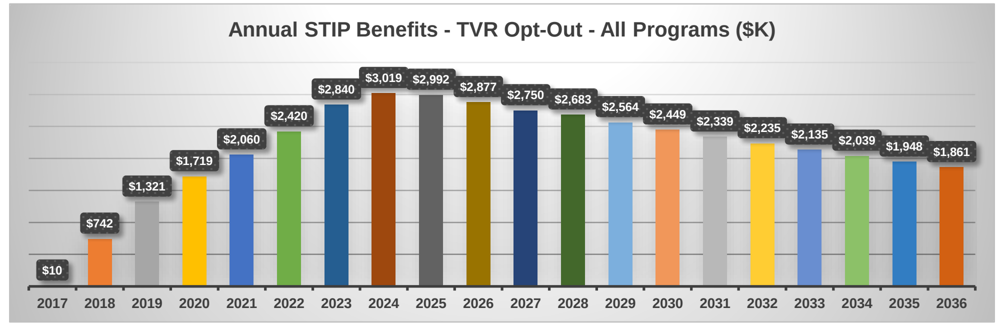

STIP B/C Ratios - TVR Opt-Out - Initiatives
5.91
0.00
Workforce Management
Outage & Restoration Management
Control Package / Software
Better Information & Communications

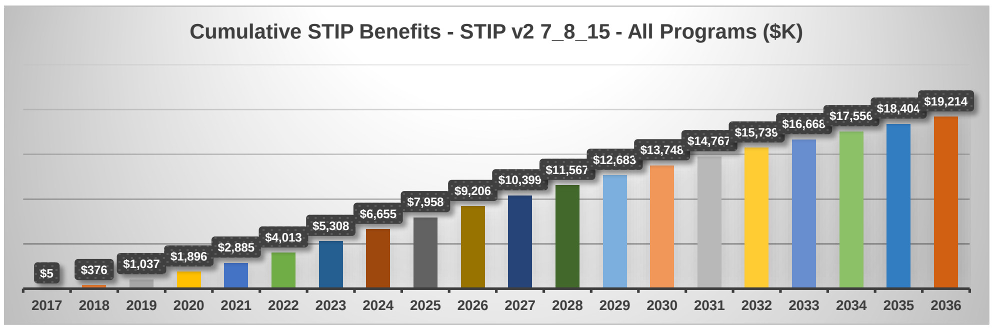

11.13
8.08
Better Information & Communications
DER Interconnection
DER Management Platform
DER Distribution Upgrades
Communications Network
Automated Field Devices

22.26
16.15
New Service Options (Opt-In)
DER Interconnection
DER Management Platform
DER Distribution Upgrades
Communications Network
Automated Field Devices

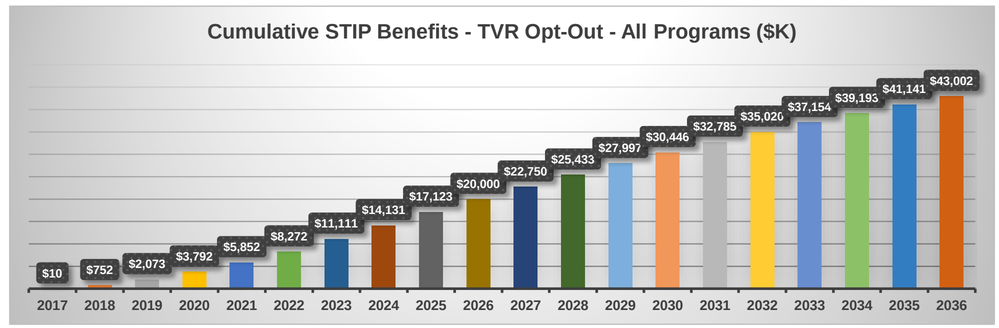
## Comparison Trends - Programs

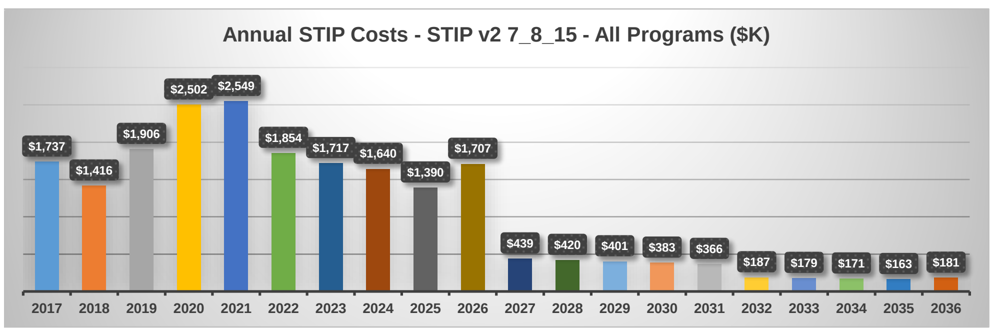
| STIP Case 1 | STIP Case 2 |
|---|---|
| STIP v2 7_8_15 | TVR Opt-Out |

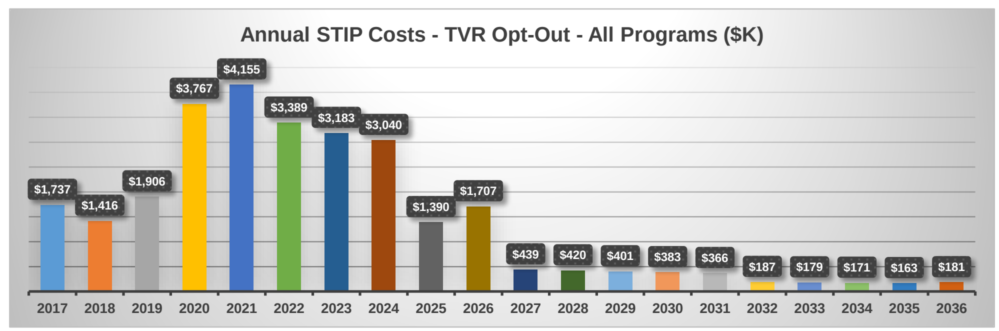


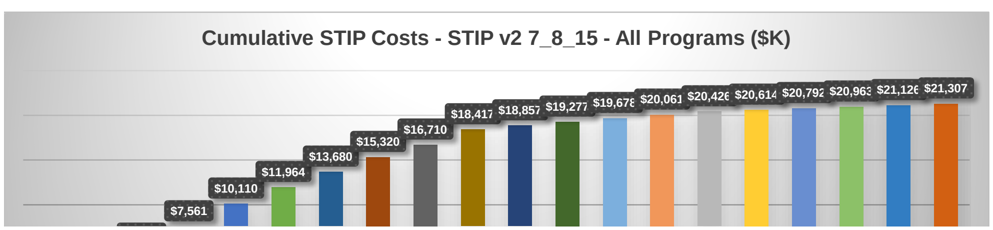



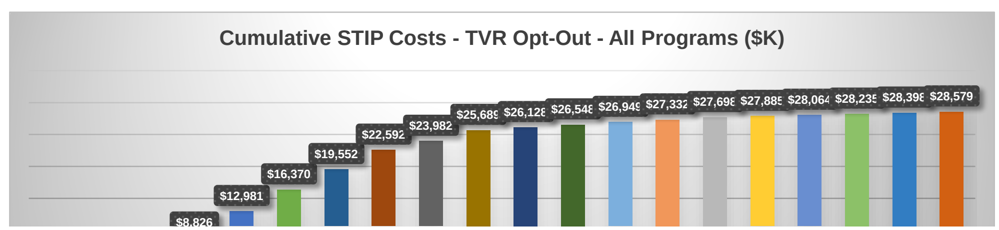



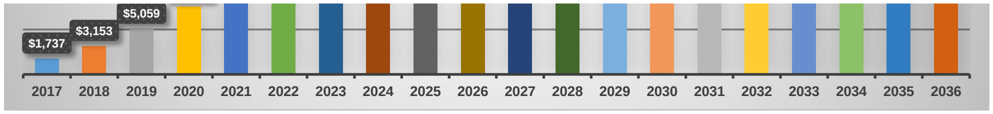



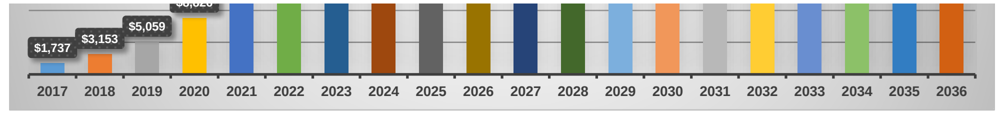



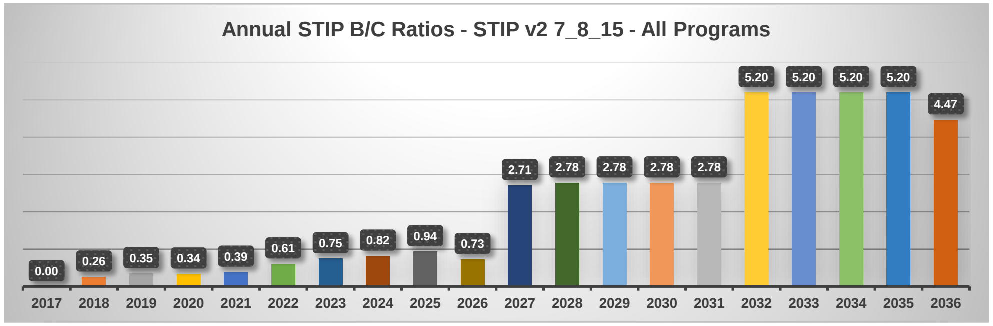



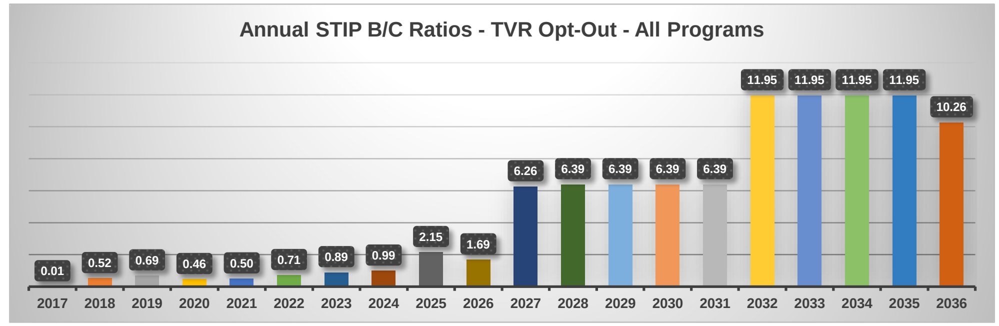



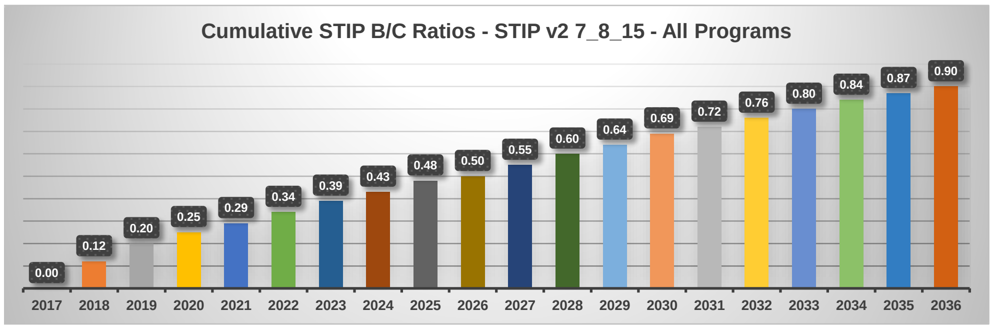



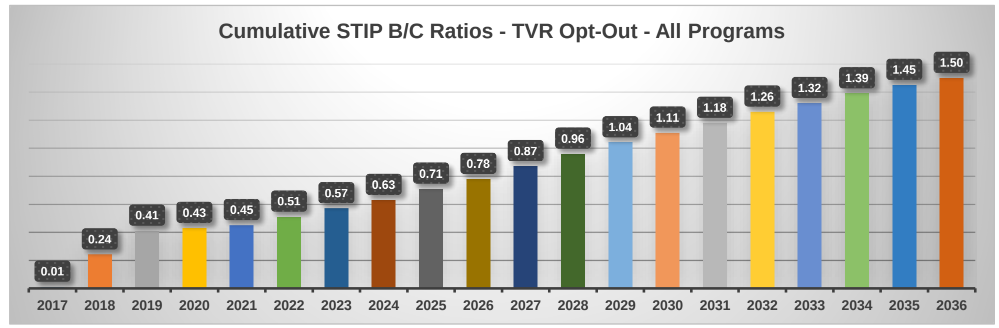


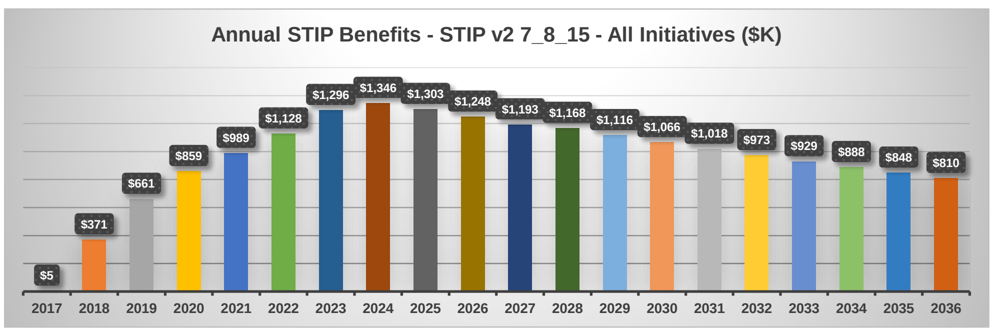



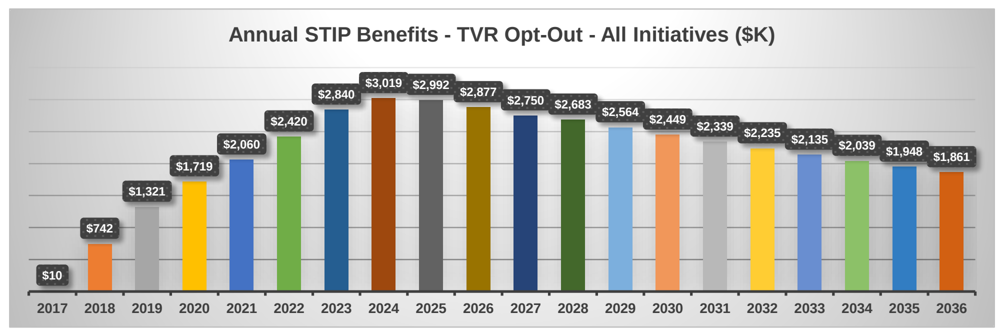



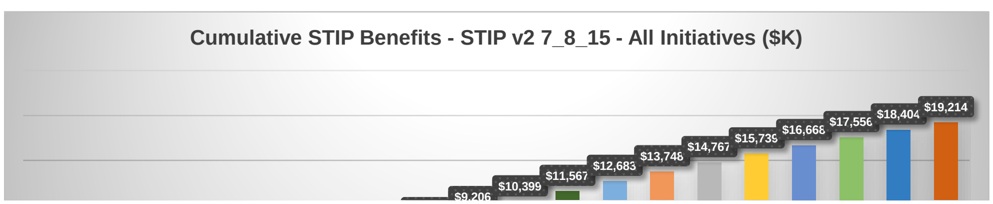



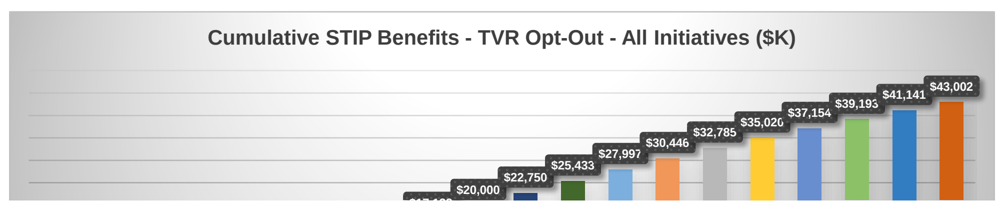

**Comparison Trends - Initiatives**

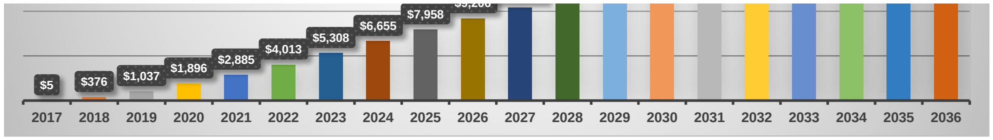
| STIP Case 1 | STIP Case 2 |
|---|---|
| STIP v2 7_8_15 | TVR Opt-Out |

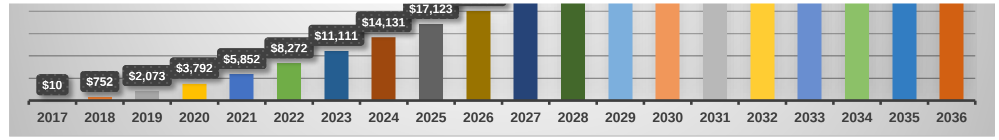


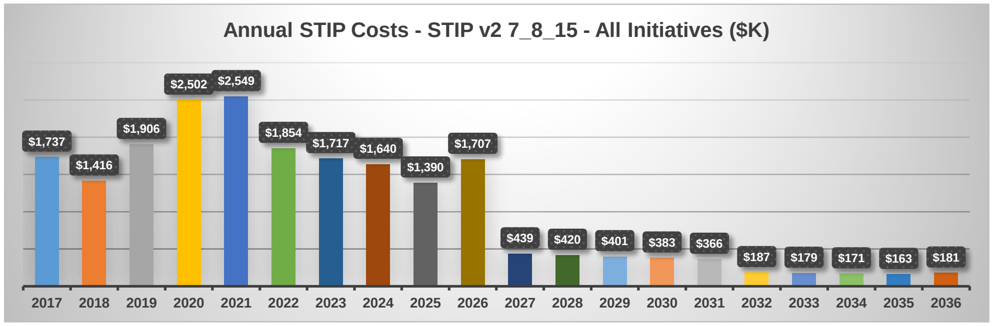



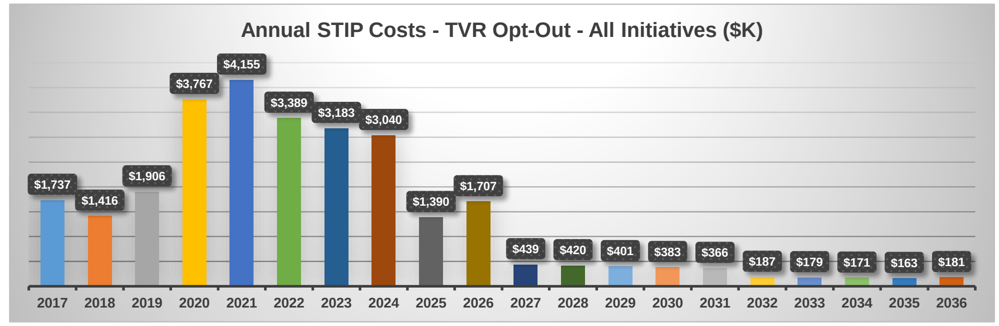



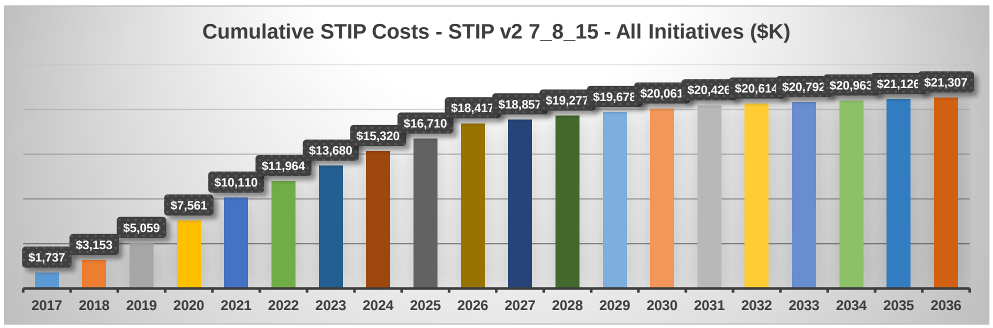



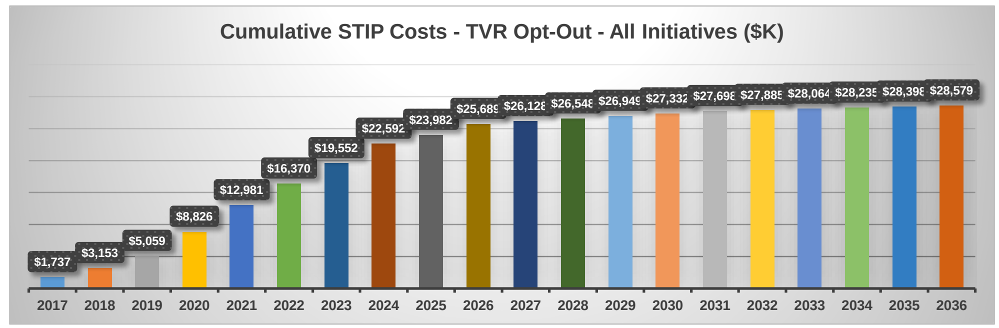

$5 $376 $1,037 $1,896 $2,885 $4,013 $5,308 $6,655 $7,958
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036

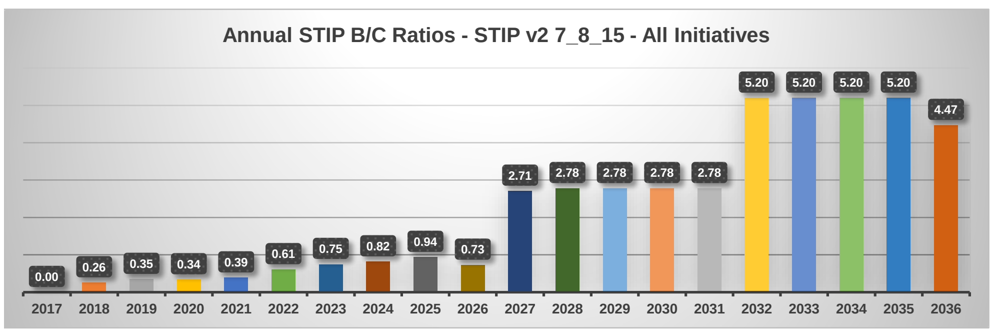

$10 $752 $2,073 $3,792 $5,852 $8,272 $11,111 $14,131 $17,123
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036

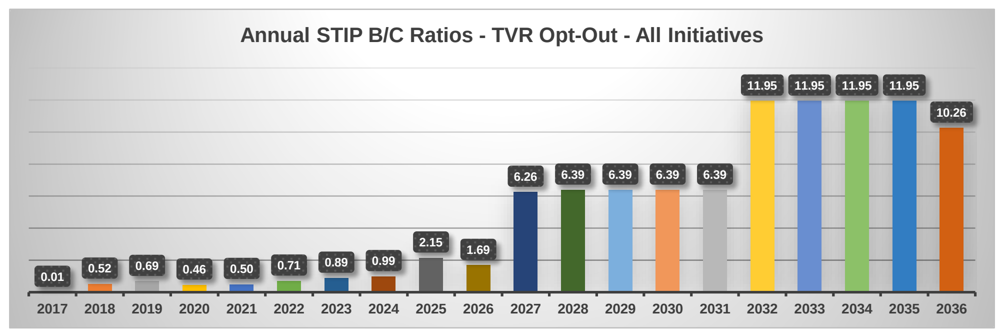

Annual STIP Costs - STIP v2 7_8_15 - All Initiatives ($K)
$1,737 $1,416 $1,906 $2,502 $2,549 $1,854 $1,717 $1,640 $1,390 $1,707 $439 $420 $401 $383 $366 $187 $179 $171 $163 $181
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036

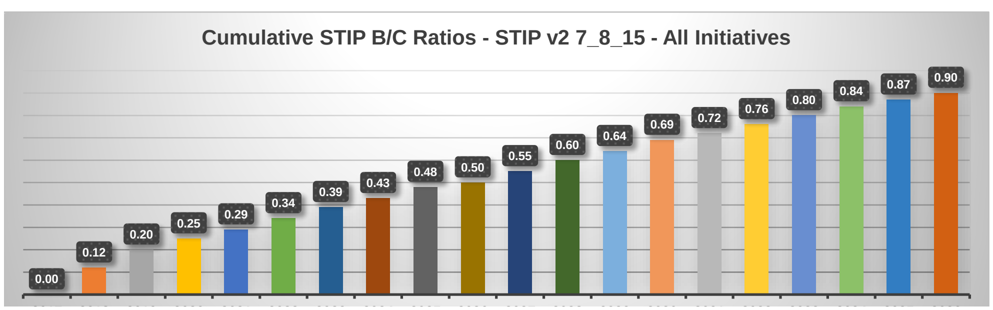

Annual STIP Costs - TVR Opt-Out - All Initiatives ($K)
$1,737 $1,416 $1,906 $3,767 $4,155 $3,389 $3,183 $3,040 $1,390 $1,707 $439 $420 $401 $383 $366 $187 $179 $171 $163 $181
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036

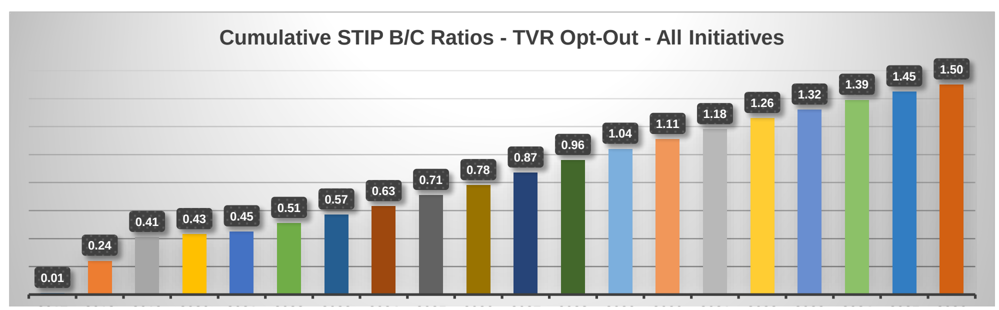

Cumulative STIP Costs - STIP v2 7_8_15 - All Initiatives ($K)
$1,737 $3,153 $5,059 $7,561 $10,110 $11,964 $13,680 $15,320 $16,710 $18,417 $18,857 $19,277 $19,678 $20,061 $20,426 $20,614 $20,792 $20,963 $21,126 $21,307
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036


Cumulative STIP Costs - TVR Opt-Out - All Initiatives ($K)
$1,737 $3,153 $5,059 $8,826 $12,981 $16,370 $19,552 $22,592 $23,982 $25,689 $26,128 $26,548 $26,949 $27,332 $27,698 $27,885 $28,064 $28,235 $28,398 $28,579
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036


Annual STIP B/C Ratios - STIP v2 7_8_15 - All Initiatives
0.00 0.26 0.35 0.34 0.39 0.61 0.75 0.82 0.94 0.73 2.71 2.78 2.78 2.78 2.78 5.20 5.20 5.20 5.20 4.47
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036


Annual STIP B/C Ratios - TVR Opt-Out - All Initiatives
0.01 0.52 0.69 0.46 0.50 0.71 0.89 0.99 2.15 1.69 6.26 6.39 6.39 6.39 6.39 11.95 11.95 11.95 11.95 10.26
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036


