MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	February 27, 2020		Agenda Item 7*
Company	Minnesota Power		
Docket No.	**E015/M-19-684**		
	In the Matter of Minnesota Power's 2019 Integrated Distribution Plan		
Issues	1. Should the Commission accept or reject Minnesota Power's Integrated Distribution Plan (IDP)? 2. Should the Commission adjust any of the IDP filing requirements for Minnesota Power's next IDP?		
Staff	Michelle Rosier	Michelle.rosier@state.mn.us	651-201-2212

✓ **Relevant Documents**	**Date**
Minnesota Power, 2019 Integrated Distribution Plan	Nov. 1, 2019
Department of Commerce-Division of Energy Resources, Initial	Jan. 15, 2020
Office of Attorney General – Residential Utilities Division, Initial	Jan. 15, 2020
Clean Energy Economy Minnesota, Initial	Jan. 15, 2020
Bruce Schnell, Public Comment	Jan. 28, 2020
Vicki Andrews, Public Comment	Jan. 29, 2020
Minnesota Power, Reply	Jan. 29, 2020
Department of Commerce-Division of Energy Resources, Reply	Jan. 29, 2020
Office of Attorney General – Residential Utilities Division, Reply	Jan. 29, 2020
Simon Gretton, Public Comment	Jan. 29, 2020

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I. Statement of the Issues

Should the Commission accept or reject Minnesota Power's Integrated Distribution Plan (IDP)?

Should the Commission adjust any of the IDP filing requirements for Minnesota Power's next IDP?

II. Background

On November 1, 2019, Minnesota Power filed the Company's inaugural Integrated Distribution Plan (IDP) in response to filing requirements established by the Commission's February 20, 2019 Order Adopting Integrated Distribution Plan Filing Requirements in Docket No. E015/CI-18-254. The purpose of the Commission's IDP filing requirements is to facilitate a utility's IDP filing that will meet the following planning objectives[1]:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution-system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

On January 15, 2020, the Department of Commerce-Division of Energy Resources (Department), Office of Attorney General- Residential Utilities Division (OAG), and Clean Energy Economy Minnesota (CEEM) submitted initial comments.

By January 29, 2020, Minnesota Power, the Department, and OAG filed reply comments; in addition, three citizens filed public comments on Minnesota Power's IDP.

III. Staff Summary of the Issues

Parties agree the Commission should accept Minnesota Power's 2019 IDP with clarification that acceptance is not an advanced determination of prudency for any proposed system modifications or investments (**Decision Option 1**). The Department, OAG and CEEM describe the 2019 IDP as foundational in beginning a dialogue between Minnesota Power, the Commission, and stakeholders interested in achieving the IDP planning objectives. Further,

[1] MN PUC, ORDER ADOPTING INTEGRATED DISTRIBUTION PLAN FILING REQUIREMENTS (February 20, 2019), Docket No. E015/CI-18-254, p. 2

these parties agree Minnesota Power's future IDPs should become more refined to help assess which IDP filing requirements and investments are beneficial to ratepayers and which are not.[2] Minnesota Power agrees to all suggested modifications (**Decision Options 2-3**).

All parties recognize that the IDP process (i.e. filing requirements) and filings (i.e. IDP) are an iterative process between Minnesota Power, the Commission, and stakeholders. Minnesota Power's IDP filing requirements are biennial; thus, the next IDP is due November 1, 2021. To capture this detail, staff propose language for the Commission and parties to consider **(Decision Option 4)**.

There are no contested decision options.

IV. Summary of Minnesota Power's 2019 IDP

Theme

Minnesota Power's 2019 IDP contains three key themes: People, Resiliency, and Innovation.

Distribution Planning Evolution

Minnesota Power outlines how Distribution Planning engages with Resource Planning and Load Forecasting today on issues like the Integrated Resource Plan and Annual Forecast Report.[3] In the near-term, Minnesota Power's distribution planning process is evolving to include more active coordination between Distribution Planning and Resource Planning for load forecasting and vetting of non-wires alternatives.[4]

Engagement

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[2] Department Initial, pp. 2,6. Minnesota Power Reply, p. 1, OAG Reply, p. 2,

[3] Minnesota Power, 2019 IDP, pp. 32-34

[4] IBID

The Company hosted an IDP stakeholder forum and notes existing customer survey results (JD Power, 2018 and Rapp Strategies, "recent.") Customer surveys and engagement in industry forums has led to Minnesota Power launching digital platforms like online credit card payment, additional MyAccount tools (e.g. start, stop, transfer service, and mobile app outage notification), and a "Voice of the Customer" online discussion board.[5]

Below staff summarizes Minnesota Power's IDP in alignment with the headings found in the Commission's filing requirements: Baseline Data, Long-Term Distribution System Modernization and Infrastructure Investment Plans, Hosting Capacity and DER interconnection, DER Scenario Analysis, and Non-Wires Alternatives Analysis. Minnesota Power provides a Compliance Matrix for all filing requirements as Appendix A of the IDP.[6]

1. Baseline Data (System, Financial and Distributed Energy Resources)

System

The Company provides a matrix of IDP filing requirement and location in the 2019 IDP; including where to find the baseline data required.[7] Staff summarizes in the table below Minnesota Power's customer-focused and distribution operation systems.

