414 Nicollet Mall
Minneapolis, MN 55401

May 21, 2021

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: REPLY COMMENTS
DISTRIBUTION SYSTEM – HOSTING CAPACITY ANALYSIS REPORT
DOCKET NO. E002/M-20-812

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy (the Company), submits the enclosed Reply Comments to the Minnesota Public Utilities Commission in response to Comments received from parties April 7, 2021.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on all parties on the attached service list. Please contact Jody Londo at jody.l.londo@xcelenergy.com or me at bria.e.shea@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE XCEL ENERGY 2020 HOSTING CAPACITY REPORT UNDER MINN. STAT. § 216B.2425, SUBD. 8

DOCKET NO. E002/M-20-812

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments to the Minnesota Public Utilities Commission in response to the April 7, 2021 Comments from the Minnesota Department of Commerce, the Interstate Renewable Energy Council (IREC) and the Institute for Local Self Reliance (ILSR).

We agree with the Department and other parties that the time is ripe to move the HCA in the long-term direction the Commission set-out in its July 31, 2020 Order in Docket No. E002/M-19-685. Our hosting capacity analysis (HCA) Report provided information to the Commission regarding the components, steps, and timeline necessary to achieve its long-term goal of using the HCA in the Minnesota Distributed Energy Resources Interconnection Process (MN DIP) Fast Track Screens. In Comments, parties had questions about the necessity and cost of certain aspects of that journey, which we address in this Reply.

The biggest questions were around the foundational asset data validation initiative we explained is necessary to achieve increased levels of accuracy in hosting and interconnection screening results – and that is necessary to further mature our HCA and interconnection tools for stakeholders, as the Electric Power Research Institute (EPRI) report included with our HCA Report also explained. That said, we understand parties' concerns and questions with regard to the costs, timeline, and role of the comprehensive asset data initiative in the various HCA and MN DIP integrations and automations we outlined. While there are some trade-offs in deferring the asset data initiative to some point in the future, in this Reply we offer an alternative path for the Commission to consider that would provide more immediate improvements and benefits to developers.[1] The alternative path would push out the start of the comprehensive asset data initiative until after the limited asset data initiative for the Advanced Distribution Management System (ADMS) is complete, which is also when we expect to have improved technologies, such as Advanced Metering Infrastructure (AMI) in place that we expect will reduce the amount of manual data collection that would otherwise be necessary. We note however, with either path, we would be able to initiate work on specific HCA and MN DIP improvements concurrent with an asset data initiative, delivering some more immediate benefits to users and then realizing even greater benefits for users upon completion of the data initiative.

We agree with parties and stakeholders that that the greatest value improvement for the HCA in the near-term is for it to be updated monthly, so we include that as the first initiative in both of the paths that we outline. Importantly, the work to support a monthly HCA is also foundational to achieving the Commission's long-term goal for the HCA – providing essential system integrations and automations that make integration with MN DIP Screens possible. If the Commission determines a monthly HCA is in the public interest and directs the Company to implement it, we are prepared to initiate that work in Fall 2021 and expect it would go live in 2023. We would plan to seek cost recovery of the costs associated with advancing the HCA through the Transmission Cost Recovery Rider as provided by relevant statutes.[2]

If the Commission determines we should also initiate the comprehensive asset data initiative, we would also be prepared to begin our planning of that in Fall 2021 – returning to the Commission with a more refined plan, costs, timeline, and proposal for cost recovery in 2022. We note that we would still be able to initiate the work toward a monthly HCA, as these efforts can run in parallel. Further efforts to integrate the HCA with MN DIP Screens, however, are dependent on completion of the monthly HCA.

We therefore request the Commission to provide further guidance on its expectations for an integrated HCA and MN DIP screening process, so we can perform a more detailed requirements analysis and return to the Commission with refined plans, costs, and timelines and proposals for cost recovery, so we are prepared to execute on the next step toward the long-term goal for the HCA in 2023.

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[1] The trade-offs include the level of efficiency gains from the automation and system integrations, no increase in the level of accuracy in the HCA or MN DIP screening results from today – and, limited ability to gain significant efficiencies in Fast Track Initial Review Screens.

[2] Minn. Stat. § 216B.16, subd. 7b(4) "allows the utility to recover costs associated with distribution planning required under section 216B.2425."

In the balance of this Reply, we outline two alternative paths for the Commission to consider, and we respond to parties' questions, comments, and requests for additional information.

REPLY COMMENTS

I. POTENTIAL HCA FUTURES – ALTERNATIVE PATHS

In this section, after summarizing our approach and insights from stakeholders, we outline two alternative paths to achieving the potential future HCA Use Cases the Commission directed the Company to examine: (1) a path consistent with what we outlined in our HCA Report that includes a foundational data initiative, and (2) an alternative path that captures some benefits for HCA and MN DIP users sooner. We also include information that responds to parties' questions about the foundational asset data initiative and other aspects of the potential future Use Cases we examined in our HCA Report. Finally, we discuss the costs and benefits of the two alternative paths, as well as cost recovery considerations.

A. Summary of Approach and External Insights

As background, in our HCA Report, we outlined four potential future HCA Use Cases that we examined in response to the Commission's direction, as follows:

1- The HCA remains an early indicator for interconnection

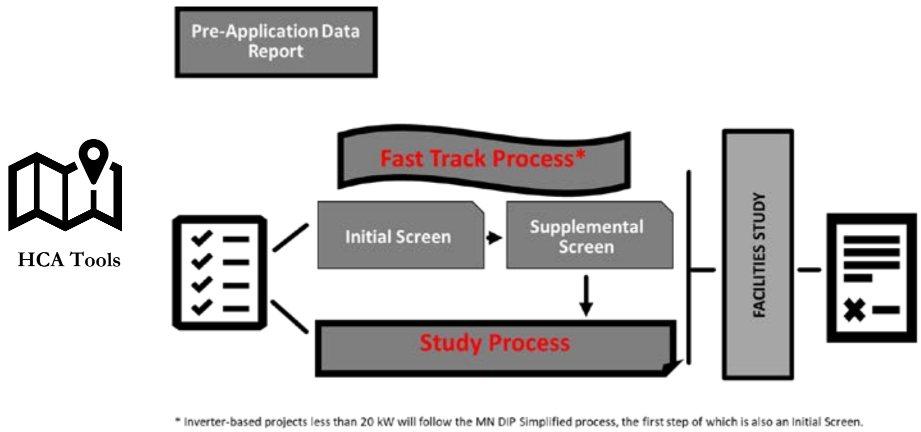
2- Integrate the HCA with the MN DIP Pre-Application Data Report

3- The HCA integrates with MN DIP to replace or augment the Fast Track Initial or Supplemental Screens

4- The HCA integrates with MN DIP to automate the interconnection studies more broadly.

For reference, we provide as Figure 1 below, the HCA in relation to a summarized view of the MN DIP process Fast Track Screens and Pre-Application Data Reports.

Figure 1: HCA in Relation to Summarized View of MN DIP Fast Track Screens



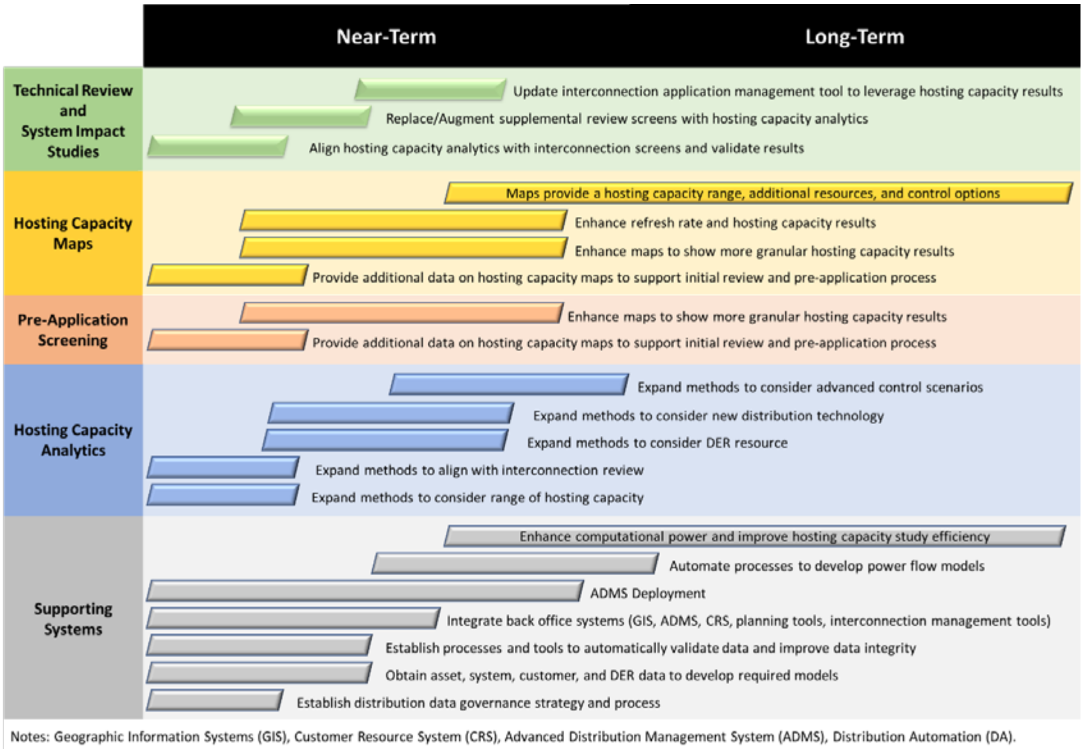
We note that we agree with the Department that use of the HCA in the Fast Track Supplemental Review Screen (FTSRS) of the MN DIP is the Use Case most closely aligned with the Commission's long-term goal for the HCA. We also note that while the improvements to the Fast Track Initial Review Screens are not as tightly tied to the improvements associated with integrating the HCA and MN DIP Fast Track Supplemental Screens, we believe they will deliver significant benefits to users of those screens.

To inform our examination of these Use Cases, we conducted a series of interactive stakeholder workshops, and we worked with the Electric Power Research Institute (EPRI) to provide insights from across the industry and to help define a roadmap for integrating hosting capacity in the interconnection process. Importantly, EPRI observed that we are in line with industry efforts in terms of evolving our interconnection processes, the screening and technical review of specific interconnection requests to meet new requirements as application volume grows, and examining how hosting capacity can be used to augment internal supplemental review screening.

1. *EPRI Roadmap to Maturing the HCA and Interconnection Process*

EPRI's roadmap for Xcel Energy identified the core capabilities needed to more fully utilize hosting capacity to improve interconnection processes as well as the tools, technologies and other resources needed to enable those capabilities. The EPRI Whitepaper included with our HCA Report also identifies a broader set of opportunities not directly related to hosting capacity that could result in efficiency improvements to the interconnection process – as did our evaluation. We repeat the EPRI roadmap to maturing our HCA and interconnection processes in Figure 2 below.

Figure 2: Xcel Energy - Potential Roadmap to Maturing HCA and Interconnection Processes



Source: EPRI Whitepaper (Figure 6), *Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process (October 2020)*.

2. *Stakeholder Insights and Requests*

We heard from stakeholders that our current HCA can provide sufficient information and reliable estimates to be a starting point for interconnection, as long as it is updated more frequently. The participants identified the ideal cadence as monthly.