Cumulative STIP B/C Ratios - STIP v2 7_8_15 - All Initiatives
0.00 0.12 0.20 0.25 0.29 0.34 0.39 0.43 0.48 0.50 0.55 0.60 0.64 0.69 0.72 0.76 0.80 0.84 0.87 0.90


Cumulative STIP B/C Ratios - TVR Opt-Out - All Initiatives
0.01 0.24 0.41 0.43 0.45 0.51 0.57 0.63 0.71 0.78 0.87 0.96 1.04 1.11 1.18 1.26 1.32 1.39 1.45 1.50

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

# GMP BCA Model

**DPU Template - STIP v2 7_8_15 - Benefits**

| ID | Outages | Demand | DG | Operations | Program (Technology) | Initiative (Function) | Project (Benefit Category) | Sub-Component (Benefit Sub-Category) | Primary Beneficiary | Monetizable | PV ($K) | Quantifiable | Quantifiable Benefits | Policies | GM Impact | Unquantifiable Benefits |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A-2 | | | X | | DER Enablement | DER Interconnection | Circuit Capacity Study | | Customer & Utility | Yes | $64 | Yes | Large DG developers will no longer need to submit multiple applications to | X | X | |
| A-5 | | X | X | | DER Enablement | DER Management Platform | Analytics & Visualiation System Platform | | Utility Only | No | $0 | Yes | None specified | X | | This will accommodate new installations of DER and support innovative |
| A-6 | | | X | | DER Enablement | DER Distribution Upgrades | Substation 3V0 Protection | | Utility Only | No | $0 | No | | X | X | Enables DG. |
| A-7 | | | X | | DER Enablement | DER Distribution Upgrades | Substation Voltage Regulation Control | | Utility Only | No | $0 | No | | X | X | |
| B-8 | X | | | X | Grid Reliability | Outage & Restoration Management | Mobile Damage Assessment Tool | | Customer & Utility | Yes | $3,840 | Yes | Reduced customer minutes interrupted (CMI) will have a financial benefit to | | | Customer satisfaction should improve with Unitil's improved ability to provide |
| B-9 | X | | | X | Grid Reliability | Outage & Restoration Management | AMI & OMS Integration | | Customer & Utility | Yes | $693 | Yes | Customers will benefit from AMI/OMS integration by experiencing, on | X | X | Unquantifiable customer benefits include satisfaction with utility company |
| C-2 | | X | | | Distributed Automation | Automated Field Devices | Automated Cap Banks | | Customer & Utility | No | $0 | No | | | X | |
| C-3 | | X | | | Distributed Automation | Automated Field Devices | Automated Voltage Regulators | | Customer & Utility | No | $0 | No | | | X | |
| C-4 | | X | | | Distributed Automation | Automated Field Devices | Automated Transformer & Load Tap Changers | | Customer & Utility | No | $0 | No | | | X | |
| C-5 | X | | X | | Distributed Automation | Communications Network | Fitchburg SCADA Communications | | Customer & Utility | No | $0 | Yes | Reduced outage time, for full quantification of benefits, see form C-7. | | X | Potentially better customer information on outage restoration |
| C-6 | X | X | X | X | Distributed Automation | Communications Network | Field Area Network | | Customer & Utility | No | $0 | Yes | No benefits directly related to FAN. This is an enabling technology. For full | X | X | No benefits directly related to FAN. This is an enabling technology. |
| C-7 | X | X | X | | Distributed Automation | Control Package / Software | ADMS | | Customer & Utility | Yes | $9,159 | Yes | Reduction in energy consumption | | X | Better outage information. |
| D-1 | | X | | | Customer Empowerment | Better Information & Communications | Customer Web Portal | | Customer & Utility | Yes | $100 | Yes | Real-time usage data enables customers to make informed energy usage | | | Enhanced customer engagement leads to an increase in customer |
| D-3 | | X | | | Customer Empowerment | Better Information & Communications | Gamification Pilot | | Customer & Utility | Yes | $310 | Yes | We anticipate energy and dollar savings resulting from changed behaviors | | | Increased customer satisfaction and engagement. |
| D-6 | | X | X | | Customer Empowerment | New Service Options (Opt-In) | TVR & Demand Response | | Customer & Utility | Yes | $980 | Yes | Customers will be able to reduce their electric bills by purchasing equipment | X | X | Achieve Energy Policy goals. Reducing peak and critical peak energy and |
| E-1 | X | | | X | Workforce & Asset Management | Workforce Management | Mobility Platform & System | | Customer & Utility | Yes | $4,067 | Yes | Customer benefits were estimated for a 15-minute savings per outage at | | | Customers will get better and more timely informaiton on estimated |

| ID | Outages | Demand | DG | Operations | Program (Technology) | Initiative (Cost Category) | Project (Cost Sub-Category) | FERC Account | PV ($K) | Cost Classification | DPU CapEx Tracker |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A-2 | | | X | | DER Enablement | DER Interconnection | Circuit Capacity Study | | $220 | Non-Capitalized O&M | No |
| A-5 | | X | X | | DER Enablement | DER Management Platform | Analytics & Visualiation System Platform | | $1,361 | Direct Capital | Yes |
| A-6 | | | X | | DER Enablement | DER Distribution Upgrades | Substation 3V0 Protection | | $1,568 | Direct Capital | No |
| A-7 | | | X | | DER Enablement | DER Distribution Upgrades | Substation Voltage Regulation Control | | $408 | Direct Capital | No |
| B-8 | X | | | X | Grid Reliability | Outage & Restoration Management | Mobile Damage Assessment Tool | | $502 | Direct Capital | Yes |
| B-9 | X | | | X | Grid Reliability | Outage & Restoration Management | AMI & OMS Integration | | $60 | Capitalized Overhead | Yes |
| C-2 | | X | | | Distributed Automation | Automated Field Devices | Automated Cap Banks | | $2,108 | Direct Capital | Yes |
| C-3 | | X | | | Distributed Automation | Automated Field Devices | Automated Voltage Regulators | | $5,293 | Direct Capital | Yes |
| C-4 | | X | | | Distributed Automation | Automated Field Devices | Automated Transformer & Load Tap Changers | | $528 | Direct Capital | Yes |
| C-5 | X | | X | | Distributed Automation | Communications Network | Fitchburg SCADA Communications | | $784 | Direct Capital | Yes |
| C-6 | X | X | X | X | Distributed Automation | Communications Network | Field Area Network | | $2,196 | Direct Capital | Yes |
| C-7 | X | X | X | | Distributed Automation | Control Package / Software | ADMS | | $3,100 | Direct Capital | Yes |
| D-1 | | X | | | Customer Empowerment | Better Information & Communications | Customer Web Portal | | $531 | | |
| D-3 | | X | | | Customer Empowerment | Better Information & Communications | Gamification Pilot | | $389 | | |
| D-6 | | X | X | | Customer Empowerment | New Service Options (Opt-In) | TVR & Demand Response | | $1,895 | Capitalized Overhead | Yes |
| E-1 | X | | | X | Workforce & Asset Management | Workforce Management | Mobility Platform & System | | $365 | Direct Capital | Yes |

| ID | Outages | Demand | DG | Operations | Program (Technology) | Initiative (Cost Category) | Project (Cost Sub-Category) | FERC Account | PV ($K) | Cost Classification | DPU CapEx Tracker |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A-2 | | | X | | DER Enablement | DER Interconnection | Circuit Capacity Study | | $220 | Non-Capitalized O&M | No |
| A-5 | | X | X | | DER Enablement | DER Management Platform | Analytics & Visualiation System Platform | | $1,361 | Direct Capital | Yes |
| A-6 | | | X | | DER Enablement | DER Distribution Upgrades | Substation 3V0 Protection | | $1,568 | Direct Capital | No |
| A-7 | | | X | | DER Enablement | DER Distribution Upgrades | Substation Voltage Regulation Control | | $408 | Direct Capital | No |
| B-8 | X | | | X | Grid Reliability | Outage & Restoration Management | Mobile Damage Assessment Tool | | $502 | Direct Capital | Yes |
| B-9 | X | | | X | Grid Reliability | Outage & Restoration Management | AMI & OMS Integration | | $60 | Capitalized Overhead | Yes |
| C-2 | | X | | | Distributed Automation | Automated Field Devices | Automated Cap Banks | | $2,108 | Direct Capital | Yes |
| C-3 | | X | | | Distributed Automation | Automated Field Devices | Automated Voltage Regulators | | $5,293 | Direct Capital | Yes |
| C-4 | | X | | | Distributed Automation | Automated Field Devices | Automated Transformer & Load Tap Changers | | $528 | Direct Capital | Yes |
| C-5 | X | | X | | Distributed Automation | Communications Network | Fitchburg SCADA Communications | | $784 | Direct Capital | Yes |
| C-6 | X | X | X | X | Distributed Automation | Communications Network | Field Area Network | | $2,196 | Direct Capital | Yes |
| C-7 | X | X | X | | Distributed Automation | Control Package / Software | ADMS | | $3,100 | Direct Capital | Yes |
| D-1 | | X | | | Customer Empowerment | Better Information & Communications | Customer Web Portal | | $531 | | |
| D-3 | | X | | | Customer Empowerment | Better Information & Communications | Gamification Pilot | | $389 | | |
| D-6 | | X | X | | Customer Empowerment | New Service Options (Opt-In) | TVR & Demand Response | | $9,167 | Capitalized Overhead | Yes |
| E-1 | X | | | X | Workforce & Asset Management | Workforce Management | Mobility Platform & System | | $365 | Direct Capital | Yes |

| No. | Stranded Asset (Project) | Plant Investment ($K) | Accumulated Depreciation ($K) | Cost of Removal / Net of Salvage ($K) | Unrecovered Asset Value ($K) | Remaining Depreciable Life ($K) | Carrying Charge Rate Applied (%) |
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| No. | Stranded Asset (Project) | Plant Investment ($K) | Accumulated Depreciation ($K) | Cost of Removal / Net of Salvage ($K) | Unrecovered Asset Value ($K) | Remaining Depreciable Life ($K) | Carrying Charge Rate Applied (%) |
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## General Parameters

| No. | Parameter | Value |
|---|---|---|
| 1 | Model Title | GMP BCA Model |
| 2 | Organization Name | Unitil Corporation |
| 3 | STIP Case 1 | STIP v2 7_8_15 |
| 4 | STIP Case 2 | TVR Opt-Out |
| 5 | Model Horizon Years | 20 |

## Case-Specific Parameters

| No. | Parameter | Default | Base Case (C&U) | Base Case (U) | No Comm | No Comm 10% | STIP Final | STIP v2 7_8_15 | 150% Costs | 50% Benefits | T-Bill Discounting | TVR Opt-Out | Value |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Numeric Factors** | | | | | | | | | | | | | |
| 1 | Model Start Year | 2017 | 2017 | 2017 | 2017 | 2017 | 2017 | 2017 | 2017 | 2017 | 2017 | 2017 | 2017 |
| 2 | Inflation Rate | 2.07% | 2.07% | 2.07% | 2.07% | 2.07% | 2.07% | 2.07% | 2.07% | 2.07% | 2.07% | 2.07% | 2.07% |
| 3 | Discount Rate | 6.85% | 6.85% | 6.85% | 6.85% | 6.85% | 6.85% | 6.85% | 6.85% | 6.85% | 2.69% | 6.85% | 6.85% |
| 4 | Benefit Multiplier | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 0.50 | 1.00 | 1.00 | 1.00 | 1.00 | 0.50 |
| 5 | Cost Multiplier | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.50 | 1.00 | 1.00 | 1.00 | 1.00 |
| **Calculation Filters** | | | | | | | | | | | | | |
| 6 | Primary Beneficiary | All | All | All | All | All | All | All | All | All | All | All | All |
| 7 | Cost Classification | All | All | All | All | All | All | All | All | All | All | All | All |
| 8 | Service Year (Max) | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| 9 | DPU CapEx Tracker | All | All | All | All | All | All | All | All | All | All | All | All |
| 10 | FERC Account | All | All | All | All | All | All | All | All | All | All | All | All |

**GMP BCA Model**
User Inputs - STIP v2 7_8_15

| ID | Status | Program | Initiative | Project | Sub-Component (If Applicable) | Initiative Owner(s) | Project Owner(s) | Primary Beneficiary | Cost Classification | Service Year | Project Life (Years) | DPU CapEx Tracker | FERC Account |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A-2 | ✓ | DER Enablement | DER Interconnection | Circuit Capacity Study | | John Bonazoli | John Bonazoli | Customer & Utility | Non-Capitalized O&M | 2 | 10 | No | |
| A-5 | ✓ | DER Enablement | DER Management Platform | Analytics & Visualization System Platform | | John Bonazoli | | Utility Only | Direct Capital | 3 | 10 | Yes | |
| A-6 | ✓ | DER Enablement | DER Distribution Upgrades | Substation 3V0 Protection | | John Bonazoli | John Bonazoli | Utility Only | Direct Capital | 1 | 8 | No | |
| A-7 | ✓ | DER Enablement | DER Distribution Upgrades | Substation Voltage Regulation Control | | John Bonazoli | John Bonazoli | Utility Only | Direct Capital | 1 | 8 | No | |
| B-8 | ✓ | Grid Reliability | Outage & Restoration Management | Mobile Damage Assessment Tool | | | | Customer & Utility | Direct Capital | 1 | 10 | Yes | |
| B-9 | ✓ | Grid Reliability | Outage & Restoration Management | AMI & OMS Integration | | | | Customer & Utility | Capitalized Overhead | | | Yes | |
| C-2 | ✓ | Distributed Automation | Automated Field Devices | Automated Cap Banks | | Kevin Sprague | Engineering TBD | Customer & Utility | Direct Capital | | 5 | Yes | |
| C-3 | ✓ | Distributed Automation | Automated Field Devices | Automated Voltage Regulators | | Kevin Sprague | Engineering TBD | Customer & Utility | Direct Capital | | 5 | Yes | |
| C-4 | ✓ | Distributed Automation | Automated Field Devices | Automated Transformer & Load Tap Changers | | Kevin Sprague | Engineering TBD | Customer & Utility | Direct Capital | | 5 | Yes | |
| C-5 | ✓ | Distributed Automation | Communications Network | Fitchburg SCADA Communications | | Kevin Sprague | Engineering TBD | Customer & Utility | Direct Capital | 1 | 5 | Yes | |
| C-6 | ✓ | Distributed Automation | Communications Network | Field Area Network | | Kevin Sprague | Engineering/IT/EM&C TBD | Customer & Utility | Direct Capital | 5 | 5 | Yes | |
| C-7 | ✓ | Distributed Automation | Control Package / Software | ADMS | | Kevin Sprague | Engineering/EM&C TBD | Customer & Utility | Direct Capital | 1 | 10 | Yes | |
| D-1 | ✓ | Customer Empowerment | Better Information & Communications | Customer Web Portal | | Carol Valianti/Pam Bellino | Stephanie Francoeur | Customer & Utility | | 1 | 10 | | |
| D-3 | ✓ | Customer Empowerment | Better Information & Communications | Gamification Pilot | | Carol Valianti/Pam Bellino | Stephanie Francoeur | Customer & Utility | | 4 | 10 | | |
| D-6 | ✓ | Customer Empowerment | New Service Options (Opt-In) | TVR & Demand Response | | Tom Palma | Tom Palma | Customer & Utility | Capitalized Overhead | 5 | 15 | Yes | |
| E-1 | ✓ | Workforce & Asset Management | Workforce Management | Mobility Platform & System | | | | Customer & Utility | Direct Capital | 1 | 10 | Yes | |

Benefit Schedule ($K)

| ID | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A-2 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 | $10 |
| A-5 | | | | | | | | | | | | | | | | | | | | |
| A-6 | | | | | | | | | | | | | | | | | | | | |
| A-7 | | | | | | | | | | | | | | | | | | | | |
| B-8 | | | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 | $702 |
| B-9 | | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 | $117 |
| C-2 | | | | | | | | | | | | | | | | | | | | |
| C-3 | | | | | | | | | | | | | | | | | | | | |
| C-4 | | | | | | | | | | | | | | | | | | | | |
| C-5 | | | | | | | | | | | | | | | | | | | | |
| C-6 | | | | | | | | | | | | | | | | | | | | |
| C-7 | | | | $568 | $907 | $1,339 | $1,806 | $2,064 | $2,067 | $2,069 | $2,071 | $2,169 | $2,169 | $2,169 | $2,169 | $2,169 | $2,169 | $2,169 | $2,169 | $2,169 |
| D-1 | | | | | $20 | $20 | $21 | $21 | $22 | $22 | $22 | $22 | $22 | $22 | $22 | $22 | $22 | $22 | $22 | $22 |
| D-3 | | | | | | | $81 | $81 | $81 | $81 | $81 | $81 | $81 | $81 | $81 | $81 | $81 | $81 | $81 | $81 |
| D-6 | | | | | $44 | $93 | $147 | $202 | $250 | $258 | $258 | $258 | $258 | $258 | $258 | $258 | $258 | $258 | $258 | $258 |
| E-1 | | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 | $686 |

Cost Schedule ($K)

| ID | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A-2 | $30 | $30 | $15 | $15 | $15 | $15 | $15 | $15 | $15 | $15 | $15 | $15 | $15 | $15 | $15 | $15 |
| A-5 | | | | | $650 | $100 | $100 | $100 | $100 | $100 | $100 | $100 | $100 | $100 | $100 | $100 |
| A-6 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $200 | $0 | $0 | $0 | $0 | $0 | $0 |
| A-7 | $52 | $52 | $52 | $52 | $52 | $52 | $52 | $52 | $52 | $52 | $0 | $0 | $0 | $0 | $0 | $0 |
| B-8 | $150 | $150 | | | | | | | | $350 | $0 | $0 | $0 | $0 | $0 | $0 |
| B-9 | $50 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 |
| C-2 | | | | | | $338 | $338 | $338 | $338 | $338 | $338 | $338 | $338 | $338 | $338 | $0 |
| C-3 | $675 | $675 | $675 | $675 | $675 | $675 | $675 | $675 | $675 | $675 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-4 | $64 | $64 | $64 | $64 | $64 | $64 | $64 | $64 | $64 | $64 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-5 | $100 | $100 | $100 | $100 | $100 | $100 | $100 | $100 | $100 | $100 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-6 | $280 | $280 | $280 | $280 | $280 | $280 | $280 | $280 | $280 | $280 | $0 | $0 | $0 | $0 | $0 | $0 |
| C-7 | | | $700 | $700 | $700 | $160 | $160 | $160 | $160 | $160 | $160 | $160 | $160 | $160 | $160 | $160 |
| D-1 | | | $100 | $100 | $50 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 | $38 |
| D-3 | | | | $50 | $100 | $100 | $25 | $25 | $25 | $25 | $25 | $25 | $25 | $25 | $25 | $25 |
| D-6 | | | | $767 | $317 | $317 | $317 | $317 | $50 | $50 | $50 | $50 | $50 | $50 | $50 | $50 |
| E-1 | $217 | | | | | | | | | $250 | $0 | $0 | $0 | $0 | $0 | $0 |

| 2033 | 2034 | 2035 | 2036 | Quantifiable Customer Benefits | Quantifiable Utility Benefits | Unquantifiable Customer Benefits | Unquantifiable Utility Benefits | Quantifiable Customer Costs | Quantifiable Utility Costs | Unquantifiable Customer Costs | Unquantifiable Utility Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Quantifiable & Unquantifiable Benefits | | | | Quantifiable & Unquantifiable Costs | | | |
| $15 | $15 | $15 | $15 | Large DG developers will no longer need to submit multiple applications to test which location is best or to find the proposal is not feasible. Of 12 applications for DG 250kW or larger, 1 was cancelled after impact study ($35,000) and 2 were cancelled after impact study agreement ($10,000) was sent. Potential total cost | | | | | | | |
| $100 | $100 | $100 | $100 | None specified | None specified | This will accommodate new installations of DER and support innovative energy business models for Massachusetts. | This will provide Unitil a tool it can use to ensure grid reliability and efficiency with high adoption of DER. | | | | |
| $0 | $0 | $0 | $0 | | | Enables DG. | | | | | |
| $0 | $0 | $0 | $0 | | | | | | | | |
| $0 | $0 | $0 | $0 | Reduced customer minutes interrupted (CMI) will have a financial benefit to customers. Assuming a 15 minute reduction in outage minutes every for every outage, customer outage minutes will reduce by 61,730. Divided between residential and C&I minutes and costs, the benefit to customers will amount to around $644,011.50. | With better information available sooner the cost of the restoration will be decreased. Crews, both local and foreign, will finish sooner and be able to return to normal work sooner. | Customer satisfaction should improve with Unitil's improved ability to provide restoration information to its customers. | None specified | | | | |
| $1 | $1 | $1 | $1 | Customers will benefit from AMI/OMS integration by experiencing, on average, shorter outage duration. Considering 583 outages annually in the Fitchburg area, and a reduction in 50% of those outages by 5 minutes, customer outage minutes will decrease by 1,085 annually. Given the distribution between residential and commerical/industrial customers, total customer benefits amount to $107,335. | The utility will benefit from AMI/OMS integration by reducing SAIDI and CAIDI. Crew labor expenditures will also decrease. As in the customer benefits above, crew labor time will reduce by 5 minutes for 50% of the 583 outages. The utility will save $11,395 in crew labor expenditures. | Unquantifiable customer benefits include satisfaction with utility company | Unquantifiable utility benefits include contented customer-base. | | | | |
| $0 | $0 | $0 | $0 | | | | | | | | |
| $0 | $0 | $0 | $0 | | | | | | | | |
| $0 | $0 | $0 | | | | | | | | | |
| $0 | $0 | $0 | $0 | Reduced outage time, for full quantification of benefits, see form C-7. | Reduced outage time, for full quantification of benefits, see form C-7. | Potentially better customer information on outage restoration | Increased customer satisfaction. | | | | |
| $0 | $0 | $0 | $0 | No benefits directly related to FAN. This is an enabling technology. For full benefit quantification of VVO, see form C-7. | No benefits directly related to FAN. This is an enabling technology. For full benefit quantification of VVO, see form C-7. | No benefits directly related to FAN. This is an enabling technology. | Increased customer satisfaction. | | | | |
| $160 | $160 | $160 | $160 | Reduction in energy consumption<br><br>1) Reduction in supply costs - The assumed benefit of VVO is 2% or 8,000,000 kWH (400,000,000 * 0.02 = 8,000,000 Kwh) but requires LTC and regulators integrated as well. This benefit should be included within the ADMS or VVO. VVO/CVR - 2% savings in kWh - ~8,000,000 kWHs, fully realized in Year 6, yielding a benefit of $1,793,272. This is for 100% deployment across the entire FG&E system (currently assumed as projects C-2, C-3, C-4, C-6 and C-7 in | 1) Deferral of system improvements - Assume 1 reconductoring every 5 year (~$100k)<br><br>2) Reduction in customer outage minutes does not equate to elimination of an outage, still requiring crew time and truck rolls. | Better outage information. | Increased customer satisfaction. | | | | |
| $38 | $38 | $38 | $38 | Real-time usage data enables customers to make informed energy usage decisions, curbing or shifting their demand prior to a monthly billing statement, to save money. However, these values are not included in the Cost/Benefit analysis above due to the lack of available data. | Converting customers to self-service online account management can reduce call volume and decrease paper mailings, including monthly statements. Assume an increase in electronic bill presentment and payment opt-ins. Conversion to self-service account management will continue to reap increasing benefits for another two years, finally leveling off in year 13 with a benefit of $22,239. Total benefits over the course of the conversion, will sum to $170,038. | Enhanced customer engagement leads to an increase in customer satisfaction. Satisfied customers have higher positive perceptions of their service provider, are more understanding/patient when experiencing an outage or service issue, and are more receptive to educational and engagement campaigns/messages. | Highly satisfied customers place fewer calls to their utility than dissatisfied customers, and tend to manage their accounts and statements on a current basis. | | | | |
| $25 | $25 | $25 | $25 | We anticipate energy and dollar savings resulting from changed behaviors encouraged by the gamification pilot. Using an average monthly residential usage figure, the pilot group is estimated to curb their demand by an assumed 5% when engaged by the gamification platform, which periodically reminds them to shift or curb demand during peak periods. This 5% decrease is in line with other TVR programs in use by other utilities. Using an estimated kWh rate, the target pilot group will decrease their collective demand, thereby decreasing their monthly bill. Benefits will amount to approximately | Reduced line and technical losses. | Increased customer satisfaction and engagement. | Changing customer behavior, increased customer satisfaction and engagement. | | | | |
| $50 | $50 | $50 | $50 | Customers will be able to reduce their electric bills by purchasing equipment that allows them to participate in the program and by some behavior modifications. | The utility may realize a lower peak and critical peak capacity level, which could push out investments in equipment. With FGE's reducing load this is not expected to happen for the foreseeable future. | Achieve Energy Policy goals. Reducing peak and critical peak energy and usage should reduce electric rates in general. | The utility may realize a lower peak and critical peak capacity level, which could push out investments in equipment. With FGE's reducing load this is not expected to happen for the foreseeable future. | | | | |
| $0 | $0 | $0 | $0 | Customer benefits were estimated for a 15-minute savings per outage at $644,000. | Utility benefits are a result shorter durations, less overtime and the earlier release of foreign crews during outage events. | Customers will get better and more timely information on estimated restoration times thereby enabling them to make more informed decisions. | There are anticipated productivity improvements in the back office operations that will aide the restoration process and reduce some effort involved in the more manual and paper driven business processes. | | | | |

| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |

| 2.09 | 2.19 | 2.29 | 2.40 | 2.51 | 2.63 | 2.76 | 2.88 | 3.02 | 3.16 | 3.31 | 3.46 | 3.63 | 3.80 | 3.97 | 4.16 | 4.35 | 4.56 | 4.77 | 5.00 | 1.05 | 1.10 | 1.15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DPV of Benefits ($K) | | | | | | | | | | | | | | | | | | | | | | |
| $5 | $5 | $4 | $4 | $4 | $4 | $4 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $2 | $2 | $2 | $2 | $2 | $29 | $27 | $13 |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | $191 | $183 | $174 |
| | | | | | | | | | | | | | | | | | | | | $50 | $47 | $45 |
| | | $306 | $292 | $279 | $267 | $255 | $243 | $233 | $222 | $212 | $203 | $194 | $185 | $177 | $169 | $161 | $154 | $147 | $141 | $143 | $137 | |
| | $53 | $51 | $49 | $47 | $44 | $42 | $41 | $39 | $37 | $35 | $34 | $32 | $31 | $29 | $28 | $27 | $26 | $25 | $23 | $48 | $1 | $1 |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | $645 | $616 | $598 |
| | | | | | | | | | | | | | | | | | | | | $61 | $58 | $56 |
| | | | | | | | | | | | | | | | | | | | | $96 | $91 | $87 |
| | | | | | | | | | | | | | | | | | | | | $267 | $256 | $244 |
| | | | $228 | $361 | $509 | $655 | $715 | $684 | $655 | $626 | $626 | $598 | $571 | $546 | $521 | $498 | $476 | $455 | $434 | | | $610 |
| | | | | $8 | $8 | $8 | $7 | $7 | $7 | $7 | $6 | $6 | $6 | $6 | $5 | $5 | $5 | $5 | $5 | | | $87 |
| | | | | | | $29 | $28 | $27 | $26 | $24 | $23 | $22 | $21 | $20 | $19 | $19 | $18 | $17 | $16 | | | |
| | | | | $18 | $35 | $53 | $70 | $83 | $82 | $78 | $74 | $71 | $68 | $65 | $62 | $59 | $57 | $54 | $52 | | | |
| | $313 | $299 | $286 | $273 | $261 | $249 | $238 | $227 | $217 | $207 | $198 | $189 | $181 | $173 | $165 | $158 | $151 | $144 | $137 | $207 | | |

| DPV of Costs ($K) | | | | | | | | | | | | | | | | | Benefits & Costs | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1.20 | 1.26 | 1.32 | 1.38 | 1.44 | 1.51 | 1.58 | 1.65 | 1.73 | 1.81 | 1.90 | 1.99 | 2.08 | 2.18 | 2.28 | 2.39 | 2.50 | Benefits ($K) | Costs ($K) | B/C Ratio |
| $12 | $12 | $11 | $11 | $10 | $10 | $9 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | $64 | $220 | 0.29 |
| | $517 | $76 | $73 | $69 | $66 | $63 | $60 | $58 | $55 | $53 | $50 | $48 | $46 | $44 | $42 | $40 | $0 | $1,361 | 0.00 |
| $167 | $159 | $152 | $145 | $139 | $132 | $127 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,568 | 0.00 |
| $43 | $41 | $40 | $38 | $36 | $34 | $33 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $408 | 0.00 |
| | | | | | | $221 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,840 | $502 | 7.65 |
| $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $0 | $0 | $0 | $683 | $60 | 11.63 |
| | | $257 | $245 | $234 | $224 | $214 | $204 | $195 | $186 | $178 | $170 | $0 | $0 | $0 | $0 | $0 | $0 | $2,108 | 0.00 |
| $562 | $537 | $513 | $490 | $468 | $447 | $427 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $5,293 | 0.00 |
| $53 | $51 | $49 | $46 | $44 | $42 | $40 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $26 | $0 | $528 | 0.00 |
| $83 | $80 | $76 | $73 | $69 | $66 | $63 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $784 | 0.00 |
| $233 | $223 | $213 | $203 | $194 | $185 | $177 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,196 | 0.00 |
| $583 | $557 | $122 | $116 | $111 | $106 | $101 | $97 | $92 | $88 | $84 | $81 | $77 | $73 | $70 | $67 | $64 | $9,159 | $3,100 | 2.95 |
| $83 | $40 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 | $19 | $18 | $17 | $17 | $16 | $15 | $100 | $531 | 0.19 |
| $42 | $80 | $76 | $18 | $17 | $17 | $16 | $15 | $14 | $14 | $13 | $13 | $12 | $11 | $11 | $10 | $10 | $310 | $389 | 0.80 |
| $639 | $252 | $241 | $230 | $220 | $33 | $32 | $30 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 | $980 | $1,895 | 0.52 |
| | | | | | | $158 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $4,067 | $365 | 11.13 |

