EXPLORING THE FUTURE OF HOSTING CAPACITY ANALYSIS AT XCEL ENERGY

2020 HCA Workshop 6

Use Cases 2, 3, 4 – Integrate the HCA with various interconnection steps

September 15, 2020

Workshop Goals

- Get your feedback, input, and perspective
- Work toward increasing the efficiency and value of the HCA tools
- Shape the HCA roadmap for further integration with the Minnesota DER Interconnection Process (MN DIP)
- Get your feedback, input, and perspective!

AGENDA

Introductions

Recap Workshops to-date

Discuss current state and future features for remaining potential integration improvements:

- Use Case 2) Integrate with MN DIP – Pre-Application Data Report
- Use Case 3) Integrate with MN DIP – *Replace or Augment Initial or Supplemental Screens*
- Use Case 4) Integrate with MN DIP – *Automate Interconnection Process*

Introductions

Quick roundup of participants

- Name
- Organization
- Role & priorities regarding these tools

2020 HCA Workshop Recap

- **June 2** – Synergi & DRIVE capabilities, demonstration and Xcel Energy HCA analysis process
- **June 16** – HCA Criteria, Inputs and Thresholds
- **June 30** – HCA Criteria, Inputs and Thresholds
- **September 2** – Series start for potential future HCA uses
- **September 10** – Examine Use Case 1: HCA remaining an early indicator for the interconnection process
- **September 15** – Examine Use Cases 2-4: Integration of the HCA with various MN DIP steps and processes

POLL – SERIES 1

1) What is your interest in the HCA/interconnection integration topic?

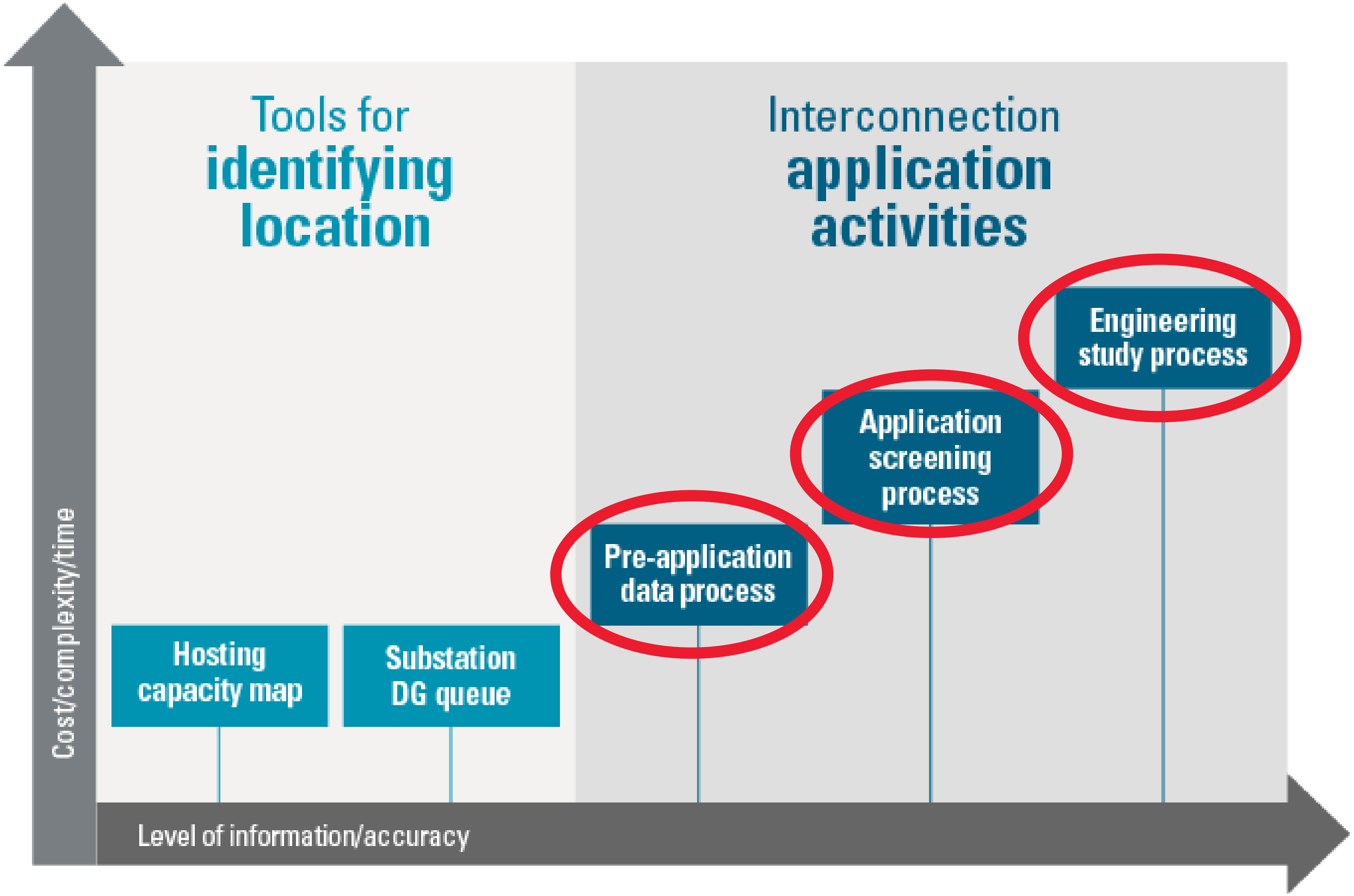
- ❑ Solar developer – engineer
- ❑ Solar developer – business operations
- ❑ Solar developer – owner
- ❑ Interested party – environmental advocate
- ❑ Interested party – solar industry
- ❑ Interested party – academic
- ❑ Interested party – regulatory oversight
- ❑ Other

