STATE OF MINNESOTA

BEFORE THE PUBLIC UTILITIES COMMISSION

In the Matter of the Distribution System Planning For Xcel Energy

PUC Docket No. E002/CI-18-251

COMMENTS OF CLEAN GRID ALLIANCE, MINNESOTA CENTER FOR ENVIRONMENTAL ADVOCACY, SIERRA CLUB AND THE UNION OF CONCERNED SCIENTISTS

INTRODUCTION

These comments on Xcel's 2018 Integrated Distribution Plan ("IDP") are being offered on behalf of Clean Grid Alliance, Minnesota Center for Environmental Advocacy, Sierra Club and the Union of Concerned Scientists, with technical assistance from Sommer Energy, LLC. Overall, we conclude that Xcel's first IDP is a step in the right direction, but could be amended to increase the uptake of non-wires alternatives and to bring more meaningful information to its Integrated Resource Plan ("IRP"). As Xcel points out in its filing, distribution planning in Minnesota is at its earliest stages. But this nascency brings the opportunity to refine the process in time to make the investments necessary to modernize the grid for large additions of distributed electricity generation, energy efficiency, and load management. The Commission has been admirably forward looking in initiating these planning processes for our state, and this foresight gives us the opportunity to inform critical investment decisions that have significant implications for our state's ability to meet its greenhouse gas reduction goals. These comments detail some suggestions for improvements in the planning process that will benefit future IDP dockets.

I. Non-Wires Alternative Initial Screening Criteria Are Overly Limiting

Xcel applied the Commission-established $2 million minimum cost to its distribution project portfolio to identify potential candidates for non-wires alternatives (NWA). This resulted in 6 mandated projects, 10 asset health related projects, and 22 capacity projects,[1] each with a total cost over

[1] Xcel Energy, *Integrated Distribution Plan, 2019-2028,* Docket No. E002/CI-18-251, Nov. 1, 2018, at Table 10, p.85 [hereinafter "Initial IDP Filing"].

$2 million. Xcel then narrowed down that list further with its own set of criteria, which included project type, costs, timeframe, and risks. Xcel eliminated projects that were considered mandated or asset health related projects. In addition, Xcel eliminated consideration of any projects that would occur in years other than between 2021 and 2023. Xcel identifies risk as one of its criteria, however, it states that a hard cutoff was not used for eliminating projects. Instead, Xcel states that the number of N-0 and N-1 risks were considered in its final selection for the project on which to perform the NWA analysis and include in the IDP. Once Xcel applied these "filters," it was left with 11 capacity projects that could be selected for the NWA analysis.

Of these criteria, three are overly limiting and/or unclear: 1) eliminating projects that cost less than $2 million, 3) ruling out projects based on N-0 and N-1 risks, and 3) limiting the time horizons to consider projects to the period between 2021 and 2023.

A. Financial threshold is too high

While the $2 million threshold for the NWA analysis was established as a part of the IDP filing requirements, we would strongly encourage the Commission to lower this amount for future IDPs. Xcel also seems to say that this threshold amount may be too high, "Per the Commission's order, we evaluated projects with costs greater than $2 million. However, we believe there's additional work to be done to best identify the range of projects [sic] costs for this filter."[2]

Liberty Utilities in New Hampshire stated in its integrated resource plan[3] that it would use a threshold of $0.5 million as the cutoff for the projects to be considered for NWA. And National Grid (serving its Rhode Island service territory), uses $1 million as its financial criteria for screening projects.[4] The New York utilities use financial criteria of $1 million or several hundred thousand dollars depending on the location or complexity of the project. These criteria are described in more detail below in Section I.E. Recommendations to Enhance Xcel's NWA Analysis.

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[2] Initial IDP Filing at 84.

[3] Liberty Utilities, State of New Hampshire before the Public Utilities, January 2016, Docket No. DE-16-097, at 39-40, 60-64, available at https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-097/INITIAL%20FILING%20-%20PETITION/16-097_2016-01- 15_GSEC_DBA_LIBERTY_LCIRP.PDF

[4] Northeast Energy Efficiency Partnerships (NEEP), *EM&V Forum and Policy Brief: State Leadership Driving Non-Wires Alternative Projects and Policies*, January 2017, at 7, available at https://neep.org/sites/default/files/resources/NWA%20brief%20final%20draft%20-%20CT%20FORMAT.pdf [hereinafter "NEEP 2017"].

