New Mexico Interconnection Rules:
Report and Recommendations to
the New Mexico Public Regulation Commission
October 15, 2021
FINAL REPORT

This Document Was Compiled from the Activities of the Interconnection Technical Stakeholder Advisory Group Process In New Mexico Public Regulation Commission Docket 20-00171-UT.

REPORT FACILITATORS
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Disclaimer: This report represents the work product of the Interconnection Technical Stakeholder Advisory Group (also known as the Working Group) to develop a series of proposals for updates to New Mexico's interconnection rule and related revisions of the NM jurisdictional utilities' Interconnection Manual and agreement forms. It does not represent an official policy of the New Mexico Public Regulation Commission unless considered and adopted – in whole or in part with modification – as part of a Notice of Proposed Rulemaking process [20-00171-UT].

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1. SUMMARY

On January 13, 2021, the New Mexico Public Regulation Commission issued an Initial Order Establishing and Providing Notice of Inquiry and Requesting Written Public Comments on the matter of revising New Mexico's Rule for Interconnection of Generation Facilities with a Rated Capacity Up to and Including 10 MW Connecting to a Utility System [Title 17, Chapter 9 Part 568].

New Mexico utilities both large and small are facing increasing demand from customers who want to install rooftop photovoltaics and storage systems, interconnection requests are on the rise, and some utility circuits are considered "at saturation" and unable to accommodate new interconnections without significant upgrades and substantial costs.

New Mexico state policies such as the Energy Transition Act and the Community Solar Act have set the state on a course to more effectively integrate distributed energy generation and storage into the electricity infrastructure. New legislation enacted in 2021 calls for the Commission to adopt by April 1, 2022, rules and policies to accommodate a Community Solar program of up to 200 MW in the three larger utility territories. The expected addition of this level of distributed generation brings additional stress to the utility network and impetus to revise and modernize interconnection rules.

The existing Rule and associated policies embodied in the Utility Interconnection Manual and Technical Guidelines documents, last revised in October 2008, no longer adequately accommodate evolving technologies and devices that are increasingly seeking behind-the-meter (BTM) interconnection to utility distribution networks. In addition, recently developed technical standards IEEE 1547-2018/IEEE1547.1-2020/UL1741SB are being adopted by state jurisdictions across the nation to provide for advanced functionalities for DC/AC inverters, and for testing and certification of interconnected devices.

When issuing the Notice of Inquiry, the Commission instituted a technical stakeholder advisory group (referred to in this document as the Working Group) process to assist with the revision and updating of the Interconnection Rule and Manual. The Working Group would also consider a plan for adoption of IEEE 1547-2018 and related technical standards on a timeline that is suitable for New Mexico's electric utility operations and developing markets for renewable energy and other distributed energy resources.

This report and recommendations document represents the collective work product of the technical advisory stakeholder group (aka, the Working Group), consisting of a broad array of active stakeholder and market participants.[1]

The technical stakeholder advisory process was structured to address issues in two phases of activities.

[1] While representatives of Rural Electric Cooperatives and the New Mexico Rural Electric Cooperative Association (NM RECA) initially participated in the Working Group, their involvement was limited to monitoring the working group's activities. No co-op representative directly participated in the drafting of this report. Instead, NM RECA argues that there should be a special consideration given to smaller entities that face resource constraints and relatively limited demands for interconnection. The existing Title 17.9.568 rule does not exclude or make special provision for co-ops from any interconnection rules or policies, though it defines small utilities as having less than 50,000 customers. For small utilities it allows for more flexibility in meeting required timelines. It would be up to the Commission to decide if special treatment is warranted for proposed revisions to the rule and policies.

Phase I of this effort primarily relates to recommending proposed amendments to Rule 17.9.568 and the Interconnection Manual last updated in October 2008. A Phase II would commence following a Commission decision on Phase I issues and directions as to the scope of subsequent activity.

During Phase I, The Working Group identified and then addressed six non-technical issues and four technical issues. Proposals for these ten issues are provided in Section 3 and summarized in Table 1.

Proposed recommendations for non-technical issues include a variety of topics:

- Allowing for pre-application review of projects;
- Defining timelines for processing of interconnection applications;
- Establishing a dispute resolution process;
- Determining categorization of projects by size;
- Defining utility reporting requirements;
- Additions or revisions to a set of definitions;

Cost-Allocation Options from around the country were considered by the Working Group and a summary of potential options is included to provide the Commission with background for future determinations of alternatives to the traditional cost-causation model for necessary upgrades.

The more technical issues include:

- IEEE-1547-2018 Adoption Timeline and Autonomous Functions;
- Establishing Capacity Levels and Initial Review Screens;
- Non-Export, Limited Export, and Inadvertent Export of Energy into the Utility System;
- Prospective Paths to Hosting Capacity Information and Mapping.

In considering how to revise and update interconnection policies, the Working Group looked to two potential "models" for change: The Federal Energy Regulatory Commission's Small Generator Interconnection Protocol (FERC SGIP) and the "Model Interconnection Procedures" developed by the Interstate Renewable Energy Council (IREC), a non-profit organization that advocates for the rapid adoption of clean energy and energy efficiency. It is apparent that each model offered benefits and advantages for New Mexico's situation, depending on specific issues.

While the Manual Revision Subgroup agreed to use the IREC Model Procedure's *organizational structure* instead of the SGIP structure, the three investor-owned utilities support the use of the FERC SGIP as a basis for revising the New Mexico Interconnection Manual.

Consensus on proposals reflects the general position of the Working Group as developed over the entire duration of the Working Group. It must be noted that "consensus" does not imply a 100 percent agreement on every aspect or proposal within the report framework. In many cases, the best that could be achieved is a general agreement, with acknowledgement that more refinement may be necessary in the course of translating these discussions into a working Rule and Manual revision in the Commission's formal proceedings.

Some participants expressed reservations or alternative positions during the writing of this report, after the Working Group had concluded its scheduled discussions, which means that full consensus was not necessarily achieved.

Where a consensus was not achieved, parties and individuals were given the opportunity to provide alternate language or proposals, which are reflected in the body of this Report. Still, substantive areas of disagreement exist. In particular, these topics are presented with very different alternative proposal language offered by the utilities and representatives of industry groups:

- Timelines for Interconnection Application Reviews and Conducting Necessary Studies (Section 3.3)
- Utility Reporting Requirements (Section 3.6)
- Some elements of Capacity Levels and Initial Review Screens (Section 3.8)

It will be up to the Commission to decide on which alternatives to approve or reject so the Rule and Manual revisions can be completed within the structure of a Commission process for a Notice of Proposed Rulemaking on a timely basis.

While discussed and debated in the Working Group sessions, there was no attempt to reach consensus on the Cost Allocation Options (Section 3.4), and other important issues, such as creating Pathways for Hosting Capacity Analysis show such disagreement between the parties that they could not be resolved in Phase I and may require specific policy guidance from the Commission to continue working on them.

Table 1 below lists the ten major issues discussed by the Working Group with their status as of the drafting of this Report.

Table 1. Proposals Discussed by the Working Group

Scoped Issue	Proposal letter in Section 3	Number of discrete proposals	Proposal(s) status	Recommended actions
Definitions	A	2	A-1 consensus A-2 non-consensus	Adopt as Definitions and make decision about non-consensus definitions
Pre-Application Process	B	1	consensus	Adopt in Manual/Rule
Application Timelines	C	2	non-consensus on timelines	Consider alternatives and provide guidance for Manual/Rule
Cost-Allocation Options	D	7 options	All options are non-consensus	Consider all options; scope for further work in Phase II; connect to GridMod work and Community Solar
Dispute Resolution	E	1	consensus	Adopt in Manual/Rule
Utility Reporting Requirements	F	2	non-consensus	Consider alternatives and provide guidance for Manual/Rule
IEEE-1547-2018 Adoption	G	1	consensus	Adopt in Manual/Rule
Capacity Levels and Initial Review Screens	H	4	non-consensus[2]	Consider and resolve as part of NOPR process
Non-Export, Limited Export, and Inadvertent Export	I	2	non-consensus[3]	Consider alternatives and provide guidance for Rule/Manual as part of NOPR process
Prospective Paths to Hosting Capacity	J	6	All proposals J-1 to J-6 are non-consensus	Consider and scope for further work in either a separate venue or in Phase II of the Working Group.

[2] Facilitator's note: At the very end of the advisory process, certain utilities declared that they did not agree to treat proposals H-1, H-2, and H-3 as consensus items. They did not provide alternative language for the proposals, except to revert to FERC SGIP model, and as noted for SPS comments included herein. H-4 was already considered non-consensus.

[3] Facilitator's note: At the very end of the advisory process, certain utilities declared that they did not agree to treat these as consensus issues. They did not provide alternative language or proposals. It will be left to the Commission's rulemaking process to determine whether these issues can be included in a revised rule or left to further discussion in Phase II.

2. BACKGROUND

2.1 Mandate

On January 13, 2021, the New Mexico Public Regulation Commission issued an Initial Order Establishing and Providing Notice of Inquiry and Requesting Written Public Comments on the matter of revising New Mexico's Rule for Interconnection of Generation Facilities with a Rated Capacity Up to and Including 10 MW Connecting to a Utility System [Title 19, Chapter 9 Part 568].

Last revised in October 2008, the existing Rule and associated policies embodied in the Utility Interconnection Manual and Technical Guidelines documents no longer adequately accommodate evolving technologies and devices that are increasingly seeking behind-the-meter (BTM) interconnection to utility distribution networks. In addition, recently developed technical standards IEEE 1547-2018/IEEE1547.1-2020/UL1741SB are being adopted by state jurisdiction across the nation and internationally to provide for advanced functionalities for DC/AC inverters, and for testing and certification of interconnected devices. These standards promise to enhance the reliability of distribution operations and increase the ability of existing circuits to accommodate deeper penetration of distributed energy resources.

When issuing the Notice of Inquiry, the Commission envisioned instituting a technical stakeholder advisory group (referred to in this document as the Working Group) process to assist with the revision and updating of the Interconnection Rule and Manual. The Working Group would also consider a plan for adoption of IEEE 1547-2018 and related technical standards on a timeline that is suitable for New Mexico's electric utility operations and developing markets for renewable energy and other distributed energy resources.

These revisions are considered an essential component of "grid modernization" efforts promoted by the New Mexico Legislature via adoption of House Bill 233, the Grid Modernization Act of 2020, in furtherance of the greenhouse gas (GHG) emission reduction and clean energy goals mandated by Senate Bill 489, The Energy Transition Act of 2019.

An initial PRC workshop on February 18, 2021, was held to review preliminary information about the current state of utility interconnections and document bottlenecks in the ability of utility customers and developers to connect behind-the-meter solar photovoltaic systems and energy storage devices to constrained feeders and circuits in certain geographic areas.

As of a result of its inquiry and workshop, the Commission on March 9, 2021, authorized the technical Working Group process to meet in an attempt to reach consensus, if possible, on possible revisions to the rules/manual and for prioritizing inverter functionalities that will benefit state policies for reducing GHG, increasing renewable energy deployment, and effect a more modern electric distribution grid.

This report and recommendations document represents the collective work product of the technical advisory stakeholder group (the Working Group), consisting of representatives of electric utilities, rural electric co-operatives, renewable energy associations and individual project developers, as well as technical experts from other state agencies, academic institutions and federal-funded national laboratories. It does not represent an official policy of the Commission unless considered and acted upon in the formal Notice of Proposed Rulemaking process.

2.2 Interaction with the Community Solar Act of 2021

As the technical stakeholder advisory process was getting underway, the New Mexico Legislature passed a new law, SB 84, the Community Solar Act, which directed the Commission to establish by April 1, 2022, rules and policies to implement a Community Solar program of up to 200 MW in the three larger utility territories. The intent of the Act is to allow low-income utility customers, community organizations and local governments to better participate in markets for renewable energy. The 200 MW capacity for the initial program would be allocated among New Mexico's three investor-owned utilities, but rural co-oops – which are subject to the Interconnection Rule – are exempt unless they opt-into the program. Community Solar projects may be sized up to 5 MW, which could run into capacity constraints on the existing distribution network, depending on location.

The Commission initiated a new docket for the Community Solar Act implementation [21-00112-UT], conducted workshops and began a separate stakeholder advisory process. The agency came to understand the critical linkage between the policies being determined in the Interconnection proceeding and the potential success or failure of the nascent Community Solar program. In fact, utilities were quickly inundated with prospective project developers' requests for information about grid access and applications for interconnection or engineering reviews, even as parties were debating and developing the recommendations for updating the Rule/Manuals and standards that would greatly impact Community Solar project development.

As a result of concerns raised by electric utilities, the Commission on June 16, 2021, issued an order providing guidance to utilities and prospective developers, indicating that:

1) The Commission's existing interconnection rules and manual remain in place until amended or replaced by the Commission; and

2) A place in a utility's applicant queue for interconnection does not and will not provide any advantage for selection as a community solar project, as the Commission's rules will not be in place until on or before April 1, 2022.[4]

While imposing a new sense of urgency to completing the process for revising the Rule/Manual and associated policies, there does not appear to be a direct conflict between the previously established timeline for reaching a decision on the recommendations in this report, for adjudication of non-consensus proposals, and the necessary policy determinations for Community Solar Act implementation.

Many of the proposed revisions to the Interconnection Rule/Manual discussed in this report will have a direct bearing on the process, cost and potential ability of prospective Community Solar projects to connect to the utility grid at their preferred locations or points of interconnection. Stakeholders, particularly utilities, have identified challenges with attempting to deal with interconnection issues in parallel proceedings.[5]

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[4] ORDER ISSUING NOTICE TO ELECTRIC UTILITIES AND APPLICANTS REGARDING PENDING APPLICATIONS FOR COMMUNITY SOLAR INTERCONNECTIONS DURING RULEMAKING PROCEEDING [21-00112-UT], June 16, 2021.

[5] On June 14, 2021, SPS and El Paso Electric filed a motion for clarification, requesting that cost-allocation issues for Community Solar projects be determined in the related proceeding [21-00112-UT]. In related workshops for both proceedings, the Commission has expressed a strategy of establishing interconnection rules in 20-00171-UT, but applying them to Community Solar project implementation as warranted.

2.3 Scope

The technical stakeholder advisory process has been structured to address issues in two phases of activities.

Phase I primarily relates to recommending proposed amendments to Rule 17.9.568 and the Interconnection Manual last updated in October 2008. During Phase I, The Working Group identified and then addressed six non-technical issues and four technical issues. Proposals for these ten issues are provided in Section 3.

Proposed recommendations for non-technical issues include a variety of topics. These proposed recommendations include allowing for pre-application review of projects; defining timelines for conducting utility review of applications; establishing a dispute resolution process; and determining a categorization of projects by size, as determined by rated capacity, to determine application of a "fast track" analysis and/or the extent of supplemental reviews of system impacts. Some additions or revisions to Definitions have also been included.

In addition, the group has provided extensive background materials and a set of "options" for Commission consideration of alternative policies related to the traditional "cost causation" policy. As specified in the existing Rule (at 17.9.568.14 (a)), project developers/customers bear the responsibility for all expenses related to any distribution system upgrades (circuits, substations or transformers, etc.) that may be necessary to accommodate increased deployment of distributed energy on utility distribution system.

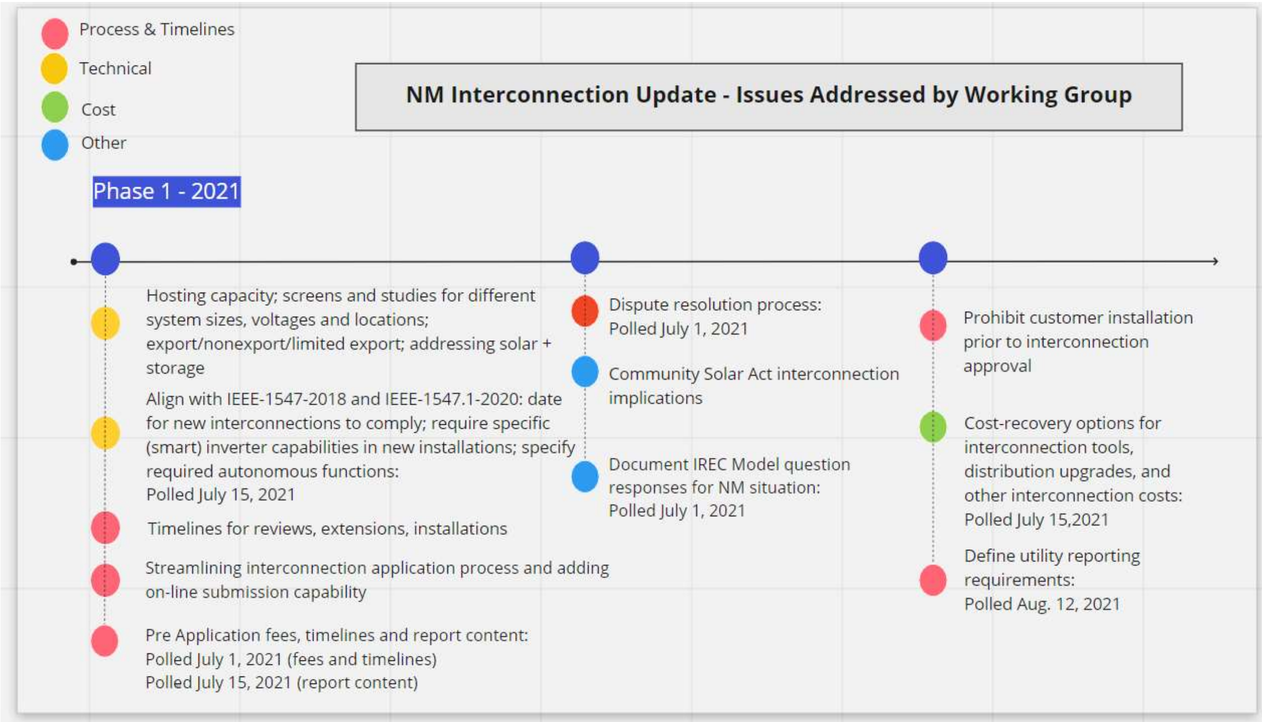
For the four technical issues, the Working Group also discussed and made recommendations on the adoption of a date by which inverters with certain advanced functionalities conforming to recent standard IEEE-1547-2018 would be required for new installations or end-of-life replacement of existing devices. The Working Group also addressed a key technical issue -- capacity levels and screens -- for ensuring simple and streamlined (or "fast track") review of interconnection applications for smaller installations by primarily residential customers.