2) **What is your main reason for attending today?**

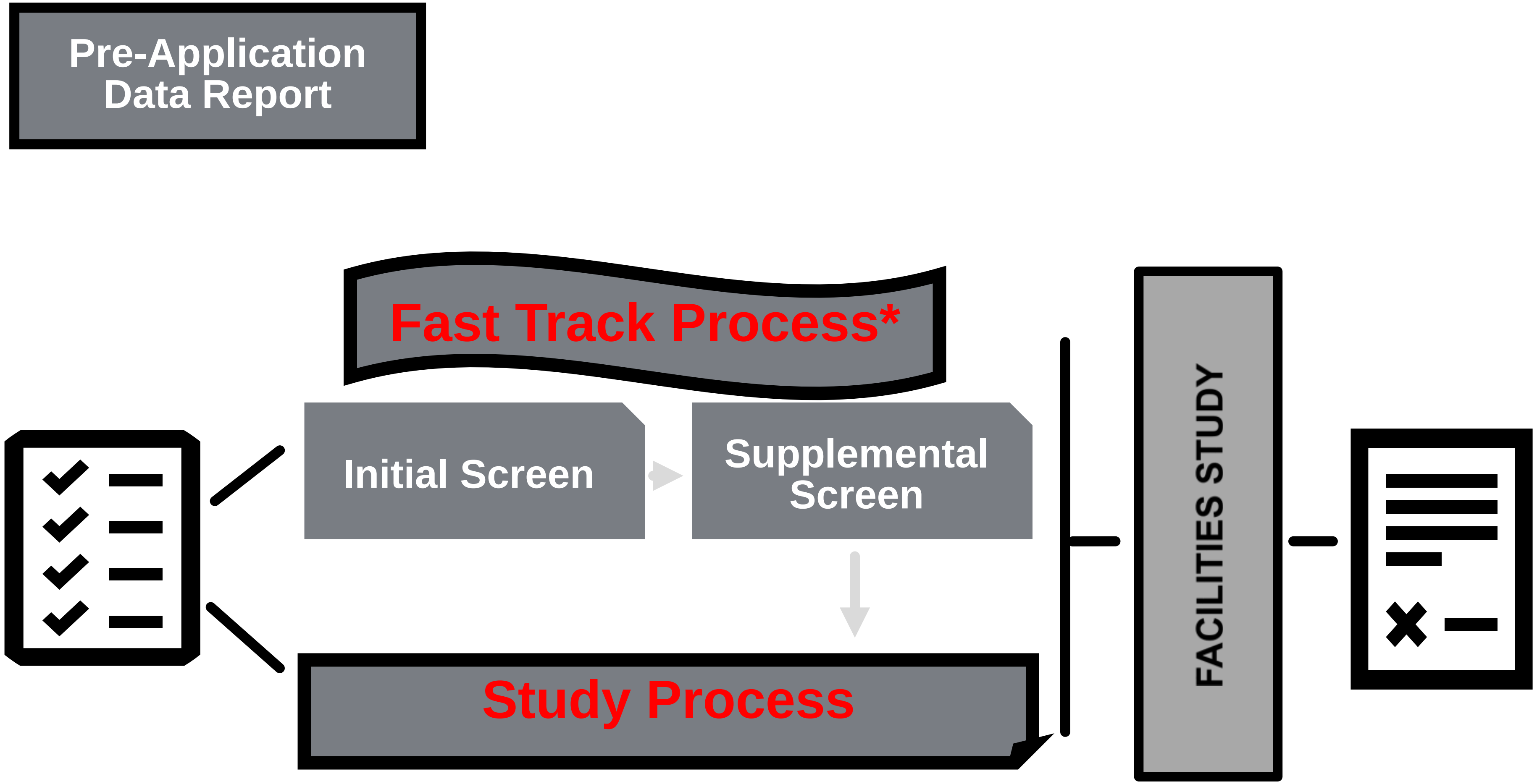
- ❑ Listen
- ❑ Learn
- ❑ Generate ideas
- ❑ Provide feedback on existing processes

PRE-APPLICATION REPORTS

HCA in Relation to MN DIP



Simplified View of MN DIP Process



* Inverter-based projects less than 20 kW will follow the MN DIP Simplified process, the first step of which is also an Initial Screen.

Current State – Pre-Application Report Example

Distributed Energy Resource Interconnection Pre-Application Data Report- Minnesota

Date: 9/15/2020

Requestor Contact Information

Company Name: Solar Garden Developer 1
Contact Name: John Smith
Address: 123 4th Ave
Phone #: 1-800-123-4567
Email: John.Smith@gmail.com

Project Information:

Project Name: Example 123
DER Nameplate Rating: 1000
DER Type: Solar PV
Number of phases: Three
Service Voltage: 120/208 3ph
Stand-alone Generator? Yes
Existing DER? New DER
Location of Existing DER: N/A
County of Existing DER: N/A

Proposed Point of Common Coupling

Street Address:
City/State/Zip Code:
County:
Cross Streets:
Latitude:
Longitude:
Meter #:
Utility Equipment #:
Other Identifying Info:

Xcel Energy has identified the substation/area bus, bank or circuit likely to serve the proposed Point of Common Coupling (PCC). This selection by Xcel Energy does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to.

Pre-Application Reports will only include pre-existing data and do not obligate Xcel Energy to conduct a study or other analysis of the proposed DER in the event that data is not available. If Xcel Energy cannot complete all or some of a Pre-Application Report due to lack of available data, Xcel Energy will provide the Interconnection Customer with a Pre-Application Report that includes the data that is available.

The provision of information on "Available Capacity" does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process. The distribution system is dynamic and subject to change and data provided in the Pre-Application Report may become outdated at the time of submission of the complete Interconnection Application. Xcel Energy will, in good faith, include data in the Pre-Application Report that represents the best available information at the time of reporting.

