APPENDIX G1 – DEMAND SIDE MANAGEMENT

I. INTRODUCTION

DSM is the modification of consumer demand for energy through various methods such as financial incentives and education. It enhances our customers' experience with energy (and energy management) by empowering them with the insights and technology to lower their energy bills. DSM also lowers the need for future generation resources and enables future CO_2 emissions reductions. DSM methods include educating customers on the benefits of purchasing energy-efficient equipment; providing customers with incentives to upgrade to more efficient equipment; encouraging participation in load management programs; and equipping customers with control systems to shift demand.

To date, DSM has largely been defined as energy efficiency and demand response. The future outlook and opportunities for DSM, however, are changing with declining cost effectiveness, increased deployment of renewables, expansion of new technology, and changing customer expectations. Future DSM opportunities will include utilizing new, integrated technologies to optimize DSM solutions by location and time while keeping costs low for customers.

There are fundamental differences between the benefits offered by traditional DSM and new technologies. Our traditional DSM resources focus on lowering energy savings through more efficient equipment and/or reducing peak demand on the hottest summer days. Many newer technologies (e.g. smart thermostats) also offer benefits beyond simply reducing overall and peak usage, including features that make it easier for customers to use energy during non-peak energy times when it is less expensive. Future demand response options will include technologies designed to proactively shift load during specific times of the day, controlling customer load in targeted locations facing peak conditions, and giving the Company the flexibility to control customer load as needed – further benefiting the operation of our generation mix and delivering cost savings to customers.

These evolving options require reconsidering the current approach to assessing the value of DSM investments. In order to incentivize our customers to embrace new flexible options, we will need to leverage and account for a range of benefits offered by new technologies, beyond energy reductions. The Company will need to provide incentives for automated energy management systems and other technologies that allow for flexible control and adjustment to load. Although DSM programs are generally approved through the Company's Conservation Improvement Program (CIP); recent decisions suggest that new enabling technologies largely fall outside the current

parameters for recovery through CIP. In order to support new programs and opportunities to grow demand management through pilots, incentives, and/or rates for new energy solutions, the Company will need to find other avenues for cost recovery.

In the meantime, we are significantly expanding our commitment to achieving high levels of DSM savings, particularly with energy efficiency. The Preferred Plan increases our commitment to energy efficiency and includes savings, on average, of more than 700 GWh each year in permanent energy reduction. This commitment will help offset the need for future additional energy resources and our modeling confirms the cost effectiveness of these energy efficiency savings.

The Preferred Plan also complies with Commission direction to add an additional 400 MW of demand response by 2023.[1] But, making new demand response resources (or programs) cost-effective in the short term is challenging, and the Strategist modeling confirms this. First, based on our current resource mix, we are not forecasting a need for capacity for a number of years. Second, in the Preferred Plan, we also are not forecasting a need for a firm dispatchable resource until the 2030s. This limits the effectiveness of traditional demand-response resources because the primary benefit of these resources is avoiding peaking generation which is one of the options to meet the firm, dispatchable need.

The Company is firmly committed to innovation and the adoption of DSM in our plan, and we are committed to taking the following key steps:

- *Demand Response*: We are committed to securing an additional 400 MW of demand response by 2023; however, for a demand response portfolio to be successful, we need the flexibility to procure resources as needed to maximize all benefits – including benefits outside traditional demand response. Some additional demand response can be implemented through existing mechanisms. Other programs may require new cost-recovery opportunities, and we are committed to working with stakeholders to identify these. Additionally, we believe battery storage may be a resource we could use to meet demand response

[1] We note that when we first announced a Preferred Plan in May 2019, it did not include demand response additions because demand response was not the least-cost resource when compared to energy efficiency and solar resources. Based on feedback we received, however, and in light of the Commission's Order, we included cost-effective (though still not least cost) demand response resources in the Preferred Plan presented in this Resource Plan.

needs, and we propose allowing incremental storage to meet some portion of the 400 MW requirement.

- *Energy Efficiency*: We intend to aggressively pursue unprecedented energy efficiency savings levels outlined in our Preferred Plan that will achieve between 2-2.5% annual energy savings in the planning period. Estimated savings include utility sponsored programs as well as conservation occurring naturally in the market as a result of increasing efficiency options. Specific details regarding how the Company achieves energy efficiency is addressed in our various CIP Triennial Plans.

We look forward to working with our stakeholders to address some of the challenges presented in the remainder of this appendix and create more flexible paths to enable greater deployment of DSM resources. This will effectively position the Company to add more DSM in the future in a cost-effective manner.

II. DEMAND RESPONSE RESOURCES

Demand response resources generally can be grouped into two buckets: traditional and non-traditional resources:

1. ***Traditional demand response***, often referred to as load management, provides a temporary reduction to system peak. Often these products are referred to as dispatchable resources because the utility may control them directly. This peak reduction has a similar impact on our system as a combustion turbine (CT) because it can be brought on- and off-line quickly for short periods of time as an operational reserve.
2. ***Non-traditional demand response***, often referred to as demand management, provides the opportunity for our customers to plan for and manage their electric demand differently. Compared to traditional methods of peak demand reduction during the hottest days of year, these methods allow customers to shift portions of their electric loads to lower-cost periods of the day when carbon-free generation is highest. As noted by Lawrence Berkeley National Laboratory, in systems with high renewable penetration, demand management can unlock customer benefits like production cost savings of renewable resources.[2]

[2] Lawrence Berkley national Laboratory: 2025 California Demand Response Potential Study (Charting California's Demand Response Future), March 1, 2017. (http://www.cpuc.ca.gov/General.aspx?id=10622)

The Preferred Plan adds a significant amount of renewable resources and has little to no need for additional load-supporting resources (or peak reduction) in the near-term. Because a substantial portion of the value of demand response resources is the avoidance of load-supporting generation,[3] the cost-effectiveness of new demand response resources at this time is limited. If demand response were to be effectively used to avoid non-peaking generation, the hours during which the Company would need to control customer load would need to significantly increase. Our January 30, 2019 control event shows this impact as we moved from a traditional four-hour control period to a six-hour period requested by MISO during the reliability event. Meeting this extended duration was a challenge for many customers.[4] And, in the future, such reliability events could be even longer, possibly for days.

In the following section, we provide information about how the Company intends to meet specific demand response requirements for this Resource Plan as ordered by the Commission within this landscape. We also discuss the impact of emerging non-traditional demand response.

A. Integrated Resource Planning Requirements for Demand Response

The Commission's January 11, 2017, Order in Docket No. 15-21, at Order Point 10 and 14(e), states:

- Xcel shall acquire no less than 400 MW of additional demand response by 2023; and
- In its next resource plan filing, Xcel shall: …. 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.

[3] The Brattle Group, The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, June 2019.
[4] The Company had a total of 1,770 Minnesota customers who were required to interrupt their controllable load throughout the six-hour event by maintaining a peak load at or below their firm service level, which is the Predetermined Demand Level (PDL) specified by each interruptible customer. A total of 931 of these customers did not fully comply with their load control requirement and had peak load that exceeded their PDL by at least one kW for all or a portion of the six-hour curtailment event.

The Commission's Order does not specify a basis for measuring the 400 MW. We have assumed this requirement to be a capacity equivalent number and therefore grossed up for line losses and reserve requirements. As noted in the Brattle Study, after accounting for reserve requirements, this is equivalent to 391 MW of generation (Gen. MW).

B. Stakeholder Engagement

In preparing for this Resource Plan, and in order to facilitate compliance with the Commission's Order, we engaged stakeholders early in order to obtain insights that could inform both the study details and future portfolio planning. The Company hired Great Plans Institute and the Center for Energy and Environment to lead seven demand response stakeholder discussions between December 2017 and January 2019. (The detailed minutes and results for this stakeholder engagement process can be found in the Demand Response Stakeholder Engagement Summary, Appendix G4.) In connection with this stakeholder process, we received valuable input regarding benefits associated with demand response, future design principles as we moves toward adjusting our demand response portfolio, products in development, and our overall strategic direction for demand response.

Stakeholders specifically identified three main design principles for programs and products that are being developed:

- Compensating demand response participants for the specific benefits provided to the utility;
- Ensuring pricing and expectations are clear, concise and transparent for customers; and
- Providing flexibility and options for customers.

Stakeholders also provided specific details they would like to see in ongoing filings for new demand response offerings. These include:

- Be clear about the outcomes that demand response offerings are designed to achieve and how those should be measured down the road;
- Fully evaluate demand response program costs and benefits;
- Address reliability and resilience of demand response offerings, as relevant;
- Delineate between dispatchable and non-dispatchable demand response; and
- Show transparency toward meeting the objectives listed above.