In addition, new capabilities of smart inverters, energy storage devices, and power control systems can in some circumstances allow for non-exporting or limited-exporting systems that can conserve or limit the need for hosting capacity or physical upgrades on a given distribution line. The Working Group also considered proposals to allow such non-export or limited export, together with addressing reliability and safety issues potentially caused by inadvertent export of such systems.

Finally, there was also preliminary discussion about methods for ascertaining available "hosting capacity" and/or mapping of utility distribution networks to provide more information about capacity constraints or the location and availability of unconstrained interconnection paths.

While many of these issues have reached a relatively high level of agreement among the parties, others represent non-consensus items that should be considered for resolution by Commission decision in the rulemaking proceeding. In such instances, the report provides the alternative positions of parties with commentary that may provide the Commission with a sufficient basis for making such determinations.

The figure below lists issues that were addressed by the Working Group during Phase I.



Phase II, which is expected to commence following a Commission decision on Phase I issues, would provide for a stakeholder report and recommendations on several issues. A key topic is Smart Inverter Functionalities, including thresholds for activation of autonomous functionalities and potential adoption of more advanced functions related to communications and control over inverter operations. (See Section 5.1 for more information on Proposed Scope for Phase II.)

2.4 Process

The New Mexico Public Regulation Commission initiated a notice of inquiry regarding updates to the state's interconnection rules on January 13, 2021, under case number 20-00171-UT. After holding a workshop in February, a Working Group was formed of interested individuals. Biweekly facilitated meetings were held from April through September. This report is the result of the Working Group's efforts.

To lead off the discussion of three of the technical issues related to capacity screens, non-export, and hosting capacity, an initial technical workshop was held on April 22, 2021, as one of the regularly scheduled biweekly Working Group meetings. Representatives from industry, the New Mexico utilities, advocates, and research institutes EPRI and Sandia National Laboratories contributed perspectives and reference information that provided a strong foundation for the Working Group discussions to follow. Links to presentations are provided in Annex C.

During Phase I, Working Group members volunteered to work on specific issues or topics that surfaced and were organized into Subgroups. The Subgroups developed options, recommendations, proposals, and reference documents for consideration by the full Working Group. The results of the Subgroups' efforts were then translated into proposed updates to the NM Interconnection Rule and NM Interconnection Manual.

A variety of platforms were employed to engage people in the Interconnection Update Process. ZOOM meetings of the Working Group were held every two weeks; attendance varied between 30 and 50 people. OneDrive was used as the repository for reference material, working documents, Subgroup reports, participant contact lists, meeting agendas and meeting summaries.[6] An electronic white board was created in an application called MIRO[7] and used as a polling mechanism. Working Group members participated in polling to assess the degree of support for specific Subgroup recommendations discussed at prior meetings. Participants with comments or objections to recommendations were invited to submit revisions or alternate recommendations. When this occurred, a second poll was conducted at a subsequent meeting.

A total of 15 workshops and Working Group meetings were held between February and September of 2021. (See Annex B for the dates and links to recordings of each).

Over 100 stakeholders participated in this process at some point and are listed in Annex A. All who wished to be involved were included on the Working Group distribution list, invited to attend meetings, and sent meeting summaries. Representation included:

- renewable energy industry - 41 representatives,
- utilities (including cooperatives) - 45 representatives, and
- public agencies, universities and interested individuals – 20 representatives

Thirty-eight individuals contributed substantially through one of twelve working Subgroups, organized around specific interconnection topics. A list of the Subgroups and members is shown below with the Subgroup lead listed first in bold type.

Rule Redline Subgroup – **Adam Alvarez (PNM),** Ed Brolin (ConEd Clean Energy Business), Joseph Hererra (Socorro Electric Co-op), Scott Risley (Nautilus Solar), Steven Rymsha (Sunrun), and Taiyoko Sadewic (Positive Energy)

Pre-Application Subgroup – **Jim DesJardins (REIA-NM)**, Abbas Akhil, Adam Harper (Osceola Energy), Andrea Contreras (PNM), David Spradlin (Springer Electric Co-op), Jane Yee (City of Albuquerque), Kevin Cray (Community Solar Access), Kyle Reddell (Xcel Energy), Lisa Mattson (Pivot Energy), Roberto Favela (El Paso Electric), and Zoe Lees (Xcel Energy)

Cost Allocation Options Subgroup – **Ed Brolin (ConEd Clean Energy Business),** Chris Worley (Sunrun), Kevin Cray (Community Solar Access), Roberto Favela (El Paso Electric), Ryan Jerman (PNM), Scott Risley (Nautilus Solar), Taiyoko Sadewic (Positive Energy), and Zoe Lees (Xcel Energy)

IREC Model Questions Subgroup – **Jacqueline Waite (NM EMNRD),** Jon Hawkins (PNM), Kyle Reddell (Xcel Energy), Mario Romero (Otero County Electric Co-op), Olga Lavrova (NMSU), Sara Birmingham (SEIA), Taiyoko Sadewic (Positive Energy), and Zoe Lees (Xcel Energy)

Technical Issues Utilities Subgroup –**Zoe Lees (Xcel Energy)**, Andrea Contreras (PNM), Ed Rougemont (NM RECA), Frank Andazola (PNM), Jon Hawkins (PNM), Keven Groenewold (NM RECA), Luis Reyes (Kit Carson Co-op), Matt Hagen

[6] The OneDrive site for the Interconnection Working Group is: https://onedrive.live.com/?authkey=%21AJKlY%5FS0wfPCqb8&id=5891771FBA4AFF14%212412&cid=5891771FBA4AFF14

[7] The MIRO whiteboards for the Interconnection Working Group are located at: https://miro.com/app/board/o9J_lG1Vyp0=/

(Xcel Energy), Michael D'Antonio (Xcel Energy), Richard Martinez (Kit Carson Electric Co-op), and Roberto Favela (El Paso Electric)

Technical Issues Subgroup – Olga Lavrova (NMSU) and Jane Yee (City of Albuquerque)

Technical Issues Industry Subgroup – **Sara Birmingham (SEIA),** Adam Harper (Osceola Energy), Chris Worley (Sunrun), Jim DesJardins (REIA-NM), Kevin Cray (Community Solar Access), Lisa Mattson (Pivot Energy), Steven Rymsha (Sunrun), and Taiyoko Sadewic (Positive Energy)

IEEE 1547 Adoption Subgroup – **Travis Dorr (Xcel Energy),** Roberto Favela (El Paso Electric), Satish Ranade (NMSU), Scott Risley (Nautilus Solar), Steven Rymsha (Sunrun), and Taiyoko Sadewic (Positive Energy)

Dispute Resolution Subgroup – **Matt Hagen (Xcel Energy),** Jim DesJardins (REIA) and Lisa Mattson (Pivot Energy)

Manual Revision Utilities Subgroup – **Roberto Favela (El Paso Electric),** Andrea Contreras (PNM), Frank Andazola (PNM), Kyle Reddell (Xcel Energy), Matt Hagen (Xcel Energy)

FERC SGIP, IREC, NM Reconciliation Subgroup – **Matt Hagen (Xcel Energy),** Olga Lavrova (NMSU), Taiyoko Sadewic (Positive Energy), Jim DesJardins, (REIA) and Tye Pollard (El Paso Electric)

Public Projects Subgroup – **Harold Trujillo (NM EMNRD),** David Griego (NM EMNRD), Dylan Connelly (Affordable Solar), Jane Yee (City of Albuquerque), and Jim DesJardins (REIA-NM)

Utility Reporting Requirements Subgroup – **Jim DesJardins (REIA-NM).** Note: The investor-owned electric utilities provided an alternate set of proposed reporting requirements as detailed in Section 3.6 Proposal F-2.

The Working Group appreciates the participation by Michael Ropp (Sandia National Laboratories) and Tom Key (EPRI) in several technical discussions.

2.5 Existing NM Interconnection Rule and Manual

As previously noted, the existing Interconnection Rule [17.9.568.1 NMAC] and Manual were last updated in late 2008. At the time, electric utility interconnections for distributed energy resources of less than 10 MW were minimal in most jurisdictions of New Mexico, and across the country.

The 2008 Rule and Manual documents adopted by New Mexico at that time are largely based on Federal Energy Regulatory Commission ("FERC") Order No. 2006, issued in 2005, which standardized small generator interconnection procedures ("SGIP") and agreements ("SGIA") with broad consensus and agreement in the industry for Generating Facilities no larger than 20 MW.

As such, the policies embodied in these sets of rules reflected the regulations and policy initiatives of the Federal Energy Regulatory Commission, which during the prior decade was extending its authority over interstate electric transmission access and wholesale electric markets – especially in areas with "organized markets" (aka, Regional Transmission Operators/Independent System Operators).[8]

[8] See PNM website, https://www.pnm.com/interconnecting-large-facilities, as example of larger capacity interconnection processes.

Increasingly, however, intrastate utility purchases of renewable energy – mainly from solar power and to a lesser extent, wind or biomass projects – were moving from transmission-level interconnections to distribution level, particularly as the installed cost of rooftop photovoltaic systems fell dramatically. State policies to require minimum levels of purchases under Renewable Portfolio Standards and adoption of Net Energy Metering programs, in which customers are able to net their self-generated power against utility deliveries and receive payments or credits for the renewable energy, also drove greater interest in smaller scale PV and a greater dispersal of these generating resources throughout the utility network, with increased impacts on utility distribution grids that were not designed to accommodate such facilities.

Another development was the rapid market adoption of battery storage systems. From a very low level of market penetration in 2010, battery storage of several types and chemical configurations, but mainly lithium ion based, has advanced in the last decade. Both larger scale systems for utility grade operations and smaller, home and commercial scale deployment are seeing almost exponential growth patterns. Increasingly, photovoltaic solar is being paired with battery storage, and the combination of technologies has challenged both the existing parameters of utility distribution operations and the rules that govern interconnection.

These market and technological changes were first seen dramatically in a few states. California, with a Million Solar Rooftop program, a vibrant NEM program, and hundreds of millions of dollars in direct payment and buy-down incentives for small generator installations, experienced both huge market growth and interconnection pressures on utilities. Hawaii, where utility energy rates were traditionally high and reliability of service sporadic at best, faced a virtual tsunami of Distributed Energy Resources (DER), also called distributed generation (DG), and PV penetration across the often-remote island utility territories.

Both states responded with regulatory initiatives to update and streamline interconnection policies, and to investigate and implement technology standards for inverter-based distributed generation that went well beyond the capabilities allowed for under the existing international standard IEEE 1547. This, in turn, spurred the entire electric industry to commence revisions and updates to these standards, in an effort still underway but promising to allow for new inverter functionalities and reliability benefits from interconnected devices of many types that previously would not have been allowed to operate in the face of distribution system events or even relatively minor fluctuations to voltage or frequency values. Currently, some twenty-one states have or are pursuing adoption of the revised IEEE 1547.

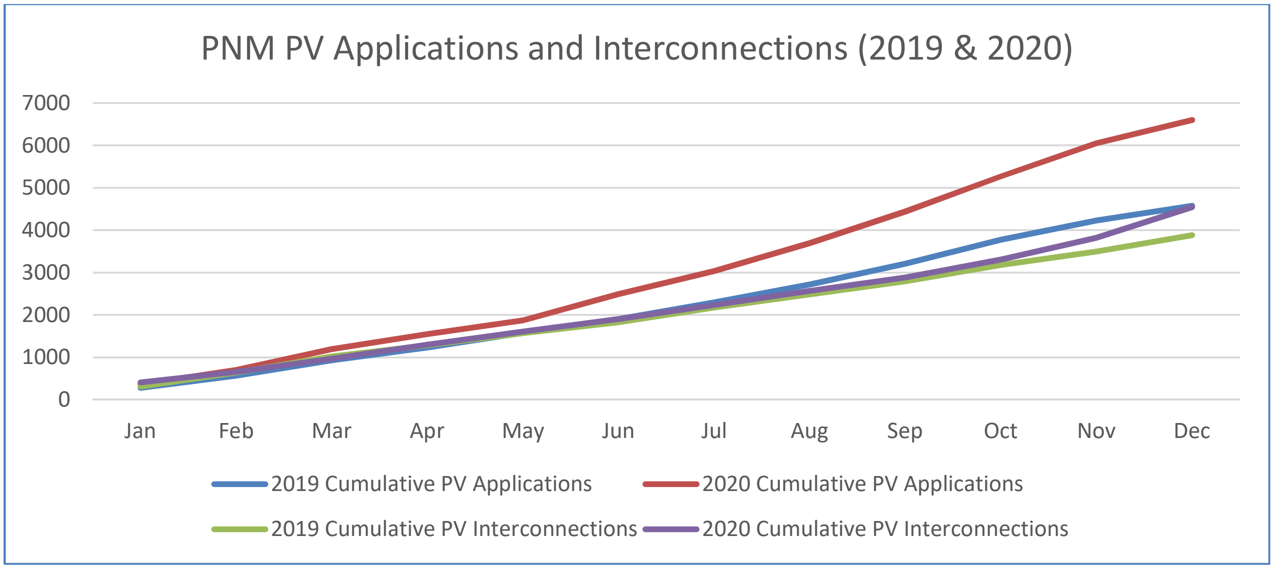
While New Mexico was not in the forefront of these changes, it was certainly not immune to them. Utilities both large and small are facing increasing demand from customers who want to install rooftop PV and storage systems, interconnection requests are on the rise, and some utility circuits are even declared “at saturation” and unable to accommodate new DER interconnections without significant upgrades and substantial costs.

Evidence of this was presented at the PRC’s initial interconnection workshop on February 18, 2021, via slides and presentations from the investor-owned utilities and rural co-operatives. In particular, the state’s largest utility, PNM, documented a strong demand for new interconnections as well as an increasing concern about system constraints.

The chart below shows the growth in interconnection applications processed by PNM 2019-2020, with interconnection applications increased by 44 percent and completed installations up by 17 percent.

Additionally, PNM reported that 18 out of 492 (4%) of its distribution feeders are at greater than 90% of their rated capacity, meaning the utility cannot readily interconnect new DER on those circuits. The utility added that system improvements costing over $1 million (depending on specifics to applicable feeder) are required to add additional capacity in order to allow additional interconnections. Additionally, utility engineers cite thermal stability of the feeder at risk with decreasing load and increased PV interconnection.[9]

Chart 1 - PNM Numbers of Applications and Completed Interconnections 2019-2020



PNM has developed a web-based map so that customers/developers can see if their location might be subject to such costly constraints. What is apparent is that rather large portions of PNM's system – especially fast growing communities in Albuquerque's west side and South Valley – are not able to readily interconnect new resources. When customers request interconnection they may be told there is no capacity and no current plan to upgrade the circuits.

In response, the NM Public Regulation Commission initiated its formal proceeding to modernize both the Interconnection Rule/Manual and consider adoption of the updated IEEE 1547 standard and deputized the technical stakeholder group to make recommendations.

2.6 FERC SGIP and IREC Models

In considering how to revise and update interconnection policies, the Working Group looked to two potential "models" for change: The Federal Energy Regulatory Commission's Small Generator Interconnection Protocol (FERC SGIP) and the "Model Interconnection Procedures" developed by the non-profit Interstate Renewable Energy Council (IREC).

FERC's SGIP is mainly geared to the interconnection of small generation resources with capacity of 20 MW and smaller that are engaged in utility power sales or wholesale markets and are interconnected to utility high-voltage transmission networks and to distribution lines subject to FERC tariffs. Originally adopted in 2005, via Order 2006, the SGIP comprised of *pro forma* terms, conditions and agreement forms to ensure that utilities provided non-discriminatory access to these small generators on equivalent terms with larger scale generators.

[9] Presentation by PNM to the New Mexico PRC Interconnection workshop, February 18, 2021, in 20-00171-UT.

The rules have been revised several times to address evolving market and operational needs. The most significant changes came via Order 792 in 2013, which provided for a pre-approval application review process, revisions to thresholds for expedited (“fast track”) review of applications that did not require system upgrades, requirements associated with “supplemental” engineering reviews for projects not eligible for fast-track treatment, and associated revisions to the *pro forma* rules and agreement forms. Details of the FERC SGIP process are included in Annex D.

More limited revisions were adopted in 2016 (Order 828) for alignment with the IEEE 1547 standard revisions allowing for frequency and voltage “ride through” capabilities (see subsequent report section on the IEEE 1547 standards), and in 2018 with technical updates for “primary frequency response” as an ancillary market service.

The revisions under Order 792 are those primarily concerned with streamlining and standardizing interconnections, and are most relevant to New Mexico’s current inquiry, but the version of the SGIP adopted in July 2016 in FERC’s RM16-8-000 docket remains the operative set of rules and interconnection agreement forms.

IREC’s Model Procedures, in contrast, focused on distribution-level interconnections, and was developed beginning in 2005, to assist state regulators and local utilities with a “best practices” approach to modernizing interconnections, especially for streamlining the application screening and review process. IREC claims its model incorporates lessons learned from the organization’s participation in dozens of state interconnection proceedings and builds upon FERC’s SGIP in ways that are especially relevant to evolving intrastate market needs. The Model Procedures were revised several times, with the most current version issued in 2019. Among the most recent revisions include:

- Interconnection of energy storage systems (an ongoing developmental issue)
- Recommendations for interconnection queue management and transparency
- Updating a dispute resolution process
- Agreement form updates to reflect these

Participants in the New Mexico Interconnection Working Group initially tended to gravitate toward advocating SGIP if they represented utilities (“It’s what we use and has worked well.”) or the IREC model by renewable energy developers’ associations (“It is more up to date and relevant to our concerns.”) However, it soon became apparent that each model offered benefits and advantages for New Mexico’s situation, depending on specific issues.