Substation

Substation Name:
Substation Transformer:
Transformer Rating (MVA):
Transformer Peak Loading (MVA):
Transformer Daytime Min Loading (MVA):
LTC or Regulator:

Transformer Absolute Min Loading (MVA): 12.793
Existing Generation (MVA): 10
Total Queued Generation (MVA): 2
Available Transformer Generation Capacity: 29 MVA
Circuit distance from PCC to Substation (feet): 71183

Feeder

Feeder Name:
Feeder Rating:
Feeder Peak Loading (MVA):
Feeder Daytime Min Loading (MVA):
Absolute Feeder Min Loading (MVA):

Feeder Voltage (kV): 23.9
Existing Generation (MVA): 9
Total Queued Generation (MVA): 6
Available Feeder Generation Capacity: 13 MVA

Point of Interconnection

Nominal Voltage at PCC (kV):
Spot/Grid Network, or Radial Feeder: Radial
Number of phases: 3
If not 3-phase, circuit distance to 3-phase:

Protective Devices and Regulators between Site and Substation

Device	Size/Type
Recloser	Viper-LT

Conductor between Site and Substation

Conductor Type	Rating (Amps)	Total Length, ft*
ML_OH_556_ACSR	730	55
ML_OH_336_ACSR	565	10810
ML_OH_2/0_ACSR	295	1911
ML_UG_1000_AL	590	836
ML_UG_750_AL	505	150
ML_OH_336_AL	560	49
ML_OH_4/0_ACSR	380	37297
3P_OH_1/0_ACSR	260	5637
ML_OH_336_CU	650	10969
3P_OH_2/0_CU	390	3469

*Total length represents the total footage of all instances of a particular conductor size. The presented data is not necessarily in any particular order, nor does it indicate that the conductor is segmented in any particular way. The data represents the overall conductor lengths to be used in determining the overall impedance between the site and the substation.

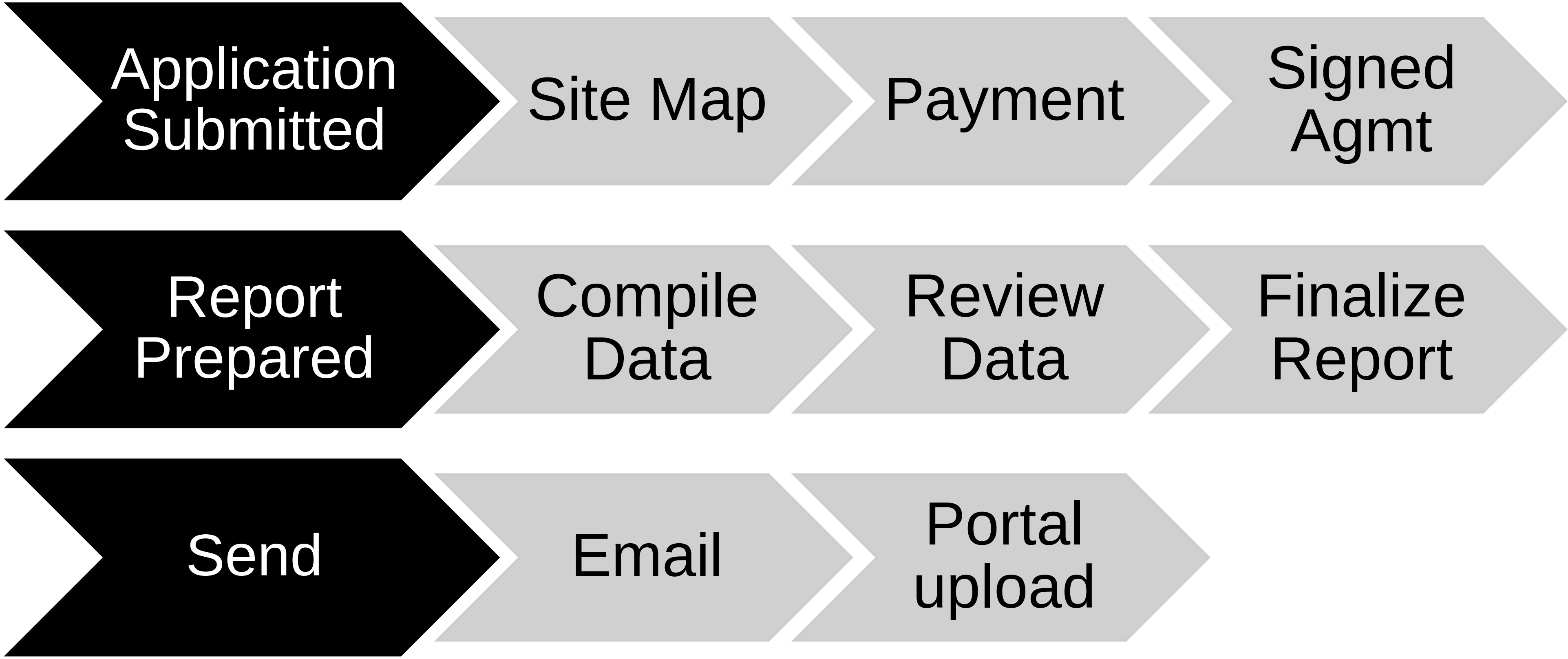
Other existing or known constraints, including, but not limited to, short circuit interrupting capacity issues, power quality or stability issues, capacity constraints:

Current State – Pre-Application Report Process

MNDIP

- Online Application portal
- $300 e-pay
- 15 business days
- Non-Disclosure Agreement
- Based on address or GPS, plus photo or map

Current State – Pre-Application Report Process (*Continued*)



DISCLAIMERS – Pre-Application Report

MN DIP

1) the existence of “Available Capacity” in no way implies that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process,

2) the distribution system is dynamic and subject to change and

3) data provided in the Pre-Application Report may become outdated and not useful at the time of submission of the complete Interconnection Request.