The Company intends to focus on these details established by stakeholders as we request approval of new and expanded programs from the Department and/or Commission.

C. Potential Study Analysis

Also in preparing our Resource Plan, we engaged The Brattle Group to analyze the benefits of demand response. The Brattle Group's report, *The Potential for Load Flexibility in Xcel Energy's Northern States Power Territory* ("2019 Potential Study"), included as Appendix G2, estimated the potential capabilities of cost-effective demand response that could be deployed in Xcel Energy's Northern States Power service territory, including Minnesota, North Dakota, South Dakota, and Wisconsin. The study focused on the addition of non-traditional (non-conventional) demand response resources. The study did not, however, address incremental demand from existing customers or the impact of customers limiting or ceasing participation in the future. In other words, existing program participation was a constant value.

The Brattle Group concludes the following from their analysis:

1) The largest benefit from demand response continues to be avoided generation capacity cost;
2) Xcel Energy could grow demand response resources by 293 Gen. MW at an annual cost of up to $59/kW per year for traditional demand response resources by 2023;
3) Cost-effective non-traditional demand response could be used to further grow peak reduction by 13 Gen. MW, increasing the cost-effective potential for incremental demand response to 306 Gen. MW; and
4) In 2025, the potential cost-effective demand response increases by an additional 87 Gen. MW, driven by the ability to offer time-varying rates.

1. Demand Response Benefits

The 2019 Potential Study accounted for cost benefits that are commonly included in assessments of traditional demand response, based on reductions in system peak demand:

- Avoided generation capacity costs – reduced need for new peaking capacity;
- Reduced peak energy costs – reduced load during high-priced peak periods; and
- System-wide deferral of transmission and distribution – reduced need for peak-driven upgrades in transmission and distribution capacity.

The study also identified additional benefits that may be achievable with advanced non-traditional demand response products:

- Geotargeted distribution capacity investment deferral – targeted demand response investments where load reductions would defer localized needs for capacity upgrades;
- Ancillary services – e.g., real-time adjustments to load from some end-use applications to mitigate system imbalances; and
- Load building/valley filling – shifting on-peak load to off-peak hours.[5]

The 2019 Potential Study compared potential benefits as a result of increased demand response to the additional resource need for a CT (the resource used for avoided generation comparison) to analyze cost-effectiveness. The flex model, also used as part of the analysis, extended the potential benefits for demand response to include additional values outside this traditional avoided generation (such as ancillary services noted above). By adding these benefits, the 2019 Potential Study was able to determine what additional value demand response could provide, and if these too would impact cost-effectiveness. The study found these new values account for approximately 20 percent of the total benefits today. However, as a result of the Resource Plan analysis, the need for a CT (or other load supporting resources) now extends beyond this planning period. This impacts the modeled cost-effectiveness of traditional demand response resources and is not reflected in the 2019 Potential Study.

The 2019 Potential Study also reviewed potential benefits (frequency regulation, transmission and distribution deferral, etc.) in a high sensitivity analysis that included high renewable penetration. As highlighted below in Figure 1, even under the high-sensitivity case, 75 percent of the demand response benefits projected in 2030 were tied to the avoidance of new generation capacity in 2030. The remaining benefits include energy cost reductions, transmission and distribution deferral, and frequency regulation.[6]

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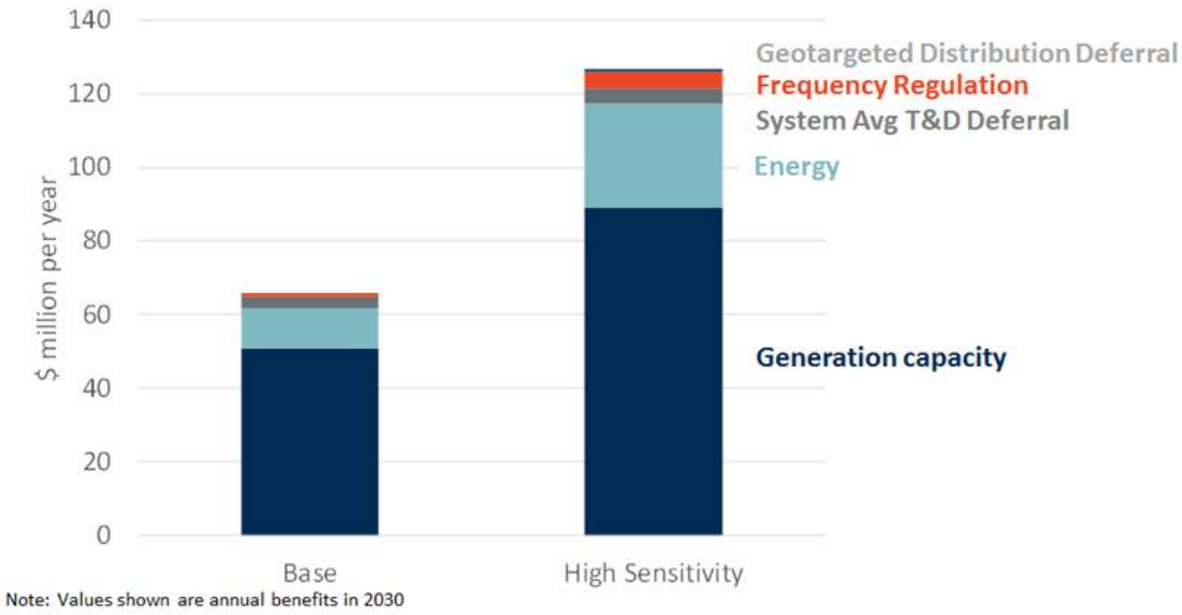
[5] The Brattle Group, The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, June 2019, pages 7-8.
[6] Frequency regulation allows utilities to provide market-based compensation to resources that have the ability to adjust output or consumption in response to an automated signal helping manage generation to demand.

Figure 1: Demand Response Avoided Cost Benefits (2030)[7]



This analysis provides two key takeaways: (1) traditional demand response as a cost-effective resource is highly contingent on the need to reduce and avoid generation capacity (e.g. a CT); and, (2) when more renewables exist within the utility's resource mix (as in the high-sensitivity case), the benefits of demand response shift to include more products and services that help integrate renewable resources, focusing on energy, transmission and distribution deferral, and ancillary services as shown in the analysis of the high sensitivity.

2. Avoided Generation Comparison

The 2019 Potential Study compared the cost of demand response against a CT. CTs are load-supporting units with relatively high variable costs; they typically run up to a few hundred hours of the year when electricity demand is very high and/or there are system reliability concerns. Demand response programs are typically limited to less than 100

[7] *The Potential for Load Flexibility in the NSP Service Territory,* Study Overview Presentation. Presented by Ryan Hledik, Amhmad Farugui and Tony Lee, Demand Response Workgroup Meeting #7, January 22, 2019.

hours a year to avoid customer fatigue and limit program drop-outs.[8] In contrast, new intermediate or baseload capacity (e.g., a gas-fired combined cycle plant) has a higher capital cost and lower variable cost than a CT, and therefore will run thousands of hours per year. Traditional demand response tools 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 involves permanent load reduction that applies to a much broader range of hours.[9] We explored the operational constraints of demand response programs in late 2017 and found that, in order to achieve larger load reductions, demand response needs to be dispatched during more hours of the year.[10] An increased target for demand response, for example, could require the Company to control many different hours of the day on multiple consecutive days in a given year.[11] But, this level of control would likely be unsustainable given customer fatigue anticipated with multiple events.

3. Cost-Effective Demand Response Potential - 2023

Under base case assumptions,[12] the study found that the Company could not approach the 2023 procurement requirement of 391 Gen. MW with cost-effective demand response until after 2025.

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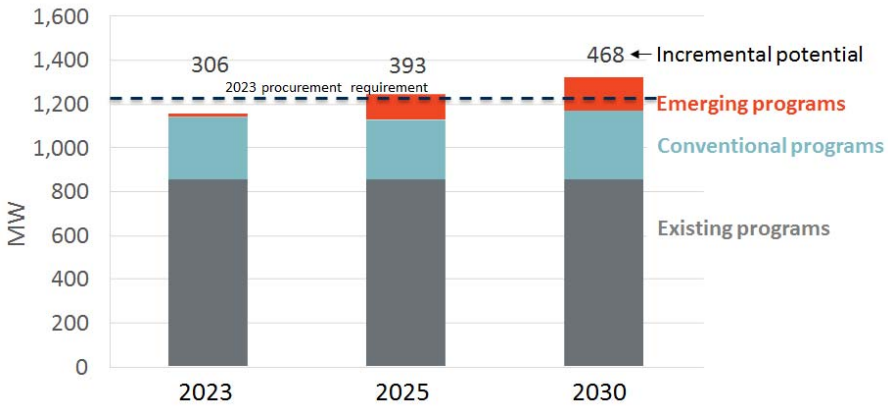
[8] *The Cost-Effectiveness of Demand Response in NSP's Service Territory*, Presented by Ryan Hledik, Amhmad Farugui and Tony Lee, December 2017. Slide 15. *See* Appendix G3.
[9] *Id.*
[10] *Id.*
[11] *Id.* at slide 40.
[12] As opposed to "high sensitivity" assumptions, which include higher assumed generation capacity cost, more volatile energy prices, significant reductions in emerging demand response technology costs, and increased need for frequency regulation.