B. Elimination of N-1 projects

Xcel identified the number of N-0 and N-1 risks as one of its "filters" utilized in the screening processes for projects. An N-0 risk occurs when the system is intact and operating in normal conditions, and an N-1 risk occurs when there is a contingency event, such as a loss of a feeder. When this contingency occurs, other feeders may become overloaded from the lost load being transferred to them. For those projects exceeding the $2 million threshold, Xcel reported the number of N-0 and N-1 risks for each project (see Table 10 of the IDP). For the New Viking Feeder project that was evaluated for NWA, Xcel identified four risks associated with the project. Two of the risks were N-0 conditions, where feeders were overloaded during normal operations whereas the other two risks were N-1 conditions where overloads occurred due to a loss of a feeder. Xcel states that these risks were one of the screening criteria to determine which projects would be candidates for NWA analysis: "We did not use a hard cutoff for this filter but factored it in as we determined which project would be best for a NWA analysis."[5] We think it may be more straightforward to exclude projects for NWA on the basis of how much energy reduction is needed, e.g. 25% reduction or more on the feeder. For instance, in Rhode Island, National Grid uses a criterion that "if load reduction is necessary, it is expected to be less than 20% of the relevant peak load in the area of the defined need."[6] Similarly, Liberty Utilities in New Hampshire eliminates a project from consideration for a NWA solution if a reduction of more than 20% of the total load in the area of the distribution deficiency is needed.[7]

The Brattle Group's 2019 load flexibility report prepared for Xcel[8] used a similar criterion to screen projects for deferral through the use of Demand Response ("DR"). The Brattle Group eliminated projects with more than 6 MVA of load at risk, since 6 MVA accounts for approximately half of the load on a typical Xcel feeder.

C. Timeline for analysis

NWA projects should be considered for a 10-year budget cycle to allow for enough time to develop alternative solutions to the identified need on the distribution system. For Xcel's IDP, a 5-year cycle was used for evaluating projects. Northeast Energy Efficiency Partnerships (NEEP) has

[5] Initial IDP Filing at 84.

[6] NEEP 2017 at 7.

[7] *Id.* at 4.

[8] Hledik, R., Faruqui, A., Donohoo-Vallett, & T. Lee, THE BRATTLE GROUP, *The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory*, 2019.

recommended[9] that initial screening criteria have enough lead time to allow for the deferral of a transmission and distribution investment. It may also be possible to achieve larger reductions in load with a longer lead time.

D. Cost benefit analysis considerations

The New Viking Feeder Project that Xcel selected to analyze for this report indicated that the optimal NWA solution was going to have a significantly larger cost than the traditional solution budgeted for this feeder. Xcel stated that the cost of the optimal DER solution to mitigate the four risks associated with the Viking project was significantly higher than the cost of the traditional solution, which is to install a new feeder to pick up the load from the overloaded feeders. It appears that the extent of Xcel's cost-benefit analysis is to compare the cost of the traditional project with the NWA solution without considering potential benefits from the implementation of an NWA solution. Because little detail was given it's not clear whether Xcel accounted for such benefits as avoided transmission and distribution operations and maintenance, voltage and power quality, reliability,[10] avoided energy and greenhouse gas emissions, avoided losses, and other ancillary services or societal benefits[11] that may be associated with a NWA solution. Leaving these out would bias the result towards traditional solutions over NWAs. A report by GridLab[12] highlighted two states (California and New York) in which a comprehensive cost benefit analysis framework is utilized. A report by E4TheFuture, Peak Load Management Alliance (PLMA), and the Smart Electric Power Alliance on NWA highlights how important comprehensive cost-benefit analysis has been for NWA projects pursued by utilities across the United States.[13] In New York, the Joint Utilities of New York were directed to develop a Benefit-Cost Analysis Handbook which outlines some of the significant benefits and costs to evaluate, including avoided costs of bulk systems, avoided distribution system infrastructure, avoided costs of restoring power during outages, and avoided emissions and land

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[9] Grevatt, J., and Neme, C., ENERGY FUTURES GROUP, *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments,* available at https://neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf.

[10] One tool that can be used to estimate reliability is the Berkeley Lab Interruption Cost Estimate Calculator (ICE). The ICE calculator can be accessed at https://eaei.lbl.gov/tool/interruption-cost-estimate-calculator.