The “Reconciliation” Subgroup has provided a highly useful summary document, comparing how the existing NM Manual, SGIP and IREC treat major issues (See Annex D).[10] Some differences have been resolved, others remain. The three IOUs continue to support the FERC SGIP as the basis for New Mexico’s Interconnection policies.[11]

The IREC Model Procedures also provided a useful set of 16 questions for jurisdictions to establish a kind of baseline of existing policies. The document developed by the IREC Questions Subgroup is found at Annex I and may prove a valuable first stop for decision makers to review the current state of interconnection policies in New Mexico.

[10] A companion Excel spreadsheet contains additional details of this comparison. A link to the document is included in Annex D, as it is not easily incorporated into the report format.

[11] See discussion of the utilities’ position in Annex D.

3. PROPOSALS AND OPTIONS FOR INTERCONNECTION UPDATES

3.1 Definitions

PROPOSAL A-1: CONSENSUS DEFINITIONS

Facilitator's note: Consensus. These definitions have been developed collaboratively by the Definitions Subgroup, but those that are not agreed to by everyone are moved to Proposal A-2. Additional definitions related to technical issues that have been provided by the Industry Group are included in Proposal A-2 as they are still non-consensus. Additional modifications may be added as necessary to reflect terminology used in proposed Rule and Manual documents.

"Anti-Islanding" means a control scheme installed as part of the Generating or Interconnection Facility that senses and is intended to prevent the formation of an Unintended Island.

"Applicant" means a person or entity that has filed an Application to interconnect a Generating Facility to an Electric Delivery System. For a Generating Facility that will offset part or all of the load of a Utility customer, the Applicant is that customer, regardless of whether the customer owns the Generating Facility or a third party owns the Generating Facility.[12] For a Generating Facility selling electric power to a Utility, the owner of the Generating Facility is the Applicant.

"Applicant or Customer Options Meeting" means a meeting designed to review the current status of the application initial review results, or to determine next steps that are needed to permit safe and reliable interconnection.

"Application" means the Applicant's request, in accordance with these Interconnection Procedures, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Utility's Electric Distribution System.

"Area Network" means a section of an Electric Delivery System served by multiple transformers interconnected in an electrical network circuit generally used in large, densely populated metropolitan areas in order to provide high reliability of service and having the same meaning as the term "grid network" as defined in IEEE Std 1547.6™. An area network is also referred to as a grid network or a street network.

"Auxiliary Load" means electrical power consumed by any auxiliary equipment necessary to operate the Generator. This is intended for in front of the meter, large systems.

"Business Day" means Monday through Friday, excluding Federal and State Holidays.

[12] For a variety of reasons, a Generating Facility may be owned by a third party that contracts to sell energy or furnish the Generating Facility to the Utility's customer. In those cases, the Utility's customer is still the Applicant under this Agreement, though the Applicant may choose to designate the owner as Applicant's representative. Customers may also designate on the Application form installers or others to act on their behalf in the process.

"Screening process" is the process described in the interconnection manual for determining whether an interconnection application is approved or requires additional studies.

"Certified" means a piece of equipment has been tested in accordance with the applicable requirements of IEEE Std 1547™ and IEEE Std 1547.1™ by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify equipment pursuant to the applicable standard and the equipment has been labeled and is publicly listed by such NRTL at the time of the interconnection application.

"Commission" means the New Mexico Public Regulation Commission. http://www.nmprc.state.nm.us/index.html

"Customer Options Meeting" is a meeting designed to review the current status of the application initial review results, or to determine next steps that that are needed to permit safe and reliable interconnection.

"Detailed Study" means the procedure for evaluating an interconnection request that may include a scoping meeting, feasibility study, system impact study, and facilities study.

"Distribution Service" means the service of delivering energy over the Electric Distribution System pursuant to the approved tariffs of the Utility other than services directly related to the interconnection of a Generating Facility under these Interconnection Procedures.

"Distributed Energy Resource" (DER) is a source of electric power that is not always connected to a bulk power system. DERs may include distributed generation (DG) resources, distributed energy storage, demand response, energy efficiency, and electric vehicles and chargers that are connected to the electric distribution power grid. DERs may be capable of exporting active power to an Electric Power System (EPS). The DER includes the Customer's Interconnection Facilities but shall not include the Area EPS Operator's Interconnection Facilities.

"Electric Delivery System" means the equipment operated and maintained by a Utility (may include: Independent System Operators, Transmission Owner/Operator, Vertically Integrated Utilities, Electric Cooperatives, Municipals, and Distribution Companies) to deliver electric service to end-users, including without limitation transmission and distribution lines, substations, transformers, Spot Networks and Area Networks.

"Electric Power System" (EPS) means the facilities that deliver electric power to a load.

"Energy Storage Device" means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For purposes of these procedures, an Energy Storage Device can be considered a component of a Generating Facility.

"Energy storage system" (ESS) means any commercially available, customer-sited system or utility-sited system, including batteries and batteries paired with on-site generation, that is capable of retaining, storing, and delivering electrical energy by chemical, thermal, mechanical, or other means.

"Export capacity" means the amount of alternating current (AC) electrical power and/or energy that an interconnected resource is intended to transfer to the utility's system across the point of interconnection.

"Facilities Study" specifies and estimates the cost of the equipment, engineering, procurement, and construction work (including overheads) needed to implement the conclusions of the System Impact Study.

"Fast Track" describes the process in which an Interconnection Request that meets the eligibility requirements advances to an Interconnection Agreement without requiring any distribution system upgrades.

"Fault Current" means electrical current that flows from one conductor to ground or to another conductor due to an unintended connection between the two. An electrical fault can be phase to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase. A Fault Current is typically several times larger or more in magnitude than the current that normally flows through a circuit.

"Generating Facility" means the interconnection customer's device for the production of electricity identified in the interconnection application, including all generators, electrical wires, equipment, and other facilities owned or provided by the interconnection customer for the purpose of producing electric power.

"Host Load" means the electrical power, less the Generator Auxiliary Load, consumed by the Customer, to which the Generating Facility is connected.

"IEEE" means the Institute of Electrical and Electronic Engineers.

"IEEE Standards" means the standards published by the IEEE, often in collaboration with American National Standards Institute (ANSI), National Institute of Standards and Technology (NIST), UL and National Fire Protection Institute (NFPA), available at www.ieee.org.

"Inadvertent export" means the potential condition in which a normally non-exporting or limited-exporting DER experiences an unscheduled, export that does not exceed limitations in terms of magnitude or duration as specified in UL 1741 CRD for PCS.[13]

"Interconnection Agreement" means a standard form agreement between an Interconnection Customer and a Utility governing the interconnection of a Generating Facility to a Utility's Electric Delivery System, as well as the ongoing operation of the Generating Facility after it is interconnected.

"Interconnection Customer" means any person or entity that applies to interconnect its Generating Facility with Utility's system.

"Islanding" refers to a condition when a generator remains active on a line section that has been isolated due to maintenance or due to a fault.

"Limited Export" means the exporting capability of a Generating Facility whose Generating Capacity is limited by the use of any configuration or operating mode.

"Line Section" means that portion of the Utility's Electric Delivery System connected to a Customer bounded by automatic sectionalizing devices or the end of the distribution line.

"Material Modification" means a modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any Interconnection Facilities or Distribution Upgrades, or a material impact on the cost, timing, or design of any Application with a later queue priority date or the

[13] "UL 1741 CRD for PCS" means the Certification Requirement Decision for Power Control Systems for the standard titled " Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources " (March 8, 2019), Underwriters Laboratories Inc., 333 Pfingsten Road, Northbrook IL 60062-2096.

safety or reliability of the Utility. A change to the point of interconnection would require a new application or a change in queue position.

“Minor System Modifications” means modifications to a Utility’s Electric Delivery System that involve little work or low costs. Minor System Modifications include, but are not limited to, activities like changing the fuse in a fuse holder cut-out or changing the settings on a circuit recloser. Minor modifications shall not require utility design or construction.

“Nameplate Rating” refers to the rated maximum operating capacity of a piece of electrical equipment as defined by the manufacturer.

“Net Rating” means the Nameplate Rating of the Generating Facility minus the consumption of electrical power of the Auxiliary Load.

“Non-Export” or “Non-Exporting” means when the Generating Facility is sized and designed such that the output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the Generating Facility to the Electric Delivery System.

“Non-exporting system” means an interconnection resource that is designed so that it does not intentionally transfer electrical energy to the utility’s distribution or transmission system across the point of common coupling. Such systems may be used to supply part or all of a customer’s load continuously or during an outage. A system can be non-exporting by virtue of inverter programing or by some other on-site limiting element. Non-exporting systems may or may not produce inadvertent exports.

“Parallel Operation” Any electrical connection between the utility power delivery system and the customer’s generation source.

“Parties” means the Applicant and the Utility in a particular Interconnection Agreement. “Either Party” refers to either the Applicant or the Utility.

“Point of common coupling” means the point where the small generator facility is electrically connected to the electric distribution system. The point of common coupling is the point of measurement for the application of Institute of Electrical and Electronics Engineers standard (IEEE) 1547.

“Point of Interconnection” means the point where the Interconnection Facilities connect with the Electric Distribution System.

“Power Control System” means systems or devices which electronically limit or control steady state currents to a programmable limit and certified under UL 1741 CRD for Power Control Systems (PCS) by a nationally recognized testing laboratory.

“Protective Function” means the equipment, hardware and/or software in a Generating Facility (whether discrete or integrated with other functions) whose purpose is to protect against conditions that, if left uncorrected, could result in harm to personnel, damage to equipment, loss of safety or reliability, or operation outside pre-established parameters required by the Interconnection Agreement.

“Scoping Meeting” is a meeting to review the completed application and determine next steps for detailed study.

“Secondary Network” is an AC distribution system where the secondaries of the distribution transformers are connected to a common network for supplying electricity directly to consumers. There are two types of secondary networks: grid networks (also referred to as area networks or street networks) and spot networks.

“Small utility” means a utility that serves fewer than 50,000 customers.

“Spot Network” means a section of an Electric Delivery System that uses two or more inter-tied transformers to supply an electrical network circuit. A Spot Network, is a form of area network, generally used to supply power to a single Utility customer or to a small group of Utility customers, and has the same meaning as the term is used in IEEE Std 1547™.

“Supplemental Review” means additional engineering studies to determine any requirements for processing the application through the expedited (Fast Track) process or determine if a detailed study is required..

“UL” means the company by that name which has established standards, previously known as Underwriter’s Laboratory.

“Unintended Island” means the creation of an Island without the approval of the Utility.

“Utility” means an operator of an Electric Delivery System.[14]

[14] Some interconnection procedures reference the operator of the Electric Delivery System as the “Company” or the “Electric Delivery Company (EDC).” Here the term “Utility” is meant to include all investor-owned and public utilities, including cooperatives, municipal utilities and public utility districts. In deregulated states, the “wires” company is the Utility while the energy provider is not.

PROPOSAL A-2 NON-CONSENSUS DEFINITIONS

These definitions, supported by the Industry representatives, relate to terms used in Prospective Paths to Hosting Capacity, Section 3.10. The Utilities contend they should not be included in this Phase of the proceeding.[13]

“Closed circuit” means an electric distribution system circuit with no available hosting capacity except for new inadvertent export facilities less than 25kW programmed for customer self-consumption.

“Estimated gross daytime minimum load” means the calculated coincidental customer demand derived by adding the circuit/substation Net Minimum Load and load side generators aggregate Operating Profiles coincidental with timing of Net Minimum Load. This calculation negates the impact of the existing DER on the load measured at the circuit and substation level so that total, raw load can be properly allocated in the technical review or modeling.

“Export capacity” means the maximum possible simultaneous generation of the Generating Facility, and is calculated as the maximum amount of export as permitted by limiting the amount of the Generating Facility’s export at the Point of Common Coupling.

“Hosting capacity” (1) means the amount of aggregate generation that can be accommodated on the electric distribution system without requiring infrastructure upgrades.[15]

“Hosting capacity reporting system” means the information available on a utility website providing reports, tabular data, or maps of hosting capacity available on the electric distribution system.

“Hosting capacity upgrade plan” means a plan to open restricted and closed circuits or areas on an electric system in the aggregate that includes a cost recovery method, under conditions that are approved by the Commission.

“Interconnection facility cost sharing” means the allocation of distribution interconnection facility upgrade costs among multiple small generator facility projects that utilize the hosting capacity created by an interconnection facility upgrade.

“Net daytime minimum load” means the measured circuit/substation load coincidental with solar production.

“Net minimum load” means the lowest measured circuit/substation load irrelevant of time of day.

“Reserve hosting capacity” (for Level 1) means a percentage of currently available hosting capacity for future Level 1 projects in suburban and urban areas.

[15] Proposal A-2 Position of Joint Utilities Group on Hosting Capacity definition: *As part of a pathway towards hosting capacity information and mapping (see Proposal J), there needs to be a clear definition of many terms and phrases related to hosting capacity, as terminology can mean different things to different people resulting in confusion. For example, “hosting capacity” refers to a single value at a specific location, as differentiated from “hosting capacity analysis,” which is a process and methodology that can lead to hosting capacity values at many locations for a specific moment in time, often displayed through mapping. Similarly, a common vocabulary that considers the dynamic nature of utility circuits is needed when talking about “available” capacity or “limits” to capacity.*

Non Consensus items from September 16 and September 30, 2021 – These definitions were discussed by the Working Group but could not find agreement.

"Aggregate Capacity" or "Aggregate Generation Capacity" means the aggregated ongoing operating capacities of all small generator facilities across multiple points of common coupling, within a defined portion of the distribution system.

"Capacity Upgrade Planning" a study to determine an appropriate upgrade plan with consideration for future customer adoption of generation and or storage.

Two alternative definitions for "Generating Capacity":

[Industry] "Generating Capacity" means the maximum Nameplate Rating of a Generating Facility in alternating current (AC), except that where such capacity is limited by any of the methods of limiting electrical export; generating capacity shall be the net capacity as limited though the use of such methods (not including inadvertent export).

[Utilities] "Generating Capacity" means the maximum Nameplate Rating of a Generating Facility in alternating current (AC).

"Operating mode" means the mode of DER operational characteristics that determines the performance during normal and abnormal conditions. For example, an operating mode such as "export only," "import only," and "no exchange."

"Ongoing operating capacity" means the actual simultaneous Generating Capacity, taking into account the operational differences of load offset and export. If the contribution of energy storage to the total contribution is limited by programing of the maximum active power output, use of a power control system, use of a power relay, or some other mutually agreeable, on-site limiting element, only the capacity [defined as ongoing operating capacity] that is designed to inject electricity to the utility's distribution or transmission system (other than inadvertent exports and fault contribution) will be used within certain technical screens and evaluations.

"Operating profile" means the manner in which the Facility is designed to be operated, as designated in the Interconnection Application materials, including the amount of export, the times of year, hours of the day and other relevant conditions. The Utility may require assurances that the system will operate as designed.

3.2 Pre-Application Process

PROPOSAL B: PRE-APPLICATION REPORT

Proposal status: consensus. Provided by the pre-application Subgroup after polling during the July 1 and July 15, 2021, meetings.

Content of Pre-Application Reports

The proposed pre-application report content is taken directly from the 2019 IREC model and language:

1. The Pre-Application Report shall include the following information, if available:

   a. Total capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site.
   b. Aggregate existing Generating Capacity (MW) interconnected to the substation/area bus or bank and circuit likely to serve proposed site.
   c. Aggregate queued Generating Capacity (MW) proposing to interconnect to the substation/area bus or bank and circuit likely to serve proposed site.
   d. Available capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site. Available capacity is the total capacity less the sum of existing and queued Generating Capacity, accounting for all load served by existing and queued generators. Note: Generators may remove available capacity in excess of their Generating Capacity if they serve on-site load and utilize export controls which limit their Generating Capacity to less than their nameplate rating.
   e. Whether the proposed Generating Facility is located on an area, spot or radial network.
   f. Substation nominal distribution voltage or transmission nominal voltage if applicable.
   g. Nominal distribution circuit voltage at the proposed site.
   h. Approximate circuit distance between the proposed site and the substation.
   i. Relevant Line Section(s) and substation actual or estimated peak load and minimum load data, when available.
   j. Number and rating of protective devices and number and type of voltage regulating devices between the proposed site and the substation/area.
   k. Whether or not three-phase power is available at the site and/or distance from three-phase service.
   l. Limiting conductor rating from proposed Point of Interconnection to distribution substation.
   m. Based on proposed Point of Interconnection, 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.
   n. Any other information the Utility deems relevant to the Applicant.

Facilitator's note: *One member of the Subgroup proposed to delete item f. and to keep item g. A proposal was offered to substitute f. and g. with "circuit voltage at the proposed site" At this time, this has not been resolved.*

2. The Pre-Application Report need only include pre-existing data. A Pre-Application Report request does not obligate the Utility to conduct a study or other analysis of the proposed project in the event that data is not available. If the Utility cannot complete all or some of a Pre-Application Report due to lack of available data, the Utility will provide the potential Applicant with a Pre-Application Report that includes the information that is available and identify the

information that is unavailable. The provision of information on "available capacity" pursuant to item 1.d above does not imply that an interconnection up to this level may be completed without impacts.

3. Notwithstanding any of the provisions of this Section, the Utility shall, in good faith, provide Pre-Application Report data that represents the best available information at the time of reporting.

Costs of Pre-Application Reports

Pre-application reports for front-of-the-meter and behind-the-meter interconnections should be treated differently:

- Pre-application reports for front-of-the-meter interconnections: $500. However, if a utility can provide documentation that the cost is higher, then they would be paid that additional amount.