Minnesota Power's Customer-Focused Systems	
Customer Information System (CIS)	Designed to securely store customer information and act as the primary billing and rate engine. Planned for upgrade in 2019-2020 to enable additional functionality.[8]
Metering – *automated meter reading (AMR) and Advanced Metering Infrastructure (AMI)*	AMR installed between 2002-2006 utilizing 1st generation power line carrier technology (versus radio frequency), which transmit kWh and kW data every 27 hours, and became obsolete in 2009 (Minnesota Power has self-supported since 2011.) Minnesota Power plans to transition to AMI for all retail customers by 2023. As of June 2019, about 60% of meters were AMI (82,000 meters). Historical deployment was 6-8% per year but the Company is supplementing AMI expansion budget to accelerate deployment.[9] Minnesota Power describes the AMI meter functionality: "The meters act as 'smart nodes' at each customer's premises, allowing a number of benefits including: efficient deployment of advanced time-based customer rate offerings; outage notifications; notification of service issues

[5] Id, p. 7
[6] Id., App. A, pp. 1-4.
[7] Id, App. A, pp. 1-3 highlight locations of the baseline data required.
[8] Id, p. 10
[9] Id, pp. 26, 28

	(such as low/high voltage, over current, and tamper warnings); improved load control; more frequent customer usage data; and the ability to more quickly reconnect customers who may have been involuntarily disconnected due to non-payment."[10]
Meter Data Management (MDM)	Validation, editing, estimating, and storing of rate and operational information from metering system (AMI, AMR, and interconnected industrial meters). Planned to replace various existing systems in 2019-2020 with optimized for billing and rates into 2021.[11]
Meter Asset Management	Stores specific AMI meter attributes (e.g. firmware management, TOU schedules, load/voltage profile structures, specific rate data) to allow for automation of some commands and features with AMI meters and billing system (e.g. verification of meter configuration and readiness for specific rates within MDM). Planned with MDM in 2020.[12]
My Account	Online customer portal began with consumption and usage data (now provided daily and hourly); bill view and online payment (2017); outage reporting; stop, start or transfer service; and other account functions. Plan to continue enhancements through 2030. Example: Customer Preference Center (2020-2021) for notifications preferences.[13]
Smart Grid Gateway (SGG)	Enables MDM to talk to head-end metering systems by using standard data models within the AMI system to integrate with other systems (e.g. CIS, Advanced Meter Billing System, MDM, Meter Asset Management, Service Order Management). Planned for implementation with MDM and Meter Asset Management in 2020.[14]
Mobile Workforce	Paperless processing of work orders. First phase (2017) focused on interfacing CIS field order for Metering and Collections resulted in nearly 30,000 paperless customer orders. Second phase (2019) was OMS trouble tickets resulting in 4,000 electronic orders. Third and final phase (2020) will focus on integration of work and asset management systems.[15]
Outage Management System (OMS)	Contains all reports of power outages, manages planned outages, and predicts failed equipment and fault location based on outage reports. Source data for customer-facing outage data and records for regulatory reporting. Requires GIS data but current incompatibility issues reduce efficiency and effectiveness. Slated for replacement in 2020 due to declining

[10] Id, pp. 23, 27
[11] Id, p. 10
[12] Id, p. 11
[13] Id, p. 10
[14] Id, p. 11
[15] Id, pp. 11-12

	manufacturer support, and to enable possible future advanced distribution management system (ADMS) or DERMs.[16]
Minnesota Power's Operational Systems	
Geographic Information System/Utility Network Model (GIS)	Used for nearly 30 years to provide geographical and spatial aspects to operational data requiring GIS staff to transfer data between systems. Planned transition to a real-time Utility Network model interconnected to all systems with accuracy and security for customer, internal and stakeholder applications scheduled to begin in 2020.[17]
Energy Management System (EMS), Distribution Management System (DMS), Distributed Energy Resource Management System (DERMS)	EMS used for nearly 40 years. Current version combines transmission operations and high capacity distribution substations for situational awareness and remote switching of equipment. Plan to determine future system requirements in 2023-2024 for possible DMS capability as communication options and automation is expanded into distribution enabling features like volt/VAR optimization and conservation voltage regulation. Minnesota Power has and is considering pilots in this area. Due to low DER penetration, the Company does not see DERMS as necessary at this time.[18]
Infrastructure/Distribution Asset Management	Minnesota Power's plan for asset renewal, preventative measures, and emergency replacement. Asset renewal in recent years target reliability and resilience priorities. At substation level, programs are integrated into a single modernization project to address all asset renewal needs at once.[19]
Supervisory Control and Data Acquisition (SCADA)	Installed on half of the Company's feeders (181 of 360 feeder) and oversees state and health of primary and 3-phase distribution with analog data in 4 second intervals (e.g. amps, MW, MVar, MVA, kV) and binary in 60 second intervals and when there is a change of state (e.g. statuses, alarms, outages). Historical database stores data for engineering planning and analysis. SCADA enables system operators to remotely operate breakers and motor-operated switches to isolate faulted equipment and feeder sections. Since 2017, 46% of the feeders without SCADA (83 feeders) have had smart sensors installed to monitor voltage and current near the feeder breaker and store data offsite for later review and download. Plans to complete roll out of smart sensors on distribution feeder breakers by 2020. Continuing use of smart sensors for fault location. Plans to expand smart sensors to most substations to gather better data and eliminate manual reads.[20]

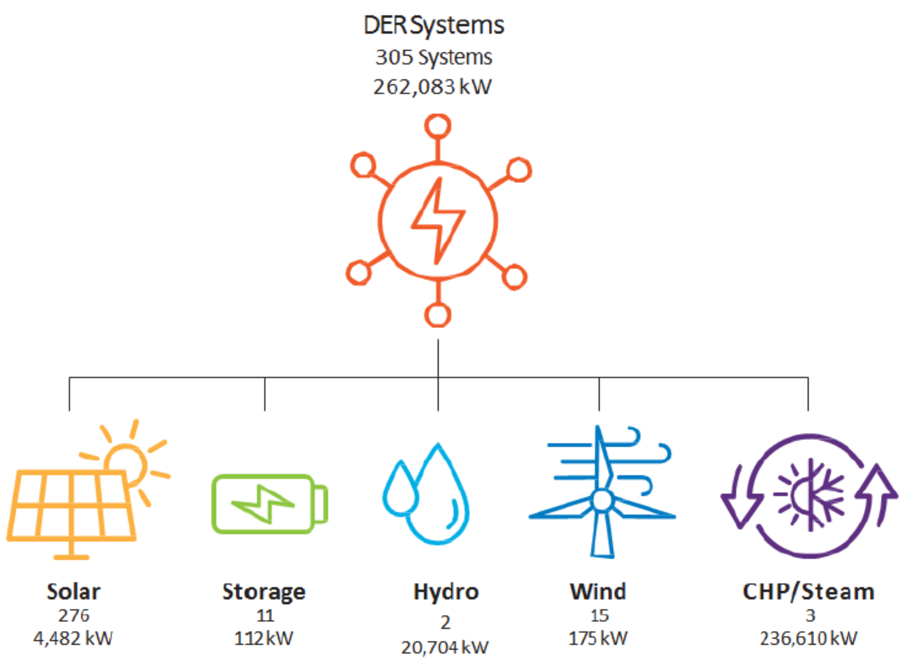
[16] Id, pp. 12, 21-22
[17] Id, pp. 12, 22
[18] Id, p. 12
[19] Id, pp. 12-13
[20] Id., pp. 26-27