**GMP BCA Model**
User Inputs - TVR Opt-Out

| ID | Status | Program | Initiative | Project | Sub-Component (if Applicable) | Initiative Owner(s) | Project Owner(s) | Primary Beneficiary | Cost Classification | Service Year | Project Life (Years) | DPU CapEx Tracker | FERC Account |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A-2 | ✓ | DER Enablement | DER Interconnection | Circuit Capacity Study | | John Bonazoli | John Bonazoli | Customer & Utility | Non-Capitalized O&M | 2 | 10 | No | |
| A-5 | ✓ | DER Enablement | DER Management Platform | Analytics & Visualization System Platform | | John Bonazoli | | Utility Only | Direct Capital | 3 | 10 | Yes | |
| A-6 | ✓ | DER Enablement | DER Distribution Upgrades | Substation 3V0 Protection | | John Bonazoli | John Bonazoli | Utility Only | Direct Capital | 1 | 8 | No | |
| A-7 | ✓ | DER Enablement | DER Distribution Upgrades | Substation Voltage Regulation Control | | John Bonazoli | John Bonazoli | Utility Only | Direct Capital | 1 | 8 | No | |
| B-8 | ✓ | Grid Reliability | Outage & Restoration Management | Mobile Damage Assessment Tool | | | | Customer & Utility | Direct Capital | 1 | 10 | Yes | |
| B-9 | ✓ | Grid Reliability | Outage & Restoration Management | AMI & OMS Integration | | | | Customer & Utility | Capitalized Overhead | | | Yes | |
| C-2 | ✓ | Distributed Automation | Automated Field Devices | Automated Cap Banks | | Kevin Sprague | Engineering TBD | Customer & Utility | Direct Capital | | 5 | Yes | |
| C-3 | ✓ | Distributed Automation | Automated Field Devices | Automated Voltage Regulators | | Kevin Sprague | Engineering TBD | Customer & Utility | Direct Capital | | 5 | Yes | |
| C-4 | ✓ | Distributed Automation | Automated Field Devices | Automated Transformer & Load Tap Changers | | Kevin Sprague | Engineering TBD | Customer & Utility | Direct Capital | | 5 | Yes | |
| C-5 | ✓ | Distributed Automation | Communications Network | Fitchburg SCADA Communications | | Kevin Sprague | Engineering TBD | Customer & Utility | Direct Capital | 1 | 5 | Yes | |
| C-6 | ✓ | Distributed Automation | Communications Network | Field Area Network | | Kevin Sprague | Engineering/IT/EM&C TBD | Customer & Utility | Direct Capital | 5 | 5 | Yes | |
| C-7 | ✓ | Distributed Automation | Control Package / Software | ADMS | | Kevin Sprague | Engineering/EM&C TBD | Customer & Utility | Direct Capital | 1 | 10 | Yes | |
| D-1 | ✓ | Customer Empowerment | Better Information & Communications | Customer Web Portal | | Carol Valianti/Pam Bellino | Stephanie Francoeur | Customer & Utility | | 1 | 10 | | |
| D-3 | ✓ | Customer Empowerment | Better Information & Communications | Gamification Pilot | | Carol Valianti/Pam Bellino | Stephanie Francoeur | Customer & Utility | | 4 | 10 | | |
| D-6 | ✓ | Customer Empowerment | New Service Options (Opt-in) | TVR & Demand Response | | Tom Palma | Tom Palma | Customer & Utility | Capitalized Overhead | 7 | 15 | Yes | |
| E-1 | ✓ | Workforce & Asset Management | Workforce Management | Mobility Platform & System | | | | Customer & Utility | Direct Capital | 1 | 10 | Yes | |

| 2033 | 2034 | 2035 | 2036 | Quantifiable & Unquantifiable Benefits: Quantifiable Customer Benefits | Quantifiable Utility Benefits | Unquantifiable Customer Benefits | Unquantifiable Utility Benefits | Quantifiable & Unquantifiable Costs: Quantifiable Customer Costs | Quantifiable Utility Costs | Unquantifiable Customer Costs | Unquantifiable Utility Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $15 | $15 | $15 | $15 | Large DG developers will no longer need to submit multiple applications to test which location is best or to find the proposal is not feasible. Of 12 applications for DG 250kW or larger, 1 was cancelled after impact study ($35,000) and 2 were cancelled after impact study agreement ($10,000) was sent. Potential total cost [illegible] | | | | | | | |
| $100 | $100 | $100 | $100 | None specified | None specified | This will accommodate new installations of DER and support innovative energy business models for Massachusetts. | This will provide Unitil a tool it can use to ensure grid reliability and efficiency with high adoption of DER. | | | | |
| $0 | $0 | $0 | $0 | | | Enables DG. | | | | | |
| $0 | $0 | $0 | $0 | | | | | | | | |
| $0 | $0 | $0 | $0 | Reduced customer minutes interrupted (CMI) will have a financial benefit to customers. Assuming a 15 minute reduction in outage minutes every for every outage, customer outage minutes will reduce by 611,730. Divided between residential and C&I minutes and costs, the benefit to customers will amount to around $644,011.50. | With better information available sooner the cost of the restoration will be decreased. Crews, both local and foreign, will finish sooner and be able to return to normal work sooner. | Customer satisfaction should improve with Unitil's improved ability to provide restoration information to its customers. | None specified | | | | |
| $1 | $1 | $1 | $1 | Customers will benefit from AMI/OMS integration by experiencing, on average, shorter outage duration. Considering 583 outages annually in the Fitchburg area, and a reduction in 50% of those outages by 5 minutes, customer outage minutes will decrease by 1,085 annually. Given the distribution between residential and commercial/industrial customers, total customer benefits amount to $107,335. | The utility will benefit from AMI/OMS integration by reducing SAIDI and CAIDI. Crew labor expenditures will also decrease. As in the customer benefits above, crew labor time will reduce by 5 minutes for 50% of the 583 outages. The utility will save $11,395 in crew labor expenditures. | Unquantifiable customer benefits include satisfaction with utility company | Unquantifiable utility benefits include contented customer-base. | | | | |
| $0 | $0 | $0 | $0 | | | | | | | | |
| $0 | $0 | $0 | $0 | | | | | | | | |
| $0 | $0 | $0 | | | | | | | | | |
| $0 | $0 | $0 | $0 | Reduced outage time, for full quantification of benefits, see form C-7. | Reduced outage time, for full quantification of benefits, see form C-7. | Potentially better customer information on outage restoration | Increased customer satisfaction. | | | | |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | | | |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | | | |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | | | |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | | | |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | | | |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | | | |

| Calculation Filters: Primary Beneficiary | Cost Classification | Service Year | DPU CapEx Tracker | FERC Account | Product | Project Service Years: 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |

| DPV of Benefits ($K): 1.05 | 1.10 | 1.16 | 1.20 | 1.26 | 1.32 | 1.38 | 1.44 | 1.51 | 1.58 | 1.65 | 1.73 | 1.81 | 1.90 | 1.99 | 2.08 | 2.18 | 2.28 | 2.39 | 2.50 | 1.05 | 1.10 | 1.15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $10 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | $6 | $6 | $5 | $5 | $5 | $5 | $4 | $4 | $4 | $29 | $27 | $13 |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | $191 | $183 | $174 |
| | | | | | | | | | | | | | | | | | | | | $50 | $47 | $45 |
| | | $612 | $585 | $559 | $534 | $510 | $487 | $465 | $444 | $424 | $405 | $387 | $370 | $353 | $338 | $323 | $308 | $296 | $281 | $143 | $137 | |
| | $107 | $102 | $97 | $93 | $89 | $85 | $81 | $78 | $74 | $71 | $68 | $65 | $62 | $59 | $56 | $54 | $51 | $49 | $47 | $48 | $1 | $1 |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | $645 | $616 | $588 |
| | | | | | | | | | | | | | | | | | | | | $61 | $58 | $56 |
| | | | | | | | | | | | | | | | | | | | | $96 | $91 | $87 |
| | | | | | | | | | | | | | | | | | | | | $267 | $256 | $244 |
| | | | $456 | $721 | $1,017 | $1,311 | $1,431 | $1,368 | $1,309 | $1,252 | $1,252 | $1,196 | $1,143 | $1,092 | $1,043 | $996 | $952 | $909 | $868 | | | $610 |
| | | | | $16 | $16 | $15 | $15 | $14 | $14 | $13 | $13 | $12 | $12 | $11 | $11 | $10 | $10 | $9 | $9 | | | $87 |
| | | | | | | $59 | $56 | $53 | $51 | $49 | $47 | $45 | $43 | $41 | $39 | $37 | $35 | $34 | $32 | | | |
| | | | | $117 | $235 | $355 | $467 | $551 | $544 | $520 | $496 | $474 | $453 | $433 | $413 | $395 | $377 | $360 | $344 | | | |
| | $626 | $598 | $572 | $546 | $522 | $499 | $476 | $455 | $434 | $415 | $396 | $379 | $362 | $346 | $330 | $315 | $301 | $288 | $275 | $207 | | |

| DPV of Costs ($K) | | | | | | | | | | | | | | | | | | Benefits & Costs | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1.20 | 1.26 | 1.32 | 1.38 | 1.44 | 1.51 | 1.58 | 1.65 | 1.73 | 1.81 | 1.90 | 1.99 | 2.08 | 2.18 | 2.28 | 2.39 | 2.50 | | Benefits ($K) | Costs ($K) | B/C Ratio |
| $12 | $12 | $11 | $11 | $10 | $10 | $9 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | | $128 | $220 | 0.58 |
| | $517 | $76 | $73 | $69 | $66 | $63 | $60 | $58 | $55 | $53 | $50 | $48 | $46 | $44 | $42 | $40 | | $0 | $1,361 | 0.00 |
| $167 | $159 | $152 | $145 | $139 | $132 | $127 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | $1,568 | 0.00 |
| $43 | $41 | $40 | $38 | $36 | $34 | $33 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | $408 | 0.00 |
| | | | | | | $221 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $7,679 | $502 | 15.31 |
| $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $0 | $0 | $0 | | $1,387 | $60 | 23.26 |
| | | $257 | $245 | $234 | $224 | $214 | $204 | $195 | $186 | $178 | $170 | $0 | $0 | $0 | $0 | $0 | | $0 | $2,108 | 0.00 |
| $562 | $537 | $513 | $490 | $468 | $447 | $427 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | $5,293 | 0.00 |
| $53 | $51 | $49 | $46 | $44 | $42 | $40 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $26 | | $0 | $528 | 0.00 |
| $83 | $80 | $76 | $73 | $69 | $66 | $63 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | $784 | 0.00 |
| $233 | $223 | $213 | $203 | $194 | $185 | $177 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $0 | $2,196 | 0.00 |
| $583 | $557 | $122 | $116 | $111 | $106 | $101 | $97 | $92 | $88 | $84 | $81 | $77 | $73 | $70 | $67 | $64 | | $18,319 | $3,100 | 5.91 |
| $83 | $40 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 | $19 | $18 | $17 | $17 | $16 | $15 | | $200 | $531 | 0.38 |
| $42 | $80 | $76 | $18 | $17 | $17 | $16 | $15 | $14 | $14 | $13 | $13 | $12 | $11 | $11 | $10 | $10 | | $639 | $399 | 1.59 |
| $1,904 | $1,858 | $1,775 | $1,696 | $1,620 | $33 | $32 | $30 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 | | $6,535 | $9,167 | 0.71 |
| | | | | | | $158 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | $8,134 | $365 | 22.28 |

# GMP BCA Model

## Short-Term Investment Plans (STIPs)

| No. | Rank | Case | Link | Description |
|---|---|---|---|---|
| 1 | 1 | Base Case (C&U) | Base Case (C&U) | |
| 2 | 2 | Base Case (U) | Base Case (U) | |
| 3 | 3 | No Comm | No Comm | |
| 4 | 4 | No Comm 10% | No Comm 10% | |
| 5 | 5 | STIP Final | STIP Final | |
| 6 | 6 | STIP v2 7_8_15 | STIP v2 7_8_15 | |
| 7 | 7 | 150% Costs | 150% Costs | |
| 8 | 8 | 50% Benefits | 50% Benefits | |
| 9 | 9 | T-Bill Discounting | T-Bill Discounting | |
| 10 | 10 | TVR Opt-Out | TVR Opt-Out | |

| No. | Rank | Source | Objective | Description |
|---|---|---|---|---|
| **DPU Order 12-76-B** | | | | |
| 1 | 1 | DPU Order 12-76-B | Reduce the Effect of Outages | Improve reliability, resiliency and security, meet customer expectations, and mitigate risk. |
| 2 | 2 | DPU Order 12-76-B | Optimize Demand | Maintain reliability, realign pricing  amd economics, and ensure a sustainable business model. |
| 3 | 3 | DPU Order 12-76-B | Integrate DG | Motivate the consumer, asset utilization and efficiency, and customer expectations and satisfaction. |
| 4 | 4 | DPU Order 12-76-B | Improve Workforce & Asset Management | Reduce OpEx spending, improve outage response, and optimize asset life and value. |
| **Unitil Corporation** | | | | |
| 5 | 5 | Unitil Corporation | Improve Customer Satisfaction | Improve ease of doing business, access to information, two-way communication, and customer options. |
| 6 | 6 | Unitil Corporation | Empower the Customer | Place additional information, improved tools, and greater control in the hands of the customer. |

| No. | Rank | Objective | Program | Description |
|---|---|---|---|---|
| **All Objectives** | | | | |
| 1 | 2 | All Objectives | DER Enablement | Accommodate reliability, realign pricing and economics, and support utility-enabled energy efficiency. |
| 2 | 4 | All Objectives | Grid Reliability | Maintain reliability, avoid regulator penalties, and ensure restoration performance. |

| No. | Rank | Program | Initiative | Description |
|---|---|---|---|---|
| **DER Enablement** | | | | |
| 1 | 11 | DER Enablement | DER Tariff & Pricing | |
| 2 | 8 | DER Enablement | DER Interconnection | |
| 3 | 9 | DER Enablement | DER Management Platform | |
| 4 | 7 | DER Enablement | DER Distribution Upgrades | |
| 5 | 10 | DER Enablement | DER RD&D | |
| **Grid Reliability** | | | | |
| 6 | 15 | Grid Reliability | Resiliency | |
| 7 | 14 | Grid Reliability | Outage & Restoration Management | |

| No. | Rank | Initiative | Project | Description |
|---|---|---|---|---|
| **DER Tariff & Pricing** | | | | |
| 1 | 16 | DER Tariff & Pricing | Customer-Owned DG Tariff | Implement a tariff for customer-owned DG (A-1). |
| **DER Interconnection** | | | | |
| 2 | 10 | DER Interconnection | Circuit Capacity Study | Conduct a circuit capacity study of locations and improvements (no enhancements capability study) (A-2). |
| 3 | 15 | DER Interconnection | Customer-Focused DER Interconnection | Implement a customer-focused DER interconnection process (A-3). |
| **DER Management Platform** | | | | |
| 4 | 18 | DER Management Platform | DG Monitoring & Control Pilot | Conduct a DG monitoring and control pilot program (A-4). |
| 5 | 3 | DER Management Platform | Analytics & Visualiation System Platform | Implement an analytics and visualization platform for system-wide DG (A-5). |
| **DER Distribution Upgrades** | | | | |
| 6 | 28 | DER Distribution Upgrades | Substation 3V0 Protection | Install 3V0 protection at substations (A-6). |
| 7 | 29 | DER Distribution Upgrades | Substation Voltage Regulation Control | Install voltage regulation control at substations (A-7). |
| **DER RD&D** | | | | |

**GMP BCA Model**

**Validation List 1 - Programs**

| | 1 |
|---|---|
| **No.** | **Programs** |
| 1 | Customer Empowerment |
| 2 | DER Enablement |
| 3 | Distributed Automation |
| 4 | Grid Reliability |
| 5 | Workforce & Asset Management |
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| **Total** | **5** |

**GMP BCA Model**
**Validation List 2 - Initiatives**

| | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| No. | Initiatives | DER Enablement | Grid Reliability | Distributed Automation | Customer Empowerment | Workforce & Asset Management |
| 1 | Asset Management | DER Tariff & Pricing | Resiliency | Automated Field Devices | Better Information & Communications | Workforce Management |
| 2 | Automated Field Devices | DER Interconnection | Outage & Restoration Management | Communications Network | New Service Options (Opt-in) | Asset Management |
| 3 | Better Information & Communications | DER Management Platform | | Control Package / Software | Customer RD&D | |
| 4 | Communications Network | DER Distribution Upgrades | | Energy Efficiency Tariff & Pricing | | |
| 5 | Control Package / Software | DER RD&D | | | | |
| 6 | Customer RD&D | | | | | |
| 7 | DER Distribution Upgrades | | | | | |
| 8 | DER Interconnection | | | | | |
| 9 | DER Management Platform | | | | | |
| 10 | DER RD&D | | | | | |
| 11 | DER Tariff & Pricing | | | | | |
| 12 | Energy Efficiency Tariff & Pricing | | | | | |
| 13 | New Service Options (Opt-in) | | | | | |
| 14 | Outage & Restoration Management | | | | | |
| 15 | Resiliency | | | | | |
| 16 | Workforce Management | | | | | |
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| Total | 16 | 5 | 2 | 4 | 3 | 2 |

GMP BCA Model
Validation List 3 - Projects

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Projects | DER Tariff & Pricing | DER Interconnection | DER Management Platform | DER Distribution Upgrades | DER RD&D | Resiliency | Outage & Restoration Management | Automated Field Devices | Communications Network | Control Package / Software | Energy Efficiency Tariff & Pricing | Better Information & Communications | New Service Options (Opt-in) | Customer RD&D | Workforce Management | Asset Management |
| 1 | ADMS | Customer-Owned DG Tariff | Circuit Capacity Study | DG Monitoring & Control Pilot | Substation 3V0 Protection | DER RD&D | SRP Cycle Reduction | Mobile Damage Assessment Tool | Automatic Throw-Over Switches | Fitchburg SCADA Communications | ADMS | VVO Energy Efficiency Tariff | Customer Web Portal | TVR & Demand Response | Customer RD&D | Mobility Platform & System | Condition-Base Maintenance |
| 2 | AMI & OMS Integration | | Customer-Focused DER Interconnection | Analytics & Visualization System Platform | Substation Voltage Regulation Control | | Hazard Tree Enhancement | AMI & OMS Integration | Automated Cap Banks | Field Area Network | | | Gamification Pilot | | | Work Management Automation & Integration | |
| 3 | Analytics & Visualization System Platform | | | | | | Jacketed Tree Wire & Spacer Cable | OMS Resiliency & Hot Standby | Automated Voltage Regulators | | | | Customer Education | | | | |
| 4 | Automated Cap Banks | | | | | | Breakaway Service Connector Pilot | | Automated Transformer & Load Tap Changers | | | | | | | | |
| 5 | Automated Sectionalizing & Restoration | | | | | | | | Automated Sectionalizing & Restoration | | | | | | | | |
| 6 | Automated Transformer & Load Tap Changers | | | | | | | | | | | | | | | | |
| 7 | Automated Voltage Regulators | | | | | | | | | | | | | | | | |
| 8 | Automatic Throw-Over Switches | | | | | | | | | | | | | | | | |
| 9 | Breakaway Service Connector Pilot | | | | | | | | | | | | | | | | |
| 10 | Circuit Capacity Study | | | | | | | | | | | | | | | | |
| 11 | Condition-Base Maintenance | | | | | | | | | | | | | | | | |
| 12 | Customer Education | | | | | | | | | | | | | | | | |
| 13 | Customer RD&D | | | | | | | | | | | | | | | | |
| 14 | Customer Web Portal | | | | | | | | | | | | | | | | |
| 15 | Customer-Focused DER Interconnection | | | | | | | | | | | | | | | | |
| 16 | Customer-Owned DG Tariff | | | | | | | | | | | | | | | | |
| 17 | DER RD&D | | | | | | | | | | | | | | | | |
| 18 | DG Monitoring & Control Pilot | | | | | | | | | | | | | | | | |
| 19 | Field Area Network | | | | | | | | | | | | | | | | |
| 20 | Fitchburg SCADA Communications | | | | | | | | | | | | | | | | |
| 21 | Gamification Pilot | | | | | | | | | | | | | | | | |
| 22 | Hazard Tree Enhancement | | | | | | | | | | | | | | | | |
| 23 | Jacketed Tree Wire & Spacer Cable | | | | | | | | | | | | | | | | |
| 24 | Mobile Damage Assessment Tool | | | | | | | | | | | | | | | | |
| 25 | Mobility Platform & System | | | | | | | | | | | | | | | | |
| 26 | OMS Resiliency & Hot Standby | | | | | | | | | | | | | | | | |
| 27 | SRP Cycle Reduction | | | | | | | | | | | | | | | | |
| 28 | Substation 3V0 Protection | | | | | | | | | | | | | | | | |
| 29 | Substation Voltage Regulation Control | | | | | | | | | | | | | | | | |
| 30 | TVR & Demand Response | | | | | | | | | | | | | | | | |
| 31 | VVO Energy Efficiency Tariff | | | | | | | | | | | | | | | | |
| 32 | Work Management Automation & Integration | | | | | | | | | | | | | | | | |
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| Total | 32 | 1 | 2 | 2 | 2 | 1 | 4 | 3 | 5 | 2 | 1 | 1 | 3 | 1 | 1 | 2 | 1 |

**GMP BCA Model**

**Validation List 4 - Miscellaneous**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Cases | #REF! | #REF! | #REF! | Years | #REF! | Benefit / Cost | Chart Type | GMP Category | STIP Projects | STIP Program Count 1 | STIP Initiative Count 1 | STIP Project Count 1 | STIP Program Count 2 | STIP Initiative Count 2 | STIP Project Count 2 | Data Rows 1 | Data Rows 2 |
| 1 | Base Case (C&U) | ✓ | All | All | 1 | All | Benefit | Bar | Program | Customer-Owned DG Tariff | 1 | 0 | 0 | 1 | 0 | 0 | 1 | 1 |
| 2 | Base Case (U) | X | Customer & Utility | Direct Capital | 2 | Yes | Cost | Pie | Initiative | Circuit Capacity Study | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| 3 | No Comm | | Customer Only | Capitalized Overhead | 3 | Partially | B/C Ratio | | Project | Customer-Focused DER Interconnection | 3 | 3 | 0 | 3 | 3 | 0 | 3 | 3 |
| 4 | No Comm 10% | | Utility Only | Non-Capitalized O&M | 4 | No | | | | DG Monitoring & Control Pilot | 4 | 4 | 0 | 4 | 4 | 0 | 4 | 4 |
| 5 | STIP Final | | | | 5 | | | | | Analytics & Visualization System Platform | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 6 | STIP v2 7_8_15 | | | | 6 | | | | | Substation 3V0 Protection | | 0 | 6 | | 0 | 6 | 6 | 6 |
| 7 | 150% Costs | | | | 7 | | | | | Substation Voltage Regulation Control | | 7 | 7 | | 7 | 7 | 7 | 7 |
| 8 | 50% Benefits | | | | 8 | | | | | DER RD&D | | 8 | 0 | | 8 | 0 | 8 | 8 |
| 9 | T-Bill Discounting | | | | 9 | | | | | SRP Cycle Reduction | | 9 | 0 | | 9 | 0 | 9 | 9 |
| 10 | TVR Opt-Out | | | | 10 | | | | | Hazard Tree Enhancement | | 0 | 0 | | 0 | 0 | 10 | 10 |
| 11 | | | | | 11 | | | | | Jacketed Tree Wire & Spacer Cable | | 0 | 0 | | 0 | 0 | 11 | 11 |
| 12 | | | | | 12 | | | | | Breakaway Service Connector Pilot | | 0 | 0 | | 0 | 0 | 12 | 12 |
| 13 | | | | | 13 | | | | | Mobile Damage Assessment Tool | | 13 | 13 | | 13 | 13 | 13 | 13 |
| 14 | | | | | 14 | | | | | AMI & OMS Integration | | 14 | 14 | | 14 | 14 | 14 | 14 |
| 15 | | | | | 15 | | | | | OMS Resiliency & Hot Standby | | 0 | 0 | | 0 | 0 | 15 | 15 |
| 16 | | | | | 16 | | | | | Automatic Throw-Over Switches | | 16 | 0 | | 16 | 0 | 16 | 16 |
| 17 | | | | | 17 | | | | | Automated Cap Banks | | | 17 | | | 17 | | |
| 18 | | | | | 18 | | | | | Automated Voltage Regulators | | | 18 | | | 18 | | |
| 19 | | | | | 19 | | | | | Automated Transformer & Load Tap Changers | | | 19 | | | 19 | | |
| 20 | | | | | 20 | | | | | Automated Sectionalizing & Restoration | | | 0 | | | 0 | | |
| 21 | | | | | 21 | | | | | Fitchburg SCADA Communications | | | 21 | | | 21 | | |
| 22 | | | | | 22 | | | | | Field Area Network | | | 22 | | | 22 | | |
| 23 | | | | | 23 | | | | | ADMS | | | 23 | | | 23 | | |
| 24 | | | | | 24 | | | | | VVO Energy Efficiency Tariff | | | 0 | | | 0 | | |
| 25 | | | | | 25 | | | | | Customer Web Portal | | | 25 | | | 25 | | |
| 26 | | | | | 26 | | | | | Gamification Pilot | | | 26 | | | 26 | | |
| 27 | | | | | 27 | | | | | Customer Education | | | 0 | | | 0 | | |
| 28 | | | | | 28 | | | | | TVR & Demand Response | | | 28 | | | 28 | | |
| 29 | | | | | 29 | | | | | Customer RD&D | | | 0 | | | 0 | | |
| 30 | | | | | 30 | | | | | Mobility Platform & System | | | 30 | | | 30 | | |
| 31 | | | | | 31 | | | | | Work Management Automation & Integration | | | 0 | | | 0 | | |
| 32 | | | | | 32 | | | | | Condition-Base Maintenance | | | 0 | | | 0 | | |
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| Total | 10 | | | | | | | | | | | | | | | | | |