- Pre-application reports for behind-the-meter interconnections: $300 for up to 1 MW system size, and $500 for over 1 MW. If a utility can provide documentation that the cost is higher, then they would be paid that additional amount. However, consensus on this point was not unanimous, with at least one participant supporting lower costs, free-of-charge up to 100 kW system size and $300 for over 100 kW.

For smaller systems, the Working Group understands that although utilities may not want to formally agree to provide pre-application information at no charge, this is often supplied as a courtesy, and as utilities are able, and within reason, utilities would continue to provide this type of information informally at no charge. SPS, however, stated that since this is done as a courtesy to applicants, there should be no explicit obligation to provide specific information for free.

The Working Group recognized that utilities may not always know in advance what the actual costs of producing a pre-application report will be, especially if a utility contracts with an outside engineering firm do the report.

Time Frames for Pre-Application Reports

Pre-application reports for front-of-the-meter and behind-the-meter interconnections should be treated differently:

- Pre-application reports for front-of-the-meter interconnections should be completed in 15 business days. However, if it can be documented that a utility cannot meet this deadline due to circumstances beyond their control, then they would be given more time.

- Pre-application reports for behind-the-meter interconnections should be completed in 10 business days for system sizes up to 1 MW, and 15 business days for system sizes greater than 1 MW. If it can be documented that a utility cannot meet this deadline due to circumstances beyond their control, then they would be given more time. However, consensus on this point was not unanimous, with at least one participant supporting shorter timeframes, 3 business days for system sizes up to 100 kW and 8 business days for system sizes over 100 kW.

Length of Time for Accuracy of Information

Due to the dynamic nature of providing pre-application reports and the volume of requests, reports should be considered a "snap-shot in time" and accuracy cannot be guaranteed past the time of completion of a report.

However, consensus on this point was not unanimous. At least one participant supported a guaranteed accuracy of 24 hours after completion of the report. SPS, however, argued that "accuracy cannot be guaranteed for any specified length of time as capacity for interconnection is not formally reserved in the pre-application process.” PNM concurred that a guarantee would not be workable.

Other Aspects of Pre-Application Reports

For all other aspects of pre-application reports, the Working Group proposes to use the pre-application language from the IREC model.

3.3 Interconnection Application Timelines

Facilitator's Note: *At the May 19, 2021, Working Group session, the Industry Group offered a proposal for timelines associated with applications. The Utility Group on August 16 countered with a number of proposed changes, especially related to how much time a utility has to complete various steps and more detail of activities and processes. These differences have not been reconciled, so are recorded herein as two proposals for consideration by the Commission.*

PROPOSAL C-1: APPLICATION TIMELINES (INDUSTRY GROUP)

○ Completeness Review

- Utility shall provide a first written notification to the Interconnection Customer within ten (10) Business Days of receipt of the Interconnection Request, which notice shall state whether the Interconnection Request is deemed complete and valid.

○ Initial Review

- Upon receipt of a complete and valid Interconnection Request, Utility shall perform Initial Review. The Initial Review determines if (i) the Generating Facility qualifies for Fast Track Interconnection through Initial Review, or (ii) the Generating Facility requires a Supplemental Review. Absent extraordinary circumstances, Utility shall notify Applicant in writing of the results of Initial Review within fifteen (15) Business Days following validation of an Interconnection Request.
- For all Interconnection Requests that pass Initial Review and do not require Interconnection Facilities or Distribution Upgrades, Utility shall provide Applicant with a Generator Interconnection Agreement within fifteen (15) Business Days of providing notice of Initial Review results. For Interconnection Requests that pass Initial Review but do require Interconnection Facilities or Distribution Upgrades, within fifteen (15) Business Days of providing notice of Initial Review results, Distribution Provider shall provide Applicant with a non-binding cost estimate of the Interconnection Facilities or Distribution Upgrades.
- For Interconnection Requests that fail Initial Review, Utility shall provide the technical reason, data and analysis supporting the Initial Review results in writing and provide Applicant the option to either attend an "Initial Review Results" meeting or proceed directly to Supplemental Review.

○ Supplemental Review

- If Applicant requests Supplemental Review and submits a nonrefundable Supplemental Review fee, if required, Utility shall complete Supplemental Review within twenty (20) Business Days, absent extraordinary circumstances, following authorization and receipt of the fee. Supplemental Review determines if (i) the Generating Facility qualifies for Fast Track Interconnection, or (ii) the Generating Facility requires Detailed Study.

○ Detailed Study

- Absent extraordinary circumstances, Utility shall complete and issue a final Interconnection System Impact Study and Facilities Review report within sixty (60) Business Days after the execution of a Detailed Study Agreement.

○ Permission to Operate

- For Level 1 and 2 Generating Facilities with a capacity of 1 MW or smaller, Utility approval for Interconnection (i.e., Permission to Operate) shall normally be processed not later than thirty (30) Business Days following Distribution Provider's receipt of:
    - a completed Net Energy Metering Interconnection Request including all supporting documents and required payments;
    - a completed signed Net Energy Metering Generator Interconnection Agreement; and
    - evidence of Applicant's final electric inspection clearance from the Governmental Authority having jurisdiction over the Generating Facility. If the 30-day period cannot be met, Utility shall notify Applicant and the Commission of the reason for the inability to process the Interconnection Request and the expected completion date.

PROPOSAL C-2: APPLICATION TIMELINES (UTILITY GROUP)

○ Completeness Review

- Utility shall provide a first written notification to the Interconnection Customer within ten (10) Business Days of receipt of the Interconnection Request, which notice shall state whether the Interconnection Request is deemed complete and valid. If the Application is incomplete, the Utility shall provide the Applicant with a list of all information that the Applicant must provide to complete the Application. The Applicant must provide the requested information within ten (10) Business Days, or the Application will be deemed withdrawn.

○ Initial Review

- Upon receipt of a complete and valid Interconnection Request, Utility shall perform Initial Review if the Generating Facility qualifies for the Fast Track process. The Initial Review determines if (i) the Generating Facility may be interconnected safely and reliably, or (ii) the Generating Facility requires a Supplemental Review. Absent extraordinary circumstances, Utility shall notify Applicant in writing of the results of Initial Review within fifteen (15) Business Days following validation of an Interconnection Request.

- For all Interconnection Requests that pass Initial Review and do not require Interconnection Facilities or Distribution Upgrades, Utility shall provide Applicant with a Small Generator Interconnection Agreement within fifteen (15) Business Days of providing notice of Initial Review results. For Interconnection Requests that fail Initial Review but the Distribution Provider determines the interconnection request can be approved with Minor Modifications, Distribution Provider shall provide Applicant with a non-binding cost estimate of the Minor Modifications and a Small Generator Interconnection Agreement within fifteen (15) Business Days of providing notice of Initial Review results.

- For Interconnection Requests that fail Initial Review, Utility shall provide within tem (10) days[16] the technical reason, data and analysis supporting the Initial Review results in writing and provide Applicant the option to either attend a "Customer Options" meeting or proceed directly to Supplemental Review. The Applicant must notify the Utility of its selection within ten (10) Business Days or the Application will be deemed withdrawn.

○ Supplemental Review

[16] Confirmed as 10 days by EPE on September 30.

- If Applicant requests Supplemental Review and submits a nonrefundable Supplemental Review fee, if required, Utility shall complete Supplemental Review within thirty (30) Business Days, absent extraordinary circumstances, following authorization and receipt of the fee. Supplemental Review determines if (i) the Generating Facility may be interconnected safely and reliably, or (ii) the Generating Facility requires Detailed Study.

○ Detailed Study Process

- Utility shall complete and issue a final Interconnection System Impact Study and Facilities Review report within sixty (60) Business Days after the execution of a Detailed Study Agreement.
- If the Utility determines the Application cannot be approved without evaluation under the Detailed Study Process, at the time the Utility notifies the Applicant of either the Initial Review or Supplemental Review results, the Utility shall provide the Applicant the option of proceeding to Detailed Study or of participating in Scoping Meeting, The Applicant shall notify the Utility in writing that it requests a scoping meeting or that it would like to proceed to Detailed Study within fifteen (15) Business Days of the Utility's notification, or the Application shall be deemed withdrawn. If the Applicant requests a Scoping Meeting, the Utility shall offer to convene a meeting at a mutually agreeable time within ten (10) Business Days of the Applicant's request. The scoping meeting may be omitted by mutual agreement.

○ System Impact Study

- The utility shall provide the Interconnection Customer, no later than five (5) Business Days after the scoping meeting or five (5) Business Days after the Interconnection Request is deemed complete or after the final step in the Fast Track review process if scoping meeting is waived, a system impact study agreement including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.
- In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within thirty (30) Business Days.
- A distribution system impact study shall be completed, and the results transmitted to the Interconnection Customer within thirty (30) Business Days after the execution of a system impact study agreement. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within forty-five (45) Business Days after the execution of a system impact study agreement, or in accordance with the Utility or Area Electric Power System queuing procedures.

○ Facilities Study

- The utility shall provide the Interconnection Customer, no later than five (5) Business Days after the completion of a system impact study, a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study.
- In order to remain under consideration for interconnection, or, as appropriate, in the Transmission Provider's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within thirty (30) Business Days.
- In cases where Upgrades are required, the facilities study must be completed within forty-five (45) Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within thirty (30) Business Days.
- Upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the Transmission Provider shall

provide the Interconnection Customer an executable interconnection agreement within five (5) Business Days.

- Interconnection Agreement

  - After receiving an interconnection agreement from the Utility, the Interconnection Customer shall have thirty (30) Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement. If the Interconnection Customer does not sign the interconnection agreement within thirty (30) Business Days, the Interconnection Request shall be deemed withdrawn. After the interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

- Permission to Operate

  - For Level 1 and 2 Generating Facilities, Utility approval for Interconnection (i.e. Permission to Operate) shall normally be processed not later than thirty (30) Business Days following Distribution Provider's receipt of:

    1. a completed Net Energy Metering Interconnection Request including all supporting documents and required payments.
    2. a completed signed Net Energy Metering Generator Interconnection Agreement; and
    3. evidence of Applicant's final electric inspection clearance from the Governmental Authority having jurisdiction over the Generating Facility. If the 30-day period cannot be met, Utility shall notify Applicant and the Commission of the reason for the inability to process the Interconnection Request and the expected completion date.

PROPOSAL C-2.1: APPLICATION TIMELINES (SPS REVISION PROPOSAL)

Facilitator's note: *Although Proposal C-2 is characterized as a Utility Group proposal, SPS in its comments stated that some of its positions were not reflected. SPS requested the following modifications to reflect its positions:*

"The Utility proposal for Interconnection Timelines was a modified version of the Industry Proposal to be more aligned with the timelines illustrated in FERC Order 792 referenced in Annex K. It is the Utilities' preference to use the timelines directly from the FERC SGIP model as a broad consensus and provide consistency between jurisdictions. These represent the maximum timelines considering a wide range of DER technology."

"Prior to a DER system's initial interconnection or operation in parallel with the Area EPS [Electric Power System], the Area EPS Operator may require verification and testing of the DER interconnection. For DER systems utilizing certified inverters, which meet the IEEE 1547 interconnection requirements, the testing shall be to confirm the proper installation and configuration of the equipment. The applicable DER evaluation, commissioning tests and verifications, shall be performed per IEEE 1547, IEEE 1547.1, and Area EPS Operator's technical requirements. If the witness test is not satisfactory, the Area EPS Operator has the right to disconnect the DER. The Interconnection Customer has no right to operate in parallel, except for optional testing not to exceed two hours, until permission to operate is granted by the Area EPS Operator."

Additionally, SPS recommended "the option for the Utility to perform a Facilities Study prior to providing the Interconnection Agreement to determine the cost estimates for the Interconnection Facilities and required Distribution Upgrades."

Finally, SPS requested the following language: "If the Interconnection Customer does not sign the interconnection agreement and submit payment for the required system upgrades within 30 Business Days, the Interconnection Request shall be deemed withdrawn."

Facilitator's note: In the Detailed Study section, PNM stated it preferred six (6) months to conduct the study, not 60 days. On Sept. 22, 2021, PNM proposed the following alternative timelines: *Completeness Review (15 business days); Initial Review (15 business days); Supplemental Review (80 business days divided up between Planning Group & Protection Group); and Full Detail Study (120 business days divided up between Planning Group & Protection Group).*

3.4 Cost Allocation Options

The existing Interconnection Rule specifies:

17.9.568.14 GENERAL PROVISIONS APPLICABLE TO INTERCONNECTION CUSTOMERS:

A. The cost of utility system modifications required pursuant to the fast track process or the full interconnection study process shall be borne by the interconnection customer unless otherwise agreed by the parties.

The Cost Allocations Options Subgroup was formed to explore potential alternatives to the traditional "triggering cost causer pays" approach to funding the costs of upgrading the utility distribution network in order to enable the interconnection of distributed generation (DG) resources. Recent experience on other "high-DG" jurisdictions has demonstrated that adherence to that principle results in significant challenges to the development of a healthy, sustained DG industry and fails to recognize the benefits that DER bring to the electric grid.

The Subgroup's work is informed both by recent (and in many cases ongoing) proceedings in several of those high-DER states and by New Mexico's recent legislation including the Energy Transition Act (SB 489 - 2019) and Grid Modernization Act (HB 233 - 2020).

All of these proposals, or options, are non-consensus items, intended to inform future Commission actions on specific upgrade project requests. The output of the Cost Allocation Subgroup was not subject to any attempt to reach consensus in the larger Working Group. The goal was to provide the Commission with a variety of potential solutions and identify general Pros and Cons for them. In addition, the section identifies several project types that might trigger the need for system upgrades and that appear to be likely candidates for alternative cost-sharing treatment. A table indicates which parties generally see a value in this approach for the corresponding project type.

As a generalized statement, SPS commented: *"If it is determined that upgrades are needed for system reliability, then some cost sharing can be appropriate; however, if the costs are incurred only to connect a generator, and would not have otherwise been incurred, then SPS believes there should be no cost sharing as a generator cannot demonstrate societal benefits."*

The discussion below is a summary of the more detailed discussion report found in Annex H.

COST ALLOCATION PRINCIPLE STATEMENT AND OPTIONS

The cost allocations Subgroup of the Working Group developed the following statement of principle:

The ideal cost allocation solution should promote the cost-effective interconnection of distributed generation in support of New Mexico's Grid Modernization Roadmap, decarbonization goals, economic development and resiliency, while facilitating efficient utilization of existing available capacity and equitably allocating the costs of necessary upgrades to all beneficiaries.

SPS asked to add this statement:

> *"Cost Allocation for DER integration should not cause deferral of reliability improvement projects as budgeted and planned by the Utility."*

Additionally, Utilities argued that cost-sharing arrangements for Community Solar projects may violate statutory prohibitions against cross-subsidization. However, the Commission has not yet established any policies in this matter.

The Subgroup explored the following alternatives, or options:

- **#1**: Retroactive Cost Sharing between all interconnecting DG facilities.
- **#2:** Prospective, Location-Specific Cost Sharing between all interconnecting DG facilities.
- **#3** Multi-Beneficiary Cost Sharing (MBCS) among not only interconnecting projects but also society at large.
- **#4:** Rate-Basing the costs of interconnection to the point of common coupling.
- **#5:** Grid Modernization Tariff/Rider Solution.
- **#6:** Network Upgrade/System Enhancement Credit
- **#7:** Class-Based Rider for BTM DER Customers

PROPOSAL DISCUSSION

Option #1: *Retroactive Cost Sharing between all interconnecting DG facilities.*

Require triggering projects to pay for the costs of interconnection but provide them with "true-up" payments collected from subsequently interconnected facilities taking advantage of the capacity created by the upgrades their facility triggered. SPS suggested that this option could also include the concept of cost sharing with beneficiaries of the upgrade in the immediate area. However, the difficulty with doing that is determining who actually benefits from the upgrade.

Supported by: SPS
Opposed by: CCSA, SEIA, REIA
Uncommitted: PNM

There have been several examples of this type of cost sharing implemented over the past several years, including in New York, Massachusetts and Maine.

Several jurisdictions have experienced issues with DG projects withdrawing due to being assessed interconnection costs which are orders of magnitude higher than those assessed to virtually identical projects due to the exhaustion of available capacity in a given area initially sought to solve the problem, namely: sharing the costs among the triggering project and subsequent DG facilities.

<u>Pros:</u>

- Represents an equitable solution while still limiting the upgrade costs to generation facilities
- Similar to methods currently used and easy to administer
- Makes economics of smaller DG facilities work
- Would not result in rate increases

<u>Cons:</u>

- Fails to address the lack of financial incentive for the utilities to interconnect
- Experience in other jurisdictions has shown this to not be a viable solution

- Triggering projects' investors cannot count on subsequent projects coming along to share in the cost and/or are unable to carry the costs of interconnection until cost sharing "true-ups" arrive
- Projects remained stalled or withdrawn in high-DER jurisdictions
- The initial interconnection facility would still bear the up-front costs
- It may be difficult for the utility to administer the true-up payments

Option #2: *Prospective Location-Specific Cost Sharing between all interconnecting DG facilities ("Cost Sharing 2.0").*

Direct utilities to determine the costs of making a system upgrade and calculating a "per kW" cost for the upgrades for a feeder or other sub-unit of the distribution network, which will be assessed to each DG facility interconnecting to that portion of the network based upon their nameplate capacity. The portions of the network targeted for upgrades may be identified either by utilities' analyses of future expansion needs or by "the market" (i.e., pending requests for interconnection).

Supported by: PNM
Opposed by: CCSA, SEIA, REIA
Uncommitted: SPS

There was discussion around current debates on Cost Allocation in jurisdictions such as New York, which saw little to no uptake on Retroactive Cost Sharing and which is seeking to develop a "Cost Sharing 2.0" mechanism. In Maine, Central Maine Power is seeking to emulate what Green Mountain Power did in Vermont to apportion costs for a near-system-wide Ground Fault Overvoltage issue.