Financial

Minnesota Power provides a bar chart and summary of annual spending by categories in the IDP.[21] Historically, the Company followed a depreciation level spending pattern on the distribution system; however, going forward, plans to increase investment above depreciation level spend to accelerate modernization and reliability projects. Between 2014 and 2018, the Company's has spent the least in the grid modernization and pilot programs category ($152,000 in 2018); whereas, reliability and power quality fluctuates between the 2nd and 4th highest spend category (3rd highest in 2018 at $3.7 million). During this same time period, the Company's annual spending on metering has increased each year and now is the second highest spend category ($7.1 million in 2018) behind the consistently highest spend category: Age-related/Asset Renewal ($10.2 million in 2018).

Distributed Energy Resources

Minnesota Power reported 305 DER systems totaling 262 MW interconnected to the distribution grid. The Company has another 1.4 MW of Community Solar Gardens. The Company's IDP provides a visual of customer-sited DERs:[22]



The IDP highlights that 90% of the customer-sited solar installations in 2018 received the Company's SolarSense rebate, and about 47% of the total customer-sited solar installs have received the rebate.[23] Minnesota Power did not charge customers an application fee for solar installations in 2018, and did not track processing costs in detail. Minnesota Power customers paid $62,393 for system upgrades to accommodate DG installations.

[21] Id, pp. 14-15
[22] Id., p. 15, figure 6.
[23] Id, p. 16; IBID figure 7

Minnesota Power has 260 MW of MISO-accredited demand response from large industrial customers – approximately 15% of peak demand. The Company also has about 8,000 residential, commercial and small industrial customers on a dual fuel rate, which requires a non-electric back-up heat source – with 4 MW Summer and 30 MW Winter demand response.[24]

Minnesota Power estimates 180 electric vehicles in its service territory; however, only 4 customers are enrolled in the off-peak EV charging tariff.[25] The Department of Energy reports 19 public EV charging stations with a total capacity of about 1 MW.[26]

Minnesota Power proudly highlights achieving 75 GWh in incremental (i.e. first year) annual energy savings between 2013 and 2018 through the Company's Conservation Improvement Program (CIP). Prior to 2017, Minnesota Power reported peak demand savings based on the Company's peak (in winter), which ranged from 6 to 9 MW. In 2017, Minnesota Power began reporting peak demand savings coincident with the MISO peak (in summer), resulting in 8.3 MW in 2017 and 2018.[27]

Minnesota Power includes a description and brief evaluation of a few current and past pilots:

IDP p.	Pilot	Status	Commission Dockets
29	Time of Day/Critical Peak Pricing	Open	E015/M-12-233
30	Solar Sense Low Income Solar	Open	E015/M-16-485
31	Home Area Network	Ended	See TOD/CPP
31	Dual Fuel Replacement	Open	Rate Cases; Current: E015/GR-19-442

In addition to these pilots, they also describe the Company's electric fleet vehicle lease program (2- 2017 Chevrolet Bolts); and 3 solar projects where the Company partnered with local organizations serving homeless, low-income and veteran communities.[28]

2. Long-Term Distribution System Modernization and Infrastructure Investment Plans

Minnesota Power provides data on historical distribution spending between 2014-2018 and the Company's 5-year future investment plan (2020-2024).[29] Staff combined this information on the chart below:

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[24] Id, pp. 16-17

[25] Id, p. 17, Cites Annual EV compliance report in Docket No. E015/M-15-120.

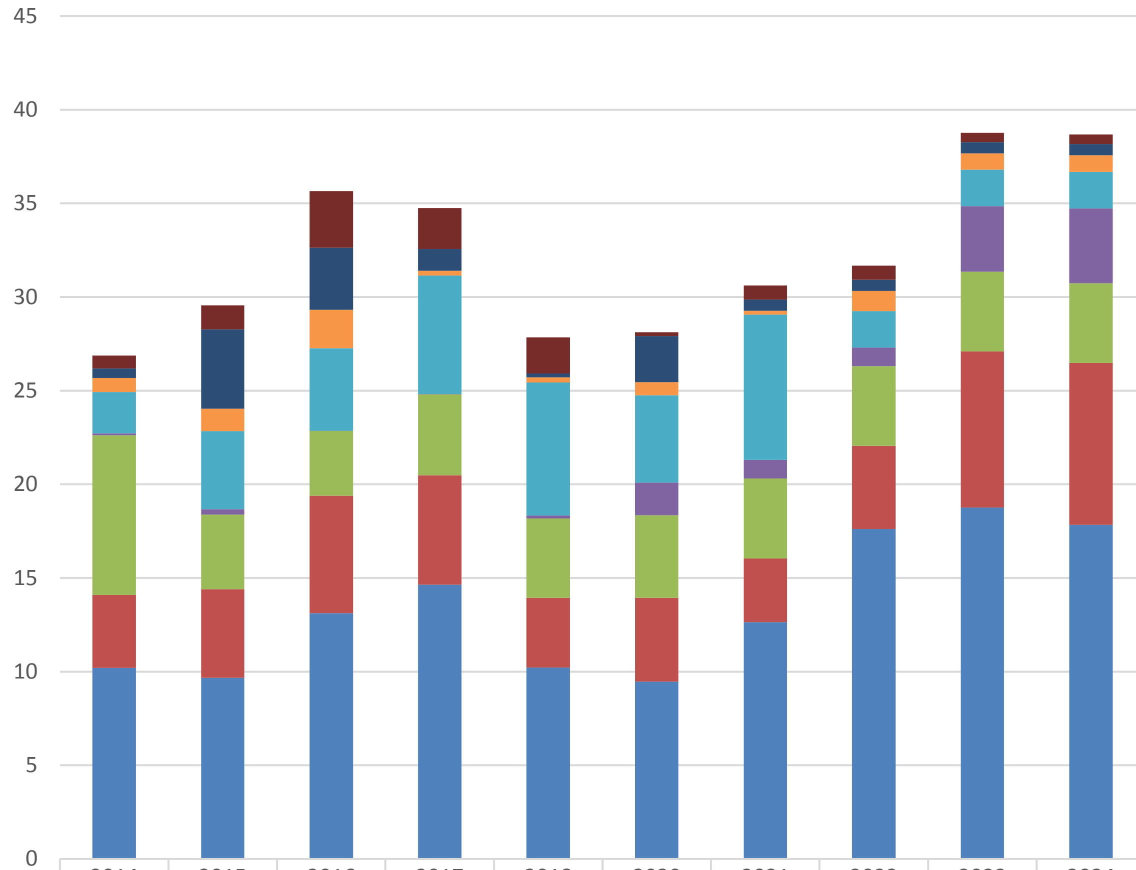
[26] IBID, Cites US Department of Energy Alternative Fuels Data Center: https://afdc.energy.gov/stations