[11] Volkmann, C., GRIDLAB, *Integrated Distribution Planning: A Path Forward,* 2018, available at https://static1.squarespace.com/static/598e2b896b8f5bf3ae8669ed/t/5b15ae6470a6ad59dcb92048/1528147563737/IDP+Whitepaper_GridLab.pdf [hereinafter "GridLab 2018"].

[12] *Id.*

[13] Chew, B., Myers, E., Adolf, T., and Thomas, E., E4THEFUTURE, PEAK LOAD MANAGEMENT ALLIANCE, AND SMART ELECTRIC POWER ALLIANCE, *Non-Wires Alternatives – Case Studies From Leading U.S. Projects*, 2018, available at https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf.

impacts. If it is not doing so already, Xcel should consider enhancing its cost benefit analysis beyond the scope of simply comparing the cost of the traditional project with the cost of the NWA in order to ensure the full range of project benefits is captured.

In addition, while Xcel acknowledges that a variety of technologies could substitute for a traditional solution, it does not appear to consider whether several together can meet the project need. That is, while it refers to the "optimal DER Solution" for the New Viking Feeder, that solution consists only of batteries. It's not clear how quickly or under what circumstances Xcel would make its consideration of NWAs broader.

E. Recommendations to enhance Xcel's NWA analysis

The IDP appears to show that Xcel is focusing its efforts on current distribution projects and areas of identified need within its system. As Xcel continues to fine tune its analysis for NWAs it will also be important to be proactive in considering projects that may help address *future* system needs. For instance, Xcel discusses the possibility that its "Minnesota service territory may see adoption of more than 40,000 electric vehicles by 2023 – with the possibility of significantly more or less adoption over this horizon as well."[14] It's not clear whether the current, budgeted distribution projects account for the increased load these EVs may bring. If not, it may make sense to consider NWAs in those areas of expected, significant EV growth now and not simply when that growth materializes. This gives Xcel enough time to bring NWA projects to fruition. There may be other circumstances like this of which Xcel has a reasonable expectation will come to pass and for which NWAs can cost-effectively meet load.

Another recommendation is to follow New York's lead and identify areas where there are current and/or foreseeable system needs in its Distributed System Implementation Plan and to also publish heat maps[15,16] to help illustrate where DER deployment may be able to help address system needs, which allows for the targeting of specific areas for DER to alleviate existing problems.[17] Similar to New York, Rhode Island also provides interactive heat maps for visualizing potential areas for DER.[18]

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[14] Initial IDP Filing at 196.

[15] New York State Dep't of Public Service, *Hosting Capacity Maps and Useful Links*, available at http: //www3.dps.ny.gov/W/PSCWeb.nsf/All/6143542BD0775DEC85257FF10056479C?OpenDocument.

[16] Joint Utilities of New York, *Overview of Currently Accessible System Data*, available at https://jointutilitiesofny.org/system-data/

[17] GridLab 2018.

[18] *See, e.g.*, Rhode Island Heat Map, available at https://ngrid.maps.arcgis.com/apps/webappviewer /index.html?id=cf7c555e06034fb2a75f092790cd3d7f

Xcel should also consider more than one or two solutions as an NWA - it may be able to develop a portfolio of solutions to compare with a traditional solution. For the New Viking Feeder Project, Xcel focused only on batteries and solar for the optimal DER. The result was that all battery storage was the optimal DER solution for this project at a cost of $22 million, which is significantly higher in cost than the traditional project budget of an estimated $2.5 million. In its IDP, Xcel acknowledges that it will continue to work on the criteria it will use to screen projects for analysis. Xcel may benefit from consideration of a hybrid approach to distribution upgrades that include a combination of NWA and traditional solutions. For example, revisions made to Rhode Island's System Reliability Procurement (SRP) include using NWA to target highly-utilized areas and considering "partial NWA" to reduce the scope of the infrastructure projects.[19,20]

Xcel may also want to consider the classification of projects for the evaluation criteria. In this report, Xcel classified projects based on whether they were "mandated", "asset health", or a "capacity project." In contrast, the joint utilities in New York proposed a framework where projects are classified into different project categories based on the type of work needed which may include new business, system expansion, risk reduction or asset replacement.[21]