POLL – SERIES 2

1) How do you use Pre-application Reports today?

❑ CSG high frequency (>25 per year)
❑ CSG moderate frequency (10-25 per year)
❑ CSG low frequency (<10 per year)
❑ CSG but never use
❑ On-site high frequency
❑ On-site moderate frequency
❑ On-site low frequency
❑ On-site but never use
❑ Not a potential user of these reports

2) How do you anticipate your Pre-application Report use changing in the next 1-3 years?

❑ More than double
❑ Double
❑ Stay about the same
❑ Drop by half
❑ Drop by more than half
❑ No longer be used
❑ Not a potential user of these report

3) What is your top priority for Pre-Application Reports?

❑ Cost
❑ Fast turn-around
❑ Security
❑ Quick & easy to request
❑ Accuracy

Discussion: Use Cases

How do you use Pre-Application Reports?

Discussion: Use Cases

What value do Pre-Application Reports add beyond hosting capacity data?

Discussion: Use Cases

Real-life success stories about Pre-Application Reports?

What worked well to enable this?

Discussion: Use Cases

Any stories about frustrations or concerns that might be resolved through HCA integration?

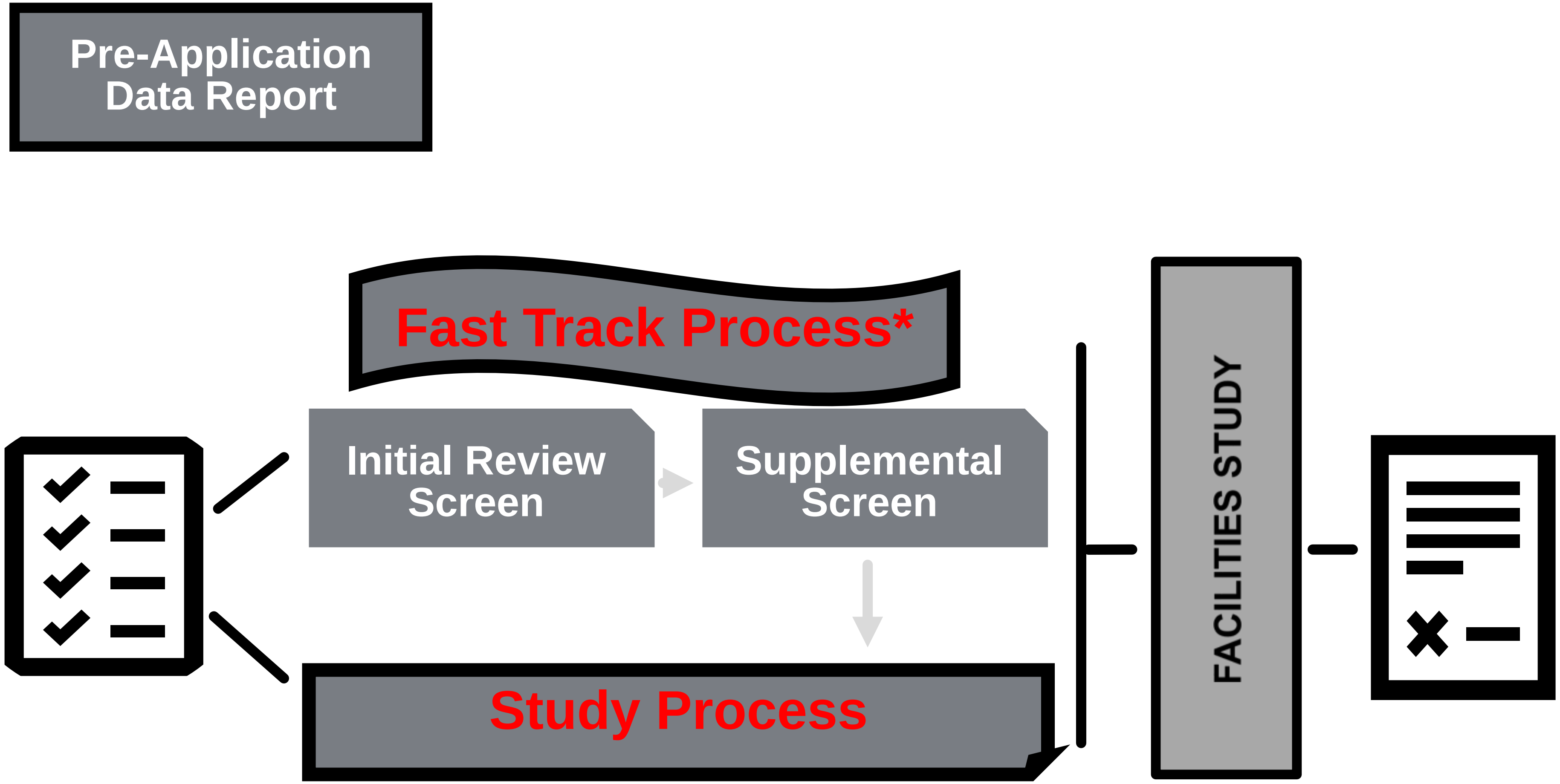
Live Ideation

Potential features & process improvements enabled by HCA integration

MN DIP – INITIAL REVIEW

Current State, Use Case, Feedback, Features Brainstorm, Prioritization

Simplified View of MN DIP Process



* Inverter-based projects less than 20 kW will follow the MN DIP Simplified process, the first step of which is also an Initial Screen.