[27] Id, pp. 18-19.

[28] Id, pp. 30-32

[29] Id, Table 1, pp. 14-15 and Table 2, p. 20. Staff note: 2019 data was not provided. Staff corrected Table 2 assuming reported data in millions rather than thousands. This staff chart provides similar data to Figure 10 (IDP p. 37); however, Figure 10 does not include cumulative annual spending and looks out an additional five years (2029) and does not include a data set.

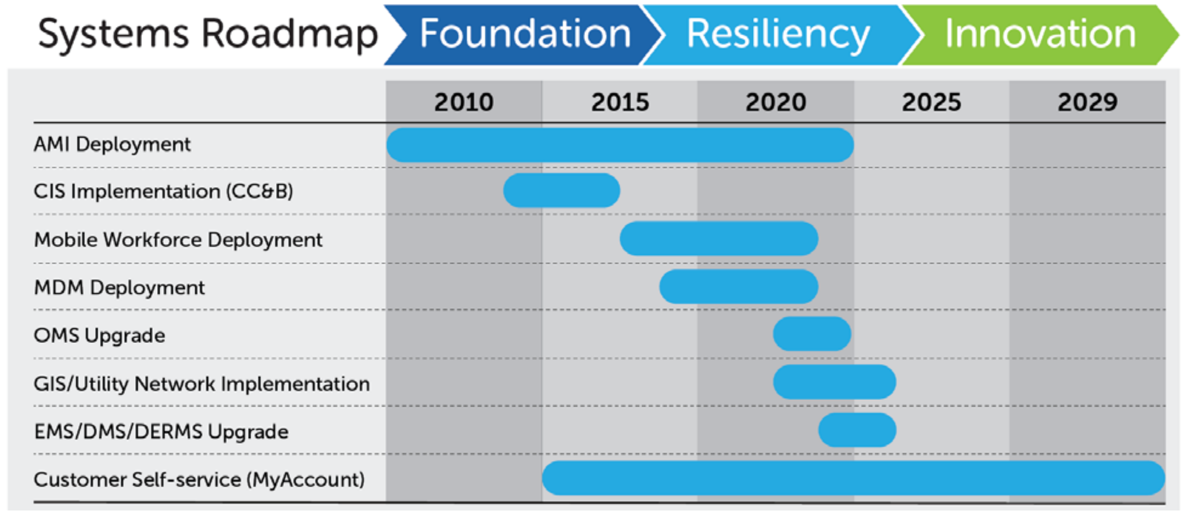
Minnesota Power Historical Spending and Future Investments on Distribution 2014-2024 *(in millions $)*



	2014	2015	2016	2017	2018	2020	2021	2022	2023	2024
Govt Requirements	0.687	1.277	3.023	2.185	1.938	0.201	0.75	0.75	0.5	0.5
Other	0.507	4.225	3.323	1.167	0.207	2.475	0.605	0.605	0.605	0.605
Capacity	0.753	1.199	2.045	0.248	0.267	0.699	0.21	1.06	0.86	0.88
Metering	2.214	4.179	4.404	6.327	7.107	4.65	7.75	1.95	1.95	1.95
Grid Modernization/Pilots	0.091	0.278	0.01	0.005	0.152	1.75	1	1	3.5	4
New Customer/New Revenue	8.525	3.993	3.469	4.333	4.242	4.412	4.257	4.257	4.257	4.257
Reliability and Power Quality	3.895	4.728	6.26	5.845	3.717	4.465	3.4	4.44	8.34	8.64
Asset Renewal	10.207	9.669	13.127	14.636	10.226	9.473	12.65	17.61	18.76	17.84

In addition, Minnesota Power offers a visual systems roadmap for the Company's long-term distribution system modernization investment plans[30]:

[30] Id, p. 15



Staff summarized the planned upgrades in this Systems Roadmap in the table in Section A of these briefing papers. In addition, Minnesota Power provides overarching project categories for the Company's 5-year distribution infrastructure investments: System Expansion Upgrade (i.e. Capacity and Reliability and Power Quality), Grid Modernization, and Pilots.[31] For the 10-year long-term plan, the Company focuses on describing considerations for six potential grid modernization pilots related to: 1) residential and commercial customer demand response; 2) renewable load optimization programs; 3) selective customer sub-metering applications; 4) solar and storage applications; 5) EV storage; and 6) conservation voltage reduction.[32]