We would recommend that both the Commission and Xcel consider utilizing criteria developed by leading states and utilities for NWA analysis, such as Rhode Island, New York, and California. This will help guide Minnesota in developing a more comprehensive set of criteria for the screening of candidate NWA projects that can defer or eliminate distribution upgrades. The Joint Utilities of New York filed the Supplemental Distributed System Implementation Plan ("DSIP") following the New York State Public Service Commission's Order Adopting Distributed System Implementation Plan Guidance. The DSIP included a framework for determining which projects were potential candidates for NWA solutions. This framework focused on three areas including project type, project timeline, and cost. Each of the six utilities provided its criteria for evaluating potential NWA projects and it are depicted in Figure 1 below.

[19] GridLab 2018.
[20] NEEP 2017.
[21] *Id.*

Table 1 - New York Utilities NWA Criteria[22]

	Con Edison, Orange & Rockland	Central Hudson	National Grid	NYSEG and RG&E
Project Type	Load Relief or Load Relief in combination with Reliability	Load Relief and Reliability	Load Relief and Reliability	Load Relief projects that do not involve a customer contribution or do not have a specific customer in-service date that is before the timeline suitability criteria of 36 months
Timeline	Large Project[23]: 36 to 60 months Small Project: 18 to 24 months	Large Project[24]: 36 to 60 months Small Project: 18 to 24 months	Large Project[25]: 24 to 60 months Small Project: 18 to 24 months	Minimum of 36 months to time of need
Cost	Large Project: No cost floor Small Project: ≥ $450,000	Large Project: ≥ $1 million Small Project: ≥ $300,000	Large Project: ≥ $1 million Small Project: ≥ $500,000	Projects with construction cost greater than $1 million

[22]Joint Utilities Filing of Utility-Specific Implementation Matrices for Non-Wires Alternatives Suitability Criteria, *In the Matter of Distributed System Implementation*, Case 16-M-0411, March 1, 2017, available at https://jointutilitiesofny.org/wp-content/uploads/2017/11/3E7E6426-F3FC-46F3-A8C4-CD44625DA792.pdf.

[23] Con Edison and Orange & Rockland define large projects as projects that are on a major circuit or substation and above. Small projects are defined at projects that are feeder level and below.

[24]Central Hudson will categorize projects based on the complexity of the traditional solution and the scope and scale of alternative DER solutions.

[25] National Grid will categorize projects based on the complexity of the traditional solution and the scope and scale of alternative DER solutions.

II. Grid Modernization

Xcel estimates it will make an investment of $632 to $822 million for AMI, FAN, and FLISR implementation. Our understanding is that all of these investments have not yet been approved by regulators nor are the details of these costs yet available. In the absence of those specifics, we strongly recommend that these investments should be cost-effective, with measurable, positive benefits for ratepayers and that to the extent that Xcel intends to develop future demand-side management programs as a result of these investments that those programs should be proposed simultaneously with a petition for rate recovery rather than those programs being promised as some future date.

III. Distributed Energy Resources

A. Energy storage adoption forecast

Xcel opts not to include an energy storage forecast in its IDP. However, Xcel reported receiving about 40 interconnection applications within its distribution system for energy storage from 2017 through October 2018.[26] Given the amount of interconnection applications received by Xcel it would be prudent to include a non-zero estimation of future interconnections and its size since assuming zero is still a forecast, just not one based upon recent experience. The forecast could be as simple as assuming that interconnections continue at the same rate as it had in the prior year with percentage variations above and below that rate.

B. Solar adoption forecast

Xcel's Reference Case for per-year distributed solar additions (MW/AC) show a large drop-off in the solar forecast for the Solar*Rewards and S*R Community programs.[27] Its solar forecast is likely to understate solar adoption even in the "high" case since it assumes much less distributed solar uptake than what has been connected to the distribution system in recent years. Figure 1 shows the base case distributed solar forecast that Xcel plans to use for its upcoming IRP filing.

[26] Initial IDP Filing at 194.

[27] *Id.* at Table 21, p.192.