<u>Pros:</u>

- Provides certainty to developers of DG systems that their interconnection costs will be manageable and gives them the security they need to move forward with their projects
- Is not contingent upon subsequent sharing projects in terms of timing or certainty
- Payment must be made before construction begins

<u>Cons:</u>

- While this will enable projects to move forward in some areas, as markets mature the necessary system upgrades to interconnect DG are becoming increasingly expensive
- Even fully equitably shared costs are beyond the ability of DG projects to bear
- These mechanisms create a substantial administrative burden for utilities
- The costs and time of study and re-study as projects enter and exit the queue for a cost-shared feeder or substation are substantial
- The costs and time of calculating and re-calculating pro-rata shares for interconnecting projects are substantial
- There are challenges around the utility holding and disbursing funds for and among projects
- This option spreads costs to every project in the queue, despite their position in the queue. For example, the first few projects in the queue may not cause a need for an upgrade; however, those projects would be required to share the cost of the upgrade caused by a project later in the queue.

Option #3: *Multi-Beneficiary Cost Sharing among not only interconnecting projects but also society at large.*

Recognizing that societal benefits may derive to support policy goals such as Beneficial Electrification and GHG emissions reductions in electricity generation, apportion some of the costs of upgrading the grid to support DG to the utility's ratepayers, with the remaining costs borne by the interconnecting projects. The cost-sharing split between the interconnecting projects and the system may be based on objective criteria (e.g., type of network improvement or type of generator) or policy.

Supported by: CCSA, SEIA, REIA, PNM
Opposed by: SPS, EPE

A number of states, including Massachusetts and California, have been recognizing that even a more sophisticated Cost Sharing mechanism which allocates interconnection upgrade costs to all beneficiaries of the additional capacity, including participating and non-participating customers, developers and others. Key to this proposal is putting a value on how upgraded interconnection of DG contributes to such policies as GHG emissions reduction or clean energy portfolio goals. Such benefits may include:

- Reduced need for transmission & distribution infrastructure
- Reduced need for new utility-scale generation
- Increased resiliency against weather-related disruptions
- Increased reliability through voltage support, reactive power and other benefits of a distributed grid

<u>Pros:</u>

- Solutions such as these recognize the economic and societal benefits of enabling the interconnection of DER
- In the context of various states' GHG reduction mandates, it is appropriate for society at large to contribute to the upgrade of the grid
- Robust solar and storage deployment promotes grid resiliency and reliability, lowering costs and providing quantifiable benefits that can be socialized among all impacted ratepayers
- Ratepayers are also voters who have elected legislatures that have passed statutes to address climate change

<u>Cons:</u>

- This policy could lead to subsidization issues as it does not clearly identify up front who are the beneficiaries of the interconnection and will require customers to pay for the interconnection of projects, even if they do not participate in the project.
- If it is determined that upgrades are needed for system reliability, then some cost sharing can be appropriate; however, if the costs are incurred only to connect a generator, and would not have otherwise been incurred, then there should be no cost sharing.

Option #4: *Rate-Basing the costs of interconnection to the point of common coupling.*

Next evolutionary step beyond MBCS, expanding the portion of interconnection costs recovered in the utility's rate base to include all upgrades on the utilities' side of the point of interconnection (i.e., for a small generator interconnecting at the customer's meter, all upgrade costs will be rate based). Some stakeholders argue that because there are broader public policy benefits to the interconnection of DG, the Distribution System should follow the example of the bulk system and consider rate basing the costs of interconnection to the point of common coupling.

Supported by: CCSA, SEIA, REIA
Opposed by: EPE, SPS
Uncommitted: PNM

Pros:

- Dominant practice in European markets, helping to expand decarbonized DER
- A truly bi-directional grid will be necessary to support decarbonization and beneficial electrification of buildings and transport
- It is unreasonable to expect that the costs of system upgrades beyond the point of common coupling be borne by DG projects
- Provides an incentive for the utilities to allocate limited resources to the work necessary to interconnect DG facilities
- Ensures that the costs are controlled through rate case oversight
- Residential or commercial customers desiring to install DG are unable to select the location in the system for their interconnection, this reduces the cost burden.

Cons:

- General objections to this proposal focus on ratepayer impact
- This could lead to inefficient location of interconnection projects if the generator does not bear the cost of interconnection
- Utilities may not see rate-case decisions as a positive

Option #5: *Grid Modernization Tariff/Rider Solution*

Utilities may submit grid modernization tariffs to the NMPRC which would define the terms and procedures for review of applications for approval of grid modernization projects, including distribution system upgrades needed to interconnect behind the meter generation. The NMPRC would review applications for consistency with a utility's filed tariff and the grid modernization statute, Section 62-8-13. If an application is approved, the utility would collect the cost of the project from all users of the distribution system consistent with the grid modernization statute.

There was discussion that this proposal essentially represents another version of MBCS (Proposal 1-c), but there was a desire to keep it distinct in this initiative as it is the only proposal that is explicitly authorized by the Public Utility Act.

Supported by: PNM, REIA
Opposed by: SPS

PNM proposed that utilities be allowed to file a Grid Modernization Tariff ("Tariff") pursuant to Rule 210 that specifies the terms and conditions of the utility's proposed cost recovery of grid modernization projects, including upgrades to feeders and other facilities required to interconnect generation facilities. Primary advantage of pursuing distribution system improvements through an application under Grid Modernization Act is that the Act provides a framework for the deployment of other grid improvements that will be beneficial as the grid evolves at the distribution level away from one-directional system.

Pros:

- Grounds the funding of system upgrades in NM's Grid Modernization effort

- Reduced customer complaints
- Utility discretion over project socialization and opportunity for stakeholders to oppose or support a utility proposal
- Solutions such as these recognize the societal benefits of enabling the interconnection of DER
- Cost Allocation solution that is grounded in established NM law and policy

Cons:

- Represents a cost-recovery mechanism and should not be used as a reason to uplift the cost to customers who do not benefit from an interconnection
- May conflict with the Community Solar legislation that limits subsidization
- Would also lead to inefficient location of interconnection projects
- Completely ignores cost causation. While it ensures that utilities get full recovery, it does so at the expense of customers that have not caused those costs.
- This is a cost recovery solution rather than a cost-allocation proposal.

Option #6: *Network Upgrade/System Enhancement Credit*

When studying a new interconnection, utility customers and facilities in that area would also be analyzed for needed upgrades. If network upgrades are found to be a common benefit for the interconnecting facility and surrounding utility customers and facilities, costs can be shared between surrounding facilities and interconnecting project.

Supported by: SPS

There was a discussion of what is currently being done in the South West Power Pool, and SPS proposed a similar solution here wherein when studying a new interconnection, utility customers and facilities in that area would also be analyzed for needed upgrades. If network upgrades are found to be a common benefit for the interconnecting facility and surrounding utility customers and facilities, costs can be shared between surrounding facilities and interconnecting project.

Pros:

- Similar to policy being used in SWPP
- Hybrid approach that analyzes whether there is a broader customer benefit to network upgrades caused by interconnections and shares the cost if such benefits exist
- Can save developers money on interconnection if they connect to a part of the system that already needs upgrades
- Motivates developers to efficiently locate interconnections

Cons:

- None listed

Option #7: *Class-Based Rider for Behind the Meter DER Customers*

Annually updated Class-based rider or surcharge for behind the meter DER customers to fund system upgrades necessary to allow for the installation of residential and commercial behind the meter DER systems. The rider or surcharge shall not include customers without DER systems.

Supported by: EPE

Pros:

- None listed

Cons:

- None listed

SCENARIOS

Facilitator's note: The subgroup was asked to provide a table that illustrated how each option might apply to different types of interconnection projects, customer and/or program types. Below is a list of scenarios and the various parties' recommendations for the most appropriate solution for each. It is by no means definitive or fully representative of all parties but is offered as a potentially useful consideration.

- Large DG array (5-10 MW)
- Community Solar array (5 MW)
- 100% Low Income Community Solar array (5 MW)
- Smaller DG array (1-5 MW)
- Built Environment/Preferred Siting DG array
- Behind the Meter Commercial and Industrial/Municipal array
- Smaller Community Solar Array (<1MW)
- BTM C&I Rooftop/Carport
- Residential Rooftop (<=25kW)

The Subgroup participants did not all provide their preferred cost sharing solution for the below scenarios:

Table 2. Project Types and Cost Allocation Options

Scenario	Retroactive CS - Option #1	Prospective CS - Option #2	Multi-Beneficiary CS – Option #3	Rate Basing – Option #4	Grid Mod Tariff – Option #5	NE/SE Credit - Option #6	Class-Based Rider – Option #7
Large DG				CCSA/SEIA			
Community Solar			REIA CCSA/SEIA #2	CCSA/SEIA #1	CCSA/SEIA #3		
Low-Income Community Solar			REIA #2 CCSA/SEIA #2	CCSA/SEIA #1 REIA #1	CCSA/SEIA #3		
Smaller DG				REIA #2	REIA #1		
Preferred Sites under 1MW				REIA #2 CCSA/SEIA	REIA #1		
BTM C&I			REIA #2 CCSA/SEIA		REIA #1 EPE*		EPE
BTM Municipal				REIA #2 CCSA/SEIA	REIA #1		
BTM C&I Rooftop/Carport			REIA #2 CCSA/SEIA		REIA #1		
Residential Rooftop				REIA #2	REIA #1 EPE*		EPE

3.5 Dispute Resolution

PROPOSAL E: DISPUTE RESOLUTION

The Working Group reviewed dispute resolution methods from other states and agencies, as well as the existing New Mexico interconnection rule and manual. Reviewed were FERC 792 – SGIP (2013), IREC Model (2019), Colorado Interconnection Rules, Minnesota Distributed Energy Resource Interconnection Process, California Rule 21, and New York State Standardized Interconnection Requirements.

The resulting proposal was developed as a hybrid of these methods and is considered a consensus item.

Proposal

A) Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner.

B) In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute. The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to make decisions for the non-disputing Party with respect to the dispute.

C) Any disputes related to the results of a Feasibility Study, System Impact Study, or Facilities Study shall be identified and provided together to be reviewed in a single resolution effort.

D) If the dispute has not been resolved in eight (8) business days for timeline related disputes or twenty (20) business days for all other disputes after the receipt of the notice, the parties may, upon mutual agreement, seek resolution through the assistance of a dispute resolution service. The dispute resolution service will assist the parties in either resolving the dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or qualified technical expert(s)) to assist the parties in resolving their dispute. Each Party will be responsible for one-half of any costs paid to neutral third-parties.

E) For any technical disputes, both parties shall have a qualified technical representative present in the attempts to resolve the dispute.

F) If the dispute remains unresolved after 30 business days, either party may petition the Commission to handle the dispute as a formal complaint or may exercise whatever rights and remedies it may have in equity or law.

3.6 Utility Reporting Requirements

Facilitator's note: *The Utility Reporting Requirements Subgroup provided a modified version of the IREC model text after several presentations to the Working Group. During the August 16 and September 9 Working Group discussions, utilities affirmed that they did not agree with the subgroup proposal and provided an alternate set of reporting proposals.*

Additionally, SPS proposed a position statement to guide Commission determination of appropriate reporting requirements: *"Reporting should have a clear, defined purpose, be coordinated with existing timeline requirements so as to not create administrative burden, and have definition on when the reports are no longer useful and may be retired. Reporting on the minimum, maximum, or average time a given application takes to progress through the process and receive an Interconnection Agreement lacks context. Any given application can take several different paths through the process, such that the timeline data is not necessarily reflective of any potential issues or problems with the process."*

As the two proposals could not be reconciled, this is a non-consensus area that will require a Commission determination.

PROPOSAL F-1: UTILITY REPORTING REQUIREMENTS (SUBGROUP PROPOSAL)
Each Utility shall submit to the Commission two times per year and make available to the public on its website an interconnection report. The report shall contain information in the form shown below, including relevant totals for both the year and the most recent reporting period.

Reporting Requirements

Each Utility shall submit to the Commission and make available to the public on its website an interconnection report with the following information. The report shall contain information in the following areas, including relevant totals for both the year and the most recent reporting period.

1. Pre-Application Reports: This information will enable tracking the efficiency and time for processing of Pre-application requests and reports. Such tracking will provide transparency for the process and help identify areas that can be improved.

    a. Total number of reports requested
    b. Total number of reports in process
    c. Total number of reports issued
    d. Total number of requests withdrawn
    e. Median processing times from receipt of request to issuance of report
    f. Number of reports processed in more than the ten (10) or fifteen (15) days as called for in Section 3.2

2. Interconnection Applications: It is essential for continued integration of DER into the NM electrical grid to have efficient and timely processing of interconnection applications. Transparency and measuring of the process will best enable it to be optimized so that it benefits all stakeholders.

    a. Total number received, broken down by:
        i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)

ii. System size (e.g., <25 kW or less, 25 kW-1 MW, > 1 MW)

b. Level 1 Review Process

i. Total number of applications processed

ii. Median processing times from receipt of complete Application to provision of counter-signed Interconnection Agreement

c. Level 2 Review Process

i. Total number of applications that passed the screens in Section 3.8

ii. Total number of applications that failed the screens in Section 3.8[17]

iii. Median processing times from receipt of complete Application to issuance of Interconnection Agreement

d. Supplemental Review

i. Total number of applications that passed the screens in Section 3.8

ii. Total number of applications that failed the screens in Section 3.8

iii. Median processing times from receipt of complete Application to issuance of Interconnection Agreement

e. Level 3 Review Process

i. System Impact Studies

ii. Total number of System Impact Studies completed under Section 3.8

iii. Median processing times from receipt of signed Interconnection System Impact Study Agreement to provision of study results

iv. Identify who performed the study.

f. Facilities Studies

i. Total number of Facilities Studies completed under Section 3.8

ii. Median processing times from receipt of signed Interconnection Facilities Study Agreement to provision of study results

iii. Median processing times for projects undergoing the study process from receipt of complete Application to issuance of Interconnection Agreement

g. Construction: Number of projects where final construction milestone was not reached by time specified in the Interconnection Agreement. Identify the average level of accuracy between costs identified in the Interconnection Application and actual costs charged.

i. Number of Projects that achieved Commercial Operation, by:

i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)

ii. System size

[17] If the specific screens failed are not tracked in the public queue, or a queue is not published for smaller projects, then the utilities should be required to report on the number of projects that are failing each screen and in what size categories. Failure of specific screens is an important indication of whether penetrations are reaching high levels or whether other issues exist that may require a broader policy or technical solution.

PROPOSAL F-2: UTILITY REPORTING REQUIREMENTS (SPS PROPOSAL, JOINED BY EPE AND PNM)

For three years following implementation of the revised interconnection standards, utilities subject to the standards shall each file a report with the Commission on interconnections that occurred during the preceding calendar year. This report shall include, at a minimum:

- Facility capacity
  - DER type (technology);
- Date of application submittal;
- Date application deemed complete;
- Date and disposition at applicable milestones in the interconnection process:
  - Initial review,
  - Supplemental review,
  - System impact study,
  - Facilities study,
  - Interconnection agreement, and
  - Permission to operate;
- Final process track;
- Number of pre-application reports requested and processed;
- A narrative of how the process is working and where there is potential for improvement by the utility or interconnection applicants. [18]

[18] This reporting requirement recommendation: *"For facilities of greater than 20 kW, the variance between the cost estimate provided in the facilities study report and the actual cost of upgrades, including an explanation of variances that fall outside a +/-20% range"*, was deleted from the Utilities' proposal during report reviews in September.

3.7 IEEE 1547-2018 Adoption

PROPOSAL G: IEEE 1547-2018 ADOPTION

Proposal status: consensus, with proposed language alternative (below)

Capability for the following three grid support functions provided by IEEE 1547-2018 shall be required for all DER installed after December 31st, 2022.

1. Shall be capable of actively regulating voltage.

2. Shall be capable of frequency response. Frequency response is the capability to modulate power output as a function of frequency. Mandatory capability for Categories II and III under high-frequency conditions, mandatory for Categories II and III under low-frequency conditions, optional for Category I.

3. Shall ride-through abnormal voltage/frequency.

In addition, capability for a fourth grid support function shall be optional:

4. May provide inertial response. Inertial response is the capability for DERs to modulate active power in proportion to the rate of change of frequency.

While capabilities for functions (1) and (2) are mandatory, their utilization is at the discretion of the Area Electric Power System (EPS) Operator.

For function (3), when determining ride-through requirements, the Area EPS Operator shall specify which of abnormal operating performance Category I, Category II, or Category III performance is required. This may be subject to regulatory requirements that are outside the scope of this standard and may consider DER type, application purpose, future regional DER penetration, and the Area EPS characteristics.

The Area EPS Operator shall notify the DER owner of the need to modify ride-through settings. The request for setting modification shall not exceed one per year.

Not specified as part of this proposal, but still needing determination are:

- Ride-through settings for abnormal voltage/frequency and frequency response
- Settings for active voltage regulation

Facilitator's note: SPS in its comments suggested somewhat alternate language for this section or in the revised Interconnection Manual, although it does not appear to conflict with the Working Group consensus.

"The New Mexico Public Regulation Commission fully adopts IEEE 1547-2018[3]™, as corrected by IEEE 1547-2018[4]™ and as amended by IEEE Std 1547a-2020[5]™, (hereafter: IEEE 1547-2018™) for all DER interconnected to its distribution system after Dec 31st, 2022. All DER interconnecting after this date shall meet requirements as specified in IEEE 1547-2018™ and be tested, verified, or certified according to applicable standards." Prior to Dec 31st, 2022, IEEE Standard 1453 (2015) remains in effect as the applicable standard.