3. Hosting Capacity and DER Interconnection

In 2018, Minnesota Power joined the EPRI DRIVE User Group[33] and could be in a position to produce a system-wide, feeder-level hosting capacity maps within the next 2-3 years[34] or as early as the Company's 2021 IDP.[35] However, in the 2019 IDP, the Company did not provide feeder-level preliminary hosting capacity data; rather, offered information about the Company's peak coincident load for the entire distribution system and explained how peak load and other information is gathered.[36]

With SCADA information available at the feeder breaker for half of the Company's feeders, Minnesota Power uses multiple means to gather load and voltage information across the utility's distribution grid. Because gathering and using daytime minimum load is resource intensive, the Company only uses it on an "as-needed basis." For example, the Company

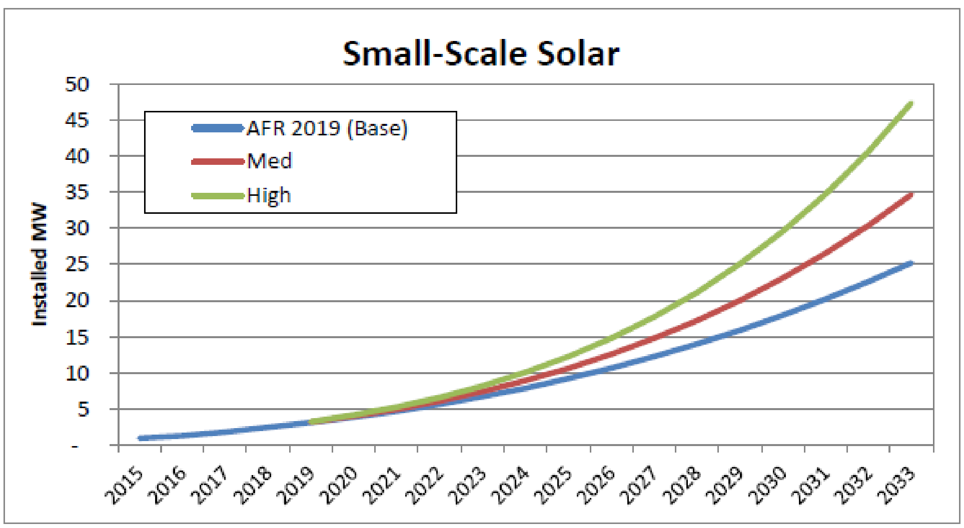
[31] Id, p. 21
[32] Id, pp. 37-39
[33] EPRI DRIVE is a hosting capacity analysis tool. Xcel Energy is also a member of the EPRI DRIVE User Group, and uses EPRI DRIVE in the Company's annual Hosting Capacity Analysis report and maps. See Dockets E002/M-17-777; E002/M-18-684; and E002/M-19-685.
[34] Id, p. 42
[35] Id. p. 25
[36] Id., pp. 44-45

gathered and used daytime minimum load in performing the system study for a 10 MW solar project PPA as part of the Energy*Forward* Resource Package.[37] For the IDP's preliminary hosting capacity data, the Company assumes minimum load[38] is 20% of peak load.[39]

4. DER Scenario Analysis

Solar

Minnesota Power modeled and forecasted installed capacity for new small-scale solar (< 60 kW) for the Annual Forecast Report (AFR) 2019[40] which results in a compound annual growth rate (CAGR) of about 18% between 2018 to projected 2030 levels for the base case[41]; 20.5% for the medium scenario; and 23% for the high scenario. The base case CAGR uses recent trends in Minnesota Power's solar installations, and the medium and high scenarios apply adders of 2.5% and 5% respectively.[42] From App. D[43] at page 2, Minnesota Power provides this chart for under 60 kW solar[44]:

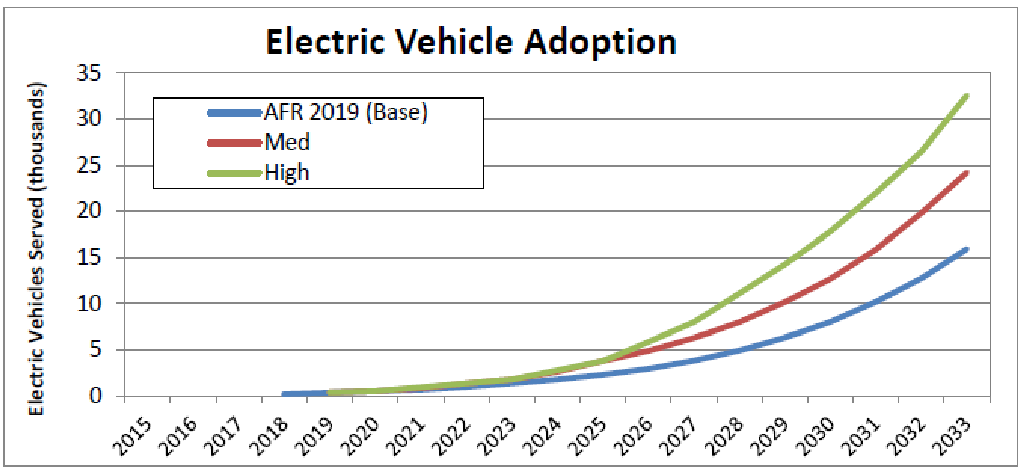


[37] From IDP p. 44: Camp Ripley has installed approximately 10 MW of nameplate solar behind the meter at a feeder circuit that has a daytime minimum load of only 0.94 MW.
[38] Minimum load and daytime minimum load are not necessarily the same thing; however, at this time, Minnesota Power would have to manually filter data to ensure the feeder is not in an abnormal state. Minimum load data is gathered as part of the hourly data collection. However, the Company currently does not track and update minimum loads across the system.
[39] Id., p. 45
[40] Minnesota Power, Annual Forecast Report (July 17, 2019), Docket No. E999/PR-19-11, pp. 12-24 describe methodology for incorporating DER (i.e. EE, DSM, distributed solar, and EV).
[41] Id, p. 45. Staff Note: Appendix D at p. 1 describes assumptions for the < 60 kW small-scale solar forecast model: for small-scale solar (under 40 kW) "assumed that installs per year would stay flat at 35 [per year]", and for large-scale solar (greater than 40 kW) "known installs, plus conservative estimated future."
[42] Id, p. 45
[43] DER Scenario Analysis is in Appendix D; Appendix E is a Line Loss Study.
[44] See footnote 9; staff is unclear why the chart uses a 60 kW threshold.