MN DIP Tracks At-A-Glance

Simplified Initial Screen	Fast – Initial Engineering Screens	Fast – Supplemental Review
<= 20 kW	Up to 5 MW, or based on voltage	Up to 5 MW, or based on voltage
Initial review screen looks at capacity, feeder & sub parameters, plus protection information to yield a pass/fail result. *Pass no upgrades*: IA *Pass with upgrades*: Facilities Study *Fail*: to Supplemental Review	Initial review screen looks at capacity, feeder & sub parameters, plus protection information to yield a pass/fail result. *Pass no upgrades*: IA *Pass with upgrades*: Facilities Study *Fail*: Supplemental Review	Looks at high-level modeling using feeder, sub and system inputs; more actual conductor information, distance. Used when initial screens raise red flags. *Pass no upgrades*: IA *Pass with upgrades*: Facilities Study *Fail*: System Impact Study
Part of engineering process fee	Part of engineering process fee	Additional cost

Fast Track Eligibility for Distributed Energy Resources		
Line Voltage	Fast Track Eligibility[8] Regardless of Location	Fast Track Eligibility for certified, inverter-based DER on a Mainline[9] and ≤ 2.5 Electrical Circuit Miles from Substation[10]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

POLL – SERIES 3

1) What is your role and application volume?

- ❑ CSG high frequency (>25 per year)
- ❑ CSG moderate frequency (10-25 per year)
- ❑ CSG low frequency (<10 per year)
- ❑ CSG but never use
- ❑ On-site high frequency
- ❑ On-site moderate frequency
- ❑ On-site low frequency
- ❑ On-site but never use
- ❑ Non-applicable (different role)

2) What volume change do you expect to see annually in the next 2-3 years

- ❑ More than double
- ❑ About double
- ❑ Slight increase
- ❑ About the same
- ❑ Slight decrease
- ❑ About half of current
- ❑ Decrease by more than half
- ❑ Not applicable (different role)

2) What is your top priority for screening/study results?

- ❑ Cost
- ❑ Fast turn-around
- ❑ Security
- ❑ Quick & easy to request
- ❑ Accuracy

MN DIP Excerpt – *Initial Review*

3.2 Initial Review

Within 15 Business Days after the Area EPS Operator notifies the Interconnection Customer it has received a complete Interconnection Application, the Area EPS Operator shall perform an initial review using the screens set forth below, notify the Interconnection Customer of the results; including copies of the analysis and data underlying the Area EPS Operator's determinations under the screens.

The technical screens listed in this section shall not preclude the Area EPS Operator from seeking approval of tools that perform screening functions using different methodology given that the analysis is aimed at preventing the same voltage, thermal and protection limitations as the initial and supplemental review screens described below.

3.2.1 Initial Review Screens

3.2.1.1 The proposed DER's Point of Common Coupling must be on a portion of the Area EPS Operator's Distribution System.

3.2.1.2 For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured. A line section is that portion of an Area EPS Operator's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. The Area EPS Operator may consider 100% of applicable loading (i.e. daytime minimum load for solar), if available, instead of 15% of line section peak load.

3.2.1.3 For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, shall not exceed the smaller of 5% of a network's maximum load or 50 kW.[11]

3.2.1.4 The proposed DER, in aggregation with other DERs on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling.

3.2.1.5 The proposed DER in aggregate with other Distributed Energy Resources on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

3.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Area EPS Operator's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

3.2.1.7 If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER, shall not exceed 20 kW or 65% of the transformer nameplate rating.

3.2.1.8 If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

3.2.1.9 If the proposed DER is single-phase and is to be interconnected to a three-phase service, its Nameplate Rating shall not exceed 10% of the service transformer nameplate rating.

3.2.1.10 If the DER's Point of Common Coupling is behind a line voltage regulator[12], the DER's Nameplate Rating shall be less than 250 kW.

3.2.2 If the proposed interconnection passes the screens, or if the proposed interconnection fails the screens, but the Area EPS Operator determines that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Interconnection Application shall proceed as follows:

3.2.2.1 If the proposed interconnection requires no construction of facilities by the Area EPS Operator on its own system, the Area EPS Operator shall provide the Interconnection Customer an executed Interconnection Agreement within five (5) Business Days after the determination.

3.2.2.2 If the proposed interconnection requires construction of any facilities, the Area EPS Operator shall notify the Interconnection Customer of such requirement when it provides the Initial Review results and copies of the analysis and data underlying the Area EPS Operator's determinations under the screens and either: 1) provide a good faith cost estimate; or 2) require a facilities study pursuant to 4.4.1. Within five (5) Business Days, the Interconnection Customer shall inform the Area EPS Operator if the Interconnection Customer elects to proceed with the proposed interconnection. If the Interconnection Customer makes such an election, the Area EPS Operator shall either provide: i) an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, within twenty (20) Business Days after the Area EPS Operator receives such an election or ii) a facilities study agreement pursuant to section 4.4.

3.2.3 If the proposed interconnection fails the screens, and the Area EPS Operator does not or cannot determine from the Initial Review that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Area EPS Operator shall provide the Interconnection Customer the opportunity to attend a customer options meeting.

See for more information: https://mn.gov/puc/energy/distributed-energy/interconnection/

Current State – *Initial Review Example*

Xcel Energy®
RESPONSIBLE BY NATURE®

9/14/2020

Minnesota Distributed Energy Resources Interconnection Process (MN DIP)
Initial Review Results

Customer: John Smith
Case # 1234567
Address: 123 4th Ave NW
DER Application Size: 11.40 kVA

Interconnection Feeder:		Substation:	
DER Active on Feeder:	kW	DER Active on Substation:	kW
DER in Queue on Feeder:	0.00 kW	DER in Queue on Substation:	0.00 kW

Summary of Results:
This project has failed the Initial Review Screens, the details of which are provided below. A supplemental review will be required to determine if the DER may be interconnected consistent with safety, reliability, and power quality standards. The interconnection customer has the option to attend a customer options meeting. This meeting must be accepted or declined prior to the initiation of the Supplemental Review.

Ground Referencing Adequacy
This project is not required to install ground referencing equipment as it is less than 100 kW.