Additionally, to enable full implementation of IEEE 1547-2018™ within the interconnection process rules, industry advice may be required to determine any other minimal requirements needing to be defined for full adoption within the interconnection process rules. As indicated in EPRI's document titled Generic Technical Interconnection and Interoperability Requirements (TIIRs), August 2021, adoption by general reference can be accomplished by:

> *'General Reference: full adoption of IEEE 1547-2018 may be accomplished by general reference. This adoption method ensures full consistency and compliance with the standard and only entails that the Area EPS and/or AGIRs, as applicable, initiate the stakeholder process for the inherent decision points in IEEE 1547-2018 such as normal and abnormal performance categories assignment, any specification of functional settings that deviate from the default values, and communication protocol selection.'"*

3.8 Capacity Levels and Initial Review Screens

Proposal status: non-consensus[19]

Background

Both SGIP and IREC models provide for different capacity levels to streamline interconnection application screening. The goals of the different levels are to adopt best practices within the rules to avoid whenever possible Supplemental Review processes for applications on radial circuits, and to create efficient processes for customers and utility staff.

Participants of the Working Group considered numerous examples as proposed approaches for capacity levels and screens to determine what may align best with New Mexico. They were able to agree that:

- There should be no more than three levels for simplicity, and the levels should be consistent with broadly accepted industry norms for effectively and efficiently reviewing DER interconnections for safety and reliability
- Level 1 has fewer Initial Review screens
- Level 2 has all the Initial Review screens
- Level 3 should go straight to Supplemental Review or Detailed Study
- Circuit voltage and distance from substation should be taken into account for Level 2
- Level 1 upper bound does not impose or imply any changes on net metering policy in Rule 570
- Level 1 upper bound should allow for the addition of up to 15kW of behind-the-meter storage
- Many residential transformers are 25 kVA or smaller. Consequently, the size threshold of the Level 1 Screen will not impact or alleviate necessary transformer upgrades, and for some customers can result in the need for service conductor upgrades.

In comments, PNM pointed out that there had been not agreement reached on: the appropriate distance from a substation that should be taken into account for Level 2; whether to account for the total capacity from an energy storage system (ESS); or, whether to consider if ESS has taken energy from the grid or only the associated DG system. However, such ESS issues more appropriately pertain to the export capacity discussion.

The intention for Level 1 is to provide a streamlined and expedited Initial Review focused on the customer (secondary) infrastructure, coupled with a circuit-level aggregate generation capacity screen that alerts the need for engineering review, but does not require Supplemental Review.

For the Level 1 upper bound, while utilities' preference was to keep the Level 1 screen less than 10 kW, and while the SGIP model provides an upper bound of 10 kW for Level 1, the SGIP model was developed prior to widespread use of behind-the-meter storage, and was considered outdated in this respect. IREC provides an upper bound of 25 kW but participants recognized that a primary reason for potentially increasing the upper bound from 10 kW to 25 kW was due to the inclusion of storage, rather than to allow 25 kW of solar-only, so a compromise was reached that allows up to 25 kW total as long as any single-phase solar does not exceed 10 kW.

[19] Facilitator's note: At the very end of the advisory process, certain utilities declared that they did not agree to treat proposals H-1, H-2, and H-3 as consensus items. They did not provide alternative language for the proposals, except to revert to FERC SGIP model, and as noted for SPS comments included below.

Both SGIP and IREC models also provide different sets of screens depending on different capacity levels (or "tiers" or "lanes"). Both SGIP and IREC models, along with examples from other state jurisdictions, were considered in developing Proposals H-1, H-2 and H-3 on capacity levels and Initial Review screens and flowcharts for each level.

The current New Mexico Rule and Manual—issued in 2008—requires updates to be inclusive of new industry standards, technologies, and best practices. The current Manual is largely based on Federal Energy Regulatory Commission ("FERC") Order No. 2006, issued in 2005, which standardized small generator interconnection procedures ("SGIP") and agreements ("SGIA") with broad consensus and agreement in the industry. FERC issued an update to the SGIP model in 2014 with Order No. 792, which included a broad range of stakeholders, such as the Interstate Renewable Energy Council, who participated in its development. The FERC SGIP model has worked well for other states and utilities, and it is the model that the Utilities are most familiar with. The "tiered approach" or "multiple lane approach" to interconnection specified by the SGIP has been beneficial for both the Utilities and interconnection customers. This approach allows less-complex projects to quickly move through the interconnection process while allowing more time for detailed review of more complex projects.

The Working Group recognized that capacity levels and screens must also account appropriately for the capacity of generation and energy storage systems involving smart inverters and/or power control systems, when the Export Capacity and Ongoing Operating Capacity of such generation and/or energy storage is different than Nameplate Capacity. This is reflected in the non-export screen for both Level 1 and Level 2, and also in Proposal I-1 on non-exporting and limited-exporting systems. The Working Group recognized that since SGIP was drafted before energy storage and power control systems were commonplace, it doesn't address how to evaluate them. The IREC Model was updated (most recently in 2019) to offer an initial framework for review of energy storage systems seeking to connect to the distribution grid. Although this is an evolving space, IREC noted, the guidance was intended to begin to address the uniquely flexible and controllable nature of energy storage. Specifically, IREC added a description of screening for energy storage systems and other generation that is non-export, limited export, or otherwise managed by smart inverters and power control systems.[20]

Throughout, the Working Group recognized that regulations governing utility operations require technical screenings to be based on accepted good engineering practices, which include specific engineering calculations and actual system constraints determined through study when deemed necessary by the operating utility. Interconnection rule and manual changes should be based on accepted good engineering practices including construction capacity as opposed to feeder loading.

The proposals for capacity levels and screens were developed by two different groups during the Working Group, an industry group and a utilities group. Each group put forth its own proposals and commented on the other group's proposals, and through multiple iterations, the Working Group was able to arrive at the following proposals, along with positions of each group for those proposals or elements where consensus was not achieved.

PROPOSAL H-1 CAPACITY LEVELS

Proposal status: non-consensus

The interconnection screening process will proceed according to three different capacity levels, as defined by the generating facility's combined rated Nameplate Capacity. For the case of a generating facility that includes energy storage, the nameplate capacity is further elaborated in Proposal I on Non-Exporting and Limited-Exporting Systems.

[20] See IREC Model Interconnection Procedures, pgs. 16-17 and 26-28.

Level 1:

- 0-10 kW if single-phase solar-only
- 0-25 kW if solar <= 10 kW and storage <= 15 kW; or if three-phase solar-only

Level 2:

- Within SGIP Fast Track Eligibility Table for behind-the-meter generating facilities: always start with Initial Review (and go to Supplemental Review only if required by Initial Review screens)
- For front-of-the-meter generating facilities: go directly to Supplemental Review or Detailed Study

Level 3:

- Outside of Fast Track Eligibility Table: go directly to Detailed Study

SGIP Fast Track Eligibility Table for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline and ≤ 2.5 Electrical Circuit - Miles from Substation
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

Note on Fast Track Eligibility Table: The Fast Track Process is available to ail Interconnection Customers proposing to interconnect a Small Generating Facility with the Transmission Provider's Distribution System if the Small Generating Facility's capacity does not exceed the size limits identified in the table. Small Generating Facilities below these limits are eligible for Fast Track review. However. Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Initial Review screens or the Supplemental Review screens. Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection.

SPS also stated the following: "*The supplemental review eligibility table does not consider non-inverter based generation. SPS recommends to follow the FERC SGIP eligibility for non-inverter based generation and include, "All synchronous and induction facilities must be no larger than 2 MW AC to be eligible for the Fast Track Eligibility, regardless of location."*

"Non-exporting systems need sufficient margin between load and generation to avoid export or the use of a power control system certified to UL 1741 CRD for PCS[21] *utilizing the "Import Only Mode' or "No Exchange Mode", other methods of preventing export can be utilized such as reverse flow relays or control methods requiring more extensive reviews, often beyond screening timeframes, due to lack of certification. The evaluation of a non-exporting system requires greater consideration of the method utilized to limit export in addition to the fail-safe provisions within the method to determine how capacity needs to be evaluated. There*

[21] "UL 1741 CRD for PCS" means the Certification Requirement Decision for Power Control Systems for the standard titled " Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources " (March 8, 2019), Underwriters Laboratories Inc., 333 Pfingsten Road, Northbrook IL 60062-2096.

are similar considerations for limited export systems. As inadvertent export may occur, inclusion of power quality screens is required within the screening process."

PROPOSAL H-2 INITIAL REVIEW SCREENS FOR LEVEL 1

Proposal status: non-consensus

For Level 1, the following screens are part of Initial Review. If an application passes all screens, proceed to interconnection, otherwise proceed to Supplemental Review.

If an application does not pass either the secondary ratings or phase imbalance screens, first conduct a "minor modifications" review with the customer, in line with SGIP recommendations, to address any minor secondary-side (non-construction) modifications that may be required, and depending on the outcome of that review, either proceed with interconnection or proceed to Supplemental Review.

If an application on a network system does not pass the network system screen, or if the application on a network system is for a three-phase front-of-the-meter facility, then give the customer the option of skipping Supplemental Review and proceeding directly to Detailed Study. If an application on a network system does pass the network system screen, it does not need to pass any of the other screens.

Non-exporting system. If non-exporting system, pass if aggregate generation is less than 100% of peak load, and bypass both Aggregate Generation screen and Secondary Ratings screen (but still conduct all other screens).

Alternate language was proposed by SPS in comments, but there was no resolution achieved:

> ***"Non-exporting system.*** *If non-exporting system is not capable of inadvertent export, utilizes a protective element to prevent export or uses a certified control method that includes certified fail-safe provisions, it may bypass both Aggregate Generation screen and Secondary Ratings screen (but still conduct all other screens). When mutually agreed fail-safe provisions are not provided within a control method, at the utility's discretion, Aggregate Generation screen and Secondary Ratings screen may be evaluated using the maximum rated capacity of the capable of being exported with failure of the control method for limiting export."*

Secondary ratings. Pass if on shared secondary, aggregate generation, based on aggregate export capacity of connected customers on secondary is less than 80% of service transformer nameplate and less than 20kW.

Phase imbalance. Pass If proposed generation is single-phase and is to be connected to the center tap of a 240v service transformer, and if the imbalance between the two sides of the 240v service is less than 20% of the nameplate of the service transformer.

Power Quality. The proposed interconnection resource shall meet the rapid voltage change and flicker requirements of IEEE Standard 1453 (2015) and IEEE Standard 1547-2018, until January 1, 2022, or until such time new DERs applying for interconnection will comply with IEEE 1547- 2018 based on the appropriate test.

Network system. Pass if certified inverter and aggregation generation may not exceed the smaller of 50% of network's instantaneous minimum load or 50 kW; skip aggregate generation capacity, secondary ratings, and phase imbalance screens. For any network system, net metering and any export are not allowed.

No construction. Pass if no construction of facilities by the utility on its own system are required to accommodate the small generating facility.

PROPOSAL H-3 INITIAL REVIEW SCREENS FOR LEVEL 2

Proposal status: non-consensus

For Level 2, the following additional screens are part of Initial Review, in addition to those given in Proposal H-2 for Level 1. If an application passes all screens, proceed to interconnection, otherwise proceed to Supplemental Review.

Fault current. Pass if aggregate generation contributes less than 10% to the maximum fault current on the primary voltage level nearest to the PCC

Protection. Pass if protective devices (on aggregate generation) are less than 87.5% of the short-circuit interrupting capability

Configuration. Pass if compatible with the interconnection type

Network. Same as Level 1, except only pass if also passes fault current, protective devices, and configuration screens

PROPOSAL H-4 SCREEN FOR AGGREGATE GENERATION CAPACITY

Proposal status: non-consensus

The industry group and the utilities group each developed their own proposed screen for aggregate generation capacity. The utilities group cited the SGIP and IREC model criteria for up to 15% of circuit maximum load, and was willing to use circuit minimum load if that information was available, but said that minimum load data are not readily available for many circuits, although the extent of availability is still unknown. The industry group believed that if minimum load data were not available, that they could be estimated using temporary line recorders, and so the 15% maximum load criteria was not necessary at all.

The industry group also believed that hosting capacity information should be used if available, which is not included in this proposal but rather as Proposal I-1 Use of Hosting Capacity Information for Aggregate Generation Capacity Screen.

There was also a difference of position between the two groups on the definition of circuit minimum load. Non-consensus definitions of minimum load are provided in Proposal A-2.

It should be noted that the 15% of circuit maximum load criteria does not necessarily result in rejected applications, but may cause applications to proceed to Supplemental Review with greater expense and time.

Option 1 for Aggregate Generation Capacity Screen

Pass if aggregate generation is less than 100% of minimum actual or estimated gross daytime load. In the event SCADA and metering data are not available, distribution circuit line recorders shall be installed temporarily as required to estimate gross daytime minimum load or other estimation methods based on available data.

Option 2 for Aggregate Generation Capacity Screen

Pass if aggregate generation is less than 15% of annual peak load of the line section or less than 90% of minimum load of the line section (if such minimum load data are available).

<u>Position of SPS</u>

“The process for measuring minimum load data is an annual process, similar to that of measuring the peak load. It requires hourly data to be measured for a period of one year, then analyzed by an engineer to filter and scrub the data for errors and determine the minimum load. Load varies by the time of day, day of the week, and season of year, and it is not realistic to get an accurate measurement of annual minimum load on short notice or with a small dataset.

The FERC SGIP model uses a threshold of 10 kW for the simplified interconnection process; however, it still uses the same screens as the Fast Track initial review, or Level 2 screens in this report. The Industry’s indicated the justification for increasing that threshold is to be more flexible for non-exporting storage applications. However, despite being non-exporting those Facilities still contribute their full Nameplate rating to fault current. SPS is concerned that not including the non-capacity related screens (fault current and protection screens) for Level 1 projects it could create holes in the process allowing interconnections that are not safe or reliable.

SPS proposes to keep the current screening process where the Application proceeds straight to supplemental after the failure of any screen, which was not discussed in detail during the Working Group or in this report. This creates efficiencies for the Utility if certain datasets are more readily available than others, so that Level 1 or Level 2 projects that would fail the first screen could proceed to supplemental review faster than if the other screens are performed before proceeding to supplemental review. In aggregate, for upwards of 100 initial reviews per week, it can amount to significant time savings.

SPS disagrees with the Industry group’s position that the “Supplemental Review should only be for large projects”. Overvoltage conditions, which are common for feeders with high levels of penetration and for customers with long or small secondary wire, are not screened for in the initial reviews. Initial reviews are intended to fast track projects that are likely to interconnect safely and reliably. If overvoltage conditions are possible, a supplemental review should be performed to ensure the generating facility can be interconnected safely, reliably, and within ANSI voltage requirements. Customers experiencing high voltages or voltage fluctuations may have a poor customer experience.”

<u>Positions of Industry Group</u>

- *“We believe customer experience should be addressed, which is not a priority within the current SGIP process. Given the success of solar adoption in NM, Supplemental Review should be used only for large projects when truly needed.*
- *Reliance on a 15% of line capacity as a screening threshold for more detailed studies is perceived as a barrier to interconnection for many smaller projects. We need to develop and document an accurate reflection of required process improvements to enable customer adoption and advance interconnection processes.*
- *The industry group believes there needs to be a shift in interconnection in the medium-term and long-term towards hosting-capacity-based planning processes given NM’s circuit “closures”, and this is outlined in Proposals J-1, J-2, J-5, and J-6. For the short term, Option 1 utilizes a specific threshold of 90% of actual or estimated gross daytime minimum load. In the event SCADA data is not available distribution circuit line recorders shall be installed temporarily as required to estimate gross daytime minimum load.*

- *The industry group believes that working in conjunction with hosting capacity upgrade plans and cost allocation processes, as thresholds are triggered (i.e., 90% of estimated gross daytime minimum load), a study should be conducted to determine an appropriate upgrade plan with consideration for future customer adoption in development of prorated share to completed required hosting capacity upgrades.*
- *Modeling IREC and California procedures is directly responsive to the Commission's Initial Order in this case, in which Commission specifically requested comments on (A) updates to SGIP; (B) updated requirements for the use of advanced inverter and distributed generation devices allowed under IEE 1547-2018 and UL 1741-SB; and (C) possible inclusion of screening methodologies that would remove initial barriers to behind the meter small scale generation and storage. See Initial Order Establishing and providing Notice of Inquiry and Requesting Written Public Comments, Decretal Paragraphs A-C, Case No. 20-00171-UT, January 13, 2021."*

Additional detailed comments regarding this proposal are included in Annex J.

3.9 Non-Export, Limited Export, and Inadvertent Export

Proposal Status: non-consensus[22]

Background

As energy storage systems become more prevalent in New Mexico, it is imperative that the interconnection process be updated to include these technologies. Interconnection customers can have good reasons for choosing non-export systems. For example, they may achieve greater bill savings by using on-site energy directly to power on-site load. If the system includes storage, customers can benefit from time-of-use periods and rates, and store on-site generation and/or power purchased during periods of low rates, for use during periods with higher rates.

In some circumstances, non-export systems could enable a customer to choose to interconnect within existing grid capacity and not incur the cost or delay of distribution system upgrades, at a location where interconnection of an exporting system might otherwise require distribution system upgrades.

However, even though a customer may choose to operate as non-export, utilities must determine whether a system has the potential to export and, if so, utilities must determine the magnitude of potential safety and reliability impacts to the grid.

The ability to store energy for use at a future time offers many benefits, including demand charge management, energy time shifting, flexible ramping and frequency regulation, and potential for reduced interconnection upgrade costs.

One of the primary benefits for Behind the Meter (BTM) storage is the ability to store energy produced from a BTM solar system when more energy is being produced than is being consumed at the location, typically during the middle of the day, and instead utilize this energy in the late afternoon/early evening when demand spikes and solar production is low or non-existent. This contributes to a more functional grid by reducing how much bulk power is required to serve the distribution grid and reduces the need to overbuild peaking capacity.

Another benefit is the resilience that is provided by BTM storage. During a grid outage, a BTM storage device can provide power, enabling the use of many critical, and even life-saving applications. The need for this technology was demonstrated in the recent power outages in Texas, where BTM solar combined with storage could have mitigated many of the adverse effects of the outage.