Figure 2: Cost-effective Demand Response Potential[13]



The cost-effective opportunities identified in the study include 293 Gen. MW of incremental traditional demand response and 13 Gen. MW of incremental non-traditional demand response for a total of 306 Gen. MW. As noted above, this study did not consider expanding current customer load and is not reflective of how current customers may participate in future demand response offerings. The specific opportunities identified in the study include:

- *Traditional Demand Response potential*: This potential includes expanding our A/C Rewards program, continuing to grow Saver's Switch, and expanding commercial interruptible load. We note that expanding interruptible load is not expanding participation in current programs, but rather creating new programs to reach additional customers.
- *Non-Traditional Demand Response potential:* This potential includes smart water heating control (both thermal storage and peak control) for customers with existing electric water heaters.

As discussed below, we have included all cost-effective demand response identified in the 2019 Potential Study as part of the Preferred Plan, despite the modeling results.

[13] *The Potential for Load Flexibility in the NSP Service Territory,* Study Overview Presentation. Presented by Ryan Hledik, Amhmad Farugui and Tony Lee, Demand Response Workgroup Meeting #7, January 22, 2019.

4. Cost-Effective Demand Response Potential - 2025

The Commission's January 11, 2017, Order required the Company to provide a full and thorough cost-effectiveness study to take into account the achievability of 1,000 MW of additional resources by 2025. As shown in Figure 1, our analysis showed this was not a cost-effective option and highly dependent upon resource needs. Cost-effective demand response at any such significant level of investment would need to include an increase in additional benefits (such as those defined above) and new enabling technologies, such as smart meters.

The 2019 Potential Study assumed full deployment of smart meters by the year 2024. We clarify that the analysis of cost-effectiveness did not include the cost of the advanced meters themselves; it did however, include some costs, such as the cost to integrate the information from the advanced meters to the systems necessary to achieve identified program objectives. Advanced meters provide an increased ability to increase demand savings for customers on time-varying rates, such as time of use and critical peak pricing. In the 2019 Potential Study, scenarios involving opt-out rates to customers showed an increase in demand savings. However, the potential increase in savings under these types of scenarios is highly dependent upon customer interest and, in the case of time of use, customer behavior. Therefore, there is only a minimal increase in potential for these programs.

While these resources were not identified as cost-effective in the study until later years in the Resource Plan, we continue to explore their impact and how to further increase non-traditional options. Additional information regarding the actions the Company intends to take to procure these resources is included in the "Action Plan" section below. For additional information specific to the Strategist modeling and the inclusion of these resources, please see Appendix F2 and F3.

D. Changes in Demand Response Technologies

The NSP electric generation system is evolving. The addition of significant carbon-free renewable generation resources will change the future value and focus of demand response:

- Significant solar additions that are highly coincident with historical peaking conditions will limit the need for new load-supporting generation;
- Solar and wind additions may produce energy that meets or exceeds load, resulting in energy cost savings opportunities and increased carbon reductions throughout the year by shifting load to match periods of excess renewable generation.

New demand response technologies and programs that respond to these conditions are defined as demand management – the management of load within a customer's home and/or business. Unlike traditional demand-response tools that reduce load during the hottest days of the year, these resources move energy usage from peak periods to off-peak periods throughout the year. Non-traditional demand response will be an important part of our energy future. However, the traditional model for cost recovery of demand response is an impediment to the growth of these resources, and a new cost-recovery mechanism needs to be devised – either through a reinterpretation of the CIP statute, a legislative change, or some other means.

Demand management can help operationalize the future energy grid to maximize the benefits of intermittent resources like wind and solar generation more effectively. Examples of possible programs that would fit into this category include auto-DR (customer energy management systems that include event-based controls and that facilitate shifting load to lower usage and lower carbon times), time varying rates (including time-of-use and critical peak pricing), thermal energy storage (e.g., grid-enabled electric water heaters), and reverse demand response (utilizing excess renewable resources in the middle of the afternoon to help maintain optimal grid operation). These technologies could bring benefits beyond curbing the need for capacity generation and include system-wide deferral of transmission and distribution, geotargeted distribution capacity investment deferral, ancillary services, and load building/valley filling.

We will need to undertake significant efforts to identify and implement programs and technologies that cost-effectively produce these benefits. Among other things, we will need to produce more sophisticated modeling methods to determine the benefits at a variety of generation conditions; develop customer programs to optimally operate a variety of end-use technologies under new conditions; run pilots with limited customer groups to determine cost-effectiveness; and eventually pursue cost-effective programs at scale. But, these efforts will be worthwhile. By implementing new demand management opportunities, we will be prepared to maximize benefits for customers during the clean energy transition over the next 10-20 years, as resource flexibility and planning for operational constraints take center stage.

Although many non-traditional demand-response opportunities require future enabling technology, we are beginning to explore options today. We are developing pilots for customers to manage their demand and will soon launch our pilot to assess time-varying rates. Another example is grid-enabled water heaters (also known as smart electric water heaters), which allow customers and utilities to control the electricity used to heat residential domestic water. When enabled, these water heaters can act as

traditional demand-response tools, allowing utilities to turn off the water heaters during high-demand periods and turn them back on to run during the night. The smart water heaters also can act as demand management tools, allowing customers to primarily use electricity generated overnight to heat water, and then leverage the water heater tanks' thermal storage abilities to retain heat throughout the day and provide hot water during periods when energy prices are higher.

Although the 2019 Potential Study found this to be a promising enabling technology, incentives for thermal storage capabilities do not qualify under CIP, as recently determined by the Department.[14] Instead, we have requested approval to include grid-enabled water heaters as part of our traditional demand response portfolio (as part of our Saver's Switch program) in our 2020 CIP Extension Plan without incentivizing the thermal storage capabilities. Therefore, the savings reflected in the 2020 Plan Extension are much smaller than those predicted by the 2019 Potential Study, amounting to less than one megawatt per year for the emergency use of these systems. (If the thermal storage capabilities also were recognized, the savings could be 13 Gen. MW by 2023.)[15]

The Department has recently stated that, in order to qualify under CIP load-shifting opportunities need to reduce overall energy use at the customer meter.[16] In the case of grid-enabled water heaters, leveraging the use of thermal storage shifts energy use to off peak periods, but does not necessarily cause an overall reduction in energy use at the customer meter.

As another example of limitations for demand response, the Company recently has met challenges in providing incentives for customers to purchase ENERGY STAR-certified Level 2 electric vehicle "smart" chargers and participate in efficient, time-controlled charging (during off-peak nighttime hours).[17]

These decisions directly underscore some of the significant challenges facing the Company as we work to advance our demand-response portfolio with pilots and

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[14] See, e.g., Docket No. E,G002/CIP-16-115, Department of Commerce Decision (September 13, 2018).
[15] The Company has included 13 Gen. MW in our action plan based on the assumption that some recovery mechanism will be put into place by 2023.
[16] See, e.g. Docket No. E,G002/CIP-16-115, Department of Commerce Decision (June 12, 2019). Which states in part that "demand-side management energy savings were required" meaning that energy savings at the customer meter were required to qualify for funding under CIP Recovery.
[17] See Docket No. E,G002/CIP-16-115, Department of Commerce Decision, (June 12 2019).

customer incentives that can unlock demand-side resources to more effectively manage our system and facilitate the integration of renewable resources. Programs such as these should be part of our resource pool, but in order to include them, the Company must first be able to provide incentives to customers and receive recovery of these costs. The current options available to the Company are limited at this time.

- *CIP Rider Recovery (Minn. Stat. §216B.241)*: As noted above, under the existing statutory requirements, recovering demand management programs through CIP is unlikely. The language of the statute could be modified to support demand management, but would take a legislative change.
- *Base-Rate Recovery*: Recovering the costs of customer incentives for demand management would require a full understanding of customer interest and future enabling technologies when forecasting test years. At this time, as technologies are evolving quickly, it is difficult to forecast costs over the course of a multi-year rate plan. A more agile cost recovery mechanism is needed to address changes in technology and customer demand.
- *Other Rider Recovery:* There are currently no other riders (or enabling legislation) that specifically support recovery of demand management investments.