# GMP BCA Model
## Chart Names & Titles

| No. | Description | Benefit / Cost | Chart Type | GMP Category | Unit Type 1 | Unit Type 2 | Chart Name | Chart Title |
|---|---|---|---|---|---|---|---|---|
| **STIP Totals - STIP v2 7_8_15** | | | | | | | | |
| 1 | STIP | Benefit | Bar | Program | | $K | | STIP Benefits - STIP v2 7_8_15 - Programs ($K) |
| 2 | STIP | Benefit | Pie | Program | | % | | STIP Benefits - STIP v2 7_8_15 - Programs (%) |
| 3 | STIP | Cost | Bar | Program | | $K | | STIP Costs - STIP v2 7_8_15 - Programs ($K) |
| 4 | STIP | Cost | Pie | Program | | % | | STIP Costs - STIP v2 7_8_15 - Programs (%) |
| 5 | STIP | B/C Ratio | Bar | Program | | | | STIP B/C Ratios - STIP v2 7_8_15 - Programs |
| 6 | STIP | B/C Ratio | Pie | Program | | | | STIP B/C Ratios - STIP v2 7_8_15 - Programs |
| 7 | STIP | Benefit | Bar | Initiative | | $K | | STIP Benefits - STIP v2 7_8_15 - Initiatives ($K) |
| 8 | STIP | Benefit | Pie | Initiative | | % | | STIP Benefits - STIP v2 7_8_15 - Initiatives (%) |
| 9 | STIP | Cost | Bar | Initiative | | $K | | STIP Costs - STIP v2 7_8_15 - Initiatives ($K) |
| 10 | STIP | Cost | Pie | Initiative | | % | | STIP Costs - STIP v2 7_8_15 - Initiatives (%) |
| 11 | STIP | B/C Ratio | Bar | Initiative | | | | STIP B/C Ratios - STIP v2 7_8_15 - Initiatives |
| 12 | STIP | B/C Ratio | Pie | Initiative | | | | STIP B/C Ratios - STIP v2 7_8_15 - Initiatives |
| **STIP Totals - TVR Opt-Out** | | | | | | | | |
| 13 | STIP | Benefit | Bar | Program | | $K | | STIP Benefits - TVR Opt-Out - Programs ($K) |
| 14 | STIP | Benefit | Pie | Program | | % | | STIP Benefits - TVR Opt-Out - Programs (%) |
| 15 | STIP | Cost | Bar | Program | | $K | | STIP Costs - TVR Opt-Out - Programs ($K) |
| 16 | STIP | Cost | Pie | Program | | % | | STIP Costs - TVR Opt-Out - Programs (%) |
| 17 | STIP | B/C Ratio | Bar | Program | | | | STIP B/C Ratios - TVR Opt-Out - Programs |
| 18 | STIP | B/C Ratio | Pie | Program | | | | STIP B/C Ratios - TVR Opt-Out - Programs |
| 19 | STIP | Benefit | Bar | Initiative | | $K | | STIP Benefits - TVR Opt-Out - Initiatives ($K) |
| 20 | STIP | Benefit | Pie | Initiative | | % | | STIP Benefits - TVR Opt-Out - Initiatives (%) |
| 21 | STIP | Cost | Bar | Initiative | | $K | | STIP Costs - TVR Opt-Out - Initiatives ($K) |
| 22 | STIP | Cost | Pie | Initiative | | % | | STIP Costs - TVR Opt-Out - Initiatives (%) |

Unitil

**GMP BCA Model**

**STIP Data - STIP v2 7_8_15 - Programs**

| STIP Totals - STIP v2 7_8_15 - Programs | | | | |
|---|---|---|---|---|
| No. | Program | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Customer Empowerment | $1,390 | $2,815 | 0.49 |
| 2 | DER Enablement | $64 | $3,557 | 0.02 |
| 3 | Distributed Automation | $9,159 | $14,009 | 0.65 |
| 4 | Grid Reliability | $4,533 | $561 | 8.08 |
| 5 | Workforce & Asset Management | $4,067 | $365 | 11.13 |
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| Total | 5 Programs | $19,214 | $21,307 | 0.90 |

| STIP Benefits - STIP v2 7_8_15 - Programs ($K) | | | | | | | | | | | | | | | | | | | | | | | | |
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| No. | Program | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Distributed Automation | $0 | $0 | $0 | $228 | $361 | $509 | $655 | $715 | $684 | $655 | $626 | $626 | $598 | $571 | $546 | $521 | $498 | $476 | $455 | $434 | $9,159 | $14,009 | 0.65 |
| 2 | Grid Reliability | $0 | $53 | $357 | $341 | $326 | $311 | $297 | $284 | $271 | $259 | $248 | $237 | $226 | $216 | $206 | $197 | $188 | $180 | $172 | $164 | $4,533 | $561 | 8.08 |
| 3 | Workforce & Asset Management | $0 | $313 | $299 | $286 | $273 | $261 | $249 | $238 | $227 | $217 | $207 | $198 | $189 | $181 | $173 | $165 | $158 | $151 | $144 | $137 | $4,067 | $365 | 11.14 |
| 4 | Customer Empowerment | $0 | $0 | $0 | $0 | $26 | $43 | $90 | $105 | $117 | $114 | $109 | $104 | $100 | $95 | $91 | $87 | $83 | $79 | $76 | $72 | $1,390 | $2,815 | 0.49 |
| 5 | DER Enablement | $5 | $5 | $4 | $4 | $4 | $4 | $4 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $2 | $2 | $2 | $2 | $2 | $64 | $3,557 | 0.02 |
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| Total | 5 Programs | $5 | $371 | $661 | $859 | $989 | $1,128 | $1,296 | $1,346 | $1,303 | $1,248 | $1,193 | $1,168 | $1,116 | $1,066 | $1,018 | $973 | $929 | $888 | $848 | $810 | $19,214 | $21,307 | 0.90 |

| STIP Costs - STIP v2 7_8_15 - Programs ($K) | | | | | | | | | | | | | | | | | | | | | | | | |
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| No. | Program | Benefits ($K) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Costs ($K) | B/C Ratio |
| 1 | Distributed Automation | $9,159 | $1,069 | $1,021 | $1,586 | $1,515 | $1,447 | $1,229 | $1,174 | $1,121 | $1,071 | $1,023 | $301 | $288 | $275 | $262 | $251 | $77 | $73 | $70 | $67 | $90 | $14,009 | 0.65 |
| 2 | DER Enablement | $64 | $269 | $257 | $233 | $222 | $729 | $279 | $266 | $254 | $243 | $232 | $70 | $66 | $63 | $61 | $58 | $55 | $53 | $50 | $48 | $46 | $3,557 | 0.02 |
| 3 | Customer Empowerment | $1,390 | $0 | $0 | $87 | $764 | $372 | $346 | $276 | $264 | $75 | $72 | $68 | $65 | $62 | $60 | $57 | $54 | $52 | $50 | $47 | $45 | $2,815 | 0.49 |
| 4 | Grid Reliability | $4,533 | $191 | $138 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $222 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $0 | $0 | $0 | $561 | 8.08 |
| 5 | Workforce & Asset Management | $4,067 | $207 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $158 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $365 | 11.14 |
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| Total | 5 Programs | $19,214 | $1,737 | $1,416 | $1,906 | $2,502 | $2,549 | $1,854 | $1,717 | $1,640 | $1,390 | $1,707 | $439 | $420 | $401 | $383 | $366 | $187 | $179 | $171 | $163 | $181 | $21,307 | 0.90 |

| STIP B/C Ratios - STIP v2 7_8_15 - Programs | | | | |
|---|---|---|---|---|
| No. | Program | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Workforce & Asset Management | $4,067 | $365 | 11.14 |
| 2 | Grid Reliability | $4,533 | $561 | 8.08 |
| 3 | Distributed Automation | $9,159 | $14,009 | 0.65 |
| 4 | Customer Empowerment | $1,390 | $2,815 | 0.49 |
| 5 | DER Enablement | $64 | $3,557 | 0.02 |
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| Total | 5 Programs | $19,214 | $21,307 | 0.90 |

| STIP Totals - STIP v2 7_8_15 - Initiatives | | | | |
|---|---|---|---|---|
| No. | Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Automated Field Devices | $0 | $7,929 | 0.00 |
| 2 | Better Information & Communications | $410 | $920 | 0.45 |
| 3 | Communications Network | $0 | $2,980 | 0.00 |
| 4 | Control Package / Software | $9,159 | $3,100 | 2.95 |
| 5 | DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| 6 | DER Interconnection | $64 | $220 | 0.29 |
| 7 | DER Management Platform | $0 | $1,361 | 0.00 |
| 8 | New Service Options (Opt-In) | $980 | $1,895 | 0.52 |
| 9 | Outage & Restoration Management | $4,533 | $561 | 8.08 |
| 10 | Workforce Management | $4,067 | $365 | 11.13 |
| Total | 10 Initiatives | $19,214 | $21,307 | 0.90 |

| STIP Benefits - STIP v2 7_8_15 - Programs ($K) | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Initiative | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Control Package / Software | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $9,159 | $3,100 | 2.95 |
| 2 | Outage & Restoration Management | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $4,533 | $561 | 8.08 |
| 3 | Workforce Management | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $4,067 | $365 | 11.13 |
| 4 | New Service Options (Opt-In) | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $980 | $1,895 | 0.52 |
| 5 | Better Information & Communications | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $410 | $920 | 0.45 |
| 6 | DER Interconnection | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $64 | $220 | 0.29 |
| 7 | Automated Field Devices | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $0 | $7,929 | 0.00 |
| 8 | Communications Network | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $0 | $2,980 | 0.00 |
| 9 | DER Distribution Upgrades | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $0 | $1,976 | 0.00 |
| 10 | DER Management Platform | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $0 | $1,361 | 0.00 |
| Total | 10 Initiatives | $5 | $371 | $661 | $859 | $989 | $1,128 | $1,296 | $1,346 | $1,303 | $1,248 | $1,193 | $1,168 | $1,116 | $1,066 | $1,018 | $973 | $929 | $888 | $848 | $810 | $19,214 | $21,307 | 0.90 |

| STIP Costs - STIP v2 7_8_15 - Programs ($K) | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Initiative | Benefits ($K) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Costs ($K) | B/C Ratio |
| 1 | Automated Field Devices | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $747 | $713 | $681 | $204 | $195 | $186 | $178 | $170 | $0 | $0 | $0 | $0 | $26 | $7,929 | 0.00 |
| 2 | Control Package / Software | $9,159 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $111 | $106 | $101 | $97 | $92 | $88 | $84 | $81 | $77 | $73 | $70 | $67 | $64 | $3,100 | 2.95 |
| 3 | Communications Network | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $263 | $252 | $240 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,980 | 0.00 |
| 4 | DER Distribution Upgrades | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $175 | $167 | $159 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,976 | 0.00 |
| 5 | New Service Options (Opt-In) | $980 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $220 | $33 | $32 | $30 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 | $1,895 | 0.52 |
| 6 | DER Management Platform | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $69 | $66 | $63 | $60 | $58 | $55 | $53 | $50 | $48 | $46 | $44 | $42 | $40 | $1,361 | 0.00 |
| 7 | Better Information & Communications | $410 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $44 | $42 | $40 | $38 | $36 | $35 | $33 | $32 | $30 | $29 | $28 | $26 | $25 | $920 | 0.45 |
| 8 | Outage & Restoration Management | $4,533 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $1 | $1 | $222 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $0 | $0 | $0 | $561 | 8.08 |
| 9 | Workforce Management | $4,067 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $0 | $0 | $158 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $365 | 11.13 |
| 10 | DER Interconnection | $64 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $10 | $10 | $9 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | $220 | 0.29 |
| Total | 10 Initiatives | $19,214 | $1,737 | $1,416 | $1,906 | $2,502 | $2,549 | $1,854 | $1,717 | $1,640 | $1,390 | $1,707 | $439 | $420 | $401 | $383 | $366 | $187 | $179 | $171 | $163 | $181 | $21,307 | 0.90 |

| STIP B/C Ratios - STIP v2 7_8_15 - Programs | | | | |
|---|---|---|---|---|
| No. | Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Workforce Management | $4,067 | $365 | 11.13 |
| 2 | Outage & Restoration Management | $4,533 | $561 | 8.08 |
| 3 | Control Package / Software | $9,159 | $3,100 | 2.95 |
| 4 | New Service Options (Opt-In) | $980 | $1,895 | 0.52 |
| 5 | Better Information & Communications | $410 | $920 | 0.45 |
| 6 | DER Interconnection | $64 | $220 | 0.29 |
| 7 | DER Management Platform | $0 | $1,361 | 0.00 |
| 8 | DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| 9 | Communications Network | $0 | $2,980 | 0.00 |
| 10 | Automated Field Devices | $0 | $7,929 | 0.00 |
| Total | 10 Initiatives | $19,214 | $21,307 | 0.90 |

# GMP BCA Model

STIP Data - STIP v2 7_8_15 - Projects

**STIP Totals - STIP v2 7_8_15 - Projects**

| No. | Project | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|---|
| 1 | Circuit Capacity Study | $64 | $220 | 0.29 |
| 2 | Analytics & Visualization System Platform | $0 | $1,361 | 0.00 |
| 3 | Substation 3V0 Protection | $0 | $1,568 | 0.00 |
| 4 | Substation Voltage Regulation Control | $0 | $408 | 0.00 |
| 5 | Mobile Damage Assessment Tool | $3,840 | $502 | 7.65 |
| 6 | AMI & OMS Integration | $693 | $60 | 11.63 |
| 7 | Automated Cap Banks | $0 | $2,108 | 0.00 |
| 8 | Automated Voltage Regulators | $0 | $5,293 | 0.00 |
| 9 | Automated Transformer & Load Tap Changers | $0 | $528 | 0.00 |
| 10 | Fitchburg SCADA Communications | $0 | $784 | 0.00 |
| 11 | Field Area Network | $0 | $2,196 | 0.00 |
| 12 | ADMS | $9,159 | $3,100 | 2.95 |
| 13 | Customer Web Portal | $100 | $531 | 0.19 |
| 14 | Gamification Pilot | $310 | $389 | 0.80 |
| 15 | TVR & Demand Response | $980 | $1,895 | 0.52 |
| 16 | Mobility Platform & System | $4,067 | $365 | 11.13 |
| Total | 16 Projects | $19,214 | $21,307 | 0.90 |

**STIP Benefits - STIP v2 7_8_15 - Projects ($K)**

| No. | Project | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ADMS | $0 | $0 | $0 | $228 | $361 | $509 | $655 | $715 | $684 | $655 | $626 | $626 | $598 | $571 | $546 | $521 | $498 | $476 | $455 | $434 | $9,159 | $3,100 | 2.95 |
| 2 | Mobility Platform & System | $0 | $313 | $299 | $286 | $273 | $261 | $249 | $238 | $227 | $217 | $207 | $198 | $189 | $181 | $173 | $165 | $158 | $151 | $144 | $137 | $4,067 | $365 | 11.14 |
| 3 | Mobile Damage Assessment Tool | $0 | $0 | $306 | $292 | $279 | $267 | $255 | $243 | $233 | $222 | $212 | $203 | $194 | $185 | $177 | $169 | $161 | $154 | $147 | $141 | $3,840 | $502 | 7.65 |
| 4 | TVR & Demand Response | $0 | $0 | $0 | $0 | $18 | $35 | $53 | $70 | $83 | $82 | $78 | $74 | $71 | $68 | $65 | $62 | $59 | $57 | $54 | $52 | $980 | $1,895 | 0.52 |
| 5 | AMI & OMS Integration | $0 | $53 | $51 | $49 | $47 | $44 | $42 | $41 | $39 | $37 | $35 | $34 | $32 | $31 | $29 | $28 | $27 | $26 | $25 | $23 | $693 | $60 | 11.56 |
| 6 | Gamification Pilot | $0 | $0 | $0 | $0 | $0 | $0 | $29 | $28 | $27 | $26 | $24 | $23 | $22 | $21 | $20 | $19 | $19 | $18 | $17 | $16 | $310 | $389 | 0.80 |
| 7 | Customer Web Portal | $0 | $0 | $0 | $0 | $8 | $8 | $8 | $7 | $7 | $7 | $7 | $6 | $6 | $6 | $6 | $5 | $5 | $5 | $5 | $5 | $100 | $531 | 0.19 |
| 8 | Circuit Capacity Study | $5 | $5 | $4 | $4 | $4 | $4 | $4 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $3 | $2 | $2 | $2 | $2 | $2 | $64 | $220 | 0.29 |
| 9 | Analytics & Visualization System Platform | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,361 | 0.00 |
| 10 | Substation 3V0 Protection | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,568 | 0.00 |
| 11 | Substation Voltage Regulation Control | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $408 | 0.00 |
| 12 | Automated Cap Banks | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,108 | 0.00 |
| 13 | Automated Voltage Regulators | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $5,293 | 0.00 |
| 14 | Automated Transformer & Load Tap Changers | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $528 | 0.00 |
| 15 | Fitchburg SCADA Communications | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $784 | 0.00 |
| 16 | Field Area Network | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,196 | 0.00 |
| Total | 16 Projects | $5 | $371 | $661 | $859 | $989 | $1,128 | $1,296 | $1,346 | $1,303 | $1,248 | $1,193 | $1,168 | $1,116 | $1,066 | $1,018 | $973 | $929 | $888 | $848 | $810 | $19,214 | $21,307 | 0.90 |

**STIP Costs - STIP v2 7_8_15 - Projects ($K)**

| No. | Project | Benefits ($K) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Costs ($K) | B/C Ratio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Automated Voltage Regulation | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $5,293 | 0.00 |
| 2 | ADMS | $9,159 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $3,100 | 2.95 |
| 3 | Field Area Network | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $2,196 | 0.00 |
| 4 | Automated Cap Banks | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $2,108 | 0.00 |
| 5 | TVR & Demand Response | $980 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $1,895 | 0.52 |
| 6 | Substation 3V0 Protection | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $1,568 | 0.00 |
| 7 | Analytics & Visualization System Platform | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $1,361 | 0.00 |
| 8 | Fitchburg SCADA Communications | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $784 | 0.00 |
| 9 | Customer Web Portal | $100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $531 | 0.19 |
| 10 | Automated Transformer & Load Tap Changers | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $528 | 0.00 |
| 11 | Mobile Damage Assessment Tool | $3,840 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $502 | 7.65 |
| 12 | Substation Voltage Regulation Control | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $408 | 0.00 |
| 13 | Gamification Pilot | $310 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $389 | 0.80 |
| 14 | Mobility Platform & System | $4,067 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $365 | 11.13 |
| 15 | Circuit Capacity Study | $64 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $220 | 0.29 |
| 16 | AMI & OMS Integration | $693 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $60 | 11.63 |
| Total | 16 Projects | $19,214 | $1,737 | $1,416 | $1,906 | $2,502 | $2,549 | $1,854 | $1,717 | $1,640 | $1,390 | $1,707 | $439 | $420 | $401 | $383 | $366 | $187 | $179 | $171 | $163 | $181 | $21,307 | 0.90 |

**STIP B/C Ratios - STIP v2 7_8_15 - Projects**

| No. | Project | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|---|
| 1 | AMI & OMS Integration | $693 | $60 | 11.63 |
| 2 | Mobility Platform & System | $4,067 | $365 | 11.13 |
| 3 | Mobile Damage Assessment Tool | $3,840 | $502 | 7.65 |
| 4 | ADMS | $9,159 | $3,100 | 2.95 |
| 5 | Gamification Pilot | $310 | $389 | 0.80 |
| 6 | TVR & Demand Response | $980 | $1,895 | 0.52 |
| 7 | Circuit Capacity Study | $64 | $220 | 0.29 |
| 8 | Customer Web Portal | $100 | $531 | 0.19 |
| 9 | Substation Voltage Regulation Control | $0 | $408 | 0.00 |
| 10 | Automated Transformer & Load Tap Changers | $0 | $528 | 0.00 |
| 11 | Fitchburg SCADA Communications | $0 | $784 | 0.00 |
| 12 | Analytics & Visualization System Platform | $0 | $1,361 | 0.00 |
| 13 | Substation 3V0 Protection | $0 | $1,568 | 0.00 |
| 14 | Automated Cap Banks | $0 | $2,108 | 0.00 |
| 15 | Field Area Network | $0 | $2,196 | 0.00 |
| 16 | Automated Voltage Regulation | $0 | $5,293 | 0.00 |
| Total | 16 Projects | $19,214 | $21,307 | 0.90 |

# GMP BCA Model

STIP Data - TVR Opt-Out - Programs

| STIP Totals - TVR Opt-Out - Programs | | | | |
|---|---|---|---|---|
| No. | Program | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Customer Empowerment | $7,355 | $10,086 | 0.73 |
| 2 | DER Enablement | $128 | $3,557 | 0.04 |
| 3 | Distributed Automation | $18,319 | $14,009 | 1.31 |
| 4 | Grid Reliability | $9,066 | $561 | 16.15 |
| 5 | Workforce & Asset Management | $8,134 | $365 | 22.26 |
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| Total | 5 Programs | $43,002 | $28,579 | 1.50 |

| STIP Benefits - STIP v2 7_8_15 - Programs ($K) | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Program | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Distributed Automation | $0 | $0 | $0 | $456 | $721 | $1,017 | $1,311 | $1,431 | $1,369 | $1,309 | $1,252 | $1,252 | $1,196 | $1,143 | $1,092 | $1,043 | $996 | $952 | $909 | $868 | $18,319 | $14,009 | 1.31 |
| 2 | Grid Reliability | $0 | $107 | $714 | $682 | $652 | $623 | $595 | $568 | $543 | $518 | $495 | $473 | $452 | $432 | $412 | $394 | $376 | $359 | $343 | $328 | $9,066 | $561 | 16.16 |
| 3 | Workforce & Asset Management | $0 | $626 | $598 | $572 | $546 | $522 | $498 | $476 | $455 | $434 | $415 | $396 | $379 | $362 | $346 | $330 | $315 | $301 | $288 | $275 | $8,134 | $365 | 22.29 |
| 4 | Customer Empowerment | $0 | $0 | $0 | $0 | $133 | $251 | $429 | $537 | $619 | $609 | $582 | $556 | $531 | $507 | $485 | $463 | $442 | $422 | $404 | $386 | $7,355 | $10,086 | 0.73 |
| 5 | DER Enablement | $10 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | $6 | $6 | $5 | $5 | $5 | $5 | $4 | $4 | $4 | $128 | $3,557 | 0.04 |
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| Total | 5 Programs | $10 | $742 | $1,321 | $1,719 | $2,060 | $2,420 | $2,840 | $3,019 | $2,992 | $2,877 | $2,750 | $2,683 | $2,564 | $2,449 | $2,339 | $2,235 | $2,135 | $2,039 | $1,948 | $1,861 | $43,002 | $28,579 | 1.50 |

| STIP Costs - STIP v2 7_8_15 - Programs ($K) | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Program | Benefits ($K) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Costs ($K) | B/C Ratio |
| 1 | Distributed Automation | $18,319 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $14,009 | 1.31 |
| 2 | Customer Empowerment | $7,355 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $10,086 | 0.73 |
| 3 | DER Enablement | $128 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $3,557 | 0.04 |
| 4 | Grid Reliability | $9,066 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $561 | 16.16 |
| 5 | Workforce & Asset Management | $8,134 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $365 | 22.29 |
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| Total | 5 Programs | $43,002 | $1,737 | $1,416 | $1,906 | $3,767 | $4,155 | $3,389 | $3,183 | $3,040 | $1,390 | $1,707 | $439 | $420 | $401 | $383 | $366 | $187 | $179 | $171 | $163 | $181 | $28,579 | 1.50 |

| STIP B/C Status - STIP v2 7_8_15 - Programs | | | | |
|---|---|---|---|---|
| No. | Program | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Workforce & Asset Management | $8,134 | $365 | 22.29 |
| 2 | Grid Reliability | $9,066 | $561 | 16.16 |
| 3 | Distributed Automation | $18,319 | $14,009 | 1.31 |
| 4 | Customer Empowerment | $7,355 | $10,086 | 0.73 |
| 5 | DER Enablement | $128 | $3,557 | 0.04 |
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| Total | 5 Programs | $43,002 | $28,579 | 1.50 |