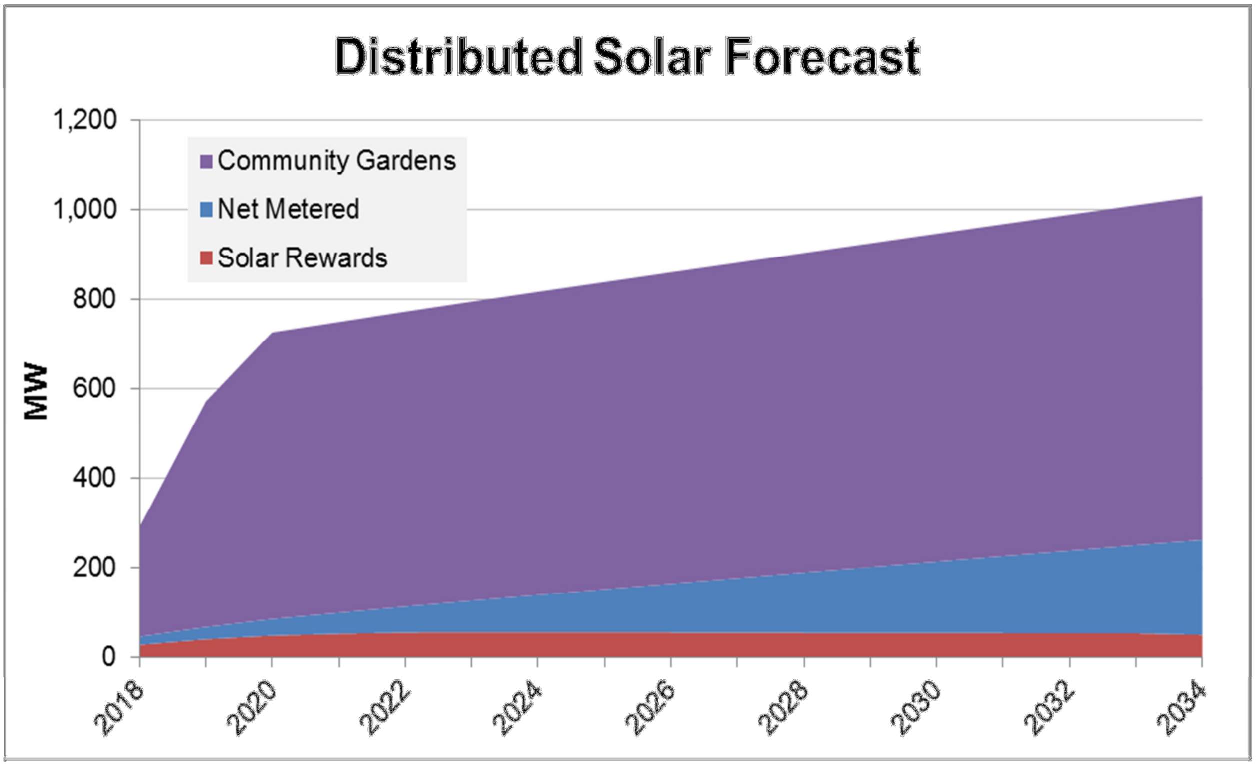

Figure 1. Xcel Distributed Solar Forecast for IRP[28]

This forecast is similar to, though slightly different than the Base Distributed Solar PV forecast in the IDP. We understand that Xcel premised this forecast on distributed solar policy changes underway as well as working out the queue of distributed solar projects that has been built up. While policy is an important driver of solar adoption, there is always the possibility that continued reductions in solar (and battery) prices will push these adoption rates higher than forecasted. The Base and High levels of Distributed Solar adoption differ by only 292.6 MW in the final year of the forecast. In our view, a more meaningful High band forecast, and one that would be useful for Xcel's IRP, would simulate rates of adoption significant enough to have a meaningful impact on Xcel's remaining load obligation, i.e., it would change the seasonal magnitude of load as well as overall total load such that resource acquisition and retirement decisions are impacted.

[28] Presented by Xcel at its February 11, 2019 workshop.

CONCLUSION

We have no reason to dispute Xcel's claim that IDP is in a relatively nascent stage in Minnesota and that some of the tools and processes that would be ideal for this purpose have not yet been formulated. However, that shouldn't mean that Xcel can't undertake NWAs for projects that meet reasonable screening criteria or that DER adoption can't be a greater part of the scenario/sensitivity analysis in Xcel's IRP. Xcel has made steps towards these objectives with this IDP, but these comments outline ways in which those steps could be more robust and larger.

Dated: February 22, 2019

Respectfully submitted,

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