Initial Review Screens

MN DIP Section

3.2.1.1 The proposed DER's Point of Common Coupling must be on a portion of Xcel Energy's Distribution System.

Passes Screen? Yes

3.2.1.2 For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured. A line section is that portion of an Area EPS Operator's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. Xcel Energy may consider 100% of applicable loading (i.e. daytime minimum load for solar), if available, instead of 15% of line section peak load.

Minimum Daytime Load (Native)		kVA
15% of Peak Load	N/A	kVA
Aggregate Generation, including proposed DER:		kVA
DER as % of Peak Load		%
Passes Screen:	No	

3.2.1.3 For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, shall not exceed the smaller of 5% of a network's maximum load or 50 kW.

Interconnection on a network?	No	
DER is Inverter Based?	N/A	
Network Maximum load:	N/A	kW
Aggregate DER, including applied-for DER:	N/A	kW
Aggregate DER as % of Network Maximum Load:	N/A	%
Passes Screen:	N/A	

Interconnection is not on a network. Screen does not apply.

3.2.1.4 The proposed DER, in aggregation with other DERs on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling.

Distribution Circuit Maximum Fault Current nearest the PCC:	2,041.48	Amps
Aggregate DER, including proposed DER, on feeder:	2,777.20	kVA
Aggregate DER fault current contribution:	232	Amps
Aggregate DER Fault current contribution as % of Distribution Circuit Max Fault Current:		%
Passes Screen?	No	

3.2.1.5 The proposed DER in aggregate with other Distributed Energy Resources on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

Lowest short circuit interrupting rating of equipment inline with DER:	10,000	Amps
Aggregate DER fault current contribution:	232	Amps
Distribution Circuit Maximum Fault Current nearest the PCC:	2,041	Amps
Total available short circuit current:	2,274	Amps
Aggregate fault current contribution as a % of short circuit interrupting rating:	23	%
Passes Screen:	Yes	

3.2.1.6 A three-phase, three wire service type requires a 3-phase 3-wire, single phase, or phase-to-phase interconnection type. A three-phase, four wire service type requires an effectively-grounded 3 phase, single phase, or line-to-neutral interconnection type.

Customer Service Type:	1P
Interconnection Type:	1P
Passes Screen:	Yes

3.2.1.7 If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER, shall not exceed 20 kW or 65% of the transformer nameplate rating.

Aggregate DER on Shared Secondary:	11.40	kW
Transformer Nameplate Rating:	75.00	kVA
Aggregate DER, as a % of Transformer Nameplate Rating:	15.20	%
Passes Screen:	Yes	

3.2.1.8 If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

Transformer Nameplate Rating:	N/A	kVA
DER Size:	N/A	kW
DER Size as a % of Transformer Nameplate Rating:	N/A	%
Passes Screen:	N/A	

Interconnection is not interconnected to a tap neutral. Screen does not apply.

Current State – Initial Review Example (*Continued*)

3.2.1.9 If the proposed DER is single-phase and is to be interconnected to a three-phase service, its Nameplate Rating shall not exceed 10% of the service transformer nameplate rating.

Transformer Nameplate Rating:	N/A	kVA
DER Size:	N/A	kW
DER Size as a % of Transformer Nameplate Rating:	N/A	%
Passes Screen:	N/A	

3.2.1.10 If the DER's Point of Common Coupling is behind a line voltage regulator, the DER's Nameplate Rating shall be less than 250 kW

Is the PCC behind a line voltage regulator?	No
Is the DER Namplate Rating < 250 kW?	Yes
Passes Screen:	N/A

2.2.3, 3.2.2 To determine if the DER can be interconnected safely and reliably, as required in both the Simplified and Fast Track Processes, Xcel Energy requires that for proposed DER on secondary services, the aggregate generation capacity, including the proposed DER, shall not exceed the transformer nameplate rating.

Transformer Nameplate:		kVA
Aggregate DER:	11.40	kVA
DER Size as a % of Transformer Nameplate Rating:	15.20	%
Is the transformer required to be replaced for this DER?	No	

Other Construction of Facilities

Construction of other facilities may be required to interconnect the DER. They are listed below.

Are construction of other facilities required?	No

Description of facilities:

Ground Referencing

Inverter-Based Systems greater than 100 kW require ground referencing. The adequacy of the provided ground referencing specifications are evaluated below.

Requirement 1:	$X_{0,\ DER}$=		p.u.
	As Specified: $X_{0,\ DER}$=	#DIV/0!	p.u.
	Requirement Met?	N/A	
Requirement 2:	$X_{0,\ DER}/R_{0,\ DER} \geq$	4.00	
	As Specified: $X_{0,\ DER}/R_{0,\ DER} \geq$	#DIV/0!	
	Requirement Met?	N/A	
Requirement 3:	Neutral Current Rating for V_0 = 4%=	#DIV/0!	amps
	Neutral Current Rating, as specified=	0	amps
	Requirement Met?	N/A	
Requirement 4:	Minimum required fault current withstand rating=	#DIV/0!	amps
	As Specified=	0	amps
	Requirement Met?	N/A	

Discussion: Use Cases

How do you use Initial Review reports?

Discussion: Use Cases

How could they be improved through HCA integration?

Discussion: Use Cases

Real-life success stories?

Discussion: Use Cases

Real-life frustrations you're hoping to resolve?

Live Ideation

Potential features & process improvements enabled by HCA integration

MN DIP – SUPPLEMENTAL SCREENS

Current State, Use Case, Feedback, Features Brainstorm, Prioritization

MN DIP Excerpt – Supplemental Review

3.4 Supplemental Review

3.4.1 To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review in the amount of the Area EPS Operator's good faith estimate of the costs of such review, both within fifteen (15) Business Days of the offer. If the written agreement and deposit have not been received by the Area EPS Operator within that timeframe, the Interconnection Application shall continue to be evaluated under the Section 4 Study Process unless it is withdrawn by the Interconnection Customer.