**GMP BCA Model**

STIP Data - TVR Opt-Out - Initiatives

| STIP Totals - TVR Opt-Out - Initiatives | | | | |
|---|---|---|---|---|
| No. | Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Automated Field Devices | $0 | $7,929 | 0.00 |
| 2 | Better Information & Communications | $820 | $920 | 0.89 |
| 3 | Communications Network | $0 | $2,980 | 0.00 |
| 4 | Control Package / Software | $18,319 | $3,100 | 5.91 |
| 5 | DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| 6 | DER Interconnection | $128 | $220 | 0.58 |
| 7 | DER Management Platform | $0 | $1,361 | 0.00 |
| 8 | New Service Options (Opt-In) | $6,535 | $9,167 | 0.71 |
| 9 | Outage & Restoration Management | $9,066 | $561 | 16.15 |
| 10 | Workforce Management | $8,134 | $365 | 22.26 |
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| Total | 10 Initiatives | $43,002 | $28,579 | 1.50 |

| STIP Benefits - STIP v2 7_8_15 - Programs ($K) | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Initiative | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Control Package / Software | $0 | $0 | $0 | $456 | $721 | $1,017 | $1,311 | $1,431 | $1,369 | $1,309 | $1,252 | $1,252 | $1,196 | $1,143 | $1,092 | $1,043 | $996 | $952 | $909 | $868 | $18,319 | $3,100 | 5.91 |
| 2 | Outage & Restoration Management | $0 | $107 | $714 | $682 | $652 | $623 | $595 | $568 | $543 | $518 | $495 | $473 | $452 | $432 | $412 | $394 | $376 | $359 | $343 | $328 | $9,066 | $561 | 16.16 |
| 3 | Workforce Management | $0 | $626 | $598 | $572 | $546 | $522 | $498 | $476 | $455 | $434 | $415 | $396 | $379 | $362 | $346 | $330 | $315 | $301 | $288 | $275 | $8,134 | $365 | 22.29 |
| 4 | New Service Options (Opt-In) | $0 | $0 | $0 | $0 | $117 | $235 | $355 | $467 | $551 | $544 | $520 | $496 | $474 | $453 | $433 | $413 | $395 | $377 | $360 | $344 | $6,535 | $9,167 | 0.71 |
| 5 | Better Information & Communications | $0 | $0 | $0 | $0 | $16 | $16 | $74 | $71 | $68 | $65 | $62 | $59 | $57 | $54 | $52 | $50 | $47 | $45 | $43 | $41 | $820 | $920 | 0.89 |
| 6 | DER Interconnection | $10 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | $6 | $6 | $5 | $5 | $5 | $5 | $4 | $4 | $4 | $128 | $220 | 0.58 |
| 7 | Automated Field Devices | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $7,929 | 0.00 |
| 8 | Communications Network | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,980 | 0.00 |
| 9 | DER Distribution Upgrades | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,976 | 0.00 |
| 10 | DER Management Platform | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,361 | 0.00 |
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| Total | 10 Initiatives | $10 | $742 | $1,321 | $1,719 | $2,060 | $2,420 | $2,840 | $3,019 | $2,992 | $2,877 | $2,750 | $2,683 | $2,564 | $2,449 | $2,339 | $2,235 | $2,135 | $2,039 | $1,948 | $1,861 | $43,002 | $28,579 | 1.50 |

| STIP Costs - STIP v2 7_8_15 - Programs ($K) | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Initiative | Benefits ($K) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Costs ($K) | B/C Ratio |
| 1 | New Service Options (Opt-In) | $6,535 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $9,167 | 0.71 |
| 2 | Automated Field Devices | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $7,929 | 0.00 |
| 3 | Control Package / Software | $18,319 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $3,100 | 5.91 |
| 4 | Communications Network | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $2,980 | 0.00 |
| 5 | DER Distribution Upgrades | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $1,976 | 0.00 |
| 6 | DER Management Platform | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $1,361 | 0.00 |
| 7 | Better Information & Communications | $820 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $920 | 0.89 |
| 8 | Outage & Restoration Management | $9,066 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $561 | 16.16 |
| 9 | Workforce Management | $8,134 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $365 | 22.29 |
| 10 | DER Interconnection | $128 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $220 | 0.58 |
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| Total | 10 Initiatives | $43,002 | $1,737 | $1,416 | $1,906 | $3,767 | $4,155 | $3,389 | $3,183 | $3,040 | $1,390 | $1,707 | $439 | $420 | $401 | $383 | $366 | $187 | $179 | $171 | $163 | $181 | $28,579 | 1.50 |

| STIP B/C Status - STIP v2 7_8_15 - Programs | | | | |
|---|---|---|---|---|
| No. | Initiative | Benefits ($K) | Costs ($K) | B/C Ratio |
| 1 | Workforce Management | $8,134 | $365 | 22.29 |
| 2 | Outage & Restoration Management | $9,066 | $561 | 16.16 |
| 3 | Control Package / Software | $18,319 | $3,100 | 5.91 |
| 4 | Better Information & Communications | $820 | $920 | 0.89 |
| 5 | New Service Options (Opt-In) | $6,535 | $9,167 | 0.71 |
| 6 | DER Interconnection | $128 | $220 | 0.58 |
| 7 | DER Management Platform | $0 | $1,361 | 0.00 |
| 8 | DER Distribution Upgrades | $0 | $1,976 | 0.00 |
| 9 | Communications Network | $0 | $2,980 | 0.00 |
| 10 | Automated Field Devices | $0 | $7,929 | 0.00 |
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| Total | 10 Initiatives | $43,002 | $28,579 | 1.50 |

# GMP BCA Model

## STIP Data - TVR Opt-Out - Initiatives

**STIP Totals - TVR Opt-Out - Projects**

| No. | Project | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|---|
| 1 | Circuit Capacity Study | $128 | $220 | 0.58 |
| 2 | Analytics & Visualation System Platform | $0 | $1,361 | 0.00 |
| 3 | Substation 3V0 Protection | $0 | $1,568 | 0.00 |
| 4 | Substation Voltage Regulation Control | $0 | $408 | 0.00 |
| 5 | Mobile Damage Assessment Tool | $7,679 | $502 | 15.31 |
| 6 | AMI & OMS Integration | $1,387 | $60 | 23.26 |
| 7 | Automated Cap Banks | $0 | $2,108 | 0.00 |
| 8 | Automated Voltage Regulators | $0 | $5,293 | 0.00 |
| 9 | Automated Transformer & Load Tap Changers | $0 | $528 | 0.00 |
| 10 | Fitchburg SCADA Communications | $0 | $784 | 0.00 |
| 11 | Field Area Network | $0 | $2,196 | 0.00 |
| 12 | ADMS | $18,319 | $3,100 | 5.91 |
| 13 | Customer Web Portal | $200 | $531 | 0.38 |
| 14 | Gamification Pilot | $619 | $389 | 1.59 |
| 15 | TVR & Demand Response | $6,535 | $9,167 | 0.71 |
| 16 | Mobility Platform & System | $8,134 | $365 | 22.26 |
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| Total | 16 Projects | $43,002 | $28,579 | 1.50 |

**STIP Benefits - TVR Opt-Out - Projects ($K)**

| No. | Project | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ADMS | $0 | $0 | $0 | $456 | $721 | $1,017 | $1,311 | $1,431 | $1,369 | $1,309 | $1,252 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $18,319 | $3,100 | 5.91 |
| 2 | Mobility Platform & System | $0 | $626 | $598 | $572 | $546 | $522 | $498 | $476 | $455 | $434 | $415 | $396 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $8,134 | $365 | 22.26 |
| 3 | Mobile Damage Assessment Tool | $0 | $0 | $612 | $585 | $559 | $534 | $510 | $487 | $465 | $444 | $424 | $405 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $7,679 | $502 | 15.31 |
| 4 | TVR & Demand Response | $0 | $0 | $0 | $0 | $117 | $235 | $355 | $467 | $551 | $544 | $520 | $496 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $6,535 | $9,167 | 0.71 |
| 5 | AMI & OMS Integration | $0 | $107 | $102 | $97 | $93 | $89 | $85 | $81 | $78 | $74 | $71 | $68 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $1,387 | $60 | 23.26 |
| 6 | Gamification Pilot | $0 | $0 | $0 | $0 | $0 | $0 | $59 | $56 | $53 | $51 | $49 | $47 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $619 | $389 | 1.59 |
| 7 | Customer Web Portal | $0 | $0 | $0 | $0 | $16 | $16 | $15 | $15 | $14 | $14 | $13 | $13 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $200 | $531 | 0.38 |
| 8 | Circuit Capacity Study | $10 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | $6 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $128 | $220 | 0.58 |
| 9 | Analytics & Visualation System Platform | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,361 | 0.00 |
| 10 | Substation 3V0 Protection | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,568 | 0.00 |
| 11 | Substation Voltage Regulation Control | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $408 | 0.00 |
| 12 | Automated Cap Banks | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,108 | 0.00 |
| 13 | Automated Voltage Regulators | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $5,293 | 0.00 |
| 14 | Automated Transformer & Load Tap Changers | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $528 | 0.00 |
| 15 | Fitchburg SCADA Communications | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $784 | 0.00 |
| 16 | Field Area Network | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,196 | 0.00 |
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| Total | 16 Projects | $10 | $742 | $1,321 | $1,719 | $2,060 | $2,420 | $2,840 | $3,019 | $2,992 | $2,877 | $2,750 | $2,683 | $2,564 | $2,449 | $2,339 | $2,235 | $2,135 | $2,039 | $1,948 | $1,861 | $43,002 | $28,579 | 1.50 |

**STIP Costs - TVR Opt-Out - Projects ($K)**

| No. | Project | Benefits ($K) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | Costs ($K) | B/C Ratio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | TVR & Demand Response | $6,535 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $33 | $32 | $30 | $29 | $28 | $26 | $25 | $24 | $23 | $22 | $21 | $20 | $9,167 | 0.71 |
| 2 | Automated Voltage Regulators | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $447 | $427 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $5,293 | 0.00 |
| 3 | ADMS | $18,319 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $106 | $101 | $97 | $92 | $88 | $84 | $81 | $77 | $73 | $70 | $67 | $64 | $3,100 | 5.91 |
| 4 | Field Area Network | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $185 | $177 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,196 | 0.00 |
| 5 | Automated Cap Banks | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $224 | $214 | $204 | $195 | $186 | $178 | $170 | $0 | $0 | $0 | $0 | $0 | $2,108 | 0.00 |
| 6 | Substation 3V0 Protection | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $132 | $127 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,568 | 0.00 |
| 7 | Analytics & Visualation System Platform | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $66 | $63 | $60 | $58 | $55 | $53 | $50 | $48 | $46 | $44 | $42 | $40 | $1,361 | 0.00 |
| 8 | Fitchburg SCADA Communications | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $66 | $63 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $784 | 0.00 |
| 9 | Customer Web Portal | $200 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $25 | $24 | $23 | $22 | $21 | $20 | $19 | $18 | $17 | $17 | $16 | $15 | $531 | 0.38 |
| 10 | Automated Transformer & Load Tap Changers | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $42 | $40 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $26 | $528 | 0.00 |
| 11 | Mobile Damage Assessment Tool | $7,679 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $0 | $221 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $502 | 15.31 |
| 12 | Substation Voltage Regulation Control | $0 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $34 | $33 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $408 | 0.00 |
| 13 | Gamification Pilot | $619 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $17 | $16 | $15 | $14 | $14 | $13 | $13 | $12 | $11 | $11 | $10 | $10 | $389 | 1.59 |
| 14 | Mobility Platform & System | $8,134 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $0 | $158 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $365 | 22.26 |
| 15 | Circuit Capacity Study | $128 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $10 | $9 | $9 | $9 | $8 | $8 | $8 | $7 | $7 | $7 | $6 | $6 | $220 | 0.58 |
| 16 | AMI & OMS Integration | $1,387 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $0 | $0 | $0 | $60 | 23.27 |
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| Total | 16 Projects | $43,002 | $1,737 | $1,416 | $1,906 | $3,767 | $4,155 | $3,389 | $3,183 | $3,040 | $1,390 | $1,707 | $439 | $420 | $401 | $383 | $366 | $187 | $179 | $171 | $163 | $181 | $28,579 | 1.50 |

**STIP B/C Ratios - TVR Opt-Out - Projects**

| No. | Project | Benefits ($K) | Costs ($K) | B/C Ratio |
|---|---|---|---|---|
| 1 | AMI & OMS Integration | $1,387 | $60 | 23.26 |
| 2 | Mobility Platform & System | $8,134 | $365 | 22.26 |
| 3 | Mobile Damage Assessment Tool | $7,679 | $502 | 15.31 |
| 4 | ADMS | $18,319 | $3,100 | 5.91 |
| 5 | Gamification Pilot | $619 | $389 | 1.59 |
| 6 | TVR & Demand Response | $6,535 | $9,167 | 0.71 |
| 7 | Circuit Capacity Study | $128 | $220 | 0.58 |
| 8 | Customer Web Portal | $200 | $531 | 0.38 |
| 9 | Substation Voltage Regulation Control | $0 | $408 | 0.00 |
| 10 | Automated Transformer & Load Tap Changers | $0 | $528 | 0.00 |
| 11 | Fitchburg SCADA Communications | $0 | $784 | 0.00 |
| 12 | Analytics & Visualation System Platform | $0 | $1,361 | 0.00 |
| 13 | Substation 3V0 Protection | $0 | $1,568 | 0.00 |
| 14 | Automated Cap Banks | $0 | $2,108 | 0.00 |
| 15 | Field Area Network | $0 | $2,196 | 0.00 |
| 16 | Automated Voltage Regulators | $0 | $5,293 | 0.00 |
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| Total | 16 Projects | $43,002 | $28,579 | 1.50 |

| | GMP BCA Model | | | Project Input Form | | |
|---|---|---|---|---|---|---|
| No. | Program | Initiative | Project | Program | Program | Program |
| 1 | DER Enablement | DER Tariff & Pricing | Customer-Owned DG Tariff | DER_Enablement | DER_Tariff_and_Pricing | A.1 Tariff for Customer owned DG |
| 2 | DER Enablement | DER Interconnection | Circuit Capacity Study | DER_Enablement | DER_Interconnection | A.2 Circuit Capacity Study |
| 3 | DER Enablement | DER Interconnection | Customer-Focused DER Interconnection | DER_Enablement | DER_Interconnection | A.3 Customer Focused DER |
| 4 | DER Enablement | DER Management Platform | DG Monitoring & Control Pilot | DER_Enablement | DER_Management_Platform | A.4 DG Monitoring and Control Pilot |
| 5 | DER Enablement | DER Management Platform | Analytics & Visualiation System Platform | DER_Enablement | DER_Management_Platform | A.5 Analytics and Visualization Platform |
| 6 | DER Enablement | DER Distribution Upgrades | Substation 3V0 Protection | DER_Enablement | Distribution_Upgrades_for_DER | A.6 3VO Protection at Substations |
| 7 | DER Enablement | DER Distribution Upgrades | Substation Voltage Regulation Control | DER_Enablement | Distribution_Upgrades_for_DER | A.7 Voltage Regulation Control |
| 8 | DER Enablement | DER RD&D | DER RD&D | DER_Enablement | DER_RDandD | A.8 DER Technology and Business Models |
| 9 | Grid Reliability | Resiliency | SRP Cycle Reduction | Grid_Reliability | Resiliency | B.1 Reduce the SRP cycle to 5 years |
| 10 | Grid Reliability | Resiliency | Hazard Tree Enhancement | Grid_Reliability | Resiliency | B.2 Enhance Hazard Tree Program |
| 11 | Grid Reliability | Resiliency | Jacketed Tree Wire & Spacer Cable | Grid_Reliability | Resiliency | B.4 Install jacketed tree wire or spacer cable |
| 12 | Grid Reliability | Resiliency | Breakaway Service Connector Pilot | Grid_Reliability | Resiliency | B.5 Breakaway service conncetor pilot |
| 13 | Grid Reliability | Outage & Restoration Management | Mobile Damage Assessment Tool | Grid_Reliability | Outage_and_Restoration_Management | B.8 Integrate Enterprise Mobile Damage Assessment Tool |
| 14 | Grid Reliability | Outage & Restoration Management | AMI & OMS Integration | Grid_Reliability | Outage_and_Restoration_Management | B.9 Integrate AMI and OMS (AMF) |
| 15 | Grid Reliability | Outage & Restoration Management | OMS Resiliency & Hot Standby | Grid_Reliability | Outage_and_Restoration_Management | B.10 OMS Resiliency - Hot Standby |
| 16 | Distributed Automation | Automated Field Devices | Automatic Throw-Over Switches | Distributed_Automation | Automated_Field_Devices | C.1 Automatic 69 kV Substation Throw Over Switches |
| 17 | Distributed Automation | Automated Field Devices | Automated Cap Banks | Distributed_Automation | Automated_Field_Devices | C.2 Automated cap banks for VVO |
| 18 | Distributed Automation | Automated Field Devices | Automated Voltage Regulators | Distributed_Automation | Automated_Field_Devices | C.3 Automated Voltage for VVO |
| 19 | Distributed Automation | Automated Field Devices | Automated Transformer & Load Tap Changers | Distributed_Automation | Automated_Field_Devices | C.4 Automated Transformer Load Tap Changers |
| 20 | Distributed Automation | Automated Field Devices | Automated Sectionalizing & Restoration | Distributed_Automation | Automated_Field_Devices | C.8 Automated Sectionalizing & Restoration |
| 21 | Distributed Automation | Communications Network | Fitchburg SCADA Communications | Distributed_Automation | Communications_Network | C.5 SCADA Comms to all FGE Substations |
| 22 | Distributed Automation | Communications Network | Field Area Network | Distributed_Automation | Communications_Network | C.6 FAN for DA |
| 23 | Distributed Automation | Control Package / Software | ADMS | Distributed_Automation | Control_Package_Software | C.7 ADMS |
| 24 | Distributed Automation | Energy Efficiency Tariff & Pricing | VVO Energy Efficiency Tariff | Distributed_Automation | Energy_Efficiency_Tariff_and_Pricing | C.9 Energy Efficiency Tariff |
| 25 | Customer Empowerment | Better Information & Communications | Customer Web Portal | Customer_Empowerment | Better_Information_and_Communications | D.1 Energy information web portal |
| 26 | Customer Empowerment | Better Information & Communications | Gamification Pilot | Customer_Empowerment | Better_Information_and_Communications | D.3 Gamification Pilot |
| 27 | Customer Empowerment | Better Information & Communications | Customer Education | Customer_Empowerment | Better_Information_and_Communications | D.4 Customer Education Program |
| 28 | Customer Empowerment | New Service Options (Opt-In) | TVR & Demand Response | Customer_Empowerment | New_Service_Options_opt_in | D.6 TVR and Demand Response Program (AMF) |
| 29 | Customer Empowerment | Customer RD&D | Customer RD&D | Customer_Empowerment | Customer_RDandD | D.7 Behind the meter interface process for third party technology |
| 30 | Workforce & Asset Management | Workforce Management | Mobility Platform & System | Work_and_Asset_Management | Workforce_Management | E.1 Mobility Platform for Field Workers |
| 31 | Workforce & Asset Management | Workforce Management | Work Management Automation & Integration | Work_and_Asset_Management | Workforce_Management | E.3 Work Management Process Automation and Integration |
| 32 | Workforce & Asset Management | Asset Management | Condition-Base Maintenance | Work_and_Asset_Management | Asset_Management | E.4 Condition based maintenance program |
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| **Total** | | **5 Programs** | **16 Initiatives** | **32 Projects** | | **5 Programs** | **16 Initiatives** | **32 Projects** |

# GMP BCA Model

## Relationships & Logic - Import Data

| | | GMP BCA Model | | | | Project Input Form | | |
|---|---|---|---|---|---|---|---|---|
| **No.** | | **Field / Address / Offset** | **Address** | **Cell Value** | | **Field / Address / Offset** | **Address** | **Cell Value** |
| 1 | | Programs | $E$7 | Program | | Right 2 | B6 | Program |
| 2 | | Initiatives | $F$7 | Initiative | | Right 2 | B7 | Initiative |
| 3 | | Projects | $G$7 | Project | | Right 1 | B9 | Project |
| 4 | | Sub_Components | $I$7 | Sub-Component (If Applicable) | | | | |
| 5 | | 1 | $J$7 | Initiative Owner(s) | | Right 1 | B8 | Initiative Owner |
| 6 | | 1 | $K$7 | Project Owner(s) | | Right 1 | B10 | Project Owner |
| 7 | | Beneficiaries | $M$7 | Primary Beneficiary | | Down 1 | B14 | Beneficiaries |
| 8 | | Cost_Classifications | $N$7 | Cost Classification | | Down 1 | H14 | Cost Classification |
| 9 | | Service_Years | $O$7 | Service Year | | Right 1 | K8 | Year in Service |
| 10 | | Project_Lives | $P$7 | Project Life (Years) | | Right 1 | K9 | Project Life (Years) |
| 11 | | CapEx_Tracker | $Q$7 | DPU CapEx Tracker | | Down 1 | M14 | DPU CapEx Tracker |
| 12 | | FERC_Accounts | $R$7 | FERC Account | | Right 1 | K10 | Uniform System of Accounts Number |
| 13 | | General_Descriptions | $U$7 | General Description | | Down 1 | B17 | General Description |
| 14 | | 3 | $X$7 | Discussion of Benefits & Costs | | Down 1 | B23 | Detailed Discussion of Benefits and Costs |
| 15 | | 3 | $AA$7 | Proposed Outcome Metrics | | Down 1 | B29 | Proposed Outcome Metrics |
| 16 | | Objectives | $AD$7 | Outages | | Right 1 | B38 | Reduce the Effect of Outages |
| 17 | | 1 | $AE$7 | Demand | | Right 1 | B39 | Optimize Demand |
| 18 | | 1 | $AF$7 | DG | | Right 1 | B40 | Integrate Distributed Generation |
| 19 | | 1 | $AG$7 | Operations | | Right 1 | B41 | Improve Workforce and Asset Management |
| 20 | | 1 | $AH$7 | Satisfaction | | Right 1 | K38 | Customer Satisfaction |
| 21 | | 1 | $AI$7 | Customers | | Right 1 | K39 | Customer Empowerment |
| 22 | | 1 | $AJ$7 | Policies | | Right 1 | K40 | Relevance to State Policy |
| 23 | | 1 | $AK$7 | GM Impact | | Right 1 | K41 | Impact on GM Objectives |
| 24 | | 2 | $AM$7 | Additional Impacts | | Down 1 | B43 | Additional Grid Modernization Impacts |
| 25 | | Benefit_Years_1 | $AP$7 | 2017 | | Down 2 | D53 | 2016 |
| 26 | | 1 | $AQ$7 | 2018 | | Down 2 | E53 | 2017 |
| 27 | | 1 | $AR$7 | 2019 | | Down 2 | F53 | 2018 |
| 28 | | 1 | $AS$7 | 2020 | | Down 2 | G53 | 2019 |
| 29 | | 1 | $AT$7 | 2021 | | Down 2 | H53 | 2020 |
| 30 | | 1 | $AU$7 | 2022 | | Down 2 | I53 | 2021 |
| 31 | | 1 | $AV$7 | 2023 | | Down 2 | J53 | 2022 |
| 32 | | 1 | $AW$7 | 2024 | | Down 2 | K53 | 2023 |
| 33 | | 1 | $AX$7 | 2025 | | Down 2 | L53 | 2024 |
| 34 | | 1 | $AY$7 | 2026 | | Down 2 | M53 | 2025 |
| 35 | | Cost_Years_1 | $BK$7 | 2017 | | Down 3 | D53 | 2016 |
| 36 | | 1 | $BL$7 | 2018 | | Down 3 | E53 | 2017 |
| 37 | | 1 | $BM$7 | 2019 | | Down 3 | F53 | 2018 |
| 38 | | 1 | $BN$7 | 2020 | | Down 3 | G53 | 2019 |
| 39 | | 1 | $BO$7 | 2021 | | Down 3 | H53 | 2020 |
| 40 | | 1 | $BP$7 | 2022 | | Down 3 | I53 | 2021 |
| 41 | | 1 | $BQ$7 | 2023 | | Down 3 | J53 | 2022 |
| 42 | | 1 | $BR$7 | 2024 | | Down 3 | K53 | 2023 |
| 43 | | 1 | $BS$7 | 2025 | | Down 3 | L53 | 2024 |

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|---|---|---|---|---|---|---|---|---|
| 44 | | 1 | $BT$7 | 2026 | | Down 3 | M53 | 2025 |
| 45 | | Quantifiable_Benefits_1 | $CG$7 | Quantifiable Customer Benefits | | Down 1 | B62 | Quantifiable Customer Benefits |
| 46 | | Quantifiable_Benefits_2 | $CJ$7 | Quantifiable Utility Benefits | | Down 1 | B68 | Quantifiable Utility Benefits |
| 47 | | Unquantifiable_Benefits_1 | $CM$7 | Unquantifiable Customer Benefits | | Down 1 | B76 | Unquantifiable Customer Benefits |
| 48 | | Unquantifiable_Benefits_2 | $CP$7 | Unquantifiable Utility Benefits | | Down 1 | B82 | Unquantifiable Utility Benefits |
| 49 | | Quantifiable_Costs_1 | $CT$7 | Quantifiable Customer Costs | | | | |
| 50 | | Quantifiable_Costs_2 | $CW$7 | Quantifiable Utility Costs | | | | |
| 51 | | Unquantifiable_Costs_1 | $CZ$7 | Unquantifiable Customer Costs | | | | |
| 52 | | Unquantifiable_Costs_2 | $DC$7 | Unquantifiable Utility Costs | | | | |
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# SECTION 8: BCA Evaluation Under Docket No. 4600

*This Section presents the GMP BCA approach and results including Docket 4600 alignment, cost contingencies, benefits by operations, customer and societal breakdown, and a cost-benefit sensitivitv analvsis.*

## 8.1 Introduction, Approach, and Summary Results

**Introduction**

The purpose of the BCA is to demonstrate the benefits and costs of implementing GMP Foundational Investments across the Rhode Island Energy service territory. The Foundational Investments are near-term solutions in the GMP roadmap, which are generally installed by 2028. The resulting platform can be built upon with future-term investments thereafter. In the BCA, benefits and expenses were included for the Foundational Investments and for DER Monitor/Manage installations forecasted through the 20-year period as well as the run-the-business ("RTB") costs including RTB OPEX and RTB telecom.

Not only are the investments proposed in the GMP critical for reliability and safety, but the overall results are significantly positive from a BCA perspective using the Docket 4600 Framework. Furthermore, the reliability and safety, customer, operational, clean energy, and financial benefits justify immediate deployment.

**Approach**

The GMP BCA uses the Docket 4600 Frame work to identify where grid modernization solutions contribute to specific cost or benefit categories. Where possible, these benefits are quantified. In cases where benefits cannot be quantified either due to lack of data or lack of an accepted method, the Company conducted a qualitative analysis of the benefits, consistent with the Docket No. 4600 Framework.

The Company made use of the assumptions, logic, and findings in the National Grid 2021 BCA (Docket No. 5114). The Company updated the assumptions, cost, and benefit calculations and performed a leading-edge, comprehensive Distribution Study to determine the avoided infrastructure cost and DER curtailment benefits of the grid modernization investments (see Section 5.0).

Due to the significant customer benefits enabled by AMF, and because the Company has a separate AMF filing, two separate but consistent, quantitative BCA models were developed: 1) AMF BCA model (used in the AMF filing) and 2) GMP BCA model. The GMP BCA model assumptions and results are described in detail in this section and the AMF BCA is described in detail in Rhode Island

Energy's AMF Business Case filing. The following key assumptions are used in the base case BCAs for both the GMP and AMF:

- Nominal Discount Rate = 6.97% (After-Tax WACC)
- Labor Escalation = 2.5%
- Non-Labor Escalation = 2.3%
- AESC Escalation = 2.0%
- Societal Discount Rate = 3.0%
- AESC Discount Rate = 2.0%.

The GMP and AMF BCA models used a consistent approach and input assumptions. The detailed BCA assumptions and results presented in this section are focused on the GMP BCA model.

**Summary Results**

As shown in Figure 8.1, over a 20-year evaluation period, Rhode Island Energy expects to invest $529 million Nominal and $373.8 million on a $2023 Net Present Value ("NPV") basis. Over the 20-year life of the GMP Foundational Investments, Rhode Island Energy expects Rhode Island utility benefits, customer benefits and societal benefits of $3.9 billion Nominal and $2.5 billion NPV-$2023. This results in a net value of benefits minus costs of $3.4 billion Nominal and $2.2 billion NPV-$2023. The benefit/cost ratios are 7.5 Nominal and 6.8 NPV.

**Figure 8.1: GMP Benefits and Costs**

| GMP Benefits and Costs | | |
|---|---|---|
| As of December 22, 2022 | | |
| **Category** | **Nominal ($M)** | **NPV ($M)** |
| **Utility** | **$ 2,928.8** | **$ 1,768.6** |
| **Direct Customer** | **$ 527.7** | **$ 377.1** |
| **Societal** | **$ 490.4** | **$ 379.1** |
| **Total Benefits** | **$ 3,946.9** | **$ 2,524.7** |
| **Total Costs** | **$ 529.0** | **$ 373.8** |
| **Benefits Less Costs** | **$ 3,417.8** | **$ 2,151.0** |
| **B/C Ratio** | **7.5** | **6.8** |

For ease of understanding, Rhode Island Energy also sorted the benefits into categories reflecting the source of the benefits. These categories include:

- Avoided Infrastructure Costs.
- Reduced DER Curtailment.
- VVO/CVR Benefits.
- Reduced Outage Frequency Benefits.
- Whole House Time-of-Use/Critical Peak Pricing (TOU/CPP).
- Electric Vehicle Time Varying Rates Benefits (EV TVR).
- Utility O&M Savings.