We believe that, if piloted and funded through an appropriate mechanism, these efforts would help the Company reach the commitment established in our Preferred Plan in the most cost-effective and sustainable fashion. The Company intends to continue to explore future recovery despite the challenges identified herein.

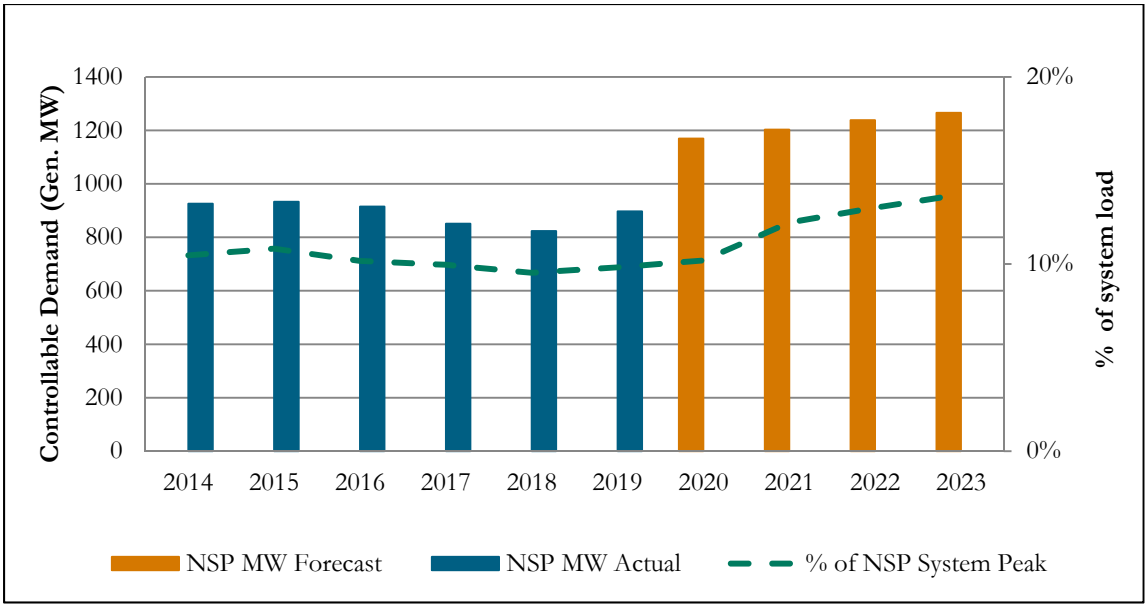
III. DEMAND RESPONSE ACTION PLAN

Our Preferred Plan includes 1,310 MW (1,266 Gen. MW) of demand response resources as part of our five year planning period. This is a significant increase in demand response for the Company, representing 14 percent of our peak load. Figure 3 below shows the demand response resources included in the Strategist modeling as part of our Preferred Plan. The Company optimized and tested traditional demand response as though it were a competitive supply-side option. We performed this modeling using several differing approaches and creating three bundles for analysis. However, the model did not choose additional demand response under any of these approaches because it never modeled as the least cost "supply-side" resource available compared to other resources such as energy efficiency and solar additions. Nonetheless, based on the Commission's Order, we include sufficient demand response additions in the Preferred Plan to comply with the requirement that the Company acquire no less than 400 MW of additional capacity-equivalent demand response by 2023. In order to meet this requirement, we plan to both increase traditional demand response resources over the

next several years (including through new programs that are dependent upon the regulatory process and customer acceptance), and explore non-traditional demand response resources.

The generic demand response bundles that were evaluated as supply-side options in our modeling were developed immediately after receiving the 2019 Potential Study and before we finalized a detailed implementation plan for acquiring the incremental 400 MW. The values included in the modeling and shown in Figure 3 served as a generic representation of general demand response additions designed to achieve 400 MW of demand response additions by 2023. Although these values are directionally consistent with our plans for demand response additions discussed in this appendix, they do not perfectly align. For example, we do not believe that we will procure a large increment of additional demand response in 2020 as reflected in the modeling. Rather, in reality, these additions will occur over time as we approach 2023, as laid out in the following sections. Because the Strategist model is generally intended to be used to help identify size, type and timing of new resources at a high level, we believe the degree to which the values in our Strategist modeling and the action plan differ is acceptable.

Figure 3: Controllable Demand (Gen. MW)



In this section, we provide further information regarding the Company's five-year action plan established to meet the resources identified in the Preferred Plan, and how this action plan increased demand response by 400 MW by 2023.

Before discussing specific programs, however, we believe it is important to emphasize the challenges in launching and marketing demand response programs sufficient to meet the Commission's target of 400 MW by 2023. First, any program we launch is subject to variances in customer adoption and use of new technologies. Demand response originally was intended to control system demand over several hours across several days throughout the summer, program dependent. As we develop new cost-effective customer programs or technology options, customer incentives will need to be aligned with the specific value provided to the system. Large discounts based only on summer afternoon load reduction forecasts will not continue to be impactful to our changing system. Instead, these programs will need to account for many events being called throughout the year, as illustrated in our discussion of the reliability requirement, which highlights the need for firm dispatchable resources particularly in winter. These increased expectations will impact customer participation. Additionally, the technological ability to control customer usage or communicate to customers in real-time is critical to the effectiveness of these technologies. Enabling technology in future programs should allow customers to participate in more events with fewer impacts to their normal operations/comfort.

Second, the current regulatory process also is a challenge for demand response. As noted above, CIP programs require energy savings, which is not the main benefit of demand response efforts. The cadence of rate cases also is not ideal for providing our customers with new demand response options. Therefore, we must look to other sources, particularly to account for the benefits from the next generation of demand management program/customer offerings.

Notwithstanding these challenges, the Company is committed to adding 400 MW of demand response by 2023, and we discuss our plans for reaching this goal below.

A. Five-Year Action Plan

Our action plan consists of three tracks: (1) expansion of existing programs where appropriate, (2) addition of new traditional programs and tariffs, and (3) addition of non-traditional opportunities. Some of these products have not yet been approved by the Commission or Department and will need to be reviewed in these forums prior to our ability to offer them to customers.

Table 1 shows our action plan by three categories, those impacting existing products, expanded and new programs (2020 programs and 2021 programs) and non-traditional demand response opportunities.

Table 1: Demand Response Five-Year Action Plan

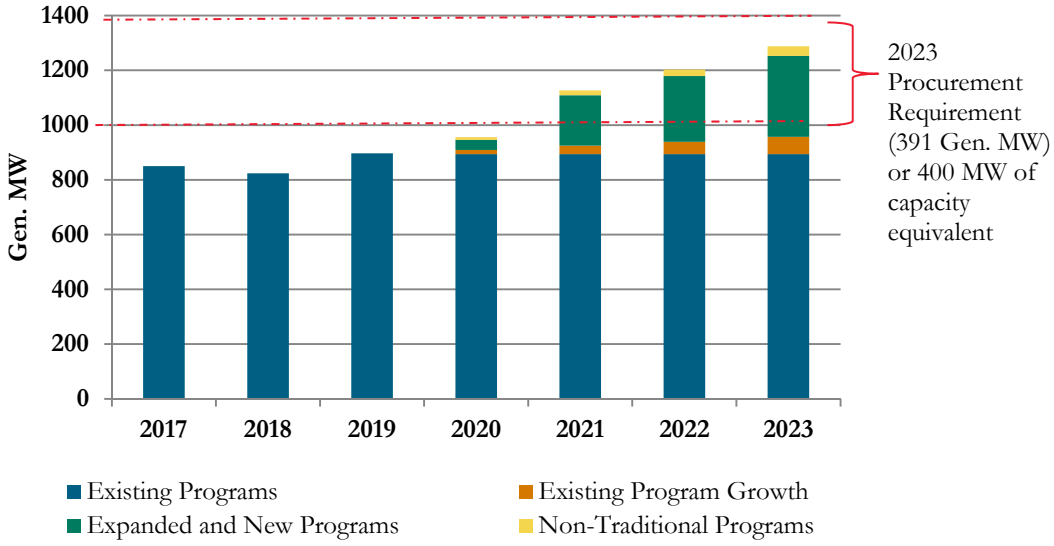
				Actuals[18]	Estimated Cumulative Potential (Gen. MW)				
	Program	**Regulatory Path**	**Status**	**2019**	**2019**	**2020**	**2021**	**2022**	**2023**
Existing Programs	Electric Rate Savings	CIP (admin); Rate Case (discounts)	Existing Program	461	-	462	464	465	466
	Saver's Switch	CIP (admin); Rate Case (discounts)	Existing Program	433	-	447	461	474	491
	Subtotal Existing			**894**	**-**	**909**	**925**	**939**	**957**
Expanded and New Programs	A/C Rewards (Smart Thermostats)	CIP	Modified in 2020 Extension Plan	3	13	23	98	103	114
	Small Business Smart Thermostats	CIP	Testing –Summer 2019; 2021-2023 Triennial Plan Filing	0	0	0	1	2	3
	Peak Partner Rewards	CIP	2020 Extension Plan	0	0	14	45	45	45
	Two way switches – Saver's Switch Technology Update	CIP	2021-2023 Triennial Plan Filing	0	0	0	0	0	19
	Interruptible Tariff(s)	Rate Cast or Miscellaneous Filing	In design - Tariff Filing 2019/2020	0	0	0	40	90	115
	Subtotal Expanded and New			**3**	**13**	**37**	**184**	**240**	**296**
Non-Traditional Programs	Grid Enabled Electric Water Heaters	Non-Traditional - TBD	In design	0	0	0	4	9	13
	Commercial Building Controls (Auto DR)	Non-Traditional - TBD	In design - Currently not cost-effective[19]	0	0	10	13	15	22
	Other	Non-Traditional- TBD	In design	-	-	-	-	-	-
	Subtotal Non-Traditional			**0**	**0**	**10**	**17**	**24**	**35**

