BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2001

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation Into Interim PURPA Action.	JOINT COMMENTS OF NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION, THE RENEWABLE ENERGY COALITION AND THE COMMUNITY RENEWABLE ENERGY ASSOCIATION ON DRAFT INTERIM INTERCONNECTION DATA PROPOSAL

I. INTRODUCTION

Northwest & Intermountain Power Producers Coalition ("NIPPC"), the Renewable Energy Coalition ("REC") and the Community Renewable Energy Association (collectively "NIPPC/REC/CREA") respectfully submit these comments regarding the appropriate interim interconnection cost data. These comments are specifically in response to the draft Oregon Public Utility Commission ("Commission" or "OPUC") Staff Initial Interconnection Data Transparency Proposal dated May 13, 2019, the Staff workshop held on May 17, 2019, and Staff's follow-up requests emailed to stakeholders on May 22, 2019.

NIPPC/REC/CREA appreciate Staff's efforts to balance the parties' interests based on information that is most helpful to the industry and the relative ease of producing it for the utilities. NIPPC/REC/CREA support Staff's draft recommendations but seek additional or clarified information where noted. The interconnection data made public in this process should hold utilities accountable for meeting the requirements in the OPUC's generator interconnection rules and guidelines, provide a baseline of utility system information to inform interconnection customer siting decisions, and inform the policy decisions that will necessarily need to be made in the broader UM 2000 OPUC Investigation into PURPA Implementation.

NIPPC/REC/CREA understand that this interim phase is intended to be very limited and to require "additional transparency for QFs … to ameliorate some of the difficulty QFs are having with the interconnection process and also, to facilitate investigation of interconnection costs and their allocation in the upcoming investigation [in UM 2000]."[1] Thus, there are two purposes. First, to provide some immediate relief to interconnection customers in gaining greater transparency regarding the unprecedented level of interconnection-related delays, inaccurate information in the interconnection process, unsatisfactory work product, overcharges, and other harmful utility actions that interconnection customers have experienced. Second, to provide necessary information (which is in the sole possession of the utilities) for the stakeholders and Commission to be able to revise interconnection-related policies and rules (or to better enforce the current policies and rules). The Commission should broadly err on the side of providing more, rather than less information to ensure that it can make informed decisions in the UM 2000 process.

The interim information being provided in UM 2001 should not be confused with providing interconnection customers substantive relief that they so desperately need now.

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[1] Re Commission Investigation Into Interim PURPA Action, Docket No. UM 2001, Order No. 19-052 at Appendix A at 4 (Feb. 19, 2019).

There are a number of interconnection-related complaint proceedings, some of which could provide immediate relief to interconnection customers. The Commission should resolve these disputes promptly, and not let projects continue to languish while the Commission proceeding unfolds. This proceeding will not result in the individual relief to which developers are entitled in the complaint processes, and will, put simply, likely take much too long in any event to provide help to developers that are suffering harms related to their current projects. In addition to this process, the Commission should take up interconnection issues in an expedited phase of UM 2000, and find a remedy for QFs' experience that PacifiCorp and Portland General Electric Company use the interconnection process to evade their responsibilities to purchase power under the Public Utility Regulatory Policies Act ("PURPA").

NIPPC/REC/CREA request that the Commission view interconnection matters with a special focus on its statutory responsibilities to protect interconnection *customers* from utility monopolies that have an economic incentive and proven track record of putting their competitors (QFs and other independent power producers) behind the utility, and perhaps out of business. ORS 756.040 states that in addition to any duties otherwise vested in the Commission, the Commission shall "protect [] customers, and the public generally, from unjust and unreasonable exactions and practices [by the utilities]." ORS 757.325 also requires that utilities not act unreasonably in giving preference or advantage to any person. A key goal when considering what information should be provided is how that information allows the Commission to better achieve its responsibility to ensure that interconnection customers are protected from the unjust and unreasonable exactions and practices they are facing today.

Finally, the Commission should recognize that interconnection-related issues go beyond PURPA implementation. This Commission's implementation of PURPA is perceived as hostile to QFs, from actions such as the *de facto* moratorium on new QFs in PacifiCorp's service territory and the *sua sponte* opening of this investigation, which may impose additional barriers and restrictions on QFs during a time in which avoided cost rates are at historic lows and there are few QFs seeking contracts with Oregon utilities.[2] Regardless of the impacts on PURPA, however, the Commission should recognize that its actions on the topic of interconnections will not just impact PURPA. Any failure to fix