Figure 8.2 depicts the benefits by category on both a nominal and NPV ($2023) basis. As provided in the chart, there are significant benefits in every category with Avoided Infrastructure Costs being the greatest at $1.1 billion, Reduced DER Curtailment (energy only) at $0.84 billion and VVO/CVR Benefits at approximately $0.75 billion.

**Figure 8.2: GMP Benefits by Category**

| GMP Benefits by Category | | |
|---|---|---|
| As of December 22, 2022 | Nominal ($M) | NPV ($M) |
| Avoided Infrastructure Costs | $ 1,093.9 | $ 464.3 |
| Reduced DER Curtailment | $ 848.7 | $ 624.5 |
| VVO/CVR Benefits | $ 755.8 | $ 582.5 |
| Reduced Outage Frequency Benefits | $ 527.7 | $ 377.1 |
| Whole House TOU/CPP | $ 366.7 | $ 272.6 |
| EV/TVR Benefits | $ 180.4 | $ 130.9 |
| Utility O&M Savings | $ 173.7 | $ 72.9 |
| **Total Calculated GMP Benefits** | **$ 3,946.9** | **$ 2,524.7** |

The benefits and costs are both estimated over a 20-year period. The bulk of the costs occur in the first five years of the program (2023-2028), while the benefits tend to occur later in the analysis period. Estimated annual costs and benefits are shown in Figure 8.3 for the GMP. Most costs occur throughout the program based on deployment schedules developed by the Company for each grid modernization solution. There are some benefits which occur earlier in the study period due to rapid deployment of FLISR/Advanced Reclosers, and VVO/Smart Capacitors and Regulators. Figure 8.3 shows annual nominal benefits and costs by year while Figure 8.4 shows cumulative nominal benefits and costs. Figure 8.4 can be used to determine the simple payback, or the length of time an investment reaches a break-even point based on nominal spend, which is estimated to be achieved in approximately eight years based on the quantified costs and benefits included in this GMP.

**Figure 8.3: Annual Nominal BCA Results for the GMP Plan**

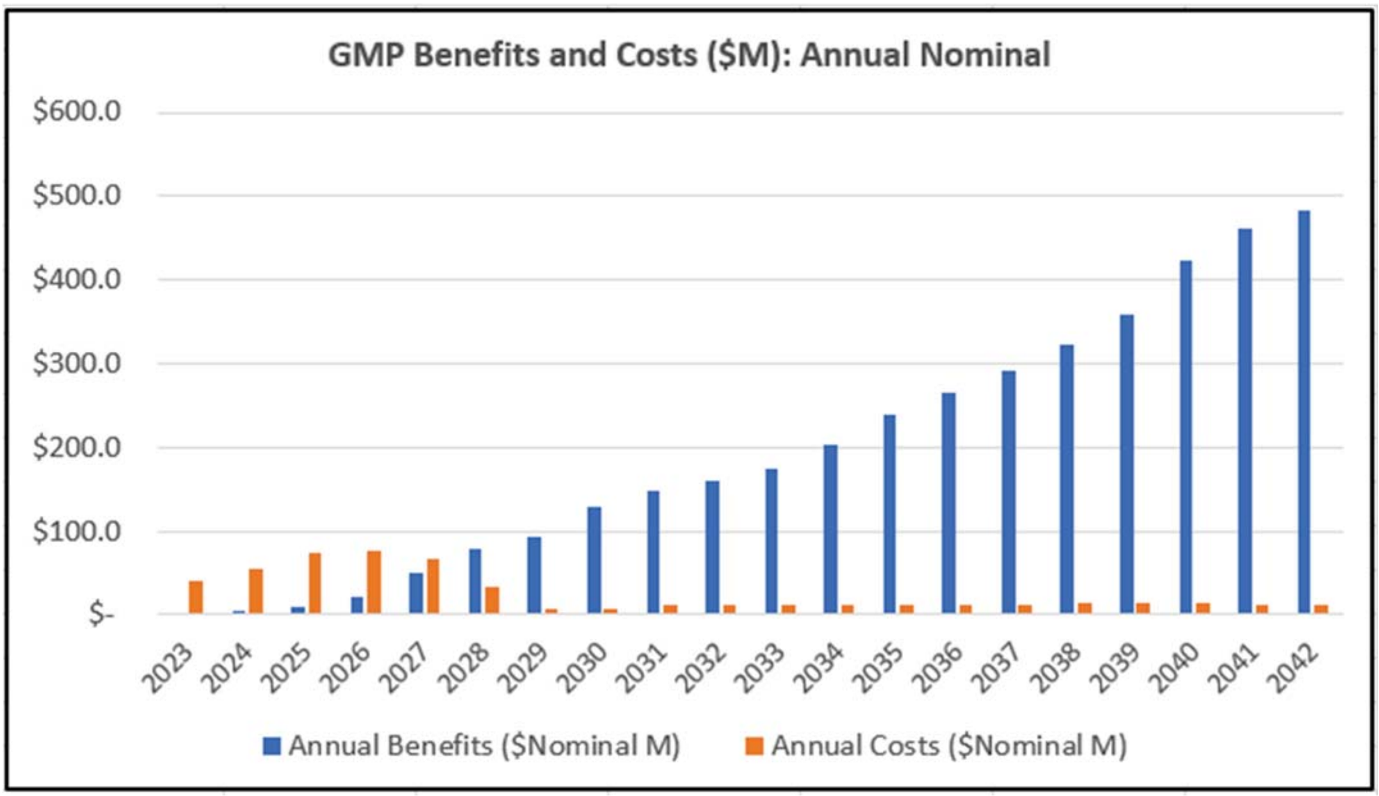
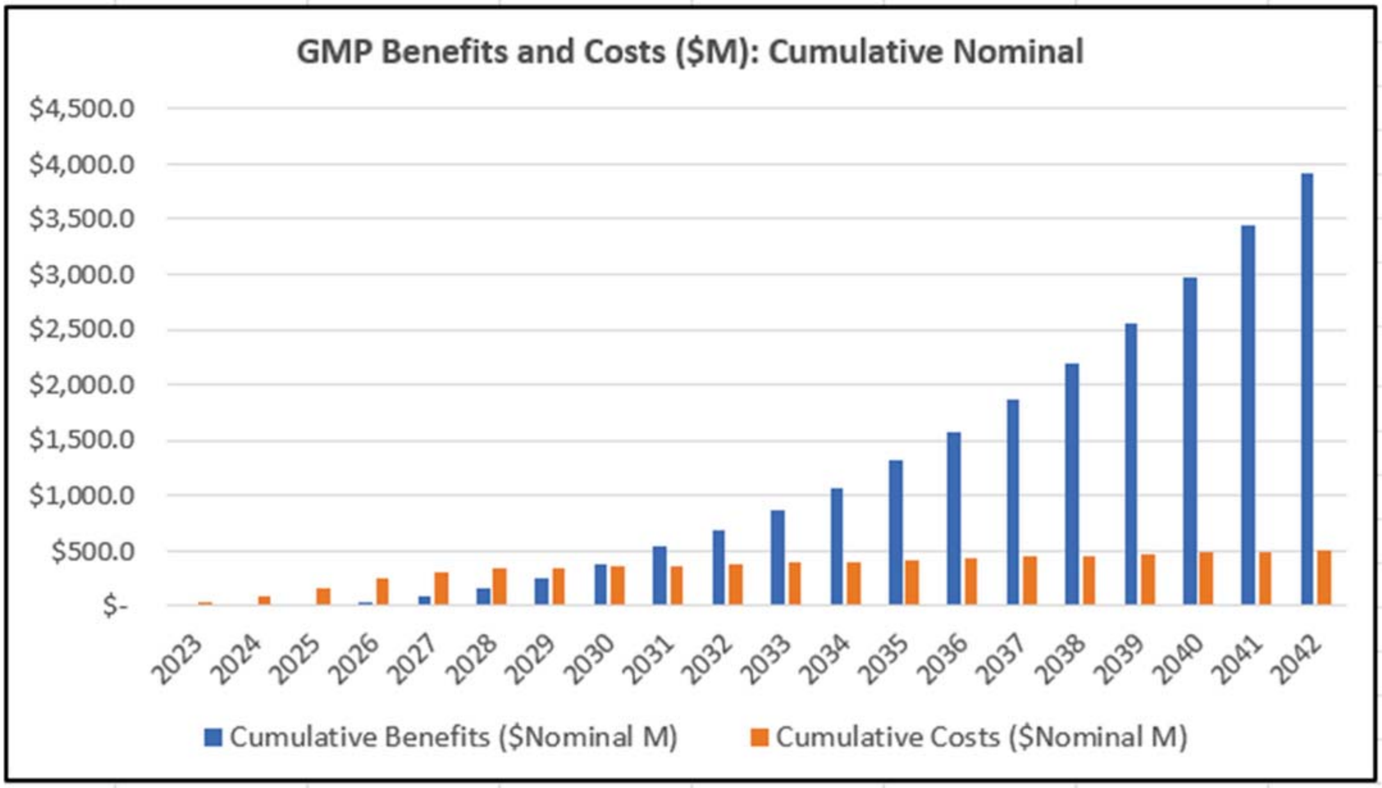


**Figure 8.4: Cumulative Nominal BCA Results for the GMP Plan**




Figures 8.5 and 8.6 show the same benefit and cost values from an NPV ($2023) perspective. When the cumulative, NPV ($2023) costs and benefits are considered, the payback period remains at approximately eight years, with the project breaking even in 2030.

**Figure 8.5: Annual NPV ($2023) BCA Results for the GMP Plan**

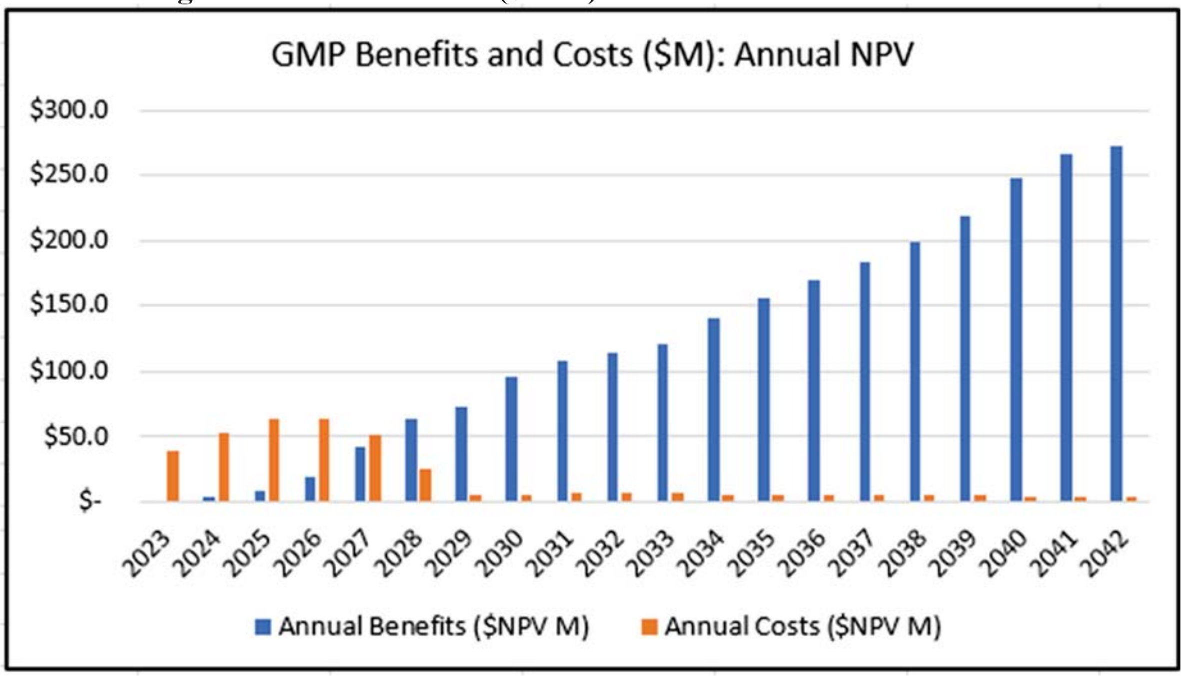
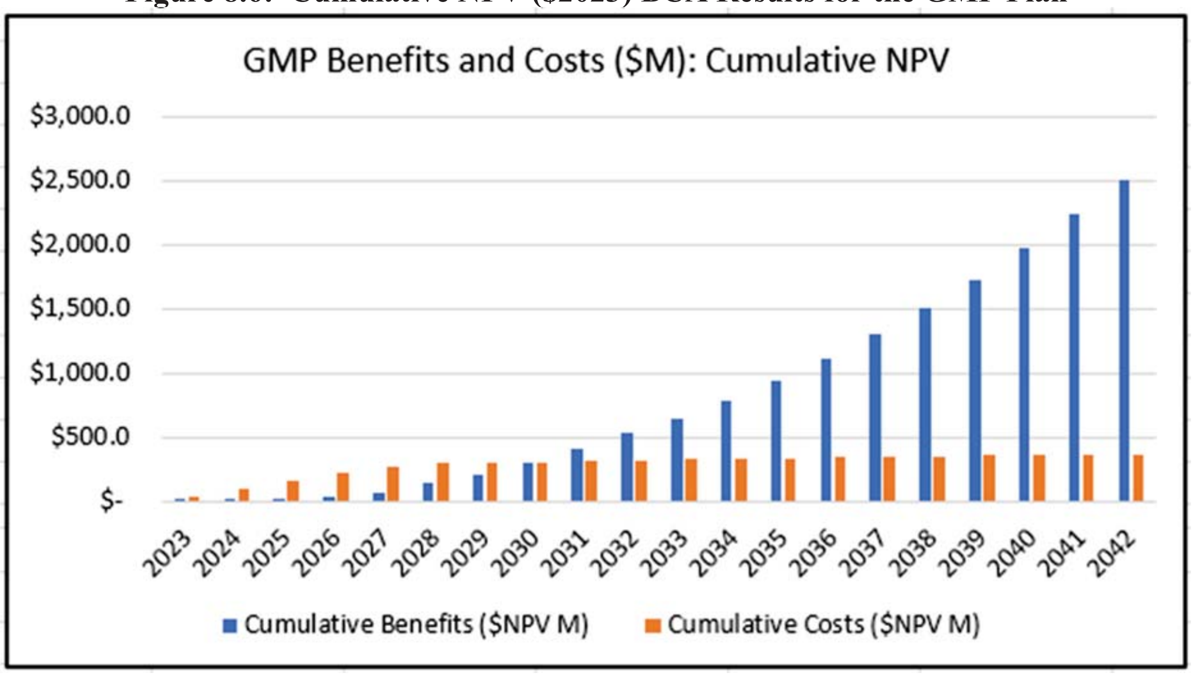



**Figure 8.6: Cumulative NPV ($2023) BCA Results for the GMP Plan**



## 8.2 System Analyses used in BCA Development

The Company used several different system and reliability analyses to estimate the benefits used in the BCA, as well as industry research, PPL Electric experience and information from Subject Matter Experts ("SMEs") from both Rhode Island Energy and PPL Electric.

**The Distribution Study**

As described in detail in Section 5 and Section 7, Rhode Island Energy conducted a leading-edge, 8760-hour long-range planning analysis for 2030, 2040, and 2050. The study analyzed the needs of the Company's system under a scenario designed to meet Rhode Island's Climate Mandates. The scenario included forecasts of DER penetration, EV growth and EHP growth. Two alternatives were studied. One alternative, the No Grid Modernization alternative was to build out the electric grid using only traditional solutions, including line rephasing, reconductoring or installing new feeders and new conductor routes, new substations; and field devices, like traditional capacitors, regulators, and reclosers with localized/un-automated controls. The second alternative, the Grid Modernization alternative, includes the Foundational Investments; Advanced Field Devices that include capacitors, regulators, reclosers, electromechanical relays, and the communications and IT software needed to automate the grid. Foundational Investments, create new capabilities and functionalities that enable the electric distribution system to respond automatically to many of the issues that arise from the anticipated growth of DER, EV and EHP adoptions. The Grid Modernization alternative case also includes the impacts of Whole House TOU/CPP energy and peak shifts, EV TVR energy and peak shifts, DER Monitor/Manage, and the use of BESS to adjust the forecasted "duck curve" load shape.

Figure 8.7 lays out the assumptions of the two alternatives. The analysis resulted in significant Avoided Infrastructure (T&D) Costs which are discussed in more detail below.

**Figure 8.7: Future State Assumptions**

| Future State Assumptions | No Grid Modernization Alternative | Grid Modernization Alternative |
|---|---|---|
| DER Penetration | Same across both alternatives | |
| EV and EHP Projections | Same across both alternatives | |
| Grid Infrastructure Technology | Traditional Solutions | Grid Modernization Solutions w/Reduced Traditional Solutions |
| Metering Technology | AMF | AMF |

| | | |
|---|---|---|
| Customer Load Management Programs | Existing Energy Efficiency, System-wide DR | Future Energy Efficiency& Feeder specific DR, NWA |
| DG Policies and Programs | Rigid Interconnection Standards Seasonal Curtailment and 100% Curtailment by DG site reclosers for large units | Flexible Interconnection Standards, Smart Inverters, Granular DG Curtailment, Voltage control and ramping provided for individual DG |
| Rate Policies and Programs | Limited TVR achievable due to AMF meters | Locational TVR and CPP implemented |

**DER Curtailment Analysis**

As part of the Distribution Study, Rhode Island Energy analyzed the amount of DER curtailment that would be needed under each of the alternatives studied. With the traditional solutions identified in the No Grid Modernization Alternative, extreme amounts of curtailment are needed to operate the system. Using the Grid Modernization alternative, with the installation of Foundational Investments, a significant reduction in the amount of DER that would need to be curtailed was enabled by DER Monitor/Manage, TOU/CPP/TVR and BESS.

**Reliability/Recloser Analysis**

A reliability analysis was performed to understand the impact of installing reclosers and using them in conjunction with the ADMS-FLISR application that is being made available to Rhode Island customers through ADMS Basic. The reclosers are used to segment customers into groups of 500 customers (known as sectionalizing). Currently, when outages occur, because the Company's system is not sufficiently sectionalized, many more customers experience outages than would occur if reclosers are installed to this standard. As described in the analysis in Section 6, reliability as measured by SAIFI, will improve by up to 30% compared to historic reliability performance. The results of this analysis were run through DOE's ICE calculation tool to determine the benefit to customers of reducing the outages they experience.

**Volt/Var Optimization Analysis**

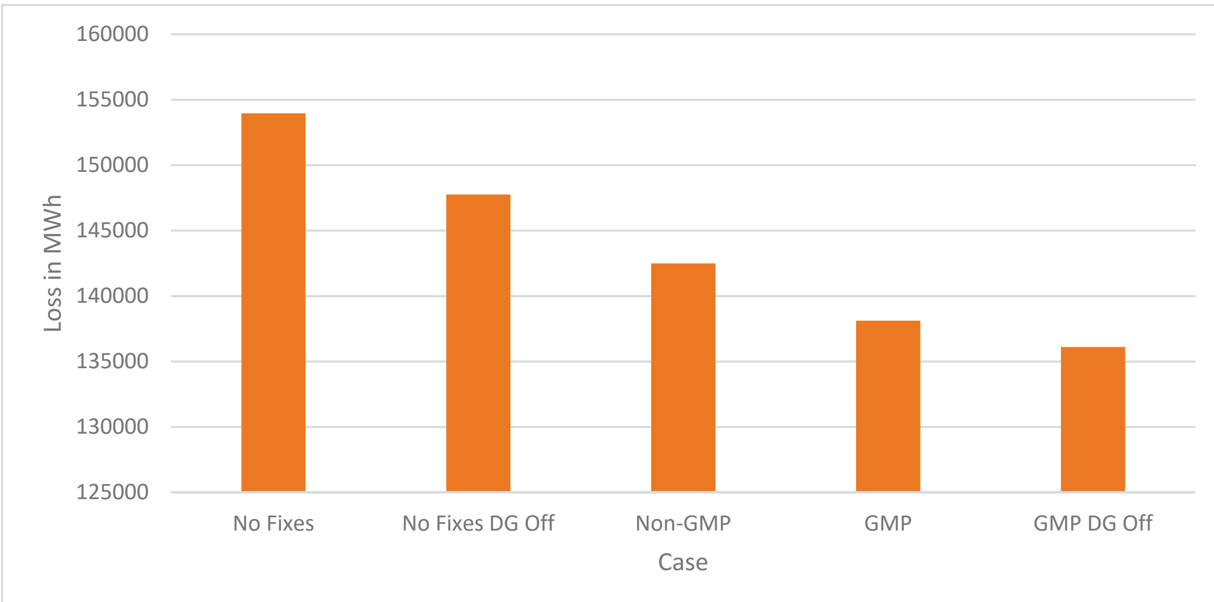
The volt/var optimization study presented in Attachment L provides an analysis performed by Rhode Island Energy to determine the potential impacts and the magnitude of the impacts that DG can have on VVO systems and also to explore how grid modernization concepts can be used to mitigate the DG impacts. This analysis illustrates the importance of grid modernization with the proliferation of DG on Rhode Island Energy distribution feeders. By enabling grid modernization functionality (i.e., DER Monitor/Manage), energy savings were maximized, even with a high penetration of DG. The analysis results indicate an energy savings in excess of 5% with grid modernization functionality as proposed in the GMP.

Rhode Island Energy has been performing a Volt/Var Optimization-Conservation Voltage Reduction pilot on several feeders in its service territory and also has conducted a significant body of research on VVO/CVR programs to develop estimates of energy and peak savings from VVO/CVR, and to determine how much could result from AMF meters and how much could result from grid modernization using Smart capacitors and Regulators, and Advanced Reclosers with ADMS - VVO. In this BCA, a conservative approach is being used to identify the GMP VVO benefits. The AMF BCA was credited with a 0.5% energy savings for VVO with the benefit of AMF meters, and the GMP BCA is credited with an additional 2% energy savings and 0.66% peak savings with the addition of Smart Capacitors and Regulators, Advanced Reclosers, and ADMS – VVO.

**System Loss Analysis**

Attachment K of this report describes the results of a transmission and distribution study to determine the total system loss differences with and without grid modernization solutions and with and without DG online for each case. The Central Rhode Island East area was used for the simulation to compare the cases. The results of the study were not used in the BCA, rather they are intended for illustrative purpose to help identify the numerous benefits of the GMP solutions. As shown in Attachment K, the grid modernization alternative provided lower system energy loss than the No Grid Modernization alternative. *See* Figure 8.8.

**Figure 8.8 CRIE Area Total Loss Over Case**




## 8.3 Benefits Discussion

### *8.3.1 Introduction*

Benefits and costs were estimated over a 20-year period, both in nominal values and in NPV ($2023). To develop NPV ($2023) values, Rhode Island Energy used its post-tax Weighted Average Cost of Capital ("WACC") at 6.97% to calculate the Costs and the Utility Savings. Rhode Island Energy used a societal discount rate of 3% to calculate the NPV ($2023) of the Direct Customer Savings and the Societal Savings. For benefits that utilized avoided costs from the Synapse AESC 2021 report, the Company expressed those amounts in $2021 real dollars regardless of the year for which they are estimated. Using those values directly resulted in summing to the NPV (in $2021) rather than summing to nominal dollars. To determine the benefits in nominal dollars, the AESC 2021 values were increased by 2%/year.

Benefits were placed into three categories: Utility Savings, Direct Customer Savings and Societal Savings. Utility Savings include those savings that are more direct savings to the utility and, ultimately, to the Rhode Island Energy customers. Direct Customer Savings include savings that go to particular groups of customers, who, in this analysis, include customers who experience an outage. Societal

Savings include costs that are incurred by society as a whole by the use of electricity but are not included ("embedded") in the price of electricity that customers pay.

For the purposes of estimating utility, customer, and societal benefits that are aligned with each grid modernization alternative, the Company developed several benefit impact areas, which are quantified in the BCA. Each quantified benefit impact area has been aligned with a particular GMP goal in Figure 8.9.

**Figure 8.9: Alignment Between Rhode Island GMP Objectives and Quantified Benefit Impacts**

| GMP Goal | Benefit Impact Area |
|---|---|
| 1) Give customers more energy choices and information | Whole House TOU/CPP |
| | Reduced DER Curtailment |
| | Electric Vehicle TVR |
| | |
| 2) Ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term | O&M Savings |
| | Reduced Customer Energy Use – VVO/CVR |
| | Reduced System Capacity Requirements – VVO/CVR |
| | Reduced Outage Frequency |
| | |
| 3) Build a flexible grid to integrate more clean energy generation | Avoided D-System Infrastructure Cost |
| | Reduced DG Curtailment |

Each benefit impact area has been defined and categorized based on the GMP benefit categories below.

### *8.3.2 Avoided Transmission and Distribution Infrastructure Costs*

The distribution study (8760-hour analysis) identified all the infrastructure that would be needed under both the Grid Modernization alternative and the No Grid Modernization alternative. The costs of that infrastructure includes:

- New and reconductored distribution lines,
- New and refurbished distribution substations,
- New and refurbished transformers,
- New transmission lines and substations, and
- BESS.

These costs are not included directly in the costs for this GMP. Rather, the total cost of the infrastructure for the Grid Modernization alternative was subtracted from the total cost of the No Grid Modernization alternative. These Avoided Infrastructure Costs are included in the benefits. Because the Grid Modernization Alternative costs were subtracted from the Avoided Infrastructure Costs, those costs are included in the analysis as a negative benefit rather than as a direct cost. The savings are presented by Planning Area in Figure 8.10.

**Figure 8.10: Avoided Grid Modernization Alternative Infrastructure Cost by Planning Area**

| Avoided GMP Infrastructure Costs | | |
|---|---|---|
| As of December 21, 2022 | Nominal ($M) | NPV ($M) |
| Tiverton Area - Avoided Infrastructure Costs | $ 54.8 | $ 23.2 |
| Providence Area - Avoided Infrastructure Costs | $ 120.7 | $ 51.2 |
| SCW Area - Avoided Infrastructure Costs | $ 37.8 | $ 16.1 |
| NCRI Area - Avoided Infrastructure Costs | $ 165.7 | $ 70.3 |
| SCE Area - Avoided Infrastructure Costs | $ 86.9 | $ 36.9 |
| BVN Area - Avoided Infrastructure Costs | $ 68.5 | $ 29.1 |
| BVS Area - Avoided Infrastructure Costs | $ 102.5 | $ 43.5 |
| CRIE Area - Avoided Infrastructure Costs | $ 94.2 | $ 40.0 |
| CRIW - Avoided Infrastructure Costs | $ 193.8 | $ 82.3 |
| EB - Avoided Infrastructure Costs | $ 33.8 | $ 14.4 |
| Newport Area - Avoided Infrastructure Costs | $ 135.1 | $ 57.3 |
| | | |
| **Total Avoided Infrastructure Costs** | **$ 1,093.9** | **$ 464.3** |

The values above are the differential between the No Grid Modernization alternative and the Grid Modernization alternative; they represent the costs that will not need to be spent on infrastructure if the GMP is implemented.

### *8.3.3 Avoided Distributed Energy Resource (DER) Curtailment*

Reduced DER Curtailment estimates the value of fewer DER applications being withdrawn due to high interconnection costs and fewer production restrictions on DER that are in service. These savings can be achieved through the ability of the distribution system operator to monitor and manage DER and optimize power output from renewable DER rather than relying on seasonal curtailment to avoid thermal or voltage constraints.