This priority for a monthly HCA was echoed in parties' April 30, 2021 comments in this docket. Stakeholders also offered suggested improvements to the Pre-Application Data Report toward increased efficiency and improvements to the selection of suitable project sites. These include providing more information about the interconnection queue and indicating whether system upgrades or mitigations are needed for interconnection. With respect to the current MN DIP process, stakeholders suggested all timelines should be reduced – for example, to five days for a Pre-Application Data Report and Initial screens. They also suggested Initial Review Screens be completed in a self-service application, which would "ping" into our records and provide a pass/fail scenario. And, finally, that some Initial/Supplemental Screens could be replaced or augmented with checks against the HCA values. To achieve any of these improvements, underlying information systems work is necessary, as are additional engineering and perhaps other resources.

Both of the alternative paths we outline below address the Fast Track Initial and Supplemental Screens, as well as integration of the HCA with the Pre-Application Data Report. In both cases, we put the monthly HCA cadence as the first deliverable, and integration with the MN DIP screens second. Stakeholders have been clear that they believe the greatest value will come from a monthly HCA. The MN DIP screens build on the work necessary to increase the cadence of the HCA. Integrating the Pre-App Report with the HCA stands on its own and is not reliant on any of the other steps or integrations. With that said, in the balance of this section, we discuss the benefits of a foundational asset data initiative to be responsive to parties' questions, and then outline two alternative approaches to the long-term goal the Commission set for the HCA.

B. Benefits of a Foundational Asset Data Initiative

The EPRI Whitepaper we included with our HCA Report identifies a foundational data effort as part of the Supporting Systems work necessary to mature HCA and interconnection processes in the long-term.[3] Such an initiative is necessary if the ultimate goal is a more frequent, more precise, more efficient, and more automated HCA and FTSRS initially – and the potential for automation of other interconnection screening processes long-term.

In the HCA Report, we parsed the foundational data initiatives into a Primary System project and a Secondary System project, as they support different functionalities. The scope of the data effort most closely aligned with the Commission's long-term goal for the HCA would be focused on the Primary System and would validate existing asset data in our GIS and collect the additional asset data necessary to support an interconnection Use Case. The Primary System data effort also most closely correlates to the current HCA focus on large solar projects.

As we discussed in our HCA Report in conjunction with our analysis of the potential future HCA Use Cases specified by the Commission, the general benefits of doing the foundational asset data work the Commission directed that we explore are that it would maximize time and cost efficiencies – and is also important in terms of providing an increased degree of accuracy with an HCA and interconnection steps

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[3] This is in addition to other foundational work such as integration of various information systems, automation of power flow models, deployment of ADMS, and development of processes and tools to automatically validate data and improve data integrity.

that are more automated. It would enable these benefits because we could run these processes with less manual intervention and oversight than would be required with the same automation investments, but using our current GIS asset data. Today, engineers must resolve specific data anomalies or gaps that result from their analysis of individual DER projects that have requested to connect to the grid. Sometimes this involves sending personnel to the field, which takes time and slows the process. Additionally, the data can appear to the engineer as being reasonable, yet contain inaccuracies that might affect the viability of the DER project as it progresses through the interconnection process.

Correlating this to specific capabilities, a foundational Primary System data initiative combined with investments in other information systems would yield more frequent and more accurate HCA results and more accurate and faster FTSRS results for large solar projects. It also lays an important foundation for additional future automation of other aspects of the interconnection process that would otherwise not be possible, due to the need for very specific and accurate asset data for those processes.

A Secondary System data effort is necessary to automate the Fast Track Initial Review Screens, generally used for rooftop systems. It is also necessary to support automation of the Supplemental Review for smaller projects connected to the secondary portions of our system. As we have discussed in the past, it has not been necessary to collect or maintain detailed secondary system information for our general operating purposes. However, for an interconnection Use Case, it is necessary to have accurate secondary transformer and conductor data, particularly, for an automated process to produce reasonably accurate results. Automation such as this would enable developers who have expressed a desire to complete Initial Screens "on their own" to input project data and allow the application system to "ping into Xcel Energy records and provide a pass/fail scenario." We believe this Use Case goes beyond the Commission's long-term goal for the HCA, but also believe it would provide significant value to developers of rooftop systems so we have included it for the Commission's consideration.

With that said, we primarily focus in this Reply on a roadmap to the Potential HCA Futures most closely correlated to the Commission's long-term goal. The asset data collection and validation work we would do on the Primary System would be complementary to what is underway and planned for the Advanced Distribution Management System (ADMS). As we explained in our annual ADMS report submitted in Docket Nos. E002/M-19-666, E002/M-19-721, and E002/M-20-680 on January 25, 2021, the final phase of the ADMS project is contemplated to include data collection, validation, and testing of feeders that are necessary to support the additional advanced functionality of ADMS. We are working to solidify our data collection and advanced application strategies for this phase of the ADMS project during 2021, and estimated that this phase of the ADMS data collection would involve the remaining $6 million in the 2021-2025 budget forecast (GIS category, specifically) and would be in the 2022 and beyond timeframe.

If the Commission directs the Company to proceed with a Primary System data collection effort to support the HCA and its integration with MN DIP, we would work closely with the ADMS team and return to the Commission with a more refined plan, costs, timeline, and proposal for cost recovery in 2022. As we explained in our response to MPUC Information Request No. 1 (filed in this Docket) and expanded upon in our response to IREC Information Request No. 10 (provided as Attachment A to this Reply) – we can say with certainty that the ADMS asset data effort is narrower in scope and scale than the full asset data collection and validation necessary for an interconnection Use Case. Our response to IREC-10 also explains the basis of our conceptual estimate, factors that will impact the overall cost and timeline differences – including efficiencies we expect to gain that have the potential to reduce the amount of effort and cost involved – and specific differences in the Primary System asset data necessary for ADMS and for an interconnection Use Case. For example, no Secondary System data is in scope for the ADMS initiative, but would be necessary to achieve efficiencies and benefits in an interconnection Use Case for smaller DER. Also, we expect the ADMS data initiative will not include all Minnesota feeders – nor will it include any underground facilities. Collection and validation of data for all Minnesota feeders would be necessary for an interconnection Use Case.

We believe there are benefits from doing a single asset data effort, where we would virtually or physically validate and/or collect data for each feeder just one time. There would also be benefits to collecting the Secondary System data as part of a comprehensive approach such as this, as we expect we would take a geographic approach, which would leverage the asset data collection resources across all aspects of our distribution grid.

However, we understand that the costs we have conceptually estimated for such an initiative are significant, that the asset data efforts to support ADMS and this HCA/interconnection effort would overlap, and there may be delays in realizing tangible user benefits for the HCA and interconnection Use Cases. We therefore outline the functionalities and benefits of automation of the HCA and integration with the FTSRS below when done with a full Primary System asset data effort in Part C below, and in Part D, we offer an alternative Path 2 that defers the Primary System data validation to a later point in time and delivers improved HCA and interconnection tools consistent with the Commission's long-term goal sooner. We intend our outline of these two paths to also be responsive to questions from the Department regarding the role of the asset data validation efforts in relation to achieving the Commission's long-term goal.

C. Path 1 – HCA Automation and Integration Combined with a Comprehensive Data Initiative in the Near-Term

With this path, we would first initiate a comprehensive Primary System asset data initiative as discussed above. If this is the way the Commission directs that we proceed with this Path, as we have otherwise noted, we would work closely with the ADMS team and return to the Commission with a more refined plan, costs, timeline, and proposal for cost recovery in 2022. As explained in our HCA Report, our estimated timeline to complete the Primary System asset data validation is approximately 2 - 3 years, and we estimate the conceptual cost is in the range of $27 million - $32 million. After we develop our detailed plan, we would update the Commission in the form of a compliance filing with our detailed plan, any intersection with the ADMS project, and any available refinement of the cost.

1. Monthly HCA

If the Commission directed the Company to pursue this path, we believe the first deliverable should be to publish the HCA Map and Tabular Results on a monthly basis. We would start the work to the information systems necessary to implement this improvement while the Primary System asset data validation initiative is underway.

In this scenario, the accuracy of the hosting capacity results and other values would increase because they would be based on more complete asset records and thus users would be able to put more trust in the HCA results, as they would more assuredly reflect an accurate set of distribution grid asset attributes. We believe this would also lead to more consistency in the HCA results and MN DIP study results, as long as the study(ies) are completed with reasonable proximity in time to consulting the HCA results. Finally, because we would be updating the analysis on a monthly basis, the HCA results would also reflect the most recent changes occurring on the system, including more up-to-date information regarding queued DER projects; however, this is a result of process automation, not completion of the foundational asset data initiative. We would identify feeders for re-analysis monthly, based on factors such as added DER, load, or changes in feeder configuration from the date of the previous HCA update. To ensure all feeders get updated regularly, we will also include a portion of feeders that did not have these kinds of changes in the monthly update – ensuring that all feeders are updated at least annually. The monthly feeder updates will additionally include updates of the Map pop-ups and Tabular Results details, including a more active list of existing and queued generation.

In addition to foundational information systems work that is necessary to support any one of the potential future HCA Use Cases the Commission specified, the following are necessary to produce a monthly HCA.[4] We note that the below work to produce the monthly HCA is further foundational to the other improvements in this Path:

- *CIM Extract for Synergi* – The first step toward meeting the Commission's goal of monthly HCA is to modify our loadflow tool Synergi to be able to import CIM (Common Information Models) in parallel with the ADMS system. CIMs include standard GIS data, but due to its association with ADMS, includes a much tighter GIS correction and feedback loop. This is important because by changing to use CIM extracts to populate Synergi models will ensure that models are up-to-date with new equipment and system information each time they are refreshed – and, with feedback to ensure that manual feeder model clean-up is minimized. It should also be noted that switching to the CIM extract will require an update of our Warehouse database and cleanup scripts. With this functionality in place, Hosting Capacity Engineers will be able to build and analyze feeder models at a faster rate to support the monthly HCA cadence.
- *Feeder Model Database* – Once Synergi is capable of loading and utilizing feeder models from the CIM extract, these models must be stored in a fully functioning database. The need for a database is driven by the Commission's goal of integrating the HCA with MNDIP processes. Storing feeder models and their associated data in a dedicated database will allow other applications, programs and systems to read or write information with the necessary efficiency compared to our current shared folder method of model storage. Additionally, this database will provide a location for feeder models required for adjacent Use Cases, such as to support study of electric vehicle or DER penetrations.
- *Synergi/CRS Integration and Cleanup* – Our CRS (Customer Resource System) contains all customer usage data. This data is imported into Synergi for use in load allocations and loadflows. However, the data being imported is often unreliable and requires significant cleanup. In order to provide a monthly HCA update, the

[4] All Business Systems costs referenced in this Reply are based on high level scoping discussions with the business area. These efforts require both requirements and detailed design workshops, including applications vendor and project team members and support teams to determine the requirements/design/solution flow to fully understand the complete scope. There is therefore a 100% contingency applied to the cost estimates. Further, the estimates assume a solution requiring Teradata and Business Objects to store relevant data and automate the report for the MN DIP screening integrations. However, a different solution may be determined upon project initiation and detailed requirements and solutioning planning. Because these tool improvements were developed as a package, there may be some cost overlap across the tool improvements; we have done our best to break down each component to each tool improvement to the best of our ability at this point. If all tool improvements do not proceed, new estimates will be necessary. These projects have been added to the Business Systems Distribution roadmap and tentatively targeted for Q3 2021 start, with completion by Q4 2022.

link between Synergi and the CRS data must be addressed with data quality reassurance and improvements.