Total Existing, Expanded, New, and Non-Traditional Programs	**897**	**907**	**956**	**1,126**	**1,203**	**1,288**
Incremental Program Capacity (Gen. MW)	-	-	-	-	-	**391**
Incremental Program Capacity with Reserve Margin (MW)	-	-	-	-	-	**400**

[18] Actual data represents what is available in the field for load control in 2019. While there may be additional load added we represent it as 2020 load within this chart.
[19] Commercial Building Controls (Auto DR) was not modeled in the 2019 Potential Study as cost-effective. We have assumed these estimates based on 1/2 of the technical potential available (accounting for potential overlap with other programs). The cost-effectiveness is largely dependent upon system and integration costs the Company believes will come down in the next several years.

Figure 4 provides a graphical representation of the growth in demand response within these categories. We project the total demand response resources available in 2023 to be 1,288 MW in our Action Plan. This is slightly higher than, but directionally consistent with, the 1,266 of demand savings modeled in the Preferred Plan.

Figure 4: Future Demand Response Growth in 5-Year Planning Period



1. Existing Load Availability

In setting a baseline for projecting future growth in demand response programs, we first look to our estimates of load availability through existing programs. Load availability is highly dependent upon two factors: customer interest and load estimates per customer as defined by the Company's measurement and verification of demand response. As shown in Figure 3, commercial load availability decreased between 2016 and 2018. Customer interest played a significant role in this decrease. We gave customers the opportunity to adjust their contracts prior to future required control testing. Customers could opt out of their contracts prior to their completion date or adjust their demand levels.[20] Many customers adjusted their contracts for our Electric

[20] See, Compliance Filing Energy Rate Savings (ERS) Tariff Waiver, Docket No. E002/M-15-189, (March 29, 2016).

Rate Savings program during this time. This resulted in a drop of estimated available load to approximately 824 Gen. MW in 2018.[21]

We determine the second factor of estimated load availability by measurement and verification of tools in the field. This process resulted in an increase to available load in 2019. Our measurement and verification process includes actual testing events for residential and commercial Saver's Switch including data logging and statistical evaluation of signal reception rates (how often the switch can hear our message). An average five-year analysis of these reception rates results in our estimation of load per switch. Our measurement and verification results in 2018 showed an increase in these rates that appears to correspond to an addition of approximately 70,000 replacement switches put in place in the previous five-year period.[22] This increase in load per switch plus increase in participation resulted in a substantial increase in available load through the Saver's Switch program. This resulted in an increase in estimated available load of approximately 73 MW in 2019. This increase offsets some of the decreases in estimated available load due to changes in participation in our Electric Rate Savings program discussed above.

For purposes of meeting the Commission's Order to acquire 400 MW of additional demand response by 2023, we have interpreted additional demand response to include increases in available load from all sources, including new programs and participation, increased load availability of current customers, and adjustments in calculations of load availability based on measurement and verification. We calculated the addition of 400 MW of capacity equivalent demand response from a baseline set at 2019 levels, which are generally consistent with the average levels of demand reduction for the past five years, including 2017 when the Commission's Order was issued.

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[21] We note this number differs from the 850 MW noted in the 2019 Potential Study. The 850 MW figure was a forecast based on data from 2017. The Company now has more accurate information about the actual results for 2018.

[22] Beginning in 2004, the Company invested in smart switches that allowed for adaptive algorithms. All residential and business participants, as well as all switches replaced for maintenance purpose receive the adaptive algorithm switch. These details are discussed in our annual compliance filing for Saver's Switch filed in Dockets No. E002/M-01-46 & E002/CI-01-1024 on February 14.

2. Existing Product Growth

The Company has had a robust traditional demand response portfolio since the early 1990s. Our portfolio is the eighth largest among all US investor-owned utilities (IOUs) when demand response is expressed as a percentage of peak demand.[23] The portfolio comprises Saver's Switch (for residential and small business customers), our interruptible tariffs (Electric Rate Savings), and our Short-Notice Rider customers (for medium and large C&I customers). Customers accounting for approximately 11 percent of medium and large C&I peak-coincident demand are enrolled in one of these offerings.

We believe that these existing programs will grow over the next few years. For example, we believe our Saver's Switch program will continue to grow to include those customers who are not interested in an interactive smart thermostat but are interested in participating in demand response for emergency purposes. Saver's Switch is a program in which customers can participate without having to take direct action for a control event – the Company directly controls these resources. We also intend to begin exploring two-way communication switches that allow for smart meter integration. Our Electric Rate Savings program, however, is expected to grow minimally over the next several years, in part due to likely adjustments to future requirements regarding MISO required testing and future winter controls. In Table 1, we have estimated an increase of 63 MW in existing programs based on our current load forecast provided to MISO.

3. Expanded and New Traditional Demand Response Programs

We estimate expanded and new program load utilizing the results of the 2019 Potential Study estimations. The expansion and addition of the traditional demand response programs identified as cost-effective results in a projected addition of 293 Gen. MW by 2023. Unlike the 2019 Potential Study, however, which front loads achievement in the beginning of the review period, we have estimated tiered growth from 2019 through 2023 to reflect likely customer adoption. This does not affect the forecasted megawatts of added demand response by 2023. Below, we discuss the programs we intend to expand and add.

[23] The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, The Brattle Group, June 2019.

The largest growth of our demand response portfolio in the next five years will be in the expansion and transition to A/C Rewards for the majority of new customers. In 2017, we launched the A/C Rewards program, which allows customers to install a smart thermostat and sign up for demand response controls, allowing for flexible participation. Currently, we have more than 4,800 customers participating in A/C Rewards in Minnesota and the program was recently launched in Wisconsin. We are also seeking approval to expand into South Dakota.[24]

The program, as part of CIP, was recently filed with the Department for approval for 2020.[25] In this plan, the Company is expanding the program to include thermostat optimization which will maximize savings for customers for energy efficiency and provide additional benefit outside of demand response to entice customer interest. We are also anticipating the expansion of direct install channels, exploring the addition of further technologies (currently we partner with Honeywell and EcoBee), and continuing to increase our marketing opportunities, making sure to make the program and demand response visible to residential customers through advertising.

In addition, the Company is working with the Center for Energy and Environment to conduct a non-wires pilot that will estimate the savings potential of geotargeting our resources to defer the cost of distribution upgrades. The pilot, beginning in 2019, will make targeted investments to increase residential demand response (Saver's Switch and A/C Rewards) in specific geographic areas and test increased control in these areas. Final details of the pilot, in regards to demand response, are in final planning.

We have also begun to study smart thermostats in small commercial settings by offering customers an Ecobee subscription service that allows customers to manage multiple thermostats and buildings within the same portal. We hope to engage customers in managing their demand and increasing participation in demand response efforts in small business. This will be a one-year test through which we hope to identify the opportunity to request a full program in 2021. Unlike the other new products included in our five-year action plan, our estimates for adoption of the Small Business

[24] *See* PETITION FOR 2018 DSM PROGRAM APPROVAL AND APPROVAL AND PROPOSED 2020 DSM COST ADJUSTMENT FACTOR, Docket No. EL19-019, (May 1, 2019).
[25] *See* Minnesota Conservation Improvement Program 2020 Extension Plan, Docket No. G,E002/CIP- 16-115, (July 1, 2019).