The Working Group considered examples of rules from other jurisdictions for non-exporting and limited-exporting systems, as well as inadvertent export. Other jurisdictions examined included Arizona, California, Colorado, Hawaii, Minnesota, Nevada, and New York. Proposals I-1 and I-2 were developed with consideration for the treatment in these other jurisdictions, as well as the IREC model.

[22] Facilitator's note: At the very end of the advisory process, certain utilities declared that they did not agree to treat these as consensus issues. They did not provide alternative language or proposals. It will be left to the Commission's rulemaking process to determine whether these issues can be included in a revised rule or left to further discussion in Phase II.

PROPOSAL I-1: NON-EXPORTING AND LIMITED-EXPORTING SYSTEMS

When a storage system is installed in conjunction with a generation system, both may be reviewed at the same time and be included in one Interconnection Agreement. This applies to an interconnection application that includes both a generation system and storage, or to an application which is adding a storage system to an already-existing generation system.

The interconnection review level (Level 1 – Level 3) will be based upon the combination of the onsite generation rated Nameplate Capacity and the storage continuous output Nameplate Capacity.

Interconnection requests are reviewed based on the combined nameplate ratings of systems accounting for their export capacity and energy storage operating mode. For purposes of certain Initial Review and Supplemental Review screens, only the capacity that is designed to inject electricity to the utility's distribution or transmission system, other than inadvertent exports and fault contribution, will be used.

This Ongoing Operation Capacity shall be based upon the lessor of:

(1) The combined kWac nameplate ratings of the sources that can be simultaneously supplied to the grid, such as two inverters; or

(2) If the contribution of the generation and energy storage to the total contribution is limited by programing or by some other mutually agreeable on-site limiting element, the Ongoing Operation Capacity as set by the power control system Operating Mode, considering the operational differences of load offset and export, can be used for certain interconnection review screens, provided that: (1) the power control system passed testing that conforms to UL 1741 CRD; (2) the power control system has an open-loop response time of no more than 2 seconds as provided in the control systems specification data-sheets, and the power control system is required to reduce Export Power to the Ongoing Operation Capacity limit within 2 seconds of exceeding the Ongoing Operation Capacity limit; and (3) UL 1741 certified and/or UL 1741 SA listed grid-support non-islanding inverters are used.[23]

Failure of hardware or software system(s) intended to limit generation and energy storage export capacity shall cause the energy storage system or power control system to enter a safe operating state. An energy storage system combined with a UL 1741 certified power control system shall be considered capable of entering a safe operating state upon failure of hardware or software system(s). When mutually agreed fail-safe provisions are not provided, at the utility's discretion, the interconnection request may be evaluated using the maximum rated Nameplate Capacity of the energy storage system.

A storage system may be located on the same side of a production meter as a generating facility when a production meter is required by these rules provided that the storage system is either non-exporting at the service meter or is charged exclusively by the generating facility and only the production recorded by the production meter will be eligible for incentives.

Any change in the use case of an existing storage system, including but not limited to changes in the operating mode, configuration, or programming, or changes to the maximum export value as set by the power control system Operating Mode is required to have an interconnection review in a new interconnection application.

[23] The California Rule 21 process provides for 2 seconds of response time for non-export and limited export capacity designations, and up to 10 seconds for inadvertent export.

Associated Definitions

Energy storage system means any commercially available, customer-sited system or utility-sited system, including batteries and batteries paired with on-site generation, that does not generate energy, that is capable of retaining, storing, and delivering electrical energy by chemical, thermal, mechanical, or other means.

Export capacity means the amount of alternating current (AC) electrical energy that an interconnection resource is intended to transfer to the utility's system across the point of interconnection.

Non-exporting system means an interconnection resource that is designed so that it does not intentionally transfer electrical energy to the utility's distribution or transmission system across the point of common coupling. Such systems may be used to supply part or all of a customer's load continuously or during an outage. A system can be non-exporting by virtue of inverter programing or by some other on-site limiting element. Non-exporting systems may or may not produce inadvertent exports as defined in paragraph (g) of this rule.

Inadvertent export means the potential condition in which a normally non-exporting or limited-exporting DER experiences a momentary export that does not exceed limitations specified in Proposal I-2.

Operating mode means the mode of DER operational characteristics that determines the performance during normal and abnormal conditions. For example, an operating mode such as "export only," "import only," and "no exchange."

PROPOSAL I-2: INADVERTENT EXPORT OF GENERATING AND ENERGY STORAGE SYSTEMS

Generating and energy storage systems may inadvertently export, so long as the magnitude of Export Power during inadvertent export remains less than the total DER facility Nameplate Rating (kWac-gross), and the time duration of Export Power during inadvertent export from the customer's generating and energy storage systems is between 2 and 10 seconds as technology allows. The utility should exercise its engineering judgement to determine whether uncontrolled inadvertent export lasting between 2 to 10 seconds would cause equipment overload or other negative system impacts. Inadvertent export events shall not exceed thermal, service voltage, power quality or network limits defined within Commission rules or interconnection requirements.
Any amount of export of real power across the point of interconnection lasting longer than this 2-to-10-second time duration for any single event shall result in a cease-to-energize of the customer's energy sources within 2 seconds of exceeding the time duration. Where applicable, any failure of the Customer's power control system for 2 seconds or more shall cause the customer's energy sources to enter a non-export operational mode where no energy will be inadvertently exported to the grid.

Equipment considered part of the power control system includes but is not limited to an internal transfer relay, energy management system, or other customer facility hardware or software system(s) intended to prevent the reverse power flow that passed testing in conformance with the UL 1741 CRD for power control systems. The proposed Generating Facility must utilize only UL 1741 certified and/or UL 1741 SA listed grid-support inverters.

During Supplemental Review the applicant shall be required to identify, within 15 days, the frequency of inadvertent export, the real power level in watts of inadvertent export and the time duration of inadvertent export. if distribution upgrades are identified then the safety and reliability review should recognize power control parameters taking into account local feeder conditions; and only the largest facility in the line section would be used for aggregate evaluation for subsequent interconnection requests.

3.10 Prospective Paths to Hosting Capacity Information and Mapping

Proposal status: non-consensus

Background

Defining and developing hosting capacity information, including mapping of that information, can provide many benefits:

- Improve utility efficiency, planning and interconnection by upgrading the feeder to accommodate many more customers through smart planning decisions anticipating the future needs of the network
- Provide a pathway for customers to interconnect that cannot today due to high study costs and inability to pay high cost for the circuit upgrades.
- Provide a streamlined pathway for Level 1 customers to interconnect without being subject to participating in longer interconnection queues with larger projects while maximizing the capacity available to all interconnecting customers.

Longer term mapping will enable sharing of information, which should lead to bring cost efficiency. Having capacity information available to developers and Engineering Procurement & Construction companies will enable better use of resources and be more cost effective. Rethinking how the industry deals with cost causation is important as it will provide more stability and allow for better decision making on allocation of resources.

However, Working Group participants diverged on venue, process, and outcomes for addressing hosting capacity information, and were not able to achieve consensus on any aspect of this issue. What follows are several non-consensus proposals.

PROPOSAL J-1: USE OF HOSTING CAPACITY INFORMATION FOR AGGREGATE GENERATION SCREEN

Proposal status: non-consensus

Supported by: REIA, Sunrun, CCSA and SEIA
Opposed by: SPS, EPE, PNM

Incorporate references to hosting capacity information into the Initial Review Screens for Level 1 and Level 2. For Level 1, If hosting capacity information is available for a given feeder, use that information to pass the screen rather than 100% of actual or estimated daytime minimum load. For Level 2, do the same as Level 1 but only pass if also the generator seasonal, monthly, daily, or hourly schedule limit DER capacity to operate within available hosting capacity.

In this Proposal J-1 as well as subsequent Proposals J-2, J-5, and J-6, The Industry Group believes that combining hosting capacity with interconnection is an appropriate use of the Interconnection Working Group, and believes the Working Group should tackle as many related issues as possible while so many stakeholders are engaged in the process. There is an overlap between hosting capacity and interconnection that makes the topics inseparable. The Public Regulation Commission may open additional rulemakings to cover other topics regarding technology and best practices to deal with such changes. Combining these topics now will promote efficiency and provide the Commission an opportunity to address these very related issues all together versus individually where the nuance overlaps could easily be missed. Grid modernization will demand further work in related areas of electrification that will be important opportunities for utilities and the Energy Transition.

We should be aiming to follow industry best practices. We have the advantage and opportunity of following the lead of multiple other states and learning from their experiences and lessons learned, rather than paving a new path blindly. In particular, being able to identify and address high penetration circuits will benefit all stakeholders, whether they are the utilities, developers or customers.

<u>Positions by utility group on Proposal J-1</u>

- Use of "available hosting capacity" is not feasible due to the volume of applications, the granularity of the Hosting Capacity Analysis, and the frequency of updates required for hosting capacity data. Hosting capacity data will not reflect secondary limitations, which is partly what the screens filter for. Colorado allows the use of new tools that accomplish the same screens or intent of the screens in the same amount of time. Recommend including that language. Smaller utilities will have more issues complying with it too.

PROPOSAL J-2: HOSTING CAPACITY POLICIES, STUDIES, AND RESERVE REQUIREMENTS

Proposal status: non-consensus

Supported by: REIA, Sunrun, CCSA and SEIA

Opposed by: SPS, EPE, PNM

It is important that screening processes be designed, when possible, to enable interconnections. Efficient Fast Track and expediting screening of applications will increase DER penetration and will provide for a more cost effective and stable grid.

Utilities shall establish hosting capacity policies subject to the following requirements: (1) Publish kW of available hosting capacity; utility shall report their closed circuits (no remaining hosting capacity), restricted circuits (only reserve hosting capacity available), and reserve hosting capacity in their hosting capacity reporting system. (2) Submit a hosting capacity upgrade plan for the Commission's review and approval, in order to open multiple closed or restricted circuits in the aggregate. (3) Have a procedure for calculating hosting capacity and perform a representative sample of hosting capacity calculation validation checks at least annually, or more frequently in areas experiencing significant growth or distributed energy resource penetration.

Utilities should also enable access to the underlying data, to enable the data to be integrated into mapping tools so it can be meshed with the following information (but not necessarily limited to): circuit voltage, circuit name, circuit rating, circuit phase, and percentage of load by rate class.

Also establish the following definitions: "closed circuit," "hosting capacity," "reserve hosting capacity," "hosting capacity reporting system," "hosting capacity upgrade plan", and "interconnection facility cost sharing."

With regards to defining limits and minimizing unnecessary upgrades, this can be viewed from a few perspectives with the emphasis on ensuring continued customer adoption through implementation of a hosting capacity reserve for Level 1 applications. These customers have paid for the existing infrastructure and are not in a position to pay for circuit upgrade costs individually based on current cost causation principles. Instead of being prescriptive on how hosting capacity should be done, it is more important to establish a procedure that encourages efficient utility processes, innovation, and savings.

Reserve 25% of currently available hosting capacity for future Level 1 projects in suburban, urban areas, adjusted in steps based on a per feeder basis, taking into account: the number and type of customers on the circuit, existing and forecasted load, as well as existing and forecasted adoption of Level 1 interconnection requests/projects to as low as 10% for rural feeders. The remaining 75% - 90% of available hosting capacity will be updated and posted monthly and available for all resources. In the event that the 75% - 90% of available hosting has been allocated to interconnection applicants, the utility will then perform initial hosting capacity upgrade plan sensitivity analysis to develop potential upgrade alternatives and cost estimates.

Subsequent non-Level 1 applications received on the circuit will undergo the interconnection review process and be offered a prorated cost sharing amount to facilitate the hosting capacity upgrade plan. Upon the initial facility accepting the cost share, the customer will receive a conditional approval date and the hosting capacity upgrade plan will be completed. All subsequent non-Level 1 customers interconnecting on this circuit will pay their prorated cost share of the upgrade. This process minimizes unnecessary upgrades in multiple ways by improving utility efficiency, planning and interconnection by upgrading the feeder to accommodate many more customers than the applicant through smart planning decisions anticipating the future needs of the network, and provides a pathway for customers to interconnect that cannot today due to high study costs and inability to pay high cost to upgrade closed circuits.

Finally, in conjunction with hosting capacity upgrade plans and cost allocation processes, as thresholds are triggered (i.e., 90% of estimated gross minimum daytime load, or insufficient hosting capacity beyond Level 1 reserve), a study shall be conducted to determine an appropriate upgrade plan with consideration for future customer adoption in development of prorated share to completed required hosting capacity upgrades.

Note on Proposal J-2 by Gridworks as discussion moderator: the utility group Proposal J-3 for a Separate Venue to Address Hosting Capacity means that utilities did not extensively discuss or respond to this Proposal J-2 on Hosting Capacity Policies, Studies, and Reserve Requirements. However, in some of their earlier comments, the utility group did provide some "proposed DER planning guidelines," which would seem to mirror the industry proposal for reserving 25% of hosting capacity. The utilities wrote: "Dedicated power producing generation facilities, such as a community solar garden, will be limited to 75% of the feeder's limiting element. This is to ensure that capacity is available for commercial and residential customers on the affected feeder who may want to add solar to serve their own load. This capacity for commercial and residential customers is 25% of the feeder's limiting element." Furthermore, PNM informed the Working Group that it already reserves 50% of the rating of the feeder for PV smaller than 1 MW. Thus, in future discussions, there may be scope for agreement related to this 75% / 25% split to reserve capacity for small systems.

PROPOSAL J-3: SEPARATE VENUE TO ADDRESS HOSTING CAPACITY

Proposal status: non-consensus

Supported by: SPS, EPE, PNM
Opposed by: REIA

Address the technical issues regarding hosting capacity outside of the interconnection rules.

The intention of the interconnection rules is to define the procedure for processing small generation interconnection applications. Defining limits to hosting capacity is outside of that scope. The interconnection process should define when those studies are needed, at what stage of the process they are performed, how long they should take, etc., and it should not be technically focused beyond what is required to reasonably screen interconnection requests. The hosting capacity data provided in maps is generally high-level information and does not have sufficient granularity and detail to be able to replace any part of the interconnection process, including the pre-application data requests. Pre-application data reports provide more granular information than a hosting capacity analysis and the costs are collected directly from the party requesting the information.

The utilities support an optional hosting capacity analysis to be used to guide developers to areas with the highest probability of success or as a method to streamline initial review screens, so long as confidential information remains confidential unless otherwise ordered by the commission. Willing participants would benefit from having a more efficient program, a more positive relationship with developers, and more experience with hosting capacity analyses if they become mandated.

See also Proposal J-4 for a separate working group below.

PROPOSAL J-4: HOSTING CAPACITY WORKING GROUP

Proposal status: non-consensus

Supported by: SPS, EPE, PNM

Conduct a workshop or working group with a defined scope and goal to be accomplished, which could then be used as the basis for a proposal to address hosting capacity that is clear, efficient, reasonable, and valuable for both the utilities and the industry.

As part of this process, also establish the following definitions: “hosting capacity,” “hosting capacity analysis,” “maximum hosting capacity,” “minimum hosting capacity”, and “DER Planning Guidelines.”

The proposed scope of a working group would be to:

1) Hosting capacity analysis workshop to clarify:
    a. The 14 criteria and thresholds used in the analysis and what they mean to a developer as far as interconnection costs
    b. what information is not available in a hosting capacity analysis, such as Transmission limitations or analysis on network feeders
2) Identify the relevant tools and data that are readily available for each utility
3) Identify what it would take for each utility to perform a full hosting capacity analysis, including rough cost estimates to implement and sustain
4) Identify cost recovery options
5) Identify reasonable security measures to protect customer and grid information
6) Define specific use cases to identify the value

The proposed objective of a working group would be to:

1) Provide information to visually guide large DER developers to areas of the utility’s service territory where their project has a higher likelihood of success.
2) Provide information to identify locations where high interconnection costs are likely for large DER applications.
3) Develop a process which the utility can use a hosting capacity analysis to support the initial or supplemental review process

After the objectives of hosting capacity are identified and defined and the scope of the working group has been achieved, clear and reasonable solutions—including timelines—can be proposed to meet those objectives. The most efficient solution that meets those objectives should be selected.

Facilitator's note*: The Industry Group expressed a position that lack of transparency about available capacity on utility systems continues to be a major concern, adding to uncertainty and costs of development. The group suggested a separate working group (in Phase II of the process) to further address these concerns.*

PROPOSAL J-5: COLLECTING PRELIMINARY OR PILOT HOSTING CAPACITY INFORMATION

Proposal status: non-consensus

Supported by: REIA, Sunrun, CCSA and SEIA
Opposed by: SPS, EPE, PNM

Consider short-term mechanisms to collect preliminary or pilot hosting capacity information. Such preliminary or pilot information might include:

- Assessment of the share of circuits for which minimum daytime load or hosting capacity information is already available.
- Conducting minimum daytime load data for a small subset of circuits, the locations of which industry and community solar developers believe could be most beneficial for near-term projects and interconnections.
- Anticipating the most needed pre-application data related to hosting capacity that would be needed for the pre-application process proposed by this Interconnection Working Group, and being proactive in getting it all at once, rather than one-off with each pre-application.
- Basic service territory maps showing geography served by a designated substation (for security, not necessarily showing the locations of the substation itself or giving details of circuit configurations).
- Understanding special considerations or accommodations for cooperative utilities, especially in relation to community solar

Note by Facilitators: SPS in early comments suggested hosting capacity information as a pre-application data source. This implies a view by at least one utility that any preliminary or pilot mechanism should target pre-applications.