- *Salesforce Integration* – Our Salesforce system currently provides an access point for developers to interact with the MNDIP process by applying for interconnections, uploading documents, and moving their applications forward. Integrating Salesforce with the feeder model database and other screening or DER tools would allow for increased automation and faster communication between engineers, the program office and developers. For example, integrating Salesforce with the feeder model build process would allow all DER projects that reach a certain step in the application process (as reflected in Salesforce) to be included in the related feeder models. Additionally, Salesforce integration could be used to significantly automate MN DIP screens or reports by using the information entered by developers to automatically input into screening tools, as we described above.

These efforts would build on foundational information systems work to set up the necessary data extracts to a Teradata database, develop and integrate a new Business Objects Universe Layer for DRIVE, and a new Oracle database and server. Additionally, incremental ongoing resources necessary to support a monthly HCA Cadence include:

- *HCA Engineers* – We will need to add two additional HCA Engineers to consistently perform hosting capacity analysis at a monthly cadence. HCA Engineers will be required to quality check and update database feeder models, perform DRIVE analysis, and quality check DRIVE results before each update. As we have previously explained in past annual HCA filings, our annual HCA process was supported by summer engineering interns working under the direction of full Engineers. Our move to quarterly HCA cadence and, should we further move to a monthly HCA cadence, will not support the use of summer interns and will be more resource intense consistently throughout the year. As such, additional full-time Engineering resources are necessary.

- *Modeling Engineers* – We will need to add two additional Modeling Engineers to work with the CIM extract and ensure model database upkeep. These engineers will be responsible for reporting any model inaccuracies, ensuring that all model variants are updated and stored appropriately, and that grid changes are reflected in new models.

- *GIS Specialists* – We will need to add one or two additional GIS Specialists to assist with monthly HCA map updates and ensure that any necessary feeder changes are reflected in GIS.

As we explained in our HCA Report, the work efforts and estimated costs we developed for the Use Cases specified by the Commission are conceptual. Once the Commission provides direction to the Company regarding the specific Use Cases to either further explore or implement, we will need to initiate a standard project process that starts with a detailed requirements phase, progresses to the design phase, then development, testing, and finally, the project goes live. Until we go through the detailed requirements phase for the specific solution the Commission directs, we will not be able to provide a more specific cost estimate.

That said, based on the above outline, we are confident we could deliver this monthly HCA in approximately 15 - 18 months from project initiation, which we would complete concurrent with the Primary System asset data validation initiative. We have estimated the Primary System asset data initiative would take approximately 2 - 3 years, so at the end of that, the monthly HCA would begin to reflect the benefits of the asset data validation. The total conceptual cost estimate for the monthly HCA functionality is $1.7 million - $3.5 million and an incremental ongoing annual cost of $375,00 - $500,000 for engineering resources. The Primary System asset data validation is a separate effort, which we have conceptually estimated in the range of $27 million - $32 million.

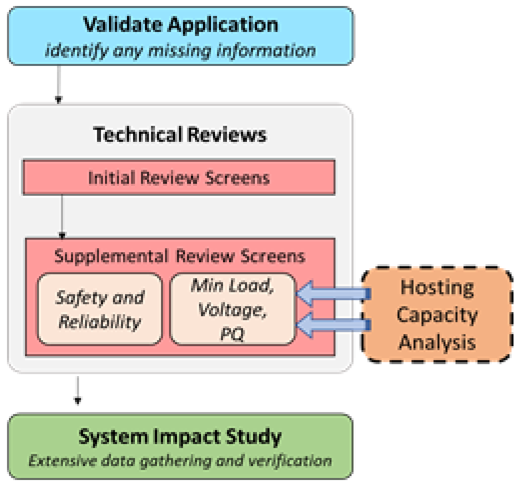
2. *Integration of the HCA and Supplemental Review Screens*

Automating the FTSRS would build on the work done to publish the HCA monthly, and we believe fits best as the second deliverable on this Path.

The Supplemental Review Screens would benefit from the combination of investments in Primary System asset validation and collection and the process automation necessary for the monthly HCA. As we explained in our HCA Report, we can integrate the HCA into this process and in doing so, replace five of the 13 total screens where a pass or fail is given.[5] These five screens are looking for high voltage, voltage fluctuation, thermal overloads, islanding potential, and reverse power flow. All of these screens can be fulfilled by the primary over-voltage, primary voltage deviation, thermal for DER, unintentional islanding, and reverse power flow thresholds, respectively, within DRIVE. We repeat the illustrative integrated HCA MN DIP Screening process below, which we initially provided as Figure 4 in Attachment F to our HCA Report.

[5] We note that we intend to explore the potential for additional supplemental screen automation via further interactions with our load flow tool Synergi's vendor DNV. If the Commission directs the Company to pursue improvements to the FTSRS, we will determine whether further automation is possible through Synergi software model changes as part of our detailed requirements analysis and update the Commission when that information is known.

Figure 3: Hosting Capacity in the Technical Review Process



The DER integration team would be able to leverage the newly validated primary system data in freshly updated and automated feeder models that were necessary to realize a monthly HCA cadence. These improvements negate currently manual portions of the supplemental screens. At the least, we believe being able to rely on asset data that has been validated will result in significantly shorter amounts of time required for screening – allowing developers to receive their screen results with greater speed. We estimate that developers would likely experience a 50 - 75 percent reduction in screening time from the current MN DIP timeline. In this scenario, developer interaction with the FTSRS process will remain through the Salesforce Portal, but we are open to exploring an alternative of having the HCA Map be the user interface that would integrate with Salesforce behind the scenes.

The information systems work to support this deliverable builds on the foundational information systems work described in Part II.C.1. above, and additionally requires the following specific information systems efforts:

- *Automated GIS/Synergi Queries* – The interconnection screening process currently requires screening engineers to manually query the GIS system or Synergi models to include conductors and feeder equipment as needed. This query would work by allowing a user to input a site address or relevant existing equipment ID, and then tracing from the input site to the substation and returning feeder conductor and equipment information (lengths, conductor types, protective devices, etc.). Implementation of an automated query system combined with the assurance of validated data would make way for nearly total screening automation.

- *Automated Screening Tools* – The existing screening tools would require significant update to leverage the before-mentioned Salesforce integration and automated querying. These screens would be triggered once Salesforce data is finalized, and then reference other data sources such as GIS, Synergi models, and system data spreadsheets to automatically provide screen results. Engineers would then quality-check these results before reporting findings to the developer.

As this functionality relies on completion of the work necessary to implement the monthly HCA, we would be able to start this effort at the time the monthly HCA goes live. From project initiation, we estimate the timeline to deliver these FTSRS improvements is approximately 9 to 12 months. The total conceptual cost estimate for the FTSRS functionality is $700,000 to $1.4 million. We note that the improvements required to implement the improvements to the FTSRS are interdependent with improvements to the Initial Review Screens. We discuss the improvements, costs, and timeline we envision for those below.

3. Initial Review Screens

We can build on the base enhancements necessary to produce the monthly HCA and the FTSRS, to nearly fully automate Initial Review Screens with the inclusion of Secondary System asset data validation. Secondary equipment data validation combined with the feeder model database necessary for the monthly HCA and automation of the FTSRS will allow for all required screening data to be housed and referenced in one location with a high degree of data accuracy. These combined create significant potential for developers to be able to submit their project site and system information (similarly to how it is currently entered in the Salesforce Portal), and for the Company to then utilize the behind-the-scenes tools referenced above and, with engineering oversight, return an expedient response to the developer. In this scenario, developer interaction with the Initial Review Screen process will remain through the Salesforce Portal, but we are open to exploring an alternative of having the HCA Map be the user interface that would integrate with Salesforce behind the scenes.

The incremental information systems changes necessary to implement an automated initial review screen are largely to the same underlying systems as for the FTSRS, however would need to be taken further to fully encompass the Initial Review Screens. Therefore, assuming the improvements are made to the GIS and SalesForce to implement the FTSRS improvements, the only incremental change to affect improvements to the FTIRS are to our Network Management System, at an estimated incremental cost of approximately $100,000 to $200,000.[6] We would be able to complete this additional work part of the overall timeline for the FTSRS. To summarize, the *combined* integration and automation of the Fast Track Supplemental Review and Initial Review Screens, done together, would cost approximately $800,000 to $1.6 million and be complete in approximately 9 to 12 months.

4. *Integrate the HCA and Pre-application Data Reports*

Pre-application Data Reports (PDR) could also become nearly fully automated with the inclusion of the Primary System asset data validation initiative. Currently to produce a PDR, Xcel Energy engineers must manually query and analyze data from the GIS system with an emphasis on quality control and assurance. Primary System data validation will provide a path for PDR to include an automatic GIS query with trust and confidence in the validated asset data results. This automation will allow for significantly faster PDR completion rates and responses. In this scenario, developer interaction with the PDR process will remain through the Salesforce Portal, but we are open to exploring an alternative of having the HCA Map be the user interface that would integrate with Salesforce behind the scenes.

The information systems projects to support this integration and automation involve changes to our GIS and our SalesForce applications, and like the other tool improvements, would rely on the work necessary to implement the monthly HCA cadence. The conceptual estimate of this improvement is approximately $375,000 to $700,000.

Figure 4 below summarizes how we envision implementing Path 1, if directed so by the Commission. We highlight that upon Commission direction, we would initiate the work to implement the enhancements to the HCA and interconnection tools concurrent with the asset data initiative – delivering those enhancements while the asset data initiative is underway. Upon completion, users of the enhanced tools would realize even greater benefits from the updated asset data.