Figure 8.11 shows the benefits associated with reduced DER curtailment. The benefits shown are the value of the energy savings from being able to produce the kWh from DER rather than purchasing the energy in the ISO-NE market.

**Figure 8.11: DER Curtailment Benefits**

| Reduced DER Curtailment | | |
|---|---|---|
| As of December 22, 2022 | Nominal ($M) | NPV ($M) |
| **Reduced Curtailment: Energy Savings** | **$ 848.7** | **$ 624.5** |

Reduced DG Curtailment also creates significant societal cost savings. Reductions in non-embedded central power plant emissions of $CO_2$, $SO_2$, and $NO_x$ result from the ability of the distribution system operator to manage DER andoptimize power output from renewable DG rather than relying on seasonal curtailment to avoid thermal or voltage constraints. Rhode Island Energy calculated the benefits associated with reduced NOx, CO2 and Public Health improvements but did not include those benefits in the BCA.

### *8.3.4 Customer Savings – Reduced Outage Frequency Using Reclosers/FLISR*

Reduced Outage Frequency (SAIFI): Reductions in customer outages due to the ability of ADMS-FLISR and associated Advanced Reclosers to control the distribution system automatically to isolate a fault and restore power (e.g., ADMS-FLISR) rather than waiting for field crews to locate and restore power. Figure 8.12 shows customer savings associated with reduced outages due to Advanced reclosers in the Foundational Investments and ADMS-FLISR. These benefits were calculated by using the "Value of Reliability Improvements" model in the DOE's ICE tool. The ICE tool allows the user to input the improvement in SAIFI, SAIDI or CAIDI, the number of customers affected, the state in which the improvement takes place (Rhode Island), and the lifetime of the improvement. Rhode Island Energy estimated the value associated with a 0.26 reduction in SAIFI (from 0.92 to 0.68) as discussed in Section 6 for all of its customers. The total dollar savings are shown in Figure 8.12 and are significant. The dollar values represent the savings to customers of not having an outage, e.g., lost production time for industrial customers. The savings are estimated by customer class – residential, Small and Medium C&I customers and Large C&I customers. The savings are very small for residential customers and very large for the Large C&I customers.

**Figure 8.12: Reduced Outage Frequency Benefits**

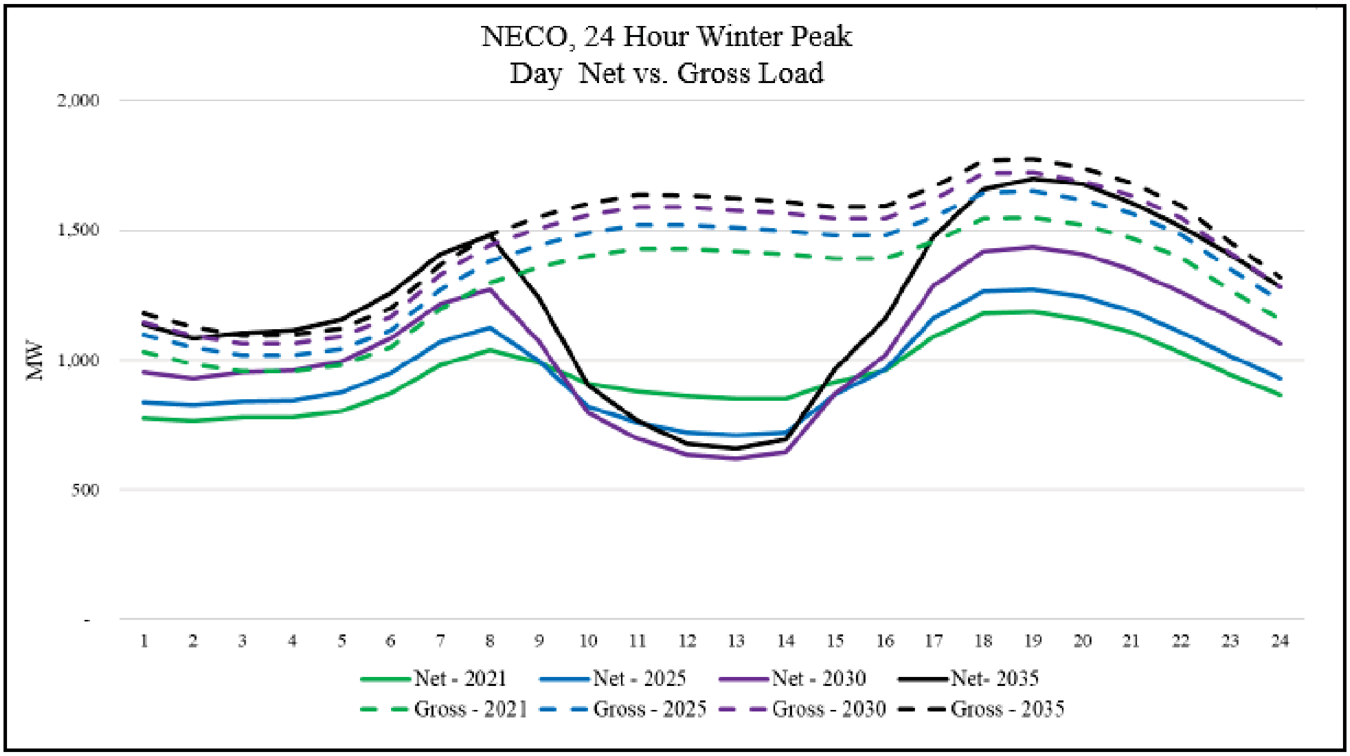
| Reduced Outage Frequency Benefits due to FLISR | | |
|---|---|---|
| As of December 21, 2022 | Nominal ($M) | NPV ($M) |
| **Reduced Outage Frequency Benefits** | **$ 527.7** | **$ 377.1** |

### *8.3.5 Whole House Time-of-Use/Critical Peak Pricing (TOU/CPP)*

EV TVR and Whole House TOU/CPP are enabled by AMF. As the system becomes increasingly complex, the times that peaking conditions occur will change and markets will likely evolve and be created to provide new value propositions. With AMF, customers' demand and interval energy usage will be visible and presented in a way that customers can easily understand their load profile and make choices that reflect rate incentives in near-real time. AMF provides a platform that will enable the Company to overlay rate design parameters that vary by time, which could be by season, month, day, hour or every few minutes. Therefore, AMF does enable EV TVR and Whole House TOU/CPP. More information is provided in Section 13 of the AMF filing.

The load shapes experienced by the utilities are changing significantly and it is much more difficult to predict when the best time is to implement higher versus lower prices. Below is an example of how the load shapes are changing. Figure 8.13 shows the dual peaks associated with winter days as well as the very low load hours during the daytime hours due to solar and the rapid ramp ups needed as the sun sets. When the variable performance of wind is added, the load shape becomes even more unpredictable. When electricity use/production is changing so dynamically, TVR will be very helpful in managing the grid, but traditional AMR meters will not be of use for TVR that will need to be flexible–both in terms of the time when incentives are needed and the rates that will apply.

**Figure 8.13: Projected Load Shapes with DER**




The Whole House TOU/CPP rate construct used in the BCA consists of a two-period (on-peak, off-peak) TOU rate and a separate CPP rate. The TOU rate is based on, and captures variation in, ISO-NE energy market prices. The CPP rate includes all generation capacity costs, allocated over 70 hours per year. Based on the Company's expected duration of CPP events, this equates to approximately 12 to 15 events per year.

To calculate energy benefits from a Whole House perspective, Rhode Island Energy used a TOU construct to calculate energy savings associated with shifting electricity use from on-peak hours to off-peak hours. For Whole House peak savings, Rhode Island Energy assumed that only residential customers would participate and that participating customers would save 20% of their peak electricity usage on a Critical Peak Pricing rate. This approach results in system capacity savings, transmission and distribution savings, and Demand Reduction Induced Price Efficiency ("DRIPE") savings. Figure 8.14 shows the savings estimated from Whole House TOU/CPP rate constructs.

**Figure 8.14: Whole House TOU/CPP Benefits**

| Whole House TOU/CPP - Mix of Opt-In and Opt-Out | | | | |
|---|---|---|---|---|
| As of December 22, 2022 | Nominal ($M) | | NPV ($M) | |
| GMP Total Trans Capacity Benefit: Whole House CPP | $ | 199.7 | $ | 148.5 |
| GMP - Total System Capacity Benefit: Whole House CPP | $ | 132.6 | $ | 98.6 |
| GMP Total Capacity DRIPE Benefit: Whole House CPP | $ | 11.93 | $ | 8.81 |
| GMP Total Dist Capacity Benefit: Whole House CPP | $ | 11.57 | $ | 8.60 |
| GMP - Total System Capacity Savings: Whole House TOU | $ | 10.84 | $ | 8.07 |
| | | | | |
| **Total Whole House TOU/CPP** | **$** | **366.7** | **$** | **272.6** |

EV TVR and Whole House TOU/CPP are included in both the AMF Business Case and in the GMP. The AMF Business Case included 20% opt-in for benefits. This limited participation was based upon only having wholesale markets to differentiate highs and lows in the rate design. With the addition of the GMP, the Company will have knowledge of localized distribution system violations that can be further included in highs and lows of rate designs. Bringing this added element to the value proposition will motivate greater participation. In the GMP BCA, the Company calculated a mix of the Opt-In program and the Opt-Out program. The Company assumed the Opt-In program would be in place from 2026-2030 and assumed the Opt-Out program would be in place starting in 2031. After calculating the value of the benefit with this mix, the Company subtracted out the benefits that were taken in the AMF Business Case to avoid double counting.

An Opt-Out approach will become both achievable and necessary over time. As customers become more familiar with TVR, the information and flexibility provided by AMF meters and energy management devices, they will also become aware of the savings potential. Furthermore, enabling technologies can be introduced to make participation easier and behavioral messaging can be performed to highlight savings opportunities that can be generated by participating in a TOU/CPP/TVR program. In addition, given the projected penetration of DER, EVs and EHPs, the Company will have an opportunity to increase the peak-to-off-peak price ratio to ramp up participation in these programs and load shifting behaviors to help the Company maintain reliability and reduce DER curtailment. The combination of customer familiarity and ease of participation and affordability will be key success factors for making the shift to a viable Opt-Out rate design with a high level of participation.[87] Several

[87] Moving Ahead with Time Varying Rates (TVR), US and Global Perspectives, Ahmad Faruqui, Ph.D., The Brattle Group, April 6, 2022, https://www.brattle.com/insights-events/publications/moveing-ahead-with-time-varying-rates-TVR-us-global-perspectives/

studies indicate that opt-out programs are much more successful in attaining and retaining customer participation than opt-in programs.[88]

#### *8.3.6 Volt/Var Optimization/Conservation Voltage Reduction (VVO/CVR)*

Distribution system operators in Rhode Island currently have very limited awareness of high or low voltage conditions across distribution feeders; reverse flow information; and distribution transformer loading issues. The Foundational Investments will provide the electric distribution system operators with critical real-time situational awareness of the electric networks including voltage deviations and the opportunity to optimize the voltage profile.

This data will include locational knowledge of energy usage, voltage, current and flow on the Rhode Island Energy feeders and some ability to adjust voltage levels. The Advanced Capacitors and Regulators coupled with ADMS-VVO will provide the opportunity for VVO, resulting in CVR. Rhode Island Energy estimates that VVO as a result of the Foundational Investments will result in 2.0% energy savings overall and 0.66% peak savings. This assumption has been confirmed as reasonable from analysis of Rhode Island Energy's VVO/CVR pilot that has been implemented at three substations. The pilot was evaluated by a third-party vendor and, for two of the three substations, the kWh savings on each feeder ranged from 1.3%-3.5% on each feeder. The weighted average savings for one of the substations was 1.5% and the weighted average savings for the other substation was 3.5%.

VVO/CVR results in many different benefits, including energy and capacity cost savings, and societal savings. The benefits begin in 2026 at 20% and increase by 20% per year until they reach 100% in 2030. Figure 8.15 shows the benefits resulting from a 2.0% reduction in energy use and 0.66% reduction in peak.

[88] *Id*.

**Figure 8.15: Benefits from GMP VVO / CVR**

| GMP VVO/CVR Benefit | | |
|---|---|---|
| As of December 22, 2022 | Nominal ($M) | NPV ($M) |
| GMP - Total Non-Embedded CO2 Benefit: VVO/CVR | $ 486.7 | $ 376.2 |
| Energy Savings: VVO/CVR | $ 154.3 | $ 119.1 |
| Monetized CO2 Benefit: VVO/CVR | $ 71.2 | $ 54.5 |
| GMP - Trans Capacity Benefit: VVO/CVR | $ 22.1 | $ 17.1 |
| GMP - System Capacity Benefit: VVO/CVR | $ 14.1 | $ 10.6 |
| GMP - Total Public Health Benefit: VVO/CVR | $ 2.3 | $ 1.8 |
| Reduced VVO Lease Costs | $ 2.2 | $ 1.1 |
| GMP - Total Non-Embedded NOX Benefit: VVO/CVR | $ 1.4 | $ 1.1 |
| GMP - Dist Capacity Benefit: VVO/CVR | $ 1.4 | $ 1.1 |
| **Total VVO/CVR Benefits** | **$ 755.8** | **$ 582.5** |

### *8.3.7 EV TVR Benefits*

AMF provides the ability to implement TVR in the future; GMP provides the knowledge of distribution load shapes and the impacts to the distribution system as the load shape changes from contributions of increased EV penetration. TVR can be used to encourage EV charging during off peak conditions thereby shifting load to avoid system constraints and violations. This section briefly describes the major assumptions Rhode Island Energy used for estimating benefits from EV TVR and presents the resulting savings. Much more detail on TVR and the Company's assumptions was presented in Section 13 of the Company's AMF filing.

The major assumptions included in estimating the benefits of EV TVR include:

- EVs are increasing in number from approximately 7,000 vehicles in 2022 to 790,000 vehicles in 2042
- EVs use between 3,500 kWh/year and 4,300 kWh/year
- EV owners moving between 13% and 27% of their total kWh charged from peak hours to off-peak hours
- EVs contribution to system peak being between 0.6 kW and 1.4 kW, depending on the year
- EV owners shifting between 29% and 60% of their peak hour usage off-peak.

It is important to note that Rhode Island Energy is assuming a significant amount of diversity in peak hour charging, i.e., not all EVs are plugged in at the same time. EVs that are plugged in draw either 1.4 kW or 7.2 kW, depending on the type of charger they have. Today, if all EVs are plugged in simultaneously, the EV load on the system would be 33.6 MWs, compared to a peak load of 1,800 MWs. In 2042, due to the number of EVs on the system, if all EVs were plugged in simultaneously, the EV load on the system would be 3,800 MWs, compared to a forecast system peak load of 3,652 MWs.

Figure 8.16 shows the benefits from Grid Modernization related to EV TVR.

**Figure 8.16: Benefits from Electric Vehicle Time Varying Rates**

| EV/TVR Benefit - Mix of Opt-In and Opt-Out | | |
|---|---|---|
| **As of December 22, 2022** | **Nominal ($M)** | **NPV ($M)** |
| **GMP - Total System Capacity Benefit: EV TVR** | **$ 172.8** | **$ 125.3** |
| **GMP - Total Energy Shift Benefits: EV TVR** | **$ 7.6** | **$ 5.6** |
| **Total EV/TVR Benefits** | **$ 180.4** | **$ 130.9** |

### *8.3.8 Avoided O&M Costs*

Grid modernization investments will provide the ability to better and more efficiently manage the distribution system. For example, this will result in fewer truck rolls, less field work and less operations analysis work to identify outage locations and the best way to restore customers. Rhode Island Energy estimated these savings by using PPL Electric's experience and the benefits achieved from more efficient operations over the last 10 years after deploying grid modernization investments. PPL Electric has managed their operations over this period with O&M expenditures increasing at 0.5%/year compared to an average distribution utility which increases O&M expenditures by approximately 2.0%/year. Using the typical annual increase for distribution O&M expenditure for U.S. utilities, avoided O&M savings were calculated based on a 2% increase per year versus a 0.5% increase per year. Analysis of Rhode Island Energy's distribution O&M costs for the last 10 years indicates that the Company's annual increase has been 3.0% per year, significantly higher than the average utility and even more so compared to PPL Electric. The results are shown in Table 8.17 below.

**Figure 8.17: Avoided O&M Costs**

| Utility O&M Savings | | |
|---|---|---|
| As of December 22, 2022 | **Nominal ($M)** | **NPV ($M)** |
| **Utility O&M Savings** | **$ 171.5** | **$ 71.8** |
| **Communication Savings due to SS Fiber** | **$ 2.2** | **$ 1.1** |
| | | |
| **Total O&M Savings** | **$ 173.7** | **$ 72.9** |

### *8.3.9 Societal Benefits*

There are a number of societal benefits that will result from grid modernization investments, including DER Monitor/Manage and these are discussed above with the programs that produce those savings.

### 8.3.10 Non-Quantified Benefits

In addition to the quantified benefits presented in this BCA, per Docket No. 4600 Guidance, the Company is providing additional non-quantified benefits that should be recognized qualitatively. These benefits are not quantified at this time due to lack of data or lack of an accepted method.

These benefits, however represent important additional grid modernization value. If considered as part of the BCA, these benefits can be considered as directionally increasing the benefit-costs ratio and potentially making the grid modernization programs even more valuable and cost-effective. These benefits will continue to be evaluated and could be quantified in future BCA results as additional data and methods are developed.

Below is a description of the benefits that were not quantified.

**Reduced Losses:** As described above, Rhode Island Energy performed a grid modernization loss study to compare the differential in system losses between the No Grid Modernization alternative and the Grid Modernization alternative. The study showed system loss reductions as a result of grid modernization, but those loss reductions were not included in the calculated benefits.

**Local Economic Impacts**: The impact of the significant GMP investments on the Rhode Island economy was not quantified in the BCA. Investments of this magnitude have ripple effects on the local economy, resulting in a multiplier impact of the investments. These ripple effects include suppliers of equipment and material, local contractors and other local businesses who may experience an increase in revenue due to the work being done across the Rhode Island Energy service territory. These benefits were not calculated as part of this BCA.

**Improved Long-Term Forecasting for Planning due to Granular Data**: Rhode Island Energy has made tremendous progress with its leading-edge 8,760-hour analysis of projected loads. However, granular data and improved situational awareness from AMF, Advanced Field Devices, and ADMS provides a step change in available data for grid planning and operations. This data can be used to more accurately design and plan for future distribution system needs through better forecasting of where and when DER will be located, used, and how the distribution system will perform over time. AMF also provides more timely, granular values that can be aligned with other system data to create actual loading and voltage profiles at all points along a feeder. This complete data set can be modeled directly, and more detailed load and DER forecasts can be developed for planning needs.

**More Equitable Cost Allocation due to Granular Data:** Grid modernization will enable improvements in the ability to allocate costs to different classes of customers in a way that more precisely reflects their respective contributions to system-level costs, and will support development of more cost-reflective rates and pricing that limits cross-subsidization. Future pricing and allocation mechanisms like TVR, AMF and other grid modernization investments will enable the Company to more accurately reflect the costs of producing and delivering electricity, which will promote economic efficiency and lead to a lower-cost system. In addition, when the prices consumers pay are more closely aligned with thecosts they represent, a more fair and equitable allocation of electricity sector costs results. AMF and other grid modernization investments are needed to provide granular (both in time and space) grid-level data.

**Improved Short-Term Forecasting for Operations due to Granular Data:** Better forecasting and monitoring of load, generation, and grid performance enabled by AMF, ADMS (i.e., ADMS-based load forecasting application), Advanced Field Devices, and DERMS can enable distribution system operators to actively manage grid demand and grid supply maximizing asset utilization and allowdispatch of a more efficient mix of generation and ancillary services (e.g., spinning reserve, frequency regulation) and reduce transmission congestion to reduce generation and transmission costs, and ultimately, reduce electricity procurement costs on behalf of customers. Improved forecasting and monitoring of load and generation may also allow for less restricted DER operation in areas susceptible to system voltage or thermal constraints and allow NWA assets to be utilized for other beneficial uses if the electric distribution system operator can forecast that it does not needthe NWA for reliability needs during a certain time period.

**Improved Storm Recovery due to Granular Data and Distributed Automation:** While a reliability benefit was quantified for outages, based on SAIDI and SAIFI reductions from Advanced Reclosers & Breakers and FLISR, the quantified benefit does not include outages dueto major storm events; however, granular data and improved situational awareness due to the expansion of both monitoring and control from Advanced Field Devices, supported by ADMS and other grid modernization investments, allows for quicker fault location confirmation and theability for the distribution system operators to remotely sectionalize faulted areas, reconfigure, and restore customers outside fault areas before field crews arrive on site during storm-related outages. Automation of these remote-control capable devices via a centralized program like FLISR will allow for the identification of a faulted area and the automated restoration of customers can provide additional reliability benefits, which have not been quantified to date.

## 8.4 Cost Estimation

### *8.4.1 Approach*

Rhode Island Energy worked with vendors, SMEs from both Rhode Island Energy and PPL Electric, used industry research, and independent expertise to develop estimated costs for this GMP. The costs include those developed through the FY2024 Electric ISR Plan proceeding (installation project costs for new distribution investments), RTB costs including O&M to maintain the devices and telecommunications costs, and costs to implement DER Monitor/Manage. As described in Section 6, the GMP investments are categorized as Operational Systems and Applications, Advanced Field Devices and Communications (Fiber). The costs were developed for a 20-year analysis period. Values are presented below in Figure 8.18 on both a nominal basis and a NPV ($2023) basis.

**Figure 8.18: 20 Year GMP Nominal and $2023 NPV Totals**

| Program Category | Project Costs (000's) | | | | Future Project | Operating Costs | | Total All BCA | Total All BCA |
|---|---|---|---|---|---|---|---|---|---|
| | Install | Remove | OPEX | Total | Costs | RTB OPEX | RTB Telecom | Costs (Nominal) | Costs (NPV) |
| Communications (Fiber) | $ 91.1 | $ 0.9 | $ 0.9 | $ 93.0 | $ - | $ 12.3 | $ - | **$ 105.3** | **$ 86.2** |
| Advanced Field Devices | $ 191.4 | $ 10.2 | $ 5.3 | $ 206.9 | $ - | $ 26.1 | $ 8.6 | **$ 241.7** | **$ 194.1** |
| Operational Systems & Applications | $ 39.4 | $ 0.3 | $ 0.3 | $ 40.0 | $ 103.3 | $ 38.7 | $ - | **$ 182.0** | **$ 93.5** |
| **Total All GMP** | **$ 321.9** | **$ 11.4** | **$ 6.6** | **$ 339.9** | **$ 103.3** | **$ 77.1** | **$ 8.6** | **$ 529.0** | **$ 373.8** |

### *8.4.2 Summary of Costs*

The Company developed cost estimates for the Foundational Investments included in the ISR plan, plus telecom costs for the advance field devices and RTB O&M costs for all categories in the GMP. For the Foundational Investments included in the ISR plan, the distribution investment costs were split between CAPEX and OPEX. Only the installation component of the CAPEX costs was included in the ISR plan. The removal component of the CAPEX costs and the OPEX component of the Foundational Investments are included in the GMP costs totals, but not included in the ISR cost totals. The ISR plan includes only those costs related to distribution assets. The costs related to the Communications (Transmission Fiber) project are not included in the ISR but are included in the GMP cost totals. The FY2024 Electric ISR Plan filed with the PUC includes a 21-month period from April 1, 2023 through December 31, 2024. – shown below as CY23 (9 months 4/23 – 12/23) and CY24 (12 months 1/24 – 12/24) totaling $81.9M. The periods CY25, CY26 and CY27, total $187.6M. And the GMP project costs include an additional year with CY28, totaling $30.1M. See figure 8.19 for the details.

**Figure 8.19: Foundational Investment Install Totals in ISR Plan CY23 – CY28**

| Program Category | CY23 (9 months) | CY24 (12 months) | CY25 | CY26 | CY27 | CY28 | Total |
|---|---|---|---|---|---|---|---|
| Communications (Distribution Fiber) Install | $ 8.1 | $ 11.3 | $17.9 | $15.3 | $ 8.0 | $ 8.0 | **$ 68.6** |
| Advanced Field Devices | $ 24.1 | $ 34.4 | $37.0 | $41.2 | $40.1 | $14.7 | **$ 191.4** |
| Operational Systems & Applications | $ 1.7 | $ 2.3 | $ 6.3 | $ 8.3 | $13.5 | $ 7.4 | **$ 39.4** |
| **Total ISR Submitted** | **$ 33.9** | **$ 47.9** | **$61.2** | **$64.8** | **$61.6** | **$30.1** | **$ 299.5** |
| Project Costs Removal | $ 0.9 | $ 1.3 | $ 1.6 | $ 2.6 | $ 2.8 | $ 1.9 | **$ 11.1** |
| Project Costs OPEX | $ 1.5 | $ 1.7 | $ 1.7 | $ 0.6 | $ 0.6 | $ 0.2 | **$ 6.3** |
| Communications (Transmission Fiber) Project Costs | $ 3.3 | $ 4.3 | $ 7.7 | $ 7.7 | $ - | $ - | **$ 23.0** |
| **Total Foundational Investments** | **$ 39.6** | **$ 55.2** | **$72.2** | **$75.7** | **$65.0** | **$32.2** | **$ 339.9** |

Figure 8.20 below depicts the GMP costs developed for the GMP. The costs are grouped into three categories following the layout of the GMP in Section 6: 1) Communications (Fiber) 2) Advanced Field Devices 3) Operational Systems and Applications. The total costs are $529 million Nominal and $373.8 million NPV ($2023). The Net Present Value is roughly 2/3 of the Nominal costs because the bulk of the spend in the GMP is from years 2023-2028.

**Figure 8.20: Total GMP BCA Costs by Category**

| Program Category | Total All BCA Costs (Nominal) | Total All BCA Costs (NPV) |
|---|---|---|
| Communications (Fiber) | $ 105.3 | $ 86.2 |
| Advanced Field Devices | $ 241.7 | $ 194.1 |
| Operational Systems & Applications | $ 182.0 | $ 93.5 |
| **Total All GMP** | **$ 529.0** | **$ 373.8** |

### *8.4.3 Operational Systems and Applications*

Operational Systems and Applications costs include IT Infrastructure, ADMS software, Mobile Dispatch and DER Monitor/Manage. Figure 8.21 shows the total $182 million Nominal and $93.5 million NPV ($2023) for Operational Systems and Applications, this category makes up 34% of the total costs of the GMP program.