Thermostats program were not based on the 2019 Potential Study. Instead, we estimated these potential savings based on product development projections of savings.

The 2019 Potential Analysis also found that there was an untapped market for traditional demand response for mid-sized customers. We have submitted for approval, through CIP, a Peak Partner Rewards program to help grow this market. [26] The Peak Partner Rewards program will offer bill credits to customers who agree to reduce their electric loads when the electric grid experiences demand response periods. The program is primarily focused on achieving dispatchable demand response savings and will be marketed to mid-sized commercial customers.

The Company continues to review opportunities for new interruptible rates that can be offered in addition to our existing Electric Rate Savings program. A new interruptible rate product the Company is designing (but has yet to include in a petition to the Department or Commission) will offer an opt-in demand reduction rate to large C&I customers that either a) are not currently on peak-controlled rates or b) were previously enrolled and still have demand reduction potential. The new rate will offer bill discounts in exchange for committed demand reductions similar to Electric Rate Savings. Unlike Electric Rate Savings, however, this interruptible rate will offer customers more participation options so they are making realistic and reliable commitments to the Company that align with their business needs. The 2019 Potential Study identified over 100 MW of opportunity for such an interruptible rate meeting the cost criteria identified in the analysis.

The 2019 Potential Study also identified an opportunity for "demand bidding." This would involve the creation of a program that allows customers to bid demand reductions into the MISO energy market through the Company. As part of the study analysis, enrollment for various programs was estimated under a variety of pricing conditions for the population of potential participants (i.e., those customers who were not already participating in any existing program). The results of this analysis suggest that, if a demand bidding program were not available, the vast majority of customers who would otherwise participate in the demand bidding program would instead be likely to participate in the interruptible rate. We have determined that the demand

[26] *See* Minnesota Conservation Improvement Program 2020 Extension Plan, Docket No. G,E002/CIP-16-115, (July 1, 2019).

bidding opportunity (and potential cost) through MISO is limited at this time, and therefore included the megawatts of load reduction potential from the demand bidding category as part of our goals for a new interruptible rate.

4. Non-Traditional Pilots and Programs

As noted above, we believe there is benefit to piloting non-traditional demand response options if a cost-recovery mechanism for these pilots can be identified. Based on an assumption that we will be able to identify such a cost-recovery mechanism, we have included some non-traditional programs in our five-year action plan.
We have currently requested approval to add electric water heaters (utilizing enabling technologies) to participate in our Saver's Switch program.[27] This would allow customers with an existing electric water heater to participate in prescribed events. The benefit of this technology, however, is estimated at less than one megawatt per year of load availability – much smaller than the potential demand savings from grid-connected electric water heaters' thermal storage capabilities. As shown in Table 1, the Potential Study estimates potential savings of 13 Gen. MW of demand response for this technology; but unless an additional funding source is identified, this potential is unlikely to materialize. Nonetheless, because the 2019 Potential Study identified this technology as cost effective, we have included in our Preferred Plan.

The total cost-effective new demand response identified in the 2019 Potential Study plus Small Business Thermostats amounts to 309 Gen. MW for both traditional and non-traditional programs. In addition, as discussed above, we currently project 63 Gen. MW of additional demand response through natural growth to existing programs between 2019 and 2023. Combined with the new and expanded demand response programs discussed above, this totals 369 Gen. MW of demand response, or 22 Gen. MW less than required by the Commission's Order.

To address this gap, we have identified, and included in our action plan, an additional opportunity that we believe will be an important program in the future of demand response, even though the 2019 Potential Study did not identify it as cost-effective. Auto DR (energy management system control of lighting and HVAC to reduce and/or shift specific commercial loads) has potential to grow our demand response portfolio,

[27] *See* Minnesota Conservation Improvement Program 2020 Extension Plan, Docket No. G,E002/CIP- 16-115, (July 1, 2019).

and has been effective in other areas of the country, like California. For purposes of the Resource Plan, and as shown in Table 1, we have conservatively estimated the potential benefit of this technology as half the technical potential shown in the 2019 Potential Study. The 22 Gen. MW of potential benefit we have identified—when combined with the other demand response additions—satisfies the Commission's requirement to acquire 400 MW of additional demand response. Like other non-traditional demand response opportunities, however, this tool is currently dependent on enabling technologies that are high in cost. We believe that a small pilot for Auto DR is an option that soon can be explored, and if enabling technology is put in place, we believe this program could achieve the savings shown in Table 1.

In Table 1, we provide a category for other non-traditional products currently in development. This category includes behavioral demand response and critical peak pricing, which would be enabled by smart meters. We are also exploring customer sited batteries, thermal energy storage, building controls and reverse demand response. All of these products and opportunities would require alternative filings and cost recovery mechanisms to pilot in Minnesota. In the meantime, we intend to pilot some of these technologies in other jurisdictions.
We note, that many of the new programs noted here could take several years to mature or develop in the market, specifically for products controlling or changing load. Some products could be difficult to understand, requiring significant incentives and education to induce customers to alter their energy usage. We anticipate that there will be periods in which peak load for existing demand response is lost as customers explore other options available to them. Therefore, although we believe the load forecasts in Table 1 are as accurate as possible at this time, actual customer load and participation may vary.

5. Battery Storage Alternative

Although we have a plan to add the 400 MW of demand response required by the Commission, we believe it is important to recognize that—because some of these resources may not be cost-effective—adding all of the demand response could come at a cost to customers. Moreover, as specific programs are developed and the Commission has the ability to weigh in on them, we believe challenges outlined in this appendix may result in a lower level of demand response than we anticipate in our action plan.
We, therefore, are exploring alternatives to demand response that would provide our customers and system with similar benefits but at a lower cost. One alternative that we believe is worth pursuing as an alternative is storage resources. Storage resources provide all of the same characteristics as demand response and likely provide greater controllability with fewer dispatch limitations. As a result, we view them as an essential resource in the future to balance high levels of renewables. While the economics of storage resource may not yet be at or below parity with a CT or some demand response

options, we believe that delta is quickly closing, and it would be more beneficial to pursue some storage resources now rather than adding non-cost-effective demand response. Doing so will allow us to start growing these resources and learning about them before we need substantially more on our system.

To be clear, we are committed to adding incremental demand response. But, as an alternative to demand response programs that may not be cost-effective, we propose allowing incremental storage to meet some portion of the 400 MW requirement.

B. Ongoing Analysis

In addition to our plans for updating and providing new demand response products in the future, we continue to test new technologies and options for customers. One example of our product development efforts is our smart thermostat optimization efforts.

The Company ran a Smart Thermostat Optimization Pilot under the name MyHome during summer 2017, summer 2018, and winter 2018/19. The pilot tested the effectiveness of Tendril's Orchestrated Energy product to provide demand response and energy efficiency savings. Tendril's product optimizes participant's smart thermostats by evaluating the thermal properties of the home, occupancy patterns within the home, and customer preferences for both comfort and energy savings, amongst other data points. All of this data goes into Tendril's product, and the result is an optimized thermostat schedule for each participant that saves energy while also maintaining customer comfort. When demand response events are dispatched, Tendril's product shifts its focus to minimizing energy usage during the event windows. Again, this is achieved by evaluating each participant individually and optimizing a load-shifting strategy that reduces energy usage during the event window while also minimizing comfort impacts to participants. Applying Tendril's product to customers' smart thermostats resulted in additional savings on top of those achieved when customers upgrade to a smart thermostat. Specifically, demand response savings were consistent with what we have seen with our A/C Rewards program, and energy efficiency savings were also observed. We continue to evaluate this technology to determine whether to include it as a full program offering.

IV. ENERGY EFFICIENCY

We currently offer more than 40 energy efficiency programs, ranging from Home Energy Squad visits and reduced-price LED light bulbs at local hardware stores to our Process Efficiency program providing comprehensive whole-building energy efficiency analysis. We continually evaluate emerging technologies and program models, looking

for new opportunities to expand our already extensive portfolio of energy efficiency options and educate customers on ways to conserve energy.

Below, we discuss the requirements related to energy efficiency arising out of our last IRP, the historical performance of the Company's Conservation Improvement Program (CIP), how the planning outlook was determined in the Preferred Plan, including a potential study conducted on behalf of the Department, the results of our modeling, and the impact of naturally occurring conservation, and a discussion of competitive bidding for customers exempt from CIP. Unlike demand response, we do not include a specific action plan for energy efficiency in this filing. Instead, we will present an energy efficiency action plan in our next CIP Triennial Plan filing.