3.4.2 The Interconnection Customer may specify with the written agreement and deposit the order in which the Area EPS Operator will complete the supplemental review screens. The order specified shall be at the level of sections 3.4.4.1, 3.4.4.2, and 3.4.4.3.

3.4.3 The Interconnection Customer shall be responsible for the Area EPS Operator's actual costs for conducting the supplemental review. The Interconnection Customer shall pay any review costs that exceed the deposit within twenty (20) Business Days of receipt of the invoice or resolution of

3.4.4 Within thirty (30) Business Days following receipt of the deposit for a supplemental review, the Area EPS Operator shall: 1) perform a supplemental review using the screens set forth below; 2) notify in writing the Interconnection Customer of the results; and 3) include with the notification copies of the analysis and data underlying the Area EPS Operator's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the Area EPS Operator shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in this section within two (2) Business Days of making such determination to obtain the Interconnection Customer's permission to: 1) continue evaluating the proposed interconnection under this section 3.4.4; 2) terminate the supplemental review and continue evaluating the DER under Section 4 Study Process; or 3) terminate the supplemental review upon withdrawal of the Interconnection Application by the Interconnection Customer. The Interconnection Customer shall respond with its choice within five (5) Business Days of notification from the Area EPS Operator.

3.4.4.1 Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed DER) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate DER capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data is not available, or cannot be calculated, estimated or determined, the Area EPS Operator shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 3.4.4.

3.4.4.1.1 The type of generation used by the proposed DER will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 3.4.4.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

3.4.4.1.2 When this screen is being applied to a DER that serves some station service load, only the net injection into the Area EPS Operator's electric system will be considered as part of the aggregate generation.

3.4.4.1.3 Area EPS Operator will not consider as part of the aggregate generation for purposes of this screen DER capacity known to be already reflected in the minimum load data.

3.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

3.4.4.3 Safety and Reliability Screen: The location of the proposed DER and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The Area EPS Operator shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

3.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

3.4.4.3.2 Whether the loading along the line section is uniform or even.

3.4.4.3.3 Whether the proposed DER is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Common Coupling is a Main line rated for normal and emergency ampacity.

3.4.4.3.4 Whether the proposed DER incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

3.4.4.3.5 Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section(s) of the DER to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

3.4.4.3.6 Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

3.4.5 If the proposed interconnection passes the supplemental screens in sections 3.4.4.1, 3.4.4.2, and 3.4.4.3 above, or if the proposed interconnection fails the screens, but the Area EPS Operator determines that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the interconnection shall proceed as follows:

3.4.5.1 If the proposed interconnection passes the supplemental screens in sections 3.4.4.1, 3.4.4.2, and 3.4.4.3 above and does not require construction of facilities by the Area EPS Operator on its own system, the Area EPS Operator shall provide the Interconnection Customer an executable Interconnection Agreement within five (5) Business Days.

3.4.5.2 If the proposed interconnection requires construction of any facilities, the Area EPS Operator shall notify the Interconnection Customer of such requirement when it provides the supplemental review results and either: 1) provide a good faith cost estimate; or 2) require a facilities study pursuant to 4.4.1. Within five (5) Business Days, the Interconnection Customer shall inform the Area EPS

Operator if the Interconnection Customer elects to proceed with the proposed interconnection. If the Interconnection Customer makes such an election, the Area EPS Operator shall either provide: i) an Interconnection Agreement, along with a non-binding good faith cost estimate and construction schedule for such upgrades, within twenty (20) Business Days after the Area EPS Operator receives such an election or ii) a facilities study agreement pursuant to section 4.4.

3.4.6 If the proposed interconnection fails the screens, and the Area EPS Operator does not or cannot determine that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Area EPS Operator shall provide the Interconnection Customer the option of commencing the Section 4 Study Process. If the Interconnection Customer wishes to proceed it shall notify the Area EPS Operator within fifteen (15) Business Days to retain its queue position.

Supplemental Review Sample

Xcel Energy
RESPONSIBLE BY NATURE

9/14/2020

Minnesota Distributed Energy Resources Interconnection Process (MN DIP)
Supplemental Review Results

Customer: John Smith
Case # 1234567
Address: 123 4th Ave NW
DER Application Size: 11.40 kVA

Interconnection Feeder:
DER Active on Feeder: kW
DER in Queue on Feeder: kW

Substation:
DER Active on Substation:
DER in Queue on Substation:

Summary of Results:
This project has failed the Initial Review Screens, but has passed the Suppplemental Review. Details can be f below. It will require construction of facilities by Xcel Energy. A facilities study will be required to determine a construction cost estimate. A facilities study agreement will be provided.

Ground Referencing Adequacy
This project is not required to install ground referencing equipment as it is less than 100 kW.

Supplemental Review Screens

3.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) voltage regulation on the line section can be maintained in compliance with relevant requiremen under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar t IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

Voltage Regulation

Does the screen indicate a high probability of compliance with ANSI C84.1 Range A for steady state voltage regulation on Xcel Energy's electric distribution primary (medium-voltage) system?	Yes
Does the screen indicate a high probability of compliance with ANSI C84.1 Range A for steady state voltage regulation on Xcel Energy's electric distribution secondary (low-voltage) system?	Yes

Voltage Fluctuation

Does the screen indicate a high probability of compliance with IEEE 1453 for voltage fluctuation at any point on Xcel Energy's electric distribution system?	Yes

3.4.4.3 Safety and Reliability:

Conductor Loading
The line section from the substation to the Point of Common Coupling is rated for the current produced by the DER.