The Company highlights the potential for reverse power flow and the corresponding use of regulator settings modifications on specific feeders as the system impacts from small-scale solar they are experiencing as of 2018. Minnesota Power mentions the potential future use of advanced inverter options; and flags the need for "clear policy frameworks for leveraging resources to investigate and plan for DER integration" related to achieving locational or resilience benefits.[45]

Electric Vehicles

Minnesota Power observed electric vehicle penetration in their service territory lags national EV adoption outlooks (Bloomberg 2017 EV Outlook combined with IHS Global Insights light vehicle sales outlook[46]) by about 4 years; as such, the Company's base case assumes continuation of the 4-year lag throughout the 15 years. The medium scenario assumes the lag shrinks to 2 years by 2025 and then remains constant; whereas, the high scenario has Minnesota Power's EV penetration at the national average by 2034.[47]



With between 165-180 identified EVs, Minnesota Power has not experienced system impacts from EVs as of 2018. The Company discusses strategies like smart chargers with off-peak EV rate structures and developing internal expertise, software systems and protocols for DER integration. Minnesota Power identifies the first steps are the Company's existing electric vehicle efforts, system integrations, and the C2M implementation.[48]

Barriers to DER Integration

Minnesota Power identifies DER upfront costs (including, if required, distribution upgrades), extended timeframes for program development and technology implementation, and the need for significant analysis and planning for integration of various DER technologies with the utility grid as barriers today.

[45] Id, p. 47
[46] Id, p. 41, ftn. 21.
[47] Id, pp. 45-46 and App. D. pp. 1, 3.
[48] Id, p. 46

FERC Order 841

Minnesota Power, like other distribution utilities in Minnesota, highlight local distribution operation concerns with distribution level and behind-the-meter energy storage resources participating in the MISO wholesale market. Minnesota Power will likely file a tariff with FERC to address distribution system upgrade costs, metering capability, reliability assurance mechanisms, and cost recovery for DER participation.[49]

5. Non-Wires (Non-Traditional) Alternatives Analysis

The Company's five-year distribution capital budget includes three identified switchgear replacement projects and an annual budget for substation modernization that each exceed the $2 million threshold in the IDP filing requirements. Each of these projects are asset renewals that do not meet the Company's non-wires alternatives analysis criteria that the project be increased capacity for non-wires alternatives analysis.[50]

Minnesota Power outlines their non-wires alternatives analysis process as: 1) Distribution Planning identifies candidate projects through regular planning assessments using criteria described below; 2) if the $2 million threshold is met, conduct both wires and non-wires alternative analysis; 3) scoping-level information (based on criteria 3 below) are developed by Distribution Planning and shared with Resource Planning to identify viable non-wires alternatives; 4) Resource Planning develop anticipated cost, implementation timeline, and potential benefits for distribution, power supply and society, and 5) beneficial non-wires alternatives could be considered as resource options in the next IRP. Minnesota Power considers supply-side (i.e. solar and batteries) and, in future IDPs, demand side solutions (i.e. residential/commercial demand response) as non-wires solutions.

Minnesota Power outlines their criteria for the type of projects suitable for non-wires alternatives; only when all three are met does the Company see a non-wires solution as viable[51]:

1. Either the project is for reliability performance (i.e. limited or no back up capability following loss of the primary source to a feeder) or load-serving (i.e. capacity of feeder or associated substation equipment) is less than peak load requirement of the feeder. (Increased capacity)
2. No significant asset renewal needed.

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[49] Id, p. 48. Staff note: On January 21, 2020, MISO submitted their compliance filing revising their tariff to comply with FERC Order 841 (Docket No. ER19-465-000). FERC Order 841 addresses distribution-connected and behind-the-meter energy storage resources, but does not explicitly address storage co-located with other DER technologies. FERC has not issued a decision on DER aggregation as of January 2020 (Docket No. RM18-9-000).

[50] Id, pp. 24-25

[51] Id, p. 34

3. Operational characteristics of the non-wires solution adequately corresponds to the need (e.g. available at the necessary time, necessary response and duration – such as, dispatchable, ramp time, load following capability, sufficient duration based on restoration time.)

While not listing it as a criterion, Minnesota Power posits that population growth is a relevant consideration highlighting a majority of case studies from a national report cite forecasts of high load growth in identifying non-wires solutions.[52] Minnesota Power's service territory is experiencing stagnant or declining population growth over the past decade and the projected trend continues through 2030.

Minnesota Power is monitoring the development of non-wires solutions, but does not have sufficient experience to provide a specific timeline for non-wires alternatives analysis and development. The Company questions whether a non-wires solution project would be contingent on the IRP process that would extend the implementation timeline to multiple years before the utility would have the certainty needed to proceed.[53]

V. Parties' Comments

Department

The Department analysis focuses on compliance with the Commission's IDP planning objectives:

Planning Objective	Dept. Determination
1- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies	Minnesota Power addressed each topic in "some substantive way." The Department provides a table with IDP citations by each topic.[54]
2 - Enable greater customer engagement, empowerment, and options for energy services	The Company "provided extensive information and discussion" of items related to this objective. Minnesota Power implemented online credit card payments, additional web-based MyAccount tools, created mobile-app-based

[52] Id, p. 35. Citing E4TheFuture, Peak Load Management Alliance, Smart Electric Power Alliance, "Non-Wires Alternatives: Case Studies from Leading U.S. Projects", November 2018, available online (with an account): https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/

[53] Id, p. 36

[54] Department, Initial, Table 1, p. 4. Cites Minnesota Power 2019 IDP at 5-7, 9, 13-16, 19-29, 31-32, 34-37, 40-41, 45-47.