A. Integrated Resource Planning Requirements for Energy Efficiency

The Commission's January 11, 2017, Order in Docket No. 15-21, at Order Point 11, 12, and 14.f states:

- An average annual energy savings level of 444 GWh for all planning years is approved; and
- Xcel shall investigate the potential for energy-efficiency competitive bidding process for customers that have opted out of the statewide Conservation Improvement Program (CIP) under Minn. Stat. §216B.241, subd 1a(b).
- In its next resource plan filing, Xcel shall . . . summarize its investigation and findings concerning the potential for an energy-efficiency competitive bidding process for customers that have opted out of CIP.

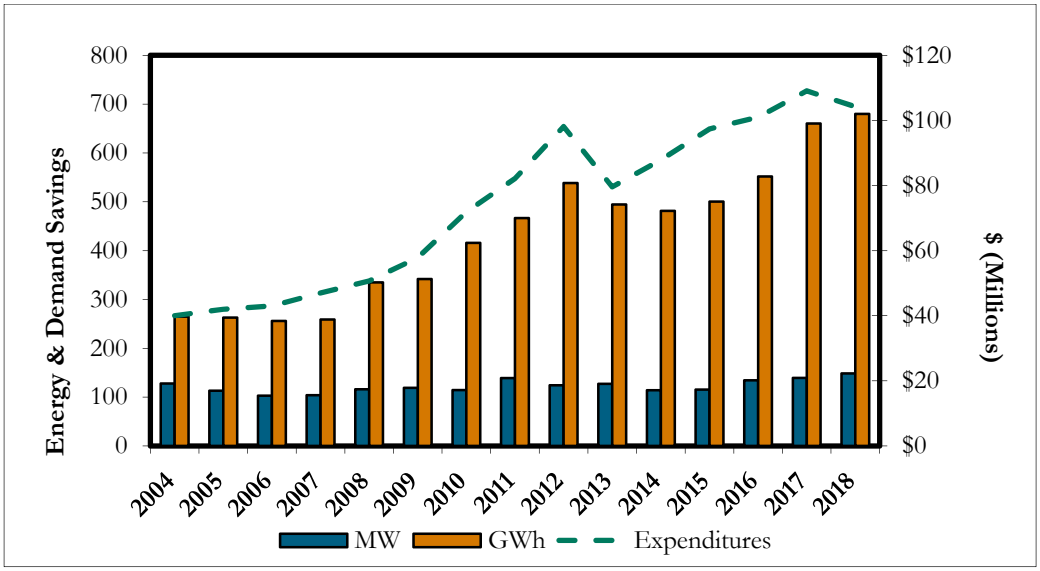
As discussed below, our Preferred Plan increases our projected energy efficiency savings in this planning period from 1.5 percent to 2.5 percent of Minnesota retail sales through a combination of both programmatic savings and naturally occurring energy savings.[28] Although this is an aggressive goal, we believe it is achievable. We further believe this can be achieved without providing an energy-efficiency competitive bidding process for opt-out customers.

[28] ORDER APPROVING PLAN WITH MODIFICATIONS ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Docket No. E002/RP-15-21, (January 11, 2017) – required 444 GWh per year in the planning period which was 1.5 percent of retail sales.

B. Historical Performance of Programmatic Energy Efficiency

Xcel Energy has one of the longest-running and most successful DSM programs in the country. Between 1990 and 2018, the Company spent $1.5 billion (nominal) on Minnesota DSM efforts and saved nearly 9,700 GWh of energy and 3,600 MW of demand. Our efforts to continuously grow and modify our customer offerings prove worthwhile as we continue to meet and exceed the state's 1.5 percent of retail sales energy savings target for CIP. The figure below highlights our historic electric CIP savings achievements.

Figure 5: Historical Electric CIP Achievements 2004-2018



Our energy efficiency portfolio has a significant impact on carbon reduction. Technologies and improvements implemented as part of energy efficiency programs generally last for several years. Reductions in energy usage based on these programs, therefore, result in commensurate reductions in carbon emissions for the same period of time. For example, our year with the highest amount of energy savings achievement in CIP was 2018. The energy efficiency measures and projects implemented during 2018 alone are anticipated to save more than 2,440,000 short tons of carbon emissions over their entire lifetimes.[29]

[29] On average, the energy efficiency projects and measures installed through CIP in 2018 have a lifetime of 12.8 years. Source: 2018 CIP Status Report (Docket No. E,G002/CIP-16-115).

The time of day and year that efficiency savings take place also impacts the level of emissions avoided. Based on 2018 results, targeting energy efficiency impacts at hours when marginal generation has the most carbon-intensive emissions rates can result in carbon emissions reductions nearly 30 percent greater than savings that occur when the marginal generation avoided is an average mix of resources.

C. Energy Efficiency Planning Outlook

The Company's projections for energy efficiency savings of 2.5 percent of retail sales are based on a combination of two major types of energy efficiency: energy savings from CIP programs and naturally occurring energy savings. In this section, we discuss the Company's current projections for efficiency savings from CIP programs, and how we developed those projections. We also discuss how naturally-occurring conservation impacts our planning outlook.

1. Energy Efficiency Scenarios

We began the development of DSM scenarios with the Minnesota Statewide Potential Study analysis conducted on behalf of the Department. The scope of this study was designed by the Department and opened to third-party bidders who committed to capture the possible measures and customer segments that would increase adoption of energy efficiency across the state. The Company was just one of many utilities that participated in the study, providing information for inputs, reviewing drafts, and participating in a stakeholder advisory committee. The study was completed as a Conservation Applied Research and Development grant.[30]

The Company was heavily involved in the potential study to help provide information that would improve the applicability of potential study results to this Resource Plan. Engagement in the potential study included:

- DSM management representation on the Potential Study Advisory Committee members;

[30] The potential study was administered by Center for Energy and Environment, Optimal Energy and Seventhwave (now Slipstream). The full report can be downloaded here: https://www.mncee.org/MNCEE/media/PDFs/MN-Potential-Study_Final-Report_Publication-Date_2018-12-04.pdf

- Providing available data to the analysis team regarding savings, market research, and forecasts; and
- Reviewing draft documents including measure lists, technical assumptions, and technical, and achievable potential.

The Company further collaborated with CEE and the study vendor to produce estimates specific to NSP-Minnesota. This supplement to the study used the portion of statewide sales in the Xcel territory for the Residential and Business classes to develop achievable potential impacts and costs for the two scenarios for the Company's Minnesota territory to be used in this Resource Plan.

The study was used as the primary input for the Company's energy efficiency potential from 2020 through 2034 and included two scenarios: "Program Achievable" and "Maximum Achievable." The two scenarios in the study differ in terms of the percent of incremental cost covered by a utility rebate. The "Program Achievable" scenario estimates adoption of measures given utility rebates equal to 50 percent of the incremental costs. The "Maximum Achievable" scenario estimates adoption at rebates equal to 100 percent of the incremental costs, effectively removing any cost barrier to adoption. Doubling the rebate levels results in higher potential impacts, but also significantly increases the cost to achieve the incremental impacts. Table 2 below shows the impacts and utility program costs (including rebate) of each scenario in the Company's territory for the first and last year included in the potential study.

Table 2: Energy Efficiency Scenarios

	2020		**2029**	
	GWh	**Costs ($M)**	**GWh**	**Costs ($M)**
Program Achievable	621	$101	762	$162
Maximum Achievable	895	$262	1,096	$419

To model levels of Energy Efficiency most accurately as a resource in the Resource Plan, the impacts for each scenario were estimated at the hourly level and expanded over the lifetime of the measures installed. The two scenarios from the study provided achievable estimates each year for various end uses from both residential and business segments.

These end uses were bucketed into the following nine "shape" groups:

- Business Cooling: End-uses that cool occupied non-residential spaces. Highly correlated to weather with highest use during hot summer weekdays.

- Business Custom: Process and lighting end-uses at non-residential sites. Correlated to operating hours at a mix of types of businesses.
- Business Compressed Air: Leakage savings from end-uses that rely on compressed air. Generally flat hourly savings.
- Energy Management Systems: Operation savings from end-uses on an energy management system to reduces load when end-uses are not in use. Generally off-peak savings.
- Flat: End-uses that have constant hourly load across a year.
- Residential Cooling: End-uses that cool occupied residential spaces. Highly correlated to weather with highest use during hot summer evenings.
- Residential Lighting: End-uses that light occupied residential spaces. Correlated to non-daylight hours and residential occupancy patterns.
- Refrigeration: End-uses providing refrigeration in both residential and non-residential spaces. Correlated to weather and hours that the refrigeration cases are opened.
- Residential Water Heating: End-uses providing hot water to residential spaces. Correlated to residential usage of hot water.