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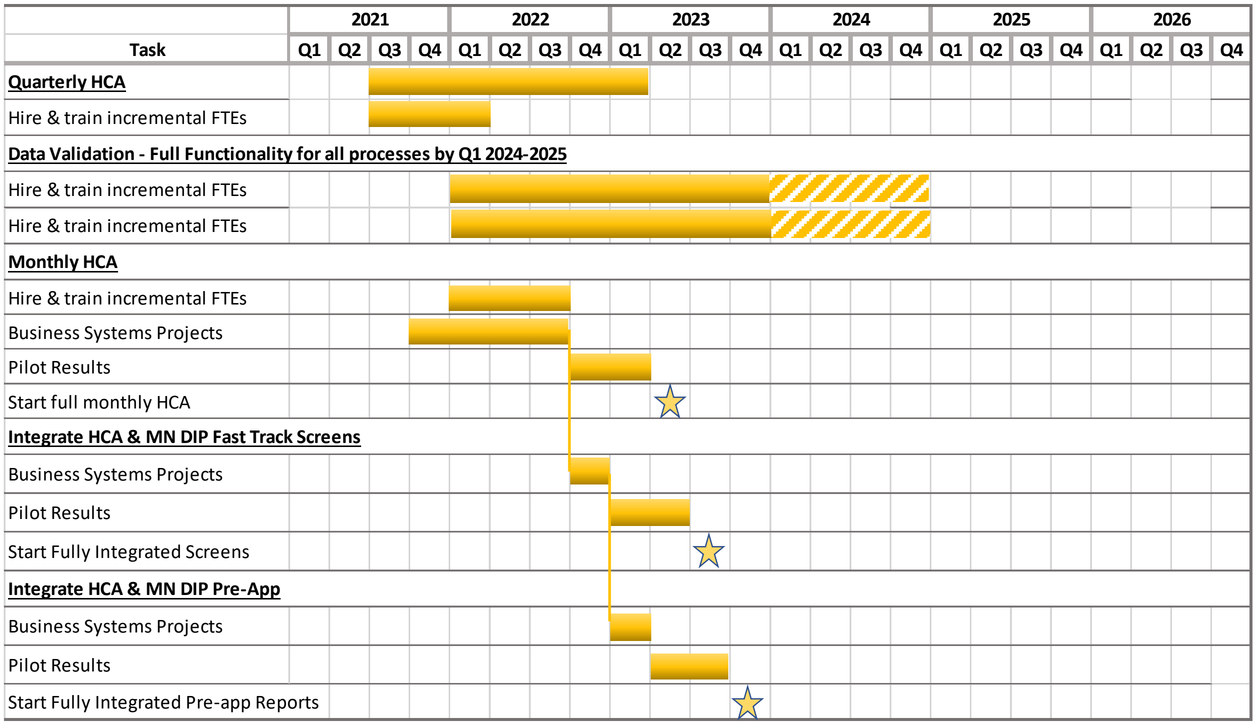
[6] There is some potential that ADMS may prove to be a better resource for this part of the process, so if the Commission directs that we further examine or implement this improvement, we would more fully explore that alternative as part of our detailed requirements and design process.

Figure 4: Proposed Implementation of Path 1



As we have noted, we continue to believe that the underlying asset data validation is essential in the long-term, but we understand stakeholder concerns with the potential overlap with our ADMS asset data initiative and the desire for the Company to deliver process improvements sooner. Therefore, in Part D below, we outline an alternative path that will deliver a monthly HCA and some other improvements quicker than if we were to complete a full asset data initiative first.

D. Path 2 – Delayed or No Foundational Asset Data Initiative

The difference in the two paths we outline in this Reply is whether we do a foundational asset data validation effort for the Primary and/or Secondary Systems now or later. We discussed in Part B above the benefits of the asset data validation. Path 2 allows the ADMS data validation effort to proceed as planned, and we deliver some near-term HCA and MN DIP improvements for developers while that plays out. Then after the ADMS effort is complete, we would initiate a further asset data update process sufficient to support an HCA/ Interconnection Use Case to fill-in where the Primary System data in our GIS is not robust enough to support an interconnection Use Case and gather and validate Secondary System asset data to enable further efficiencies for rooftop/smaller DER.

As we noted above and outlined in more detail in Attachment A, we believe by waiting, we might also be able to leverage technologies that we do not have today, including Advanced Metering Infrastructure, to gather and validate some of the information that will be needed.

Regardless of paths to the future, for the Company to get to a monthly HCA or to integrate the HCA with the MN DIP and/or automate MN DIP screens, automation of the feeder model building process is foundational to all other improvements. That means that Path 2 also proposes to begin with a monthly HCA, which all parties agree would be the greatest value improvement for the HCA and the work necessary to implement it provides the foundation on which integration with MN DIP steps become possible. In terms of timing, we are prepared to initiate the work necessary to get to monthly HCA updates as soon as Fall 2021, upon a Commission Order in this proceeding directing the Company to make that improvement. Our work with begin with a detailed requirements analysis and systems design phases, which will refine the timeline and costs. As noted previously, we are confident we can implement the monthly HCA in an approximate 18 to 21-month timeframe. So, we expect that we would deliver a monthly HCA starting on a limited/pilot basis in early 2023, with a full implementation in mid-2023.

Once the monthly HCA and feeder model build automation processes are up and running, we can initiate the work to integrate the HCA into the Supplemental Review and Initial Review Screening processes to start realizing time efficiencies for stakeholders in those processes. Finally, we could initiate the improvements to the PDR any time after the monthly HCA is up and running. We have prioritized the improvements to the MN DIP Screening processes ahead of the PDR because that is how we understood stakeholders would want to see implement, but that could be flexed due to fewer interdependencies than the other improvements.

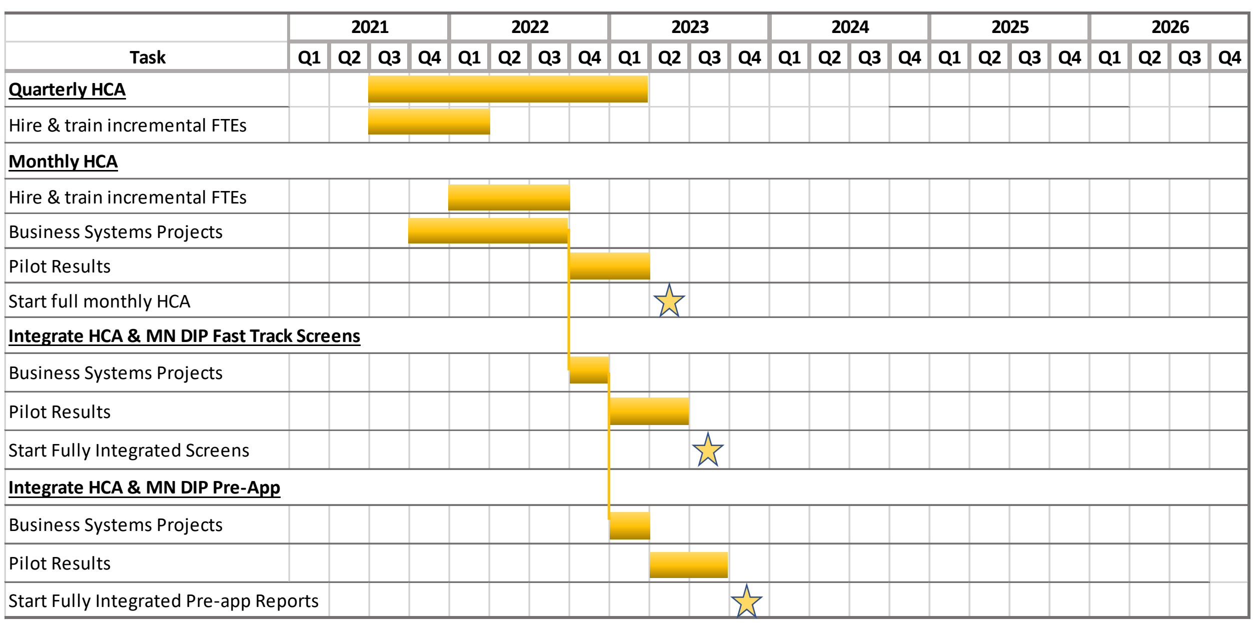
Tangibly, the trade-offs with Path 2 compared to Path 1 in the near-term are the level of efficiency gains from the automation and system integrations, no increase in the level of accuracy in the HCA or MN DIP screening results from today – and, we are limited in our ability to gain significant efficiencies in Fast Track Initial Review Screens. Long-term, without an asset data collection and validation process, we will also be limited in our ability to further automate aspects of the interconnection process. Specific implications to the various HCA and MN DIP automation and integrations with Path 2 are as follows:

- *Monthly HCA* – Any minor inconsistencies in a feeder model's conductor or equipment data will remain until the point that they are manually addressed.

- *Initial and Supplemental Review Screens* – These screens will benefit from the automation associated with the addition of the feeder model database, but will require more engineering scrutiny compared to the data validation scenario. This means that the 50 – 75 percent faster review processing timeline we estimated in Path 1 will be more in the range of a 25 - 50 percent improvement in time, and will be limited to the FTSRS. Secondary system-related interconnection screens will require the same amount of engineering input and quality control as is necessary today.
- *Preapplication Data Reports* – While the PDR will improve in terms of accuracy due to an automated process, without the data validation initiative, it will most likely not experience a significant change in speed compared to our current practice. The driver for the main benefits to the PDR are directly linked to automation of conductor and equipment queries. If the Primary System asset data validation is not included, these queries will still require significant engineering validation, which would likely prove as time-consuming as the current process.

Figure 5 below summarizes how we envision implementing Path 2, if directed so by the Commission.

Figure 5: Proposed Implementation of Path 2



E. Summary of Costs

We summarize below the costs of each of the improvements we have outlined. The only differences in costs between the Paths is the Foundational Asset Data Collection, which only applies to Path 1.

Table 1: Summary of Costs and Timelines

HCA or Interconnection Improvement	Timing (years)	Project Cost	Incremental Labor (per year)
Quarterly HCA Updates	**<1**	**Manual Effort**	**$375,000 - $500,000**
Addition of 2 HCA engineers and 1 GIS specialist		N/A	$375,000 - $500,000
Foundational Asset Data Initiative(s)	**2-3**	**$40M - $48M**	**TBD**
Primary		$27M – $32M	
Secondary		$13M - $16M	
Monthly HCA Updates (and foundational integrations and database development)	**1.5-2**	**$1.7M - $3.5M**	**$375,000 - $500,000**
Addition of 2 Modeling engineers and 1 GIS specialist		N/A	$375,000 - $500,000

Note: Improvements listed below rely on monthly HCA to be in service prior to work commencing.

Integrate with MN DIP – Supplemental Screens	**1-2**	**$700,000 - $1.4M**	**TBD**
Integrate with MN DIP – Initial Screens	**1-2***	**$700,000 - $1.4M**	**TBD**
COMBINED Integration with MN DIP Initial and Supplemental Screens	*1-2*	*$800,000 - $1.6M*	*TBD*
Integrate the HCA and Pre-Application Data Report	**1**	**$375,000 - $700,000**	**N/A**

* *Note*: These costs are only if this work is done as a stand-alone initiative. Our implementation Paths contemplate the Supplemental and Initial Screens work occurring concurrently – and so if done together, the costs of that combined effort are shown in the next row: COMBINED Integration with MN DIP Initial and Supplemental Screens.

We clarify that the Quarterly HCA Updates are in progress and on track for us to publish our first quarterly report this summer. We also reiterate that all of these timelines and conceptual cost estimates rely on the foundational integrations and database developments, and monthly HCA being the first improvement that we undertake.

We recognize that these are conceptual cost estimates, but we believe they provide the Commission with an appropriate level at this early stage of exploring potential futures for the HCA. We have explained that our first step with any or all of these initiatives would be to complete a detailed requirements and design effort that reflects the Commission's direction, which will return a refined estimate of the costs. We are happy to start that work upon receiving further direction from the Commission on the specific futures it wants us to either further explore or implement. Similarly, we are prepared to initiate the actual projects, and in that case, we offer to submit a compliance filing in this proceeding with the refined cost and timeline estimates that result from our detailed requirements and design planning efforts.

Finally, we note that we have attempted to answer the Department's questions regarding the various project components, how each interrelates with or is interdependent with the others, and clarify the specific improvements that are needed to achieve benefits for developers. To the extent we were not able to address a question through outlining two alternative paths and providing more details about the component projects, we respond to it specifically in Part II below. We address IREC's comments regarding the project components and timelines in Part II below.