	functions for MyAccount and outage notification, and an online discussion board based on customer desire to engage in digital platforms identified by customer surveys. Detailed the existing and planned programs, processes, and technologies for greater customer interaction. Discussed potential pilots; including demand response and use of meter data to inform program design and rate structures for specific electric end uses and allowing for sub-metering applications.[55]
3 - Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies	The Company's IDP "provided extensive information and discussion" related to this objective. An example is the Customer to Meter (C2M) project is an advanced meter billing system that provides the following benefits: automate billing of time-varying rates, more clear energy use data displayed in MyAccount, more accurate billing estimates, simplified remote service disconnection and reconnection, and new programs and rates (e.g. electric vehicles.)[56]
4 - Ensure optimized utilization of electricity grid assets and resources to minimize total system costs	The Company's IDP "provided extensive information and discussion" related to this objective. Examples include" developing a full Distribution Management System that would enable conservation voltage reduction and volt/VAR optimization (CVR and VVO), planned Meter Data Management integration of two metering systems into one platform, and Advanced Metering Infrastructure by 2023 with two-way communication in meters that act as "smart nodes" enabling the C2M benefits and improved load control and operational data.[57]
5 - Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value	The Company provided information and discussion related to this objective. The Department "defers to the Commission as to whether the information provided was sufficiently comprehensive."[58]

Modifications to Minnesota Power IDP Filing Requirements for future IDPs

The Department makes three recommendations for modifications to the Minnesota Power's IDP filing requirements. First, the Department recommends adopting a new filing requirement

[55] Id, p. 5. Cites Minnesota Power 2019 IDP at 7, 10-13, 37-39.
[56] Id, p. 6 Cites Minnesota Power 2019 IDP at 10-13, 22-24.
[57] Id, pp. 6-7. Cites Minnesota Power IDP at 10, 12, 27, 39-40.
[58] Id, p. 7

for Minnesota Power to complete a self-assessment of whether the Company's IDP achieves the planning objectives outlined in the IDP filing requirements **(Decision Option 2.)** The Department highlights the Commission's July 16, 2019 Order adopted this self-assessment for Xcel Energy's IDP filing requirements.[59] Minnesota Power and OAG agree with this modification to Minnesota Power's filing requirements.

Second, the Department recommends modifying Minnesota Power's IDP Requirement 3.D.1(k): as follows:

> For each grid modernization project in its 5-year Action Plan, require Minnesota Power to provide a cost-benefit analysis <u>based on the best information it has at the time and include a discussion of non-quantifiable benefits. Minnesota Power shall provide all information to support its analysis</u>. (**Decision Option 3)**

The Department suggests this recommendation for consistency, when practicable, between utility IDP reporting requirements.[60] OAG supports this recommendation. Relatedly, CEEM suggested Minnesota Power's next IDP "provide more explicit information on cost-benefit conceptualization, methodologies, and/or calculations."

Finally, the Department recommends merging two filing requirements related to the 5-year action plan and 10-year long-term plan from Minnesota Power's draft IDP filing requirements at 3.D.1 and 3.D.2. Staff does not include a decision option on this recommendation because the Executive Secretary already made this administrative edit to three utilities' IDP filing requirements, including Minnesota Power's, as attached to the Commission's February 20, 2019 Order in Docket No. E015/CI-18-254.

Minnesota Power is agreeable to all suggested modifications.[61]

<u>OAG</u>

OAG initial comments request the Commission's acceptance of the IDP "expressly note that such approval is not an implicit advanced determination of prudence with regard to the constituent proposals contained within the IDP." All parties agree with the OAG with the Department adding[62]:

> The Department agrees … that the Commission's … acceptance of MP's IDP should not be understood as pre-approval nor an advanced determination of prudence for any

[59] MN PUC, ORDER ACCEPTING REPORT, AND AMENDING REQUIREMENTS (July 16, 2019), E002/CI-18-251, Ordering Paragraph 5.

[60] Staff Note: See Department Reply (Mar. 29, 2019), Docket No. E002/CI-18-251, at pp. 10-12 for the Department and OAG's rationale for this modification for Xcel Energy's IDP filing requirements. The Commission's July 16, 2019 Order adopted this recommendation for Xcel's IDP filing requirements at Ordering Paragraph 3.

[61] Minnesota Power Reply, p. 1

[62] Department Reply, p. 1

> proposals contained within MP's IDP. Such proposals require detailed review on a case-by-case basis before those determinations can be made.

All parties supported this clarification.

CEEM

CEEM's comments focus primarily on the opportunity the IDP presents for "communities of practice" and asks the Commission to clarify how the IDP informs other docket; such as, rate cases, integrated resource plans, certification requests, and performance-based metrics.

In addition, CEEM suggests the following improvements for Minnesota Power's next IDP[63]:

1. More detailed information about customer insights (e.g. learnings from surveys) and specific opportunities for distribution system investments that enable customer options; including demand response and energy conservation;
2. More refined DER adoption forecasts (ex. adding information from industry trends or similarly-situated utility grids);
3. More refined description of non-wires alternative analysis as a concept and potential application for Minnesota Power's system;
4. Provide more explicit information on cost-benefit conceptualization, methodologies, and/or calculations; and
5. More detail on the Company's vision.

OAG specifically supports CEEM's suggestion that Minnesota Power provide additional detail on the cost-benefit analysis in the next IDP.[64] The Department agrees with "communities of practice" as a worthwhile goal to possibly[65]:

> … address the informational asymmetry between stakeholders, regulators and utilities, enable more transparent planning processes and expenditures of ratepayer funds, and help all involved learn best practices and share lessons learned.

Public Comments

Three members of a local citizen group collaborating with Grand Rapids Public Utilities (GRPU) to develop a 1 MW solar array with storage through the municipal's arrangement with Minnesota Power for a local Community Solar Garden ask why this project was not mentioned

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[63] CEEM Initial, pp. 3-4

[64] OAG Reply, p. 2

[65] Department Reply, p. 2

in the IDP.[66] The commenters mention Minnesota Power's interest in using this solar + storage project as an opportunity to learn more about this type of DER.[67]

Minnesota Power replied "the 2019 [IDP] currently evaluates retail service territory projects and planning. While there may be activities happening in conjunction with customers and entities who do not fit into the retail service category, those projects are not currently included in the Company's IDP."[68] GRPU is a wholesale customer under contract with Minnesota Power.