**Figure 8.21: Operational Systems and Applications**

| Program Category | Project Costs (000's) | | | | Future Project Costs | Operating Costs | | Total All BCA Costs (Nominal) | Total All BCA Costs (NPV) |
|---|---|---|---|---|---|---|---|---|---|
| | Install | Remove | OPEX | Total | | RTB OPEX | RTB Telecom | | |
| Total ADMS | $ 11.5 | $ 0.1 | $ 0.1 | $ 11.7 | $ - | $ 7.7 | $ - | $ 19.4 | $ 12.9 |
| Total IT Infrastructure | $ 16.4 | $ 0.2 | $ 0.2 | $ 16.7 | $ - | $ 16.9 | $ - | $ 33.6 | $ 22.1 |
| Total Mobile Dispatch | $ 0.8 | $ 0.0 | $ 0.0 | $ 0.8 | $ - | $ 0.1 | $ - | $ 0.9 | $ 0.7 |
| Total DER Monitor Manage | $ 10.7 | $ - | $ - | $ 10.7 | $ 103.3 | $ 14.0 | $ - | $ 128.0 | $ 57.8 |
| **Total Operational Systems & Applications** | **$ 39.4** | **$ 0.3** | **$ 0.3** | **$ 40.0** | **$ 103.3** | **$ 38.7** | **$ -** | **$ 182.0** | **$ 93.5** |

**ADMS:**

The ADMS system makes up approximately 11% of the total Operational Systems and Applications cost. The proposed ADMS investment is an integrated grouping of hardware and software necessary for Distribution Control Center operations to provide greater visibility, situation awareness, and optimization of the electric distribution grid as well as improved efficiencies through automating multiple control center processes. ADMS is a critical platform to provide visibility and provide the capability to manage the grid as it becomes more complex and for the integration and operational management of DER as their impact on grid performance grows. ADMS will incorporate real-time data into useful solutions from an ever-growing number of Advanced Field Devices, DER, and AMF data as it becomes available. For example, when planning to reconfigure the grid, ADMS will allow the operators to simulate the future state (i.e., reconfigured grid) to test the reconfiguration approach to understand operational ramifications. ADMS is responsible for a series of phased in applications that provide incremental benefits that are described in Section 6. One example is for DER to become operationally integrated into the ADMS network model using ADMS - DERMS in conjunction with DER Monitor/Manage to allow operators to assess the effect of DER on the grid, as well as leverage them for grid support where possible.

**IT Infrastructure:**

The IT Infrastructure costs are approximately 18% of the Operational Systems and Applications costs. The proposed underlying IT infrastructure investments in data management and enterprise integration, and corporate PI historian are necessary to achieve full benefits. Cyber security is a necessary capability to operate a safe, reliable and cost-effective electric distribution system. GMP includes investments that will build foundational data management capabilities by enabling enhanced data integrations between the various GMP applications such as ADMS, VVO/CVR, corporate PI Historian and GIS. This plan also includes a cyber services component.

**Mobile Dispatch:**

The GMP proposes investments in mobile dispatch system and associated devices. Mobile Dispatch is expected to improve restoration times, the efficiency and accuracy of restoration efforts, and worker safety.

**DER Monitor/Manage:**

As more DER are interconnected with the Company's distribution system, Rhode Island Energy will have to balance demand and generation simultaneously and will increasingly experience issues on its electric distribution system without any way to monitor and manage those resources. Solar and other intermittent resources can negatively affect the voltage on the electric distribution system, resulting in delayed interconnection or distribution system reinforcements before additional DER can be installed. Given Rhode Island Energy's current inability to directly communicate with and manage DER to mitigate resulting power quality issues and to leverage grid support functionality, the amount of intermittent generation that can be interconnected must be limited to maintain system stability and reliability. Moreover, in the absence of such ability, the reliability, safety, and efficiency of Rhode Island Energy's service will be placed at increased risk with each new DER that is interconnected with the distribution system. As more DER connect to the system, the devices need to be integrated with utility operations at all levels for management and monitoring purposes. DER Monitor/Manage is the only program category included in the GMP that includes future project/investment costs. As incremental DER are interconnected with the Rhode Island Energy system through the 20-year BCA period, costs for each DER to participate as DER Monitor/Manage to be fully integrated with the system were added into the BCA. See Attachment G for additional information on DER Monitor/Manage.

### *8.4.4 Advanced Field Devices*

This cost category includes the Advanced Field Devices that will be deployed in the field to provide the visibility, sensing and automation needed to monitor and manage Rhode Island Energy's grid. The total costs of the Advanced Field Devices are $241.7 million Nominal and $194.1 million NPV ($2023), representing approximately 46% of the total cost of the GMP program. The Advanced Field Devices include Reclosers, Electromechanical relays, Capacitor Banks (smart) and Regulators that have been included in the FY 2024 Electric ISR Plan. Figure 8.22 shows the costs for each of these components and each one is discussed further below.

**Figure 8.22: Costs of Advanced Field Devices**

| Program Category | Project Costs (000's) | | | | Operating Costs | | Total All BCA | Total All BCA |
|---|---|---|---|---|---|---|---|---|
| | Install | Remove | OPEX | Total | RTB OPEX | RTB Telecom | Costs | Costs (NPV) |
| Total Recloser Cash Flow | $ 128.9 | $ 1.3 | $ 1.3 | $ 131.6 | $ 14.1 | $ 5.2 | $ 150.9 | $ 122.7 |
| Total Cap Bank and Regs Cash Flow | $ 30.5 | $ 2.7 | $ 0.7 | $ 33.9 | $ 8.1 | $ 3.0 | $ 45.0 | $ 34.9 |
| Total Electromechanical Relay Cash Flow | $ 32.0 | $ 6.1 | $ 3.3 | $ 41.4 | $ 3.9 | $ 0.5 | $ 45.8 | $ 36.5 |
| **Total Advanced Field Devices** | **$ 191.4** | **$ 10.2** | **$ 5.3** | **$ 206.9** | **$ 26.1** | **$ 8.6** | **$ 241.7** | **$ 194.1** |

### Advanced Reclosers

Advanced Recloser deployment is being proposed to improve reliability in the near-term, add capability to remotely reconfigure the system, and to increase operational visibility. The reclosers will be used to sectionalize customers into groups of 500 customers, which will greatly reduce the number of customers impacted by outages and improve Rhode Island Energy's SAIFI performance accordingly. The proposed reclosers are a significant portion of the costs of the Advanced Field Devices, at approximately 62%.

### Electromechanical Relay Upgrades

The GMP proposes investment to upgrade electromechanical relays to digital relays. Digital relays adapt to power flow changes and other changes in system conditions with flexible settings, custom logic, and multiple settings groups. Additionally, the fault location information provided by digital relays minimizes outage duration because it helps reduce the time field technicians spend searching for issues. Improving how the power system is monitored and controlled can provide operations and maintenance benefits that exceed the initial capital investment.

**Advanced Capacitor Banks and Regulators**

Rhode Island Energy is already experiencing voltage excursions, particularly where there is a significant penetration of DER. As DER penetration increases, maintaining voltage within limits will become even more challenging. The proposed Advanced Capacitors & Regulators would adjust system voltages up or down in a dynamic manner to accommodate the variable output of these DER technologies while providing service reliably in compliance with voltage threshold requirements. In addition, the voltage control and near real-time measurements enable engineering and operations personnel to better manage voltage along individual feeders, ultimately resulting in lower costs to all Rhode Island Energy customers through optimization (e.g., VVO/CVR).

### *8.4.5 Communications (Fiber)*

The GMP proposes to replace leased line services connecting substations with fiber optic cabling to improve data flow, resiliency, security, and reliability of backhaul communications, which Rhode Island Energy would own, operate and maintain as a private fiber network. Fiber costs are broken into Distribution Fiber and Transmission Fiber.[89] Figure 8.23 below reflects the total cost for the fiber at $105.3 million Nominal and $86.2 million NPV ($2023).

**Figure 8.23: Fiber GMP Total**

| Program Category | Project Costs (000's) | | | | Operating Costs | | Total All BCA | Total All BCA |
|---|---|---|---|---|---|---|---|---|
| | Install | Remove | OPEX | Total | RTB OPEX | RTB Telecom | Costs | Costs (NPV) |
| Total Distribution Fiber | $ 68.6 | $ 0.7 | $ 0.7 | $ 70.0 | $ 9.3 | $ - | $ 79.3 | $ 64.3 |
| Transmission Fiber | $ 22.5 | $ 0.2 | $ 0.2 | $ 23.0 | $ 3.0 | $ - | $ 26.0 | $ 21.9 |
| **Total Communications (Fiber)** | **$ 91.1** | **$ 0.9** | **$ 0.9** | **$ 93.0** | **$ 12.3** | **$ -** | **$ 105.3** | **$ 86.2** |

### *8.4.6 RTB Costs*

As shown in Figure 8.24, RTB costs consist of both RTB - OPEX and RTB - Telecom. RTB – OPEX includes charges for operating and maintenance expense each year. RTB OPEX was calculated for all the Program Categories in the GMP. RTB – Telecom captures the monthly cellular costs for the advanced field devices. This category is the smallest of the four categories of costs, at $85.7 million Nominal.

[89] The fiber is a shared asset between Distribution and Transmission where only the Distribution Fiber has been included in the Foundational Investments submitted to through the FY24 ISR.

**Figure 8.24: RTB Costs**

| Program Category | Operating Costs | | Total All BCA | Total All BCA |
|---|---|---|---|---|
| | RTB OPEX | RTB Telecom | Costs | Costs (NPV) |
| Communications (Fiber) | $ 12.3 | $ - | **$ 12.3** | **$ 6.0** |
| Advanced Field Devices | $ 26.1 | $ 8.6 | **$ 34.7** | **$ 17.5** |
| Operational Systems & Applications | $ 38.7 | $ - | **$ 38.7** | **$ 17.3** |
| **Total All GMP** | **$ 77.1** | **$ 8.6** | **$ 85.7** | **$ 40.8** |

**RTB – OPEX**

RTB OPEX was calculated differently depending on the Program Category.

For the Advanced Field Devices, an annual O&M cost per device was used and escalated by 2.5% (labor escalation percentage) to determine the O&M total costs for the field devices. The price per device was provided by Rhode Island Energy personnel and is applied to all the devices in the Advanced Field Device category. The costs are set to begin based on the in-service schedule for each device.

For the Operational Systems and Applications and Communication (Fiber) categories, the Company used input from PPL Electric subject matter experts who provided a ratio of annual operating expense to total investment. This percentage was applied to the GMP investment costs to determine an annual RTB – OPEX value.

**RTB – Telecom**

RTB – Telecom cover monthly cellular costs. These costs were calculated using the in-service schedule for all Advanced Field Devices and applying a monthly service cost per device. The monthly service cost is based on the pooled rate that PPL Electric is currently paying for thousands of advanced field devices across its grid in Pennsylvania.

## 8.5 Sensitivity Analysis

This GMP leverages findings, results, and lessons learned from prior PPL deployments and from those of other utilities as well as advice and information from consultants and vendors. Any analysis would be incomplete without evaluating uncertainty. Rhode Island Energy evaluated two types of sensitivities – Basic Sensitivities and Issue-Specific Sensitivities. The Basic Sensitivities involve varying costs and benefits by some percentage to reflect the uncertainty that particular levels of costs or benefits will be achieved. Figure 8.25 lists and describes the different parameters (comprised of both cost and benefit factors) selected for the purposes of the Basic Sensitivity analyses performed by Rhode Island Energy. The analysis addresses each variable separately, and so with each sensitivity, only a single parameter is changed. Conducting the analysis in this manner helps identify the isolated impact on the GMP because of a change in a single variable.

**Figure 8.25: Summary of Sensitivities and Rationale**

| Variable | Sensitivity Analysis | Description and Rationale |
|---|---|---|
| Foundational Field Devices and Run the Business (O&M) costs | 10% Reduction (favorable)<br>10% Increase (unfavorable) | Many of the costs included in the BCA have been used by other utilities and by Rhode Island Energy; these costs are more certain. Other costs have less certainty, particularly in the long run. Rather than varying specific aspects of the cost, Rhode Island Energy calculated a +/-10% sensitivity on Foundational Field Devices and Run the Business costs. |
| Communications and IT costs and DER Monitor/Manage costs | 25% Decrease (favorable)<br>25% Increase (unfavorable) | Communications and IT costs have traditionally been more uncertain than other types of costs. DER Monitor/Manage is a leading-edge technology with uncertain costs. To address these uncertainties, the Company has developed a +/-25% sensitivity for these two categories. |
| Benefits:<br>Avoided Infrastructure Costs<br>Reduced DER Curtailment<br>Reduced Outage Frequency<br>Whole House TOU/CPP<br>VVO/CVR Benefits<br>EV/TVR Benefits<br>Utility O&M Savings | 20% Decrease (unfavorable)<br>20% Increase (favorable) | Rhode Island Energy has grouped the benefits from the GMP program into seven categories. Each of these categories is uncertain, particularly in the long run. To address this uncertainty, the Company has estimated a +/-20% sensitivity for each of the seven categories. |

### *8.5.1 Cost Sensitivities*

The cost sensitivities involve varying each of the four categories of costs. Rhode Island Energy varied the Communication and IT costs and the DER Monitor/Manage costs by +/-25% because they are more uncertain than the Field Devices and RTB costs. The Company has extensive experience with purchasing and installing field devices and maintaining them; those two categories were varied by +/-10%. Figure 8.26 shows the results of these sensitivities as well as the results if all the costs turned out to be higher or lower than projected. As provided in the chart, the benefit-cost ratios for the individual favorable sensitivities range from 6.8 to 7.4, and when the sensitivities are combined, the benefit-cost ratio is 8.2. These values are compared to a Base Case benefit-cost ratio of 6.8 from an NPV perspective. The benefit-cost ratios for the individual unfavorable sensitivities range from 6.2 to 6.7, and when those sensitivities are combined, the benefit-cost ratio is 5.8. Even given all the costs being higher than forecast, the benefit-cost ratio remains very strong.

**Figure 8.26: Cost Sensitivities**

| Costs Sensitivities | | | | | |
|---|---|---|---|---|---|
| As of December 21, 2022 | | | | | |
| Costs Sensitivities | Base NPV ($M) | NPV ($M) | B/C Ratio | NPV ($M) | B/C Ratio |
| | | Favorable: -25%/-10% | | Unfavorable: +25%/10% | |
| Foundational Field Devices | $ 176.5 | $ 158.8 | 7.1 | $ 194.1 | 6.5 |
| Communications & IT | $ 121.2 | $ 90.9 | 7.4 | $ 151.5 | 6.2 |
| Run the Business (O&M) | $ 18.3 | $ 16.5 | 6.8 | $ 20.2 | 6.7 |
| DER Monitor/Manage | $ 57.8 | $ 43.4 | 7.0 | $ 72.3 | 6.5 |
| Total Sensitivity - Costs | $ 373.8 | $ 309.5 | 8.2 | $ 438.0 | 5.8 |

### *8.6.2 Benefits Sensitivities*

Similar to the Cost Sensitivities, Rhode Island Energy has varied all of the seven benefit categories. For the benefits, they have all been varied by +/-20%. Figure 8.27 shows the results of both the individual sensitivities and combining all the Benefit Sensitivities. As demonstrated in the chart, the benefit-cost ratios for the individual favorable sensitivities range from 6.8 to 7.1, and when the sensitivities are combined, the result is a benefit-cost ratio of 8.1. These values are compared to a Base Case benefit-cost ratio of 6.8 from an NPV ($2023) perspective. The benefit-cost ratios for the individual unfavorable sensitivities range from 6.4 to 6.7, and when the sensitivities are combined, the benefit-cost ratio is 5.4. Even given lower benefits than forecast, the benefit-cost ratio remains very strong.

**Figure 8.27: Benefits Sensitivities**

| Benefits Sensitivities | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| As of December 21, 2022 | | | | | | | | | |
| Benefits Sensitivities | Base NPV ($M) | | NPV ($M) | | B/C Ratio | NPV ($M) | | B/C Ratio |
| | | | Favorable: +20% | | | Unfavorable: -20% | | |
| Avoided Infrastructure Costs | $ | 464.3 | $ | 557.2 | 7.0 | $ | 371.4 | 6.5 |
| Reduced DER Curtailment | $ | 624.5 | $ | 749.4 | 7.1 | $ | 499.6 | 6.4 |
| Reduced Outage Frequency | $ | 377.1 | $ | 452.5 | 7.0 | $ | 301.7 | 6.6 |
| Whole House TOU/CPP | $ | 272.6 | $ | 327.2 | 6.9 | $ | 218.1 | 6.6 |
| VVO/CVR Benefits | $ | 582.5 | $ | 699.0 | 7.1 | $ | 466.0 | 6.4 |
| EV/TVR Benefits | $ | 130.9 | $ | 157.0 | 6.8 | $ | 104.7 | 6.7 |
| Utility O&M Savings | $ | 72.9 | $ | 87.4 | 6.8 | $ | 58.3 | 6.7 |
| Total Sensitivity - Benefits | $ | 2,524.7 | $ | 3,029.7 | 8.1 | $ | 2,019.8 | 5.4 |

### *8.5.3 Combined Cost and Benefit Sensitivities*

To examine the impact of a "worst case" scenario, Rhode Island Energy combined the Unfavorable Cost and Benefit Sensitivities. Figure 8.28 depicts the results of these combinations. As outlined in the chart, with the favorable combination, the benefit-cost ratio increases to 9.8 while the benefit-cost ratio of the unfavorable combination decreases to 4.6. Even in a "worst case" scenario, the GMP BCA results are very strong. These are compared to Base Case benefit-cost ratios of 7.5 from a Nominal perspective and 6.8 from an NPV ($2023) perspective.

**Figure 8.28: Combined Cost and Benefit Scenarios**

| Combined Sensitivities | | | | |
|---|---|---|---|---|
| As of December 21, 2022 | | | | |
| | NPV ($M) | | NPV ($M) | |
| | Favorable | | Unfavorable | |
| Total Benefits w/Sensitivities | $ | 3,029.7 | $ | 2,019.8 |
| Total Costs w/Sensitivities | $ | 309.5 | $ | 438.0 |
| Combined Sensitivities: B/C Ratio | 9.8 | | 4.6 | |

### *8.5.4 Issue Specific Sensitivities*

Rhode Island Energy performed two issue-specific sensitivities; one to look at the benefits and costs over a 10-year period rather than over the 20-year period that has been presented thus far. The purpose was to determine the viability of the program with a shorter time frame, particularly because the cost of the GMP is more front-loaded while the benefits come later in the analysis period. Nonetheless, the GMP still has a very solid benefit-cost ratio at 1.8 Nominal and 1.7 NPV ($2023). Figure 8.29 shows the results of the sensitivity.

**Figure 8.29: Ten Year Sensitivity**

| 10-Year Sensitivity | | |
|---|---|---|
| As of December 21, 2022 | Nominal ($M) | NPV ($M) |
| **Total Benefits - First Ten Years** | $ 699.5 | $ 534.1 |
| **Total Costs - First Ten Years** | $ 390.4 | $ 320.9 |
| **Benefits Less Costs** | $ 309.1 | $ 213.2 |
| **B/C Ratio** | 1.8 | 1.7 |

The second issue-specific sensitivity revolves around the cost of carbon and the price used in calculating the Non-Embedded CO2 benefits. Rhode Island Energy made the decision to utilize the Social Cost of Carbon values developed by Synapse Energy as part of the AESC 2021 report. Traditionally, the Company has used the New England Marginal Abatement Cost (MAC) values to calculate similar benefits. The Company used the Social Cost of Carbon in both the AMF filing and in this GMP analysis. Figure 8.30 below shows the results of calculating the benefits with the New England MAC value rather than the Social Cost value. As can be seen in the chart, the benefit-cost ratios from both the nominal and the NPV ($2023) perspective remain extremely strong.

**Figure 8.30: Cost of Carbon Sensitivity**

| Cost of Carbon Sensitivity | | |
|---|---|---|
| As of December 21, 2022 | Nominal ($M) | NPV ($M) |
| **Total Benefits Using Social Cost of Carbon** | $ 3,946.9 | $ 2,524.7 |
| **Social Cost of Carbon Benefits** | $ 486.7 | $ 376.2 |
| **New England MAC Cost of Carbon Benefits** | $ 64.3 | $ 51.9 |
| **Total Benefits Using New England MAC** | $ 3,524.5 | $ 2,200.4 |
| **Total Costs** | $ 529.0 | $ 373.8 |
| **Benefits (NE MAC) Less Costs** | $ 2,995.4 | $ 1,826.6 |
| **Benefit/Cost Ration (NE MAC)** | 6.7 | 5.9 |

### 8.6 Alignment with Docket No. 4600

Many of the GMP functionalities and benefit impacts identified earlier in this document have been quantified using the Docket No. 4600 BCA methodology and inputs based on the detailed modeling. The source for many of the avoided cost value components is the "*Avoided Energy Supply Components in New England: 2021 Report"* (AESC 2021 Study) prepared by Synapse Energy Economics for AESC 2021 Study Group[90]. This report was sponsored by the electric and gas energy efficiency program administrators in New England and is designed to be used for cost-effectiveness screening in 2021 through 2023.

The GMP benefit category alignment with Docket No. 4600 benefits is presented in Figure 8.31.

**Figure 8.31: Quantifiable GMP Benefit Category Mapping to Docket No. 4600 Benefits**

| Docket 4600 Framework categories quantified in the BCA model | |
|---|---|
| Docket 4600 Table | |
| 22-Dec-22 | |
| **Docket 4600 Category** | **GMP Benefits in BCA** |
| Power Sector: Distribution Delivery Cost | Communication Savings due to SS Fiber |
| | Reduced Curtailment: Energy Savings |
| | Utility O&M Savings |
| | Reduced VVO Lease Costs |
| | Avoided Infrastructure Cost - Distribution |
| Societal: GreenHouse Gas (GHG) Externality Cost | GMP - Total Non-Embedded CO2 Benefit: VVO/CVR |
| Societal: Non-GHG Externality Cost | GMP - Total Non-Embedded NOX Benefit: VVO/CVR |
| Societal: Public Health | GMP - Total Public Health Benefit: VVO/CVR |
| Power Sector: Energy Savings | Energy Savings: VVO/CVR |
| | GMP - Total Energy Shift Benefits: EV TVR |
| Power Sector: GHG Compliance Savings | Monetized CO2 Benefit: VVO/CVR |
| Power Sector: Retail Supplier Risk Premium | Not included because risk premium added into avoided costs. |
| Power Sector: Renewable Energy Credit (REC) Value | Not included because REC value added into avoided costs. |
| Power Sector: Distribution Savings | GMP Total Dist Capacity Benefit: Whole House CPP |
| | GMP - Dist Capacity Benefit: VVO/CVR |
| Power Sector: Capacity Savings | GMP - System Capacity Benefit: VVO/CVR |
| | GMP - Total System Capacity Benefit: EV TVR |
| | GMP - Total System Capacity Benefit: Whole House CPP |
| | GMP - Total System Capacity Savings: Whole House TOU |

[90] AESC 2021 Report, Synapse Energy Economics, Inc., Executive Summary, at 8, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf.

| | |
|---|---|
| Power Sector: Transmission Savings | GMP Total Trans Capacity Benefit: Whole House CPP |
| | GMP - Trans Capacity Benefit: VVO/CVR |
| | Avoided Infrastrucuture Costs - Transmission |
| Power Sector: DRIPE Savings* | GMP Total Capacity DRIPE Benefit: Whole House CPP |
| Customer: Reliability & Resilience Impacts | Reduced Outage Frequency Benefits due to FLISR |
| Power Sector: Distribution Delivery Safety | Safety for employees and public improved but not quantified |
| Customer: Non-Participant Rate/Bill Impacts | All Rhode Island Energy customers will benefit |
| Power Sector - Transfer: Low Income | Not Directly Captured; GMP will benefit all customers, including Low Income customers |
| Societal: Cross-DRIPE Savings* | |
| Customer: Customer Bill Savings | VVO savings creates customer bill savings |
| Societal: Economic Development | Brattle Group Report inidicates significant economic development benefits |

* Demand Reduction Induced Price Effect (DRIPE)

## 8.7 Shared Cost Opportunities

To the extent there is an opportunity for cost sharing, Rhode Island will assess the applicability, and if the opportunity aligns with business needs, it will be pursued to benefit Rhode Island customers. Examples are provided below for possible cost share opportunities through The Infrastructure Investment and Jobs Act ("IIJA") and by advancing future infrastructure that would qualify as a Pool Transmission Facility through NEPOOL.[91]

IIJA: Rhode Island Energy has submitted Concept Papers to be considered for a grant under IIJA that was signed into law in November 2021. The law authorizes $1.2 trillion for transportation and infrastructure spending with $550 billion of that figure going toward "new" investments and programs. Funding from the IIJA is expansive in its reach, addressing energy and power infrastructure, access to broadband internet, water infrastructure, and more. Some of the new programs funded by the bill could provide the resources needed to address a variety of infrastructure needs at the local level. [92]

Pool Transmission Facilities: As discussed in Section 6, the fiber communication infrastructure is proposed as a shared distribution and transmission asset. The fiber transmission asset will be proposed through NEPOOL because it is a looped facility, where costs will be shared across the members. Rhode Island Energy's portion of this cost would be approximately 7% of the $23M because it is defined as a Pool Transmission Facility (PTF), based upon Rhode Island's load ratio share. In Section 5, there is also recommendation to perform additional study work to determine if converting a portion of the sub-transmission system to a higher voltage level and 115 kV expansion in Rhode Island offers additional efficiency and cost saving opportunities over the study period beyond that which has been identified through the Distribution Study. It is possible that the outcome from this analysis would result in

[91] https://nepool.com/ New England Power Pool ("NEPOOL")
[92] Infrastructure Investment and Jobs Act (IIJA) Implementation Resources (gfoa.org)

transmission facilities that would enjoy the same PTF treatment.

### 8.8 GMP BCA Conclusion

The BCA developed for the GMP was developed using Docket 4600 Guidance as discussed above. The GMP is necessary now to support the reliability and safety of Rhode Island Energy's grid, and in addition, the GMP shows significant benefits. Even after considering many different sensitivities, including a "worst case" sensitivity, the benefit-cost ratios for the GMP are significant. The GMP investments, particularly the Foundational Investments, are truly a "No Regrets" decision.

"No Regrets" is a phrase used in planning and BCA to indicate a decision or an investment that will be "used and useful" in virtually any future scenario that may emerge. It indicates that the decision maker will have "No Regrets" for having made that decision/ investment. Rhode Island Energy firmly believes that the Foundational GMP Investments requested in the GMP are "No Regrets" investments.
There are several reasons for this:

1. First and foremost, the Foundational Investments are ***needed now***. Lack of visibility and automation on Rhode Island Energy's system are significant barriers to operating the system reliably and safely, enabling customers to interconnect DER, and meet Rhode Island's Climate Mandates.
2. The Foundational Investments are designed to provide that visibility and automation.
3. The benefits, as demonstrated by the Benefit-Cost Analysis completed by the Company, show significant benefits to the Utility, Customers and Society. Many of these benefits will be realized regardless of the level of DER, EVs, and EHPs that are adopted.
    a. Increasing penetration levels of any of these technologies will only increase the benefits that can be realized.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

| | |
|---|---|
| IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF | ) ) ) ) ) Case No. 22-00058-UT ) ) ) |

AFFIRMATION (IN LIEU OF AFFIDAVIT)

OF COURTNEY LANE

In compliance with the *Temporary NMPRC Electronic Filing Policy of March 20, 2020*, and under Rule 1-011(B) NMRA of the New Mexico Rules of Procedures for the District Courts, I, Courtney Lane, hereby file this testimony on behalf of the New Mexico Attorney General and state as follows:

I hereby affirm in writing under penalty of perjury under the laws of the State of New Mexico that the statements contained in the foregoing *Supplemental Testimony of Courtney Lane on Behalf of the Office of Attorney General* are true and correct to the best of my knowledge, information, and belief.

I further declare under penalty of perjury that the foregoing is true and correct.

Executed on March 8, 2023.

__/s/__ Courtney Lane__
Courtney Lane (electronically signed)
Expert Witness on Behalf of the New Mexico Attorney General
485 Massachusetts Avenue #3
Cambridge, MA 02139

**BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

| | | |
|---|---|---|
| **IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF** | **)<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>)** | **Case No. 22-00058-UT** |

**CERTIFICATE OF SERVICE**

**I HEREBY CERTIFY** that a true and correct copy of the **Supplemental Testimony of Courtney Lane** was sent via email to the following parties on the date identified below:

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