F. Cost Recovery

As we discussed in our HCA Report, a key question in all of this is how—and from whom—the Company will recover the costs associated with the direction the Commission provides. For costs associated with advancing the HCA, the Transmission Cost Recovery Rider under Minn. Stat. § 216B.16, subd. 7b(4) "allows the utility to recover costs associated with distribution planning required under section 216B.2425." The relevant part of Minn. Stat. § 216B. 2425, subd. 8 provides:

> **Subd. 8. Distribution study for distributed generation.** Each entity subject to this section that is operating under a multiyear rate plan approved under section 216B.16, subdivision 19, shall conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued development of distributed generation resources, and shall include the study in its report required under subdivision 2.

We believe the work associated with producing a monthly HCA as we have outlined in both Paths 1 and 2 fits squarely within this provision and would therefore be eligible for recovery through the TCR. If the Commission directs the Company to implement a monthly HCA, we would include the costs for that in our Fall 2021 TCR Petition.

As we also noted in our HCA Report, we also believe the TCR would be the appropriate place to recover the costs associated with a foundational asset data improvements. These improvements will benefit the HCA and the interconnection Use Case as we have described, but they would also benefit other Company planning and operational processes as we described in our HCA Report, and so it would be appropriate for all customers to share in the costs.

For other changes to the underlying systems that will facilitate and support the HCA and/or interconnection processes, we believe a portion may be appropriate to recover through base rates and a portion may be appropriate to recovery through a cost-causation approach. We believe there is time to figure these details out, if the Commission directs the Company to take a first and foundational step toward the future by initially requiring a monthly HCA. While that is being developed, the Commission can consider further steps toward its long-term goal, and the Company can work to refine those next steps in accordance with further guidance the Commission may offer in this proceeding. At the time the Company brings the Commission more refined cost estimates and timelines in support of specific MN DIP integrations along a selected Path, we will also bring specific proposals for recovery of the associated costs.

II. QUESTIONS AND CLARIFICATIONS REGARDING OUR HCA FUTURES ANALYSIS

In this section, we address the questions and comments regarding the information we included in our HCA Report regarding the potential HCA futures that are not otherwise addressed above or that we thought would be helpful to specifically clarify in this way.

A. Actions Necessary to Integrate the HCA and Fast Track Supplemental Review Screens

The Department requested that we provide more information about the feeder model update process as it relates to achieving integration of the HCA with the SRS, as outlined in our HCA Report.

Full automation of the SRS would require that the subject feeder model(s) are updated at the time of study. We believe the monthly feeder build update process we outlined above would largely be sufficient to use in the SRS, however, we may need to run additional updates for certain feeders on an ad hoc basis to ensure we capture all relevant changes that have occurred.

Based on 2020 actual volumes, we believe it is reasonable to assume the SRS volume will be in the 100-200 per year range. We believe the monthly feeder model updates to support the monthly HCA may largely suffice because the pace of large solar projects coming through the SRS on the same feeders will be spread out. This is due to the sequential nature of MN DIP – meaning that we need to wait for one project to move through the process before we analyze another. However, smaller projects have the opportunity to move faster through the reviews if there is enough capacity. So, the feeder model update tool we will need to deliver the SRS improvements requires an ad hoc update process, to be sure that we are continually accounting for additional DER that has connected to the system since the most recent scheduled/monthly update.

We clarify that our production of quarterly HCA results is fully manual and has no bearing on integration of the HCA and the MN DIP screens. As a manual process, this means that engineers will continue to manually build the feeder models that require updating in order to produce the quarterly HCA results. As the model-build process is the most time-consuming part of producing the HCA, to increase the cadence beyond quarterly, we need to develop an automated feeder build tool and database. The automated feeder model build tool and database are also necessary precursors to integration of the HCA with the SRS that we have described.

We do expect however, to gain insights from our move to a quarterly HCA that will be helpful as we make the transition to a Monthly HCA, should the Commission decide that is where it wants the Company to go.

B. Relation Between the MN DIP Supplemental Screens and Monthly HCA Updates

The Department asked the Company to explain why it stated that the "Supplemental Screens would also require the Monthly HCA updates to be fully functional" when it previously stated the Supplemental Screens are performed "about five times less often per year than the Initial Review Screens, reducing the need to update feeder models and HCA results more frequently in comparison."

The volume of Initial Review Screens is significantly higher than that of Supplemental Review Screens. However, HCA results are not relevant to Initial Review Screens, as those are generally for smaller projects rather than the larger primary-connected projects that the HCA is intended for currently. Therefore, the feeder model update process is not relevant to Initial Review Screens. If updated feeder models were relevant and necessary to Initial Review Screens, we would need to update our analysis continuously; we have had weeks where nearly 100 Initial Reviews are performed, and these reviews are required in 15 days or less. This compares to Supplemental Reviews, which are in the 200 - 300 per year range, have a 30-day turnaround, and they are performed sequentially; this volume, process, and approach better aligns with a monthly cadence for feeder model updates. As we have explained in Part I above, while we believe a monthly feeder model update will largely be sufficient to support the Supplemental Review Screen process, we would build-in the capability for the feeder model update tool to perform ad hoc queries as needed. This will allow us to refresh relevant feeder models on an on-demand basis to complete Supplemental Review Screens.

C. IREC Comments Regarding the Project Components and Timelines we Outlined in our HCA Report

In Comments, IREC made a number of assertions regarding the project components and timelines that we outlined and that believe are necessary to achieve the Commission's long-term goal for the HCA. We issued discovery to IREC on April 15, 2021 asking for support for a number of their assertions. Two business days before they were due, IREC requested an additional week to provide its answers. We requested that they provide their responses as they are completed instead of waiting to send all at once, and if at all possible, sooner than a week beyond the due date. We received all 10 of the responses on May 4th, eight days after the standard 10-day due date (a total of 19 days after we issued the IRs to them), and few were responsive to our questions. We include IREC's responses to our Information Requests as Attachment B, and note that IREC did not provide any information to substantiate their assertions that the project components, costs, and timelines that the Company had outlined were not reasonable.

For example, IREC stated in their Comments that the "requisite procedures, costs, and time necessary to enable a monthly update cycle are considerably less onerous than what Xcel presents in its 2020 HCA Report." When we asked IREC to provide the materials it relied on to make this statement, IREC responded that this statement was intended to encapsulate the content of IREC's entire 25-page Comments filing and provided no further support for this statement (*see* IREC-5).

Elsewhere in Comments, IREC made other assertions regarding timelines and costs associated with data validation and/or automation of feeder model building. In IREC-7 and IREC-8, we asked IREC to specify the utilities that it had examined in order to compare what we had proposed for feeder model building and to implement an effective data validation process. IREC responded that it has not examined any such utility timelines, and generally noted it had participated in proceedings with several California utilities and NV Energy. The only specific reference IREC offered with regard to these assertions was to a single May 7, 2020 filing by PG&E that IREC said had "some discussion of data validation and the timelines associated with model development," also noting this was cited in footnote 41 of its Comments. We found and reviewed a May 8, 2020 filing by PG&E on the California dockets system, however, did not see any mentions of asset data validation, feeder model automation, or any timelines for these types of initiatives in this filing. Further, in its response to IREC-8, IREC also pointed us to their April 7, 2021 Comments in this proceeding where they stated, "there has been no thorough vetting of any actual [HCA] costs in public dockets." Finally, we note that in IREC-5, IREC clarified that it has never implemented a hosting capacity analysis.

IREC's statement that it expects the Company could automate its model building and implement an effective computerized data validation process in a year or less, based on reported implementation timelines from other utilities is baseless according to IREC's responses to our discovery – as are their other assertions regarding what the Company has explained is necessary to achieve the futures the Commission directed it to explore. IREC fails to demonstrate the comparative information it relied upon to make sweeping and dismissive assertions about the Company's HCA Futures Analysis. As such, IREC's claims are unsupported, should be dismissed and should not be the basis of Commission action.

Finally, we note that we were able to find one public reference in a Southern California Edison 2018 rate case to the cost of a "system modeling tool" that is defined similarly to the functionality we would achieve with our automated feeder build tool that provides some point of reference.[7] SCE defined the System Modeling Tool (SMT) as

> a set of software applications that will enable SCE engineers to perform more precise and near-real-time power-flow and capacity analyses of the electric system. The SMT replaces SCE's current software tools for capacity analyses throughout its grid, which are inadequate because they require significant manual effort and rely upon conservative assumptions that limit their precision. The added functionality in SMT will facilitate capacity planning, interconnection studies, and the [distribution resource plan's] Integration Capacity Analysis (ICA).

The cost SCE outlined and that the California Commission approved in that rate case for this specific tool was $6.457 million in 2017 and $2.467 million in 2018, for a total

[7] *See* Decision 19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company (Application of Southern California Edison Company (U338E) for Authority to Increase its Authorized Revenues for Electric Service in 2018, among other things, and to Reflect that increase in Rates, Application 16-09-001) at pages 114-115.

of $8.924 million. This timeline for this project appears to be longer than one year, and the cost is significantly higher than our estimate of $1.7 to $3.5 million to deliver a monthly HCA, which includes supporting feeder model automation.

III. COMPLIANCE REQUIREMENTS

In this section, we address the questions and comments regarding various compliance requirements for our 2020 Hosting Capacity Analysis (HCA) report.

A. Criteria Violations

The Department requested that we clarify our approach to listing the criteria violations and corresponding hosting capacity values in the pop-up field of our Hosting Map, including any technical limitations. This question stems from Order Point No. 15 that requires the Company to publish the criteria violation and corresponding hosting capacity values for each HCA model run and location, and map with appropriate caveats. As we noted in our HCA Report, we were unable to publish all criteria violations in the pop-up, because the volume of data is so large – creating both technical and usability constraints. From a technical perspective, this functionality would require the addition of at least six new fields in each pop-up – and possibly more, if the sub-feeder is located in a more dense part of our system. As we have otherwise explained, we display the public HCA Map in a heat map form for security reasons. This means that in the dense portions of our system, a pop-up likely contains results for several sub-feeder segments. To also show all of the criteria violations rather than just the most limiting factor, we would have to add six additional data fields to each of the sub-feeder results that are already displaying the results for multiple sub-feeders on multiple pop-up pages in a single pop-up. This challenges our data capabilities and even more so complicates the display – we believe, making it practicably unusable.

We complied with the requirement to provide this information by listing the all hosting capacity criteria violations by sub-feeder segment on the "Hosting Capacity Sub-Feeder Results." We provide instructions on accessing this specific information on page 10 of the "Hosting Capacity Map How-To Guide." Despite assertions that this information is not helpful without corresponding unique line segment identifiers on the hosting capacity map (see Part B below), the Sub-Feeder Tabular Results allow a user to glean how hosting capacity across the feeder progresses as conductor moves further away from the substation.

Finally, we clarify that the Feeder Names are shown in the Sub-Feeder Tabular Results, in column C of the first row for each Feeder. In response to IREC's feedback in Comments, we are updating the Sub-Feeder Results to move the Feeder Name into its own column and show it on every row for that Feeder and expect to publish the updated version by the end of May 2021.