Approximate maximum conductor loading as a percentage of rated ampacity when DER is on:		%
Passes Screen?	Yes	

Substation Transformer Loading

Substation Transformer Rating:		kVA
Aggregate DER on Substation:	1,019.18	kVA
Peak Load (Native):	2,343.00	kVA
Substation Transformer Rating Exceeded by:	0.00	kVA
Screen Passes?	Yes	

Protection Coordination

Is a study required to verify Protection Coordination?	No
Passes Screen?	Yes

Direct Transfer Trip

Is there existing rotating machine DER on the Substation Transformer?	No
Is there existing rotating machine DER on the Feeder?	No
Is a System Impact Study required to determine if Direct Transfer Trip is required?	N/A
Passes Screen?	Yes

Transmission Impacts

Is a study required to verify Transmission System Impacts	No
Passes Screen?	Yes

Voltage Supervisory Reclosing (VSR)
If the load to DER ratio is ≤ 1.25, VSR is required on reclosing devices. If this DER project causes the threshold to be exceeded, it will be responsible for installing VSR.

Peak Load (Native)	305	kVA
Aggregate DER on Feeder:	555	kVA
Load to Generation Ratio:	0.55	
New DER causes VSR threshold to be exceeded?:	No	
Is VSR required to be installed to allow this project to interconnect?:	No	

Reverse Power Flow Controls
If the feeder experiences reverse power flow, regulating devices may need to be upgraded or replaced. If this DER project is the cause of the reverse power flow, it will be responsible for these upgrades/replacements.

Reverse Power Flow on Feeder:	-250	kW
New DER causes reverse power flow?:	No	kW
Is this project responsible for upgrading regulation devices that need to be capable of reverse flow?	No	

Primary Conductor Construction
Construction of Primary Conductor may be required to convert a single-phase line to a three-phase line to the PCC.

Is a three phase primary conductor extension required?	Yes	
Approximate footage of extension:	5,216	ft

Service Conductor Upgrades
Service Conductor Upgrades may be required due to loading, voltage fluctuation violations, or steady state voltage violations.

Is a service conductor upgrade required?	No	
Approximate footage of extension:	N/A	ft

Existing conductor type(s) to be replaced:	
New conductor type(s):	

Other Construction of Facilities

Supplemental Review Sample *(Continued)*

Construction of other facilities may be required to interconnect the DER. They are listed below.

Are construction of other facilities required? No

Description of facilities:

Ground Referencing
Inverter-Based Systems greater than 100 kW require ground referencing. The adequacy of the provided ground referencing specifications are evaluated below.

Requirement 1:	$X_{0,\ DER}$=	[illegible]	p.u.
	As Specified: $X_{0,\ DER}$=	[illegible]	p.u.
	Requirement Met?	N/A	
Requirement 2:	$X_{0,\ DER}/R_{0,\ DER} \geq$	[illegible]	
	As Specified: $X_{0,\ DER}/R_{0,\ DER} \geq$	#DIV/0!	
	Requirement Met?	N/A	
Requirement 3:	Neutral Current Rating for V_0 = 4%=	[illegible]	amps
	Neutral Current Rating, as specified=	0	amps
	Requirement Met?	N/A	
Requirement 4:	Required fault current withstand rating=	[illegible]	amps
	As Specified=	0	amps
	Requirement Met?	N/A	

Discussion: Use Cases

Any differences in how you use supplemental review reports?

Discussion: Use Cases

Any incremental ways they might be improved through HCA integration?

Discussion: Use Cases

Real-life success stories?

Discussion: Use Cases

Real-life frustrations you're hoping to resolve?

Live Ideation

Potential features & process improvements enabled by HCA integration

AUTOMATE INTERCONNECTION PROCESS

Feedback, Features Brainstorm, Prioritization

Discussion: Use Cases

What opportunities do you see for improvement through HCA integration beyond these areas?

Discussion: Use Cases

Real-life success stories for how HCA integration has helped with overall interconnection?

Real-life frustrations you're hoping to resolve?

Live Ideation

Potential features & process improvements enabled by HCA integration

What’s Next?

HCA filing November 2, 2020

Will include –

- HCA Results in Tabular Report and Heat Map formats
- Summaries of our 2020 Workshops
- Our analysis of the Potential Future HCA Use Cases

THANK YOU FOR YOUR FEEDBACK

If you have additional feedback to share, please send to:

Paget.J.Pengelly@xcelenergy.com

HCA/Pre-Application Report High Level Comparison

Pre-Application Report Data Type	Data Exists in Current HCA Map?	Comments
Substation Name	Y	
Transformer Name	N	Adding in 2020 Analysis
Transformer Rating	N	
Transformer Peak	N	
Transformer DML	Y	
Transformer Absolute Min	N	Adding in 2020 Analysis
LTC or Regulator	N	Adding in 2020 Analysis
TR Existing Gen	Y	
TR Queued Gen	Y	
TR Gen Capacity	N	
Distance from PCC to sub	N	
Feeder Name	Y	
Feeder Rating	N	
Feeder Peak	N	
Feeder DML	Y	
Feeder Absolute Min	N	Adding in 2020 Analysis
Feeder Voltage	Y	
Feeder Existing Gen	Y	
Feeder Queued Gen	Y	
Feeder Gen Capacity	N	
Nominal Voltage at PCC	Y	
Network or Radial	N	Adding in 2020 Analysis
# of Phases	Y	
Distance to 3 phase circuit	N	
Protective devices in line between site and sub	N	
Conductor between site and sub	N	

Pre-Application Report Features

MN-DIP

Total capacity (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling.	Substation nominal distribution voltage and/or transmission nominal voltage if applicable	Whether the Point of Common Coupling is located behind a line voltage regulator.	Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.
Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Common Coupling.	Nominal distribution circuit voltage at the proposed Point of Common Coupling.	Number and rating of protective devices and number and type (standard, bidirectional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.	Based on the proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.
Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Common Coupling.	Approximate circuit distance between the proposed Point of Common Coupling and the substation.	Number and rating of protective devices and number and type (standard, bidirectional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.	
Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).	Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 3.4.4.1 below and absolute minimum load, when available.	Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.	