PROPOSAL J-6: HOSTING CAPACITY PATHWAY TO LONGER-TERM MAPPING AND PUBLISHING

Proposal status: non-consensus

Supported by: REIA, Sunrun, CCSA and SEIA
Opposed by: SPS, EPE, PNM

The following stages could be part of a pathway to longer-term mapping and publishing of hosting capacity information:

1. Basic service territory map and posting of a public queue (updated at least monthly or as significant changes take place)
    a. Inclusion of general locations of major facilities is preferred
    b. Specific, accurate digital maps that are compatible with GIS software (.kmz, etc) are preferred over vague PDFs
    c. Presumably utilities already have this information
2. Very static map that's created/updated for a specific round of capacity allocation

   a. Identifies applicable service territory as well as general substation locations and a very high-level view of their available hosting capacity
   b. This could be a good initial step for IOUs in regards to the initial allocation of community solar capacity or reasonable level of info for Coops opting into the community solar program to provide
3. Minimum Daytime Load (MDL) studies
   a. Needs to be accompanied with at least basic maps or locations of substations but inclusion of more facilities (particularly feeder lines) are preferred
   b. These would ideally be updated on a regular basis as loads change, potentially annually to start and semi-annually once initial data has been gathered
4. Static hosting capacity map
   a. Basic shading based on a set MW threshold
   b. Limited to no additional information
   c. May or may not include facilities (substations, feeders, etc.) but they are preferred
5. Dynamic host capacity map
   a. Interactive map with click through ability to get more

Some considerations for such a pathway including the timing for moving from stage to stage of the roadmap, the sources of funds to pay for these stages and the relationship to grid modernization and other efforts, the frequency of refresh for the data, the ability to download source data for integrating into developer GIS systems or access info through APIs, and the accuracy of data and process for refining the resources overtime. Considerations or accommodations for cooperative utilities and community solar activities are also important.

<u>Position of Utilities on Proposal J-6</u>

The utilities group have put forward their own Proposal J-3 on a separate venue and Proposal J-4 on a hosting capacity working group, rather than support this Proposal J-6. However, there are additional utility comments made on this Proposal J-6, as follows.

"As part of any pathway definition and development, there needs to be a clear understanding that the hosting capacity value at a given location reflects the lowest megawatt value that exceeds one of many thresholds. EPRI's Distribution Resource Integration and Value Estimation (DRIVE) tool includes 14 such thresholds.

Each of these thresholds has a different mitigation - sometimes multiple possible mitigations - available to upgrade those hosting capacity values to interconnect a DER project. Understanding those thresholds, and what those potential upgrades are, is important for developers using hosting capacity maps to select locations for DER.

Depending on the threshold, upgrading hosting capacity could range from $1,000 to over $1,000,000. It is impossible to tell what those costs are from a hosting capacity analysis; a system impact study and facilities study would be required.

Focusing the hosting capacity analysis on one or two of those thresholds that are more likely to indicate high interconnection costs could provide more value to the developers. The Utility just needs to know what the developers are interested in seeing. "We want to see everything" is not helpful and it doesn't tell the Utility what is most important to developers."

Some members of the Working Group proposed the term "DER Planning Guidelines" to establish reservations for residential and commercial customers to self-serve and establish the maximum generation that a single feeder, substation, or substation transformer can accommodate before requiring a new feeder or substation transformer. This term should be defined outside of the Interconnection Rule, because it is outside of the scope.

The utilities position on mapping hosting capacity information – the utilities recognize that publishing maps of Hosting Capacity Analysis results is becoming a trend in the industry as an additional source of information outside of the interconnection process. However, of the fifty (50) largest electric utility companies in the country by customer count only twenty-two (22) of them have a map of hosting capacity available. It is likely that ratio is even lower for smaller utilities based on the resources and tools available to them and the amount of processing required to conduct a hosting capacity analysis.

The hosting capacity data provided in maps is generally high-level information and does not have sufficient granularity and detail to be able to replace any part of the interconnection process, including the pre-application data requests. Pre-application data reports provide more granular information than a hosting capacity analysis and the costs are collected directly from the party requesting the information. In effort to maintain the basis of a consensus approach, the Utilities recommend keeping the long-term mapping and publishing of hosting capacity data out of the Rule and Manual. This allows utilities to focus their efforts where it is most needed and not divert the utilities' resources to attaining information that is not readily available to them or analyzing hosting capacity where DER is unlikely to interconnect.

The Utilities propose addressing the issue of mapping and publishing hosting capacity data separately from the interconnection rules in order to thoroughly define, discuss, understand, and vet the associated costs, cost recovery, methodology, security risks, and value for existing customers, interconnecting customers, and each utility. The Utilities propose adding a note in the Rule that a utility may make a map of hosting capacity data available to interconnecting customers as additional information so long as confidential information remains confidential unless otherwise ordered by the commission, as stated in section 17.9.568.B of the Rule. Utilities can be encouraged or incentivized to expand on their hosting capacity analyses and maps outside of the interconnection process.

The Utilities assert that an important consideration of publishing maps of utility information is establishing the security requirements up front. Protecting customer information, customer privacy, and grid security should be prioritized over providing a convenient source of information for interconnecting customers. Establishing security requirements for publishing maps of utility information requires significant thought and consideration towards the risks of that information falling into the wrong hands and the potential methods to reduce those risks. Minnesota has opened Docket Nos. E002/M-19-685 and E999/CI-20-800 to assess distribution grid and customer security, which has also been referenced and discussed at length in Colorado Proceeding No. 20R-0156E. The Utilities recommend taking a cautious approach until the risks are thoroughly discussed and the protective measures are vetted.

Additionally, SPS in its September 3 comments stated several positions related to the above proposals:

"SPS is unclear on a previously stated benefit that developing hosting capacity information and mapping would minimize unnecessary upgrades. The Supplemental review and Study processes are more granular than hosting capacity information and mapping and the upgrades identified in the Study Process would only be necessary upgrades."

"There should be a note that stated benefits of hosting capacity mapping is dependent on certain cost allocation methods. Under the existing tariffs and the "cost causation" approach to funding distribution upgrades and keeping customer rates down, the Utility would not plan or budget for upgrades to increase hosting capacity for interconnection customers."

"Stated benefit only applies to front-of-the-meter customers and not to behind-the-meter customers. Behind-the-meter customers cannot, economically, move their homes or businesses to areas of higher capacity.

Most of the screens and upgrades identified for Level 1 customers are on secondary systems, which hosting capacity analyses do not cover. Hosting Capacity maps are intended to be a guide, not an approval mechanism.[24]*"*

"To our knowledge, only California mandates the use of hosting capacity data in their screens. The statement, "following the lead of multiple other states and learning from their experiences and lessons learned" is not factual in this context and should be edited or removed from the report. Also, no utility engineers from California spoke at any New Mexico Interconnection Working Group meeting, so SPS argues that we are not "learning from their experiences and lessons learned" and we are "blindly" following a path paved by another state."

"Use of "hosting capacity" for interconnection screens is currently not feasible due to the volume of applications, the lack of granularity of the Hosting Capacity Analysis, and the frequency of updates required for hosting capacity data to be used in this way. Hosting capacity data will not reflect secondary limitations, which is partly what the screens filter for."

"Colorado allows the use of new tools that accomplish the same screens or intent of the screens in the same amount of time. Recommend including the following language in the New Mexico Interconnection Manual:
"A utility may utilize tools that perform screening functions using different methodology from that set out in [the Screens and Supplemental Review] as long as the analysis is aimed at preventing the same voltage, thermal and protection limitations specified under [Interconnection Review] and otherwise complies with these procedures.""

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[24] Rogers, Bruce, Enbar, Ndav, Heine, Nicholas, Rogers, Lindsey, Rylander, Matt, et al. October 2020. Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process. Palo Alto, California: , Page 6.. https://www.epri.com/research/products/000000003002020010, Page 6.

4. PROPOSED RULE AND MANUAL REVISIONS

4.1 Delineation of Content for Rule and Manual Revisions

Facilitator's Note: While a principal goal of the Stakeholder process was to establish a set of consensus items that would inform revisions and updates to the Interconnection Rule [Title 17.9.568] and the associated New Mexico Interconnection Manual, it was not possible to reach complete agreement on certain issues, as described in this report. Instead, the task of preparing a draft Rule will fall to the Commission's Office of the General Counsel for issuance within a Notice of Proposed Rulemaking (NOPR), which will establish a formal proceeding to allow consideration of the report's recommendations and determine policy directions that will guide the Rule finalization and revisions of the Manual and associated Technical Guidelines documents used by the utilities.

In simple terms, the Rule is expected to establish the legal and policy expectations that the Commission has for utility interconnection processes and procedures. The Manual is essentially a more detailed explanation of those procedures and a set of forms and agreements between Utilities and Applicants that are used in the Application and Technical Review Process.

4.2 Summary of Rule Revisions

Interconnection Rule Elements
Status: Non-consensus

Input from the working group was collected via a MIRO whiteboard as of Sept. 9, 2021. Working group members were not polled but comments were invited during the meetings. Input below is transcribed from the MIRO whiteboard.

Elements suggested by Working Group members that should go into the Interconnection Rule (those in bold have been addressed in this Report, whether or not consensus has been reached):

- **Timeframes for both developer and utility completion of all phases of the interconnection process;**
- Interconnection process should allow priority access to small generators applying for distribution grid behind the meter;
- Interconnection process should provide no cost to small generator facilities that will provide benefits to grid and will provide upgrades below a certain cost when aggregated with likely additional new small generators within a limited timeframe (e.g., 10 years);
- Interconnection rules should allow aggregation of generation and storage where the storage facility provides ability to limit export;
- Requirement that utility maintain a public queue and detailed list of elements. Should include the following: 1) Application # 2) Name of Applicant 3) Circuit and Substation IDs (Transformer, if available) 4) Proposed AC system size 5) Application date (date of utility "acceptance" or "deemed complete" 6) Date of Scoping

Meeting 7) Must proceed with System Impact Study by Date 8) Date of SIS start 9) Date of SIS completion 10) Must execute Interconnection Agreement by date 11) Date of IA execution 12) Must make IX deposit by date 13) Date of IX deposit payment made 14) Must make full IX cost payment by date 15) Date full payment of IX cost made 16) Date of project construction start (issuance of building permit) 17) Date of utility construction start 18) Utility estimated date of utility construction complete (utility ready for witness test) 19) Date of witness test 20) Date of issuance of Permission to Operate;
- Interconnection rules should allow for net-metering where the generator is located on customer site and providing generation to meet customer load, irrespective of ownership of such generator (i.e. allow for PPA);
- **Dispute resolution process;**
- **Standardized streamlined interconnection process details;**
- Technical standards that enable streamlined interconnection or common statewide protection and grid support function settings;
- Technical standards through UL should define equipment requirements. The conditions for inadvertent export give utilities discretion instead of relying on UL certification standards resulting in a formula for applying a non-technical basis for grid modernization;
- Appropriate financial penalties applicable to the utilities for failure to comply with timeframes
- Requirements that projects update the utility of changes to their AC system size at least quarterly. This is a critical issue to ensure that a useful queue that is accurately representing reality. In far too many other states, there is no incentive for developers to update the MWac size of their projects when they learn of IX costs and make a determination to resize. Coupled with Hosting Capacity information, a queue which accurately reflects the expected size of planned projects will enable developers to understand if there is available capacity. Many stakeholders recognize that in a number of northeastern states the queues have many projects which are improperly sized, resulting in an inefficient market;
- **Common definitions;**
- **Definitions not in statute and those not likely to conflict with those in the manual;**
- **There should be a definition of small utility consistent with the current rule;**
- Enable customers to interconnect non-exporting generation & storage without delay for distribution upgrades.

Facilitator's note: Some items listed above are policy statements and are subject to decisions the commission.

The following elements were suggested by Working Group members as NOT appropriate for the NM Interconnection Rule: interconnection application/agreements; detailed processes; and codes & standards, don't want to lock into a certain version. These are presumed to be included in a revised Manual or technical guidelines.

The current NM Interconnection Rule includes the following elements:
- EFFECTIVE DATE & DURATION
- OBJECTIVE
- DEFINITIONS
- CODES & STANDARDS
- APPLICATION PROCESS & FEES
- APPLICATION REVIEW FLOW CHART
- GENERAL PROVISIONS FOR UTILITIES
- GENERAL PROVISIONS FOR CUSTOMERS
- SAFETY
- VARIANCES

4.3 Summary of Manual Revisions

This summary cannot be completed until after Commission determinations on non-consensus items.

5. NEXT STEPS AND RECOMMENDATIONS

5.1 Proposed Scope for Phase II of Interconnection Working Group in 2022

During initial scoping of the Working Group in early 2021, it was recognized that the number of interconnection issues requiring attention and updating was far beyond the time allotted to the Working Group in 2021. So a two-phase approach was developed, with the most urgent and/or most readily addressed issues scoped for Phase I in 2021, and a number of important but more complex issues scoped for Phase II in 2022. Depending upon direction from the Commission in its Phase I decision, Phase II could include a number of both technical and nontechnical interconnection topics.

During the course of the Working Group in 2021, these Phase II issues were further discussed and refined. A separate report with recommendations and proposals would also be developed for Phase II.

Smart Inverter Functionalities and Activation. Proposal G IEEE-1547-2018 Adoption provides a basic requirement for smart inverter functionalities by the end of 2022, including three required capabilities and one optional capability. However, as outlined in Annex E of this Final Report, there are many more functionalities possible that Proposal G does not address, including both "autonomous" functions and "advanced" functions. In addition, Phase II would address the activation and use ("operationalizing") of these smart inverter functionalities, for autonomous functions, advanced functions, and communications and control of inverter operations. In addition, further updates to the rule or manual can be considered based on the recently adopted testing standard for smart inverters, IEEE-1547.1-2020. That standard was not considered during Phase I and by 2022 there will be further experience from other jurisdictions to draw upon.

Hosting Capacity. Proposal I on Prospective Paths to Hosting Capacity Information and Mapping contains several different alternative next actions for the Commission to consider related to hosting capacity. Depending upon direction from the Commission in its Phase I decision, Phase II may also continue exploration of hosting capacity and proposals for more transparency of data related to both the availability of interconnection capacity and the determination of costs associated with upgrades and a regulatory process for potentially applying alternative cost recovery mechanisms.

Cost Allocation. Proposal D Cost Allocation Options provides a discussion of and several options for Commission decisions related to cost allocation. Such decisions might also be related to grid modernization and other planning processes. If the Commission determines that the Working Group would be an appropriate venue to continue to examine cost allocation proposals, then this could be included in Phase II.

Interconnection Queues. The Working Group during Phase I received some partial proposals from participants outlining concerns and issues related to interconnection queues, including experience from other jurisdictions. Issues include queue management, visibility, and differential treatment of different types or sizes of project. But the Working Group during Phase I was not able to devote the time necessary for adequately working through the issues and developing full proposals.

Interconnection of Community Solar, Electric Vehicles, and Microgrids. The Working Group in Phase I began a discussion of community solar interconnection, in parallel with PRC workshops on community solar also occurring in 2021. However, the Working Group could not address in detail during Phase I, so Phase II offers an opportunity to continue to address interconnection of community solar. In addition, interconnection of electric vehicles and microgrids have become important topics for state regulators throughout the U.S., and many recent developments and approaches from other jurisdictions could be considered for New Mexico. Some possible questions to address are: What are the best approaches to supporting greater adoption of electric vehicles through interconnection policies? How to ensure that microgrid development also benefits utilities and the distribution grid? Which functionalities and use cases are most important? What can utilities do on their own versus what must be incorporated into the interconnection rule? What additional interconnection screens and review processes may be required?

Backfeed (Export) to the Transmission Grid. This issue may become more important for New Mexico in the future as larger and more numerous DERs are interconnected, both in terms of aggregate behind-the-meter capacity and also larger front-of-the-meter generating facilities including community solar. There may be more and more situations emerging where high DER capacity on a circuit exceeds the total load on that circuit. Under what conditions, if any, can backfeed to the transmission system be allowed? Is the existing rule adequate to handle these conditions? What new study and tariff provisions are required?

FERC Order 2222/222A Issues. In late 2020, the Federal Energy Regulatory Commission issued a rule Order 2222, to better enable aggregated distributed energy resources (DER) to participate in wholesale energy markets operated by Regional Transmission Operators (RTOs) or Independent System Operators (ISOs). This rule allows several sources of distributed electricity to aggregate in order to satisfy minimum size and performance requirements that each may not be able to meet individually.

In Order 2222 and subsequent Order 2222a (issued March 2021) FERC recognized that the interconnection of DERs with the grid remains subject to local utility interconnection rules that are state jurisdictional and that these rules can encourage or discourage DER activity. Order 2222a clarified that the Commission declines to exercise its jurisdiction over the interconnections of DERs, including the interconnections of Qualifying Facilities (QFs), to distribution facilities for the purpose of participating in RTO/ISO markets exclusively as part of a DER aggregation. Phase II of the Interconnection process should explore the implications of FERC's orders on *future* interconnections of DER that may aggregate for the purpose of participating in wholesale markets.

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ANNEXES

ANNEXES ARE CONTAINED IN AN ELECTRONIC FILE SEPARATE FROM THIS REPORT

ANNEX A: PARTICIPANTS IN THE WORKING GROUP

ANNEX B: LIST OF MEETINGS HELD

ANNEX C: LINKS TO TECHNICAL PRESENTATIONS

ANNEX D: SIDE-BY-SIDE COMPARISON OF EXISTING NM RULE, FERC SGIP AND IREC MODELS

ANNEX E: FURTHER BACKGROUND ON SMART INVERTERS AND IEEE 1547

ANNEX F: INTERCONNECTION RULE REVISION -NOT USED

ANNEX G: INTERCONNECTION MANUAL REVISION - NOT USED

ANNEX H: COST ALLOCATIONS OPTIONS BACKGROUND

ANNEX I: IREC MODEL QUESTIONS WITH NM BASED RESPONSES

ANNEX J: SUPPLEMENTAL WORKING GROUP COMMENTS ON PROPOSALS

ANNEX K: COMMENTS RECEIVED ON VERSION 2 OF THE WORKING GROUP’S DRAFT REPORT