VI. Staff Analysis

Cost-Benefit Analyses

Staff commends Minnesota Power on the preparation of the Company's inaugural IDP, and especially appreciates the Company's assessment of pilot and past investment cost-benefit considerations. This assessment and cost-benefit analysis is likely occurring within the Company regarding future investments in the 5-year Action Plan and 10-year long-term investment plan for the distribution system; however, details are not included in the 2019 IDP.

Notably, the Department's analysis distinguishes between "extensive information and discussion" for all other planning objectives versus "information and discussion" for cost and benefit considerations. Both CEEM and OAG request additional cost-benefit analysis consideration in Minnesota Power's IDP filings going forward.

Given all parties suggest accepting the 2019 IDP, the Commission could choose to focus on this section for improvement in Minnesota Power's 2021 IDP filing.

Distribution System Modifications and Investments

Staff notes Minnesota Power's IDP filing requirements outline a path for the Commission to "accept" not "approve" an IDP.[69] Further, under the Planning Objectives the IDP filing requirements recognize:

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[66] Public Comment (Bruce Schnell), Jan. 28, 2020. Attached to the public comment was a press release with extensive details on the project and GRPU's planned CSG program. E-filed on Jan. 30, 2020 by the Commission's Consumer Affairs Office. Public Comment (Vicki Andrews), Jan. 29, 2020. E-filed on Feb. 3, 2020 by the Commission's Consumer Affairs Office.

[67] Public Comment (Simon Gretton), Jan. 29, 2020. E-filed on Jan. 30, 2020 by the Commission's Consumer Affairs Office.

[68] Minnesota Power, Reply, p. 2

[69] MN PUC, Feb. 17, 2019 Order, attached "Minnesota Integrated Distribution Planning Requirements for Minnesota Power", Docket No. E015, CI-18-254; states under 1. Filing Date, in part: "The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above"

> Commission review of annual distribution system plans are not meant to preclude flexibility for Minnesota Power Company (Minnesota Power) to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments.

Minnesota Power's investments in the distribution system, customer systems, and grid modernization receive prudency review in the context of the Company's rate case or other cost recovery docket (e.g. riders).[70] For instance, Minnesota Power filed testimony on the distribution system budget in the current rate case using the IDP budget categories.[71] It is unclear to staff why these budgets differ somewhat from the budget offered in the IDP.

Minnesota Power's proposed investments are not eligible for the rider recovery enabled under Minn. Stat. 216B.2425 because the Company has not met the requirements of that statute at this time.

DER Scenario Analysis

DER scenario analysis allows a utility, stakeholders and the Commission to evaluate a range of possible futures and consider a variety of factors. This type of forecasting is still under development in the industry. Minnesota Power applies two types of system-wide scenario analysis in the 2019 IDP: 1) projection of historical trends for residential and commercial small-scale solar capacity interconnected to the utility's grid; and 2) an adjusted application of a national technology adoption forecast for electric vehicles. The base case of this analysis is embedded in the Company's AFR which is used in a number of dockets (e.g. rate case and IRP). Staff suggests parties interested in how the Company is developing DER adoption forecasts review Minnesota Power's 2019 AFR in Docket No. E999/PR-19-11 for a more thorough discussion of the methodology and assumptions.

The Company did not provide energy efficiency or demand response scenario analysis; however, the shift from peak demand savings for the Company's winter peak to a MISO-Coincident summer peak described in the IDP's baseline data is relevant in other dockets; such as, rate cases, resource plans, and MISO market requirements.

Non-Wires Alternatives Analysis

As Minnesota Power identifies, most non-wires alternatives currently being developed address increased capacity needs. Minnesota Power has a similar, though not identical method for evaluating possible projects to what the Commission saw in Xcel Energy's 2018 IDP[72]. The record in the instant docket does not include substantive suggestions on changes the Company should make to this process; rather, CEEM encourages more refinement on the concept and

[70] Minnesota Power's current rate case is Docket No. E015/GR-19-442.

[71] Testimony of Daniel Gunderson, Minnesota Power Initial Filing, Vol. II, Docket No. E015/GR-19-442, pp. 10, 32-40.

[72] Docket No. E002/M-18-251

potential for Minnesota Power's system. This is likely an area where Minnesota Power and stakeholders will continue to flesh out details and approach.

Public Comment

An interesting policy question emerges from the public comments: Should an IDP filing discuss resources and assets connected to the distribution system, but not used for retail service? As seen in the discussion on FERC Order 841, these types of resources and assets are an area of active discussion in the industry.

Treatment of the Information in the IDPs

Parties discuss the iterative and "communities of practice" approach to IDP. Going forward, the Commission and parties should discuss how to treat data and process descriptions included in an IDP filing. For example, highlighting or explaining significant changes or streamlining information that has not changed since the last filing. No action by the Commission is needed at this time.

VII. Decision Options

1. Accept Minnesota Power's 2019 Integrated Distribution Plan. Acceptance is not a prudency determination of any proposed system modifications or investments. (*Minnesota Power, Department, CEEM, OAG)*

2. Require Minnesota Power to discuss in future filings how the IDP meets the Commission's Planning Objectives, including: (*Department, Minnesota Power, OAG)*
   a) Analysis of how the information in the IDP relates to each Planning Objective,
   b) The location in the IDP,
   c) Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and
   d) Suggestions as to any refinements to the IDP filing requirements that would enhance Minnesota Power's ability to meet the Planning Objectives.

3. Amend IDP Requirement 3.D.1(k) of Minnesota Power's IDP Requirements to read as follows: *(Department, Minnesota Power, OAG)*

   For each grid modernization project in its 5-year Action Plan, require Minnesota Power to provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Minnesota Power shall provide all information to support its analysis.

4. Direct Minnesota Power to continue to incorporate stakeholder suggested improvements in the 2021 IDP filed by November 1, 2021. (*Staff)*