B. Unique Identifier for each Line Segment in Map Pop-Ups

We appreciate the Department concluding that our explanation was reasonable regarding our current inability to list the unique identifier for each line segment in the Map pop-up. The reasons for this are both technical- and security-related. As we note in part A above, we aggregate line section data within a set spatial area for security reasons. Since the sub-feeder segments are aggregated, we are technically unable to match a specific Section ID within the sub-feeder/heat map area, as there may be multiple segments in the aggregated area.

Further, we redact for security reasons, certain feeders from the Map but include the hosting capacity results for those feeders in the Tabular Report. If we were to create a detailed "map" between the Tabular Results and the Heat Map by specifying a line identifier, we would expose and identify the feeders that have been redacted for security reasons – negating an important security protection. As consideration of security issues proceeds in Docket Nos. E002/M-19-685 and E999/M-20-800 (the Grid Information Security proceeding), one outcome may be a tiered-access type approach, as the Company has proposed. In that case, if a bright-line connectivity map is provided with appropriate protections on a need-to-know basis, one further technical hurdle will be whether we can provide that level of detail and maintain the functionality of the map. We note that currently, there are nearly 660,000 sub-feeder sections (as shown in our Sub-Feeder Tabular Results), which would be a significant increase in the amount of data points on the map potentially impacting the functionality in its current form.

IV. OTHER ISSUES

IREC suggests that the Company should be required to provide monthly results that are specific to solar only projects and also a monthly analysis that includes energy storage, which we address in Part III.B below. As part of these analyses, IREC suggests the Company should be required to conduct its analysis such that the HCA would be useful for developers to design distributed energy resources (DER) that benefit the grid and avoid seasonal constraints, which is not currently allowed under the Minnesota Distributed Energy Resources Interconnection Process (MN DIP). We discuss IREC's specific recommendations in turn below.

A. Load Data Input to the HCA Analysis

1. Use of Monthly Load Data Instead of Annual

IREC suggests the Company should publish HCA results using Daytime Minimum Load in each month of the year to allow developers to avoid seasonal constraints. This Use Case would only be useful if seasonal curtailment were allowed under MN DIP, which it is not. Without such a Use Case, producing a monthly analysis with changing load data each month would likely cause confusion – as each month, a Feeder's hosting capacity would change without warning and with little predictability. We believe our resources are better spent on the HCA futures the Commission has identified and that we have discussed in Part II above.

2. Use of Absolute Minimum Load

IREC also suggests the Company be required to conduct an analysis using Absolute Minimum Load rather than Daytime Minimum Load – again, for the purpose of designing systems based on other generation types and a system (such as solar plus storage) to avoid seasonal constraints. First, the Use Case for the present HCA is for generation resources only. Second, MN DIP does not currently allow for systems intended to avoid seasonal constraints. Third, Absolute Minimum Load would significantly reduce hosting capacity across most, if not all, Feeders. Finally, we believe our resources are better spent on the HCA futures the Commission has identified and that we have discussed in Part II above.

3. Use of Peak and Minimum Load Profiles

IREC repeated its 2019 suggestion that the Company should move toward hourly HCA results using 24-hour load profiles of each month's peak day and minimum day – or a "576 analysis." The goal of an analysis like this is to enable developers to see seasonal variations in hosting capacity instead of only the most restrictive hours of the year. Again, the MN DIP does not currently allow for systems intended to avoid seasonal constraints. To the extent we seek a non-wires alternative to resolve a seasonal constraint as part of our Integrated Distribution Plan (IDP), it is possible that we would do an analysis such as this to inform developers of the system need. However, this analysis would be resource-intense, does not currently have broad application, nor is it aligned with the Commission's long-term goal for the HCA to integrate with or augment the Fast Track screens in the MN DIP.

B. Load HCA

At present, the Use Case for the HCA is for generation only – and solar generation is by far the dominant type of DER interconnecting to our system. Producing an HCA for load resources such as storage and EVs would be a significant expansion that would need to be prioritized along with the potential HCA futures the Commission directed the Company to explore.

C. Customer Data Privacy

IREC raises concerns regarding the Company's actions with respect to customer privacy – specifically taking issue with the Company's use of its 15/15 aggregation standard as part of its approach to address grid and customer security and confidentiality. In doing so, IREC erroneously characterizes the Company's use of its 15/15 standard to help guide its protective actions for customers as an incorrect application of the standard.

First, the 15/15 standard is an Xcel Energy standard – not a standard that is defined by the Commission or any other entity relevant to this proceeding. Therefore, the Company has discretion in how it applies the standard. Second, we explained in our HCA Report that we used the 15/15 threshold, as one tool among several, to help guide our actions toward grid security, and customer confidentiality and customer energy security. Feeders with fewer than 15 customers are very low density and as such, may provide insights into customer locations that could compromise customer energy security and customer confidentiality. Feeders where the load of one customer is 15 percent or more could also compromise customer confidentiality. Finally, we note that while we redacted these Feeders from the HCA Map, they are fully included in the public Tabular Results.

We expect that development of guidance to address grid and customer security issues related to public access to grid information will be addressed in the Grid Information Security proceeding. And similarly, the Commission intends to explore issues of customer privacy and confidentiality with respect to energy usage data in the Data Access proceeding in Docket Nos. E999/CI-12-1344 and E999/M-19-505.

D. Stakeholder Engagement

The Company disagrees with IREC's assertion in Comments that it disregarded the Commission's Order to work with stakeholders to evaluate the HCA's ability to replace or augment the review screens.[8] As evidenced in the detailed notes included with our HCA Report as Attachments D1 and D2, and the presentation materials and recordings of our Stakeholder Workshops posted on our website,[9] we held robust stakeholder workshops to explore all of the potential futures specified by the Commission. At page 17 of its Comments, IREC makes an obscure reference to a request it made in Workshop 4 with regard to initial and supplemental review screens. The Company laid out its plans for how it intended to explore the potential HCA Use Cases/futures at the outset of the Workshop series, and at the beginning of each Workshop. Just because the Company may have chosen to explore the potential futures differently than IREC wished does not mean that it did not meaningfully engage with stakeholders. To the contrary, the recordings, the polls and surveys we conducted, and our narrative that explains how we incorporated stakeholder feedback in our analysis demonstrate not only our compliance with the Commission's Order – but also how we fully embraced engagement with stakeholders in exploring potential HCA futures.

Finally, we note that IREC and ILSR include remarks or specific requests for the Company to publicly publish more information with its HCA than it does today, including a bright-line connectivity map. These issues are being examined in Docket Nos. E002/M-19-685 and E999/M-20-800, and as such we do not respond to them in this Reply.

CONCLUSION

Xcel Energy appreciates the opportunity to provide these Reply Comments that further explain our analysis and respond to parties' Comments.

Dated: May 21, 2021

Northern States Power Company

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[8] IREC Comments at page 16.

[9] *See* Recordings and Presentation Materials posted under General Resources on the Xcel Energy website: https://mn.my.xcelenergy.com/s/renewable/developers/interconnection.

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☐ **Public Document – Not Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	10
Docket No.:	E002/M-20-812		
Response To:	Interstate Renewable Energy Council		
Requestor:	Yochanan Zakai		
Date Received:	February 2, 2021		

Question:

Please provide a table, similar to the example below, comparing:

- all of the primary distribution system data that Xcel plans to field verify pursuant to existing asset management activities, including those identified in Staff Information Request No. 1,[1] and
- all of the primary distribution system data that Xcel argues is necessary to field verify to conduct more frequent hosting capacity analysis updates.[2]

This question does not pertain to field verification efforts on the secondary distribution system.

Primary Distribution System Data	**Xcel Existing Field Verification**	**Xcel Proposed Hosting Capacity Analysis Field Verification**
transformer capacity	yes	yes
location of transformer	yes	yes
etc.		

[1] MN Pub. Util. Commission Dkt. E002/M-20-812, Staff Information Request No. 1 (Jan. 6, 2021).
[2] MN Pub. Util. Commission Dkt. E002/M-20-812, Xcel Energy Hosting Capacity Analysis Report, Attachment F, at 9-12.

Response:

We provide the requested table as Attachment A to this response. We note that the Existing Field Verification column represents the current plan for additional data collection, validation, and testing of feeders that is part of our Advanced Distribution Management System (ADMS) initiative, as described in our January 25, 2021 Compliance Filing in Docket Nos. E002/M-19-666, E002/M-19-721, and E002/M-20-680 and noted in our response to MPUC-1 in this docket. The scope of the ADMS-driven initiative is more narrow than the conceptual comprehensive HCA initiative in terms of the Minnesota system data that would be completed. We further discuss below, our approach to the comprehensive field data collection initiative outlined in our HCA filing and how that correlates to our other/ongoing data validation efforts.

First, we clarify that the conceptual estimate we outlined for a comprehensive field data collection effort to support automation of the HCA to get it to a monthly cadence and to automate and/or integrate the HCA with various aspects of the interconnection process is just that – conceptual. We explained that should the Commission want us to pursue any of the potential HCA futures we outlined, it would be necessary for the Company to refine the relevant project cost and timing based on a more specific Use Case and scope, and propose the cost recovery treatment it believes is appropriate. This would include refinement of the data collection/ verification plan necessary to achieve the desired Use Case, which would take into account any overlapping data validation work that had since been completed or contemplated to be completed otherwise.

We think it is also helpful to understand the context of the conceptual estimate for the data collection and validation in the HCA filing. It is based on an estimate we had sought and received for a comprehensive field data validation effort for a subset of Minnesota feeders. We extrapolated that estimate to the entire Minnesota system and included costs for the back-office work, which is a final quality control check prior to updating this information in the system of record – GIS. We based the back-office adder on our experience with similar field validation efforts associated with our ADMS implementation in Minnesota and our Public Service Company of Colorado affiliate to-date.

After the Commission provides further direction, some of the items that we expect will impact the overall cost and timeline estimates will include:

- *Refined underground system data collection and validation.* The subset of feeders on which we based our overall estimate is largely overhead facilities, however, a portion of our Minnesota system is underground. We did not attempt to estimate the underground portions or differentiate the amount of work involved with data collection or validation of the underground parts of our system. We expect the costs and time to validate and/or collect data on the underground portion of our system will be higher than for the overhead parts. This expectation stems from the fact that a more skilled workforce would be necessary and visual inspection of overhead facilities is more straightforward and thus costs would be less than underground inspections.
- *Further data collection and validation that is completed.* In addition to our updated work practices that involve collecting additional details associated with new construction and reconstruction, we have a more narrow data validation effort underway associated with our ADMS initiative, as described in our January 25, 2020 compliance filing in Docket Nos. E002/M-19-666, E002/M-19-721, and E002/M-20-680 and MPUC Information Request No. 1 in this docket.
- *Efficiencies gained from our other overhead system data validation work.* We have already gained some efficiencies from the field data work we have done to-date, and

believe that we might be able to identify further efficiencies that will serve to reduce the overall cost of a comprehensive Minnesota field data initiative.

- *Efficiencies gained from Advanced Metering Infrastructure (AMI).* As a comprehensive field data effort will take several years to complete, our AMI implementation is nearing – and expected to start in early 2022. As noted in our HCA filing, we expect the data from AMI meters and Field Area Network (FAN) will provide additional opportunities for improvements to the data available for HCA.