The energy savings impacts for each of these "shape" groups were applied to the hourly load shapes and lifetime assumptions of these groups as used and assumed in the Company's current 2017-2019 CIP Triennial Plan. The table below shows the lifetime assumptions for each of the shape groups and the fraction of total energy savings each of the nine groups accounts for in the various forecasts.

Table 3: Percent of Portfolio Energy

		Program Achievable		Maximum Achievable	
Shape	**Lifetime**	**2020**	**2029**	**2020**	**2029**
Business Cooling	18	14.3%	18.5%	14.0%	17.7%
Business Custom	16	39.4%	46.3%	41.6%	48.4%
Business Compressed Air	17	1.5%	1.9%	1.6%	2.0%
Energy Management Systems	17	6.1%	2.8%	5.6%	2.4%
Flat	12	7.5%	13.9%	7.2%	13.3%
Residential Cooling	9	0.5%	1.3%	0.6%	1.6%
Residential Lighting	5	1.9%	0.6%	1.8%	0.5%
Refrigeration	9	26.8%	8.8%	25.8%	8.8%
Residential Water Heating	8	1.9%	5.8%	1.8%	5.4%

In addition to the two scenarios included in the study, the Company developed an "Optimized Scenario," which included a higher level of incentives for technologies that consistently save energy during on-peak hours, or hours that have the highest costs to serve. It is expected that these measures will be the most cost-effective. Specifically, the measures included in the "Optimized Scenario" are those in the Business Cooling, Residential Cooling and Residential Refrigeration shapes. The "Optimized Scenario" includes the costs and impacts of these three shape groups at the Maximum Achievable incentive level, with all of the other shape groups at the Program Achievable incentive level.

To model investments in energy efficiency to include in the Resource Plan, the three scenarios (Program Achievable, Optimized Scenario and Maximum Achievable) were expanded to cover program achievement over the 15-year plan period (2020-2034). The expected achievements and costs for 2029 were used to populate all years 2030-2034. With lifetimes extending up to 17 years, the lifetime impacts of these achievements extended from 2020 through 2050.

2. Modeling Results

To determine the most cost-effective level of future energy efficiency achievement, the following steps were taken:

- A revised load forecast was produced that removed the effect of all energy efficiency achievement over the 2020-2034 program years.
- The costs and lifetime impacts of each of the scenarios were modeled as a supply-side resource.

- The resulting total system costs were calculated assuming achievement of each of the three scenarios, expressed as both Present-Value of Revenue Requirements (PVRR) and Present-Value of Societal Costs (PVSC).
- Total system costs were compared to identify the most cost-effective level of energy efficiency.

We modeled energy efficiency as a resource in past resource plans based on utility program costs, similar to the Utility Cost Test used in DSM cost-benefit estimation performed in CIP Triennial Plans. When modeling energy efficiency as a resource, the magnitude of rebate spending should be considered. The scenario that provides the greatest benefits, when including the rebate spending, should be the Preferred Plan for energy efficiency.

The table below shows the PVRR of the three scenarios and the PVRR savings against the base case that removes the effect of all energy efficiency achievement:

Table 4: Present-Value of Revenue Requirements (PVRR)
Energy Efficiency Scenarios (in Millions)

	PVRR	Delta PVRR
No Future Energy Efficiency	$39,985	-
Program Achievable	$37,656	($2,329)
Optimal Scenario	$37,572	($2,414)
Maximum Achievable	$38,432	($1,553)

This data shows that the Optimal Scenario produces the greatest cost savings, with over $2.4 billion in savings for the 2020-2034 program years. The societal cost of emissions was also considered in modeling. The table below shows the PVSC of the three scenarios and the PVSC savings against the base case that removes the effect of all energy efficiency achievement:

Table 5: Present-Value of Societal Costs (PVSC)
Energy Efficiency Scenarios (in Millions)

	PVSC	Delta PVSC
No Future Energy Efficiency	$49,071	-
Program Achievable	$46,087	($2,984)
Optimal Scenario	$45,989	($3,082)
Maximum Achievable	$46,609	($2,462)

This metric also shows that the Optimal Scenario produces the greatest cost savings, with nearly $3.1 billion in savings for the 2020-2034 program years.

Based on these results, the Company included the Optimal Scenario in the Preferred Plan proposed in this filing.

3. Naturally Occurring Energy Conservation

Our Energy Efficiency scenarios also include conservation measures defined as naturally occurring, or energy savings achieved through implementation of high-efficiency equipment outside of or as a supplement to utility CIP programs. The drivers for naturally-occurring energy efficiency include: adoption of efficient technologies as industry standards, building code changes, customer preference for green products, and competition among manufacturers to differentiate product offerings. These factors lead to more naturally occurring energy efficiency in the market outside of or in addition to utility products and programs.

The energy savings resulting from naturally occurring energy efficiency includes customers who take action without participating in energy efficiency programs and instances of equipment that currently may be influenced by energy efficiency programs, but in the future would not be part of a energy efficiency program because an efficient technology has become common practice (also known as market transformation). Market transformation is driven by increasingly proactive manufacturers, improvements in building practices, and energy industry allies building upon our history of helping customers conserve energy.

Although the impact of the Energy Efficiency scenarios grow over time, as shown in Table 6, the utility share of savings from future energy efficiency may decline if customers achieve increased amounts of energy efficiency outside of utility programs.

The level of energy efficiency that is modeled in this Resource Plan is intended to represent the true effect of efficiency programs on sales and what is counted toward State savings targets. The Minnesota Statewide Potential Study does not take into account code and standard changes that are not already published. Rather than trying to complicate the forecasting process, the Company believes that it is appropriate to estimate the growing impact of naturally-occurring energy efficiency in the DSM goals. The effect in immediate years is small because standards for those years are well-known, but the end of the planning period will likely see an increasing amount of energy savings occurring outside of DSM programs. As a result, the achievements claimed by the utilities represent only a portion of the energy savings customers realize. For example, the Company recently discontinued the Computer Efficiency program because it had successfully transformed the market for personal computer (PC) power supplies. Even though rebates will no longer be offered and savings will not be claimed by the Company, customers will still consume significantly less energy sooner than would have occurred otherwise.

D. Energy Efficiency Bidding

In its January 11, 2017, Order, the Commission required the Company to investigate the potential for energy-efficiency competitive bidding process for customers that have opted out of CIP. We have long-standing relationships with our large Commercial and Industrial (C&I) customers. Only a handful of Xcel Energy customers have applied and qualified for exemption from the ongoing expenses of our electric CIP portfolio. The Company has investigated the process for exempt customers to bid in energy efficiency to the Company and determined there is no need for such a process at this time. This decision is based on the small number of exempt customers, the statutory requirement to continue energy efficiency analysis at these sites without the benefit of utility funds, and the nature of this customer group as described below.
CIP exceptions are defined by Minnesota Statute §216B.241, Sub. 1a. which in part states:

> The owner of a large customer facility may petition the commissioner to except both electric and gas utilities serving the large customer facility from the investment and expenditure requirements…***[of CIP]***…the filing must include a discussion of the competitive or economic pressures facing the owner of the facility and the efforts taken by the owner to identify, evaluate, and ***implement energy conservation and efficiency improvements***… (emphasis added)

Under this statute, customers seeking an exemption are required to file with the Department and must prove that they are implementing energy conservation and

efficiency improvements. They also must show there is no need for additional incentives to manage, complete, and address energy efficiency measures. Exempt customers must provide a filing every five years to the Department explaining measures that they are already taking to be efficient. Given the small number of exempt customers in the Company's territory and these statutory efficiency requirements, in investigating a potential bidding process for customers who have opted out of CIP,[31] we determined that such a process would not facilitate meaningful efficiency improvements over the status quo.

These exempt customers are motivated to continue ongoing process evaluations and energy efficiency analyses. They are naturally incentivized to pursue efficiency improvements to continue to keep their product costs as low as possible, including any and all economically viable improvements related to energy consumption. We continue to work closely with these customers, interacting with them through our account representatives to serve their current and future energy needs.

We believe that the impacts of future energy savings for these exempt customers are captured in the load forecast. With the statutory requirement to prove implementation of energy conservation and efficiency improvements, it is reasonable to assume the same rate of implementing such improvements will occur in the future as it has historically for these customers. Since the growing rate of historical energy savings from these customers is reflected in actual sales data (in the form of reduced sales), we have determined that future energy savings (reduced sales) of future energy conservation and efficiency improvements are embedded into the sales forecast at the rate by which they occurred in the past.

Given the amount of load involved in our exempt customer base, as well as the reassurance of the Department's review and acceptance of these exemptions, including verification of ongoing energy efficiency improvements, we believe that a specific bidding process for these customers is not warranted at this time.

[31] ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, (January 11, 2017), Order Point 14 (f).