In summary, depending on the timing of a Commission decision on the direction for the potential HCA futures we examined, a more refined data collection and validation estimate could vary greatly from the conceptual estimate contained in our filing.

Finally, we reiterate that highly accurate detailed distribution system data is critical to building system models and performing the complex engineering studies necessary to integrate DER on to the distribution grid and achieve other advanced grid capabilities. The historical field asset information utilities collected and maintained is not sufficient to meet the vision of automating the grid. Our approach to this to-date has been incremental – matching the costs with specific benefits, to keep costs low for our customers. A key question is how fast the Commission will want this advanced grid enabler to go.

Preparer:	Luther Miller
Title:	Engineer
Department:	Distribution Planning
Telephone:	763-493-1893
Date:	February 12, 2021

Xcel Energy Field Asset Data Collection and Validation Initiative Comparison
Primary System Data Elements

		Field Asset Data Effort	
Category	Data Field	Existing / Ongoing (ADMS)*	Conceptual HCA Futures (including for Monthly HCA cadence)
Capacitor Rack	kvar rating	Yes	Yes
Capacitor Rack	phase designation	Yes	Yes
Capacitor Rack	oh ug	Yes	Yes
Capacitor Rack	Protection type	Yes	Yes
Capacitor Rack	connection	Yes	Yes
Capacitor Rack	Orientation	Yes	Yes
Capacitor Rack	Location	Yes	Yes
Capacitor Rack	facility tag x	Yes	No
Capacitor Rack	facility tag y	Yes	No
Capacitor Rack	company number	Yes	Yes
Capacitor Rack	voltage rating	No	Yes
Cogeneration	type	No	Yes
Cogeneration	Location	No	Yes
Fault Indicator	Location	No	Yes
Lot Centroid	LAND LOT CENTROID RELATIONS	No	Yes
OH ATO	Location	No	Yes
OH Fuse	field stencil	No	Yes
OH Fuse	type	No	Yes
OH Fuse	switch number	Yes	Yes
OH Fuse	Location	Yes	Yes
OH Fuse Unit	phase	Yes	Yes
OH Fuse Unit	normal position	Yes	Yes
OH Primary	Installed length	No	Yes
OH Primary	phase orientation	Yes	Yes
OH Primary	Route	Yes	Yes
OH Switch	field stencil	No	Yes
OH Switch	type	Yes	Yes
OH Switch	continuous amp rating	No	Yes
OH Switch	tie switch indicator	No	Yes
OH Switch	switch number	Yes	Yes
OH Switch	Location	Yes	Yes
OH Switch	normal position	Yes	No
OH Switch Unit	phase	Yes	Yes
OH Switch Unit	normal position	No	Yes
OH Transformer Bank	field stencil	No	Yes
OH Transformer Bank	bank configuration	No	Yes
OH Transformer Bank	facility tag x	No	Yes

		Field Asset Data Effort	
Category	Data Field	Existing / Ongoing (ADMS)*	Conceptual HCA Futures (including for Monthly HCA cadence)
OH Transformer Bank	facility tag y	No	Yes
OH Transformer Bank	output voltage	No	Yes
OH Transformer Bank	secondary location	No	Yes
OH Transformer Bank	Location	Yes	Yes
OH Transformer Bank Unit	phase	Yes	Yes
OH Transformer Bank Unit	Protection type	No	Yes
OH Transformer Bank Unit	rated kva	Yes	Yes
Pole	framing type	No	Yes
Pole	Location	Yes	Yes
Primary Cable	phase	Yes	Yes
Primary Meter	company number	No	Yes
Primary Meter	facility tag x	No	Yes
Primary Meter	facility tag y	No	Yes
Primary Meter	Location	No	Yes
Primary Open Point	Location	No	Yes
Primary Wire	Size	Yes	Yes
Primary Wire	material	Yes	Yes
Primary Wire	insulation	No	Yes
Primary Wire	phase	Yes	Yes
Recloser Bank	company number	Yes	Yes
Recloser Bank	facility tag x	Yes	No
Recloser Bank	facility tag y	Yes	No
Recloser Bank	field stencil	Yes	Yes
Recloser Bank	rated voltage	Yes	Yes
Recloser Bank	max fault current rating	Yes	Yes
Recloser Bank	opening time	Yes	Yes
Recloser Bank	Location	Yes	Yes
Recloser Bank Unit	phase	Yes	Yes
Recloser Bank Unit	amp rating	Yes	Yes
Recloser Bank Unit	type	No	Yes
Recloser Bank Unit	curve	No	Yes
Regulator Bank	company number	Yes	Yes
Regulator Bank	facility tag x	Yes	No
Regulator Bank	facility tag y	Yes	No
Regulator Bank	Location	Yes	Yes
Regulator Bank Unit	phase	Yes	Yes
Regulator Bank Unit	kva rating	Yes	Yes
Regulator Bank Unit	amp rating	No	Yes
Sectionalizer Bank	company number	No	Yes
Sectionalizer Bank	Location	Yes	Yes
Sectionalizer Bank Unit	phase	Yes	Yes

		Field Asset Data Effort	
Category	**Data Field**	**Existing / Ongoing (ADMS)***	**Conceptual HCA Futures (including for Monthly HCA cadence)**
Step Transformer Bank	facility tag x	Yes	Yes
Step Transformer Bank	facility tag y	Yes	Yes
Step Transformer Bank	type	Yes	Yes
Step Transformer Bank	Location	Yes	Yes
Step Transformer Bank	Bank Configuration	No	No
Step Transformer Bank	size	No	Yes
Step Transformer Bank Unit	rated kva	Yes	Yes
Step Transformer Bank Unit	phase	Yes	Yes
Step Transformer Bank Unit	tap changer winding	Yes	Yes
Switching Facility	Company Number	No	Yes
Switching Facility	Location	No	Yes
Switching Facility	facility tag x	No	Yes
Switching Facility	facility tag y	No	Yes
Switching Facility	type	No	Yes
UG ATO	Location	No	Yes
UG Transformer	facility tag x	No	Yes
UG Transformer	facility tag y	No	Yes
UG Transformer	field stencil	No	Yes
UG Transformer	output voltage	No	Yes
UG Transformer	Location	No	Yes
UG Transformer Bank Unit	rated kva	No	Yes
UG Transformer Bank Unit	Phase	Yes	Yes
UG Transformer Bank Unit	protection type	No	Yes

* Note: *As noted in the narrative response to this Information Request, the scope of the ADMS-driven initiative is more narrow than the conceptual comprehensive HCA initiative in terms of the Minnesota system data that would be completed.*

Docket No.:	E002/M-20-812		
	Distribution Study – Hosting Capacity Analysis Report		
Requestor:	Xcel Energy		
Requested From:	Interstate Renewable Energy Council		
Date of Request:	April 15, 2021	Information Request No.	1
Response Date:	May 3, 2021		

Question:

On page 14, Section 5 IREC states Xcel Energy should include Queued generation in Hosting Capacity Analysis. When IREC refers to queued generation what step of the Minnesota DER Interconnection Process (MN DIP) is IREC assuming the projects are in?

Response:

Queued generation means a project that is in the queue. According to MN DIP § 1.8.1 a project enters the queue, and a "Queue Position is assigned by the Area EPS [Operator,] based on when the Interconnection Application is deemed complete."

Docket No.:	E002/M-20-812
	Distribution Study – Hosting Capacity Analysis Report
Requestor:	Xcel Energy
Requested From:	Interstate Renewable Energy Council
Date of Request:	April 15, 2021 — Information Request No. 2
Response Date:	May 3, 2021

Question:
For the current docket, provide the name of each developer or client that IREC represents and provide the legal name of each such entity.

Response:
IREC is an unaffiliated, independent public interest organization. IREC supports the creation of robust, competitive clean energy markets. IREC does not respresent any parties or developers in this proceeding

Docket No.:	E002/M-20-812		
	Distribution Study – Hosting Capacity Analysis Report		
Requestor:	Xcel Energy		
Requested From:	Interstate Renewable Energy Council		
Date of Request:	April 15, 2021	Information Request No.	3
Response Date:	May 3, 2021		

Question:
Does IREC agree that the more accurate the hosting capacity information is, the more useful it is? If not, why not? Provide all workpapers, analysis and data relied upon for your response.

Response:
Yes, generally the more accurate the hosting capacity information is the more useful it is. This must be balanced with considerations around time and cost.

Docket No.:	E002/M-20-812		
	Distribution Study – Hosting Capacity Analysis Report		
Requestor:	Xcel Energy		
Requested From:	Interstate Renewable Energy Council		
Date of Request:	April 15, 2021	Information Request No.	4
Response Date:	May 3, 2021		

Question:
Does IREC agree that having more accurate information is more important than having more frequent information that is not as accurate? If not, why not? Provide all workpapers, analysis and data relied upon for your response.

Response:
It depends upon the additional level of accuracy being achieved and the level of frequency in question. Accuracy is also difficult to achieve if the results are not updated frequently.

Docket No.:	E002/M-20-812		
	Distribution Study – Hosting Capacity Analysis Report		
Requestor:	Xcel Energy		
Requested From:	Interstate Renewable Energy Council		
Date of Request:	April 15, 2021	Information Request No.	5
Response Date:	May 3, 2021		

<u>Question:</u>
At page 2 of its April 2, 2021 Comments, IREC states: "The requisite procedures, costs, and time necessary to enable a monthly update cycle are considerably less onerous than what Xcel presents in its 2020 HCA Report."

A. Provide all workpapers, analysis and data relied upon to support this statement.
B. Provide IREC's perspective of the requisite procedures needed for Xcel Energy to enable a monthly update cycle, and provide all workpapers, analysis and data that IREC is relying on for this.
C. Provide IREC's calculation and determination of costs and time necessary for Xcel Energy to enable a monthly update cycle and provide all workpapers, analysis and data that IREC is relying on for this.
D. Has IREC ever implemented a Hosting Capacity monthly update cycle? If so, describe each such implementation in detail.

<u>Response:</u>
A-C. IREC did not file comments in this proceeding on April 2, 2021. IREC responds to this request assuming Xcel meant to refer to IREC's comments on April 7, 2021. This information request cites a summary statement that is intended to encapsulate the content of IREC's entire 25 page filing.

D. IREC is not a distribution utlity and has not implemend a hosting capacity analysis.

Docket No.:	E002/M-20-812
	Distribution Study – Hosting Capacity Analysis Report
Requestor:	Xcel Energy
Requested From:	Interstate Renewable Energy Council
Date of Request:	April 15, 2021 Information Request No. 6
Response Date:	May 3, 2021

Question:

At pages 2-3 of its April 2, 2021 Comments, IREC states: "Based on reported implementation timelines from other utilities, IREC expects that Xcel could automate its model building and implement an effective computerized data validation process in a year or less." And, at page 18 of its April 2, 2021 Comments, IREC states: "Yet Xcel's estimate that it would take 3-4 years to automate the model building process is unreasonably long. For example, Pacific Gas & Electric Company (PG&E) completed a program to automate its model building and data validation process in under 16 months."

A. Identify each utility that IREC has examined regarding the reported timelines to automate model building and implement an effective data validation process.
B. For each such utility identified in response to part A above, provide the information requested in the sub-paragraphs below, and provide for each response all documentation reviewed by IREC as to topic of each request, and specifically identify those pages of this documentation that support the answer to each request:
   i. Describe in detail all IT systems, data gathering systems and processes, and other pertinent work that were required as part of the effort to achieve automation of an accurate model building process. How much did these IT systems, data gathering systems, and other pertinent work cost and over what period of time did it take to implement these systems?
   ii. Describe in detail all IT systems, data gathering systems and processes, and other pertinent work that were required as part of the effort to achieve automation of an accurate model building process but that had already been done before the start of the time period measured to implement this as reflected in the response to sub-part (i) above. How much did these IT systems, data gathering systems, and other pertinent work cost and over what period of time did it take to implement these systems?
   iii. What information systems did each utility use for its model building and automation?
   iv. What incremental work on IT systems, data gathering systems, and other pertinent work was needed by each utility related to this once it began its efforts to automate an accurate model building and computerized data validation process in the time period reflected in response to sub-part (i) above? What was the cost and timeline of this incremental work?
   v. Has further IT or other development been required after initial implementation? Please explain in detail.
   vi. What is the ongoing O&M expense associated with this after implementation? Please explain in detail.
   vii. Please explain the referenced computerized data validation, and particularly how it gathers or validates field equipment necessary to the models.

viii. How accurate has the computerized data validation process been? Has the accuracy ever been audited or verified? If so, please explain in full the results of every such audit or validation.

C. Is there any utility that IREC is aware of that has implemented automation of the feeder building process, but IREC has chosen not to examine the timeframe for implementation? If so, identify each such utility and explain why IREC has not examined the timeframe for implementation.

Response:
IREC did not file comments in this proceeding on April 2, 2021. IREC responds to this request assuming Xcel meant to refer to IREC's comments on April 7, 2021.

A. IREC has not "examined" utility timelines to automate model building and implement an effective data validation process. IREC has participated in regulatorly proceedings that discussed HCA data validation procedures for the following utilities: Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, and NV Energy.

B. IREC objects to this request because it includes information is equally available to Xcel Energy and is unduely burdensome. Subject to and without waiving these objections, IREC responds as follows:

In the regulatory proceedings that IREC has patricipated in, there has been some discussion of data validation and the timelines associated with model development. The only utility that has provided specific data regarding the timeline for their efforts is PG&E. As noted in footnote 41 to IREC's April 7, 2020 Comments, this data can be found at: CA Pub. Util. Commission, Dkt. R.14-08-013, PG&E's Integration Capacity Analysis (ICA) Implementation Update (May 7, 2020). In other proceedings, the need has not arisen to document timelines because other utilities have met their implemenation dealdines.

C. No.

Docket No.:	E002/M-20-812 Distribution Study – Hosting Capacity Analysis Report		
Requestor:	Xcel Energy		
Requested From:	Interstate Renewable Energy Council		
Date of Request:	April 15, 2021	Information Request No.	7
Response Date:	May 3, 2021		

Question:
At page 18 of its April 2, 2021 Comments, IREC states: "The low end of Xcel's cost estimates for automating the feeder building process appear comparable to reports of the costs for both automating feeder building and data validation programs in other states, however there has been no thorough vetting of any actual costs in public dockets. Moreover, we would expect that Xcel would find efficiencies and cost savings as it implements more automated processes and completes its existing field verification activities." And, at page 19 IREC states: "Other utilities that update their HCA at monthly intervals—or more frequently—have performed similar model building and clean-up activities without a programmatic label or years-long process."

A. What is a programmatic label?
B. Please clarify the specific cost estimate amount that IREC is referring to in the above-referenced statement on page 18.
C. Identify each utility that IREC has examined regarding costs for automation of the feeder building process.
D. For each such utility identified in response to part C above, provide the information requested in the sub-paragraphs below, provide for each response all documentation reviewed by IREC as to topic of each request, and specifically identify those pages of this documentation that support the answer to each request:
   i. Is this a vertically integrated utility?
   ii. What were the actual costs?
   iii. Were the actual costs thoroughly vetted in a regulatory proceeding? If so, provide all relevant procedural references.
   iv. Was an itemization of actual costs provided? If so, provide this.
   v. How did actual costs compare to cost estimates?
   vi. How were actual costs recovered? Please explain in detail.
   vii. What was the stated goal or driver for the hosting capacity analysis?
E. Is there any utility that IREC is aware of that has implemented automation of the feeder building process, but IREC has chosen not to examine its costs? If so, identify each such utility and explain why IREC has not examined the costs.

Response:
IREC did not file comments in this proceeding on April 2, 2021. IREC responds to this request assuming Xcel meant to refer to IREC's comments on April 7, 2021.

A. A programmatic label is the defined title for an activity or program.

B. Xcel 2020 HCA Report, Attachment F at 13-14, Section II.B.2 "Montly HCA Updates."

C. IREC has not "examined" a utlity regarding the costs for automation of the feeder building process. The only utility that has provided IREC data regarding the costs of their data validaiton efforts is PG&E.

D. IREC objects to this request because it includes information is equally available to Xcel Energy, overbroad, and unduely burdensome. Subject to and without waiving these objections, IREC responds as follows:

(i). IREC does not know how Xcel Energy defines a vertically integrated utility and so is unable to answer this question.

(ii)-(vi). As noted in footnote 41 to IREC's April 7, 2020 Comments, this data can be found at: CA Pub. Util. Commission, Dkt. R.14-08-013, PG&E's Integration Capacity Analysis (ICA) Implementation Update (May 7, 2020). The cited document speaks for itself regarding the utility's assertions of its costs. As explained in IREC's April 7, 2020 comments: "there has been no thorough vetting of any actual [HCA] costs in public dockets."

(vii). As noted in section II of of IREC's April 7, 2021 comments, California authorized the use of HCA in the interconnection screening process.

E. No.

Docket No.:	E002/M-20-812 Distribution Study – Hosting Capacity Analysis Report		
Requestor:	Xcel Energy		
Requested From:	Interstate Renewable Energy Council		
Date of Request:	April 15, 2021	Information Request No.	8
Response Date:	May 3, 2021		

Question:
At page 19 of its April 2, 2021 Comments, IREC states: "Moreover, we would expect that Xcel would find efficiencies and cost savings as it implements more automated processes and completes its existing field verification activities."

Specify and quantify in dollar amounts, all efficiencies and cost savings IREC is expecting Xcel Energy to find. Provide all workpapers, analysis and data relied upon for your response.

Response:
IREC did not file comments in this proceeding on April 2, 2021. IREC responds to this request assuming Xcel meant to refer to IREC's comments on April 7, 2021. IREC based its expectation on Xcel's response to IREC Information Request No. 10, as follows:

> *Efficiencies gained from our other overhead system data validation work.* We have already gained some efficiencies from the field data work we have done to-date, and believe that we might be able to identify further efficiencies that will serve to reduce the overall cost of a comprehensive Minnesota field data initiative.
>
> *Efficiencies gained from Advanced Metering Infrastructure (AMI).* As a comprehensive field data effort will take several years to complete, our AMI implementation is nearing – and expected to start in early 2022. As noted in our HCA filing, we expect the data from AMI meters and Field Area Network (FAN) will provide additional opportunities for improvements to the data available for HCA.

IREC has not quantified Xcel's asseration of its potential efficiences and cost savings.

Docket No.:	E002/M-20-812 Distribution Study – Hosting Capacity Analysis Report		
Requestor:	Xcel Energy		
Requested From:	Interstate Renewable Energy Council		
Date of Request:	April 15, 2021	Information Request No.	9
Response Date:	May 3, 2021		

Question:
At page 19 of its April 2, 2021 Comments, IREC states: "The one-time expense of automating the model building process should be recovered from all ratepayers, not solely interconnection customers. Automating the model-building process will enable Xcel to perform more distribution engineering tasks using its power flow modeling software. This benefit is not limited to generation interconnection uses, but can also help the utility analyze the impact of new load, changes in circuit configuration, and other distribution planning activities. Therefore, it is not appropriate to allocate these one-time costs exclusively to interconnection customers."

A. Quantify the benefit to DER developers of automating the model building process. Provide all workpapers, analysis and data relied upon for your response.
B. Quantify the benefit to all retail electric service customers (not including DER developers) of automating the model building process. Provide all workpapers, analysis and data relied upon for your response.
C. Is there a dollar amount of cost allocation to DER developers that IREC believes is above a threshold that makes automating the model building process not worth the cost? If so, please specify that dollar value and provide all workpapers, analysis and data relied upon for your response.
D. Is there a dollar amount of cost allocation to retail electric service customers (not including DER developers) that IREC believes is above a threshold that makes automating the model building process not worth the cost? If so, please specify that dollar value and provide all workpapers, analysis and data relied upon for your response.

Response:
IREC did not file comments in this proceeding on April 2, 2021. IREC responds to this request assuming Xcel meant to refer to IREC's comments on April 7, 2021.

A-B. IREC has not and does not believe that it is possible to accurately quantify the benefit to some or all customers of automating the model buidling process.

C-D. As a result, no because IREC has not and does not believe that it is possible to quantify such a cost threshold as envsioned in this information request.

Docket No.:	E002/M-20-812		
	Distribution Study – Hosting Capacity Analysis Report		
Requestor:	Xcel Energy		
Requested From:	Interstate Renewable Energy Council		
Date of Request:	April 15, 2021	Information Request No.	10
Response Date:	May 3, 2021		

Question:
At pages 19-20 of its April 2, 2021 Comments, IREC states: "Automating the most time-consuming part of the HCA process could reduce the amount of time it takes for Xcel to produce HCA results and could also automate certain load forecasting and load allocation processes associated with distribution planning. Accordingly, if Xcel invests in such automation, the Commission should also require it to provide HCA results on a monthly basis and perform its analysis using monthly load data."

A. Quantify the reduction in the amount of time IREC maintains that it would take for Xcel Energy to produce HCA results in this circumstance. Provide all workpapers, analysis and data relied upon for your response.
B. Quantify the reduction in the amount of time IREC maintains that it would take for Xcel Energy to automate certain load forecasting and load allocation processes associated with distribution planning. Provide all workpapers, analysis and data relied upon for your response.
C. Quantify the amount of time IREC maintains that it would take Xcel Energy, and at what cost, to automate certain load forecasting and load allocation processes associated with distribution planning. Provide all workpapers, analysis and data relied upon for your response.
D. Please explain the correlation between automation of load forecasting and load allocation processes associated with system planning and the HCA, such that it should influence the cadence and inputs to the HCA.

Response:
A-C. IREC did not file comments in this proceeding on April 2, 2021. IREC responds to this request assuming Xcel meant to refer to IREC's comments on April 7, 2021. IREC has not quantified the time or costs necessary for Xcel Energy to perform tasks specified.

D. Load allocaiton and forecasting are a part of the HCA process for many utlities. Therefore, automating these processes will allow a utility to more efficently perform HCA.

CERTIFICATE OF SERVICE

I, Mustafa Adam, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/M-20-812

Dated this 21st day of May 2021

/s/

Mustafa Adam
Regulatory Administrator

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Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_20-812_Official Service List
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-812_Official Service List
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_20-812_Official Service List
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Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-812_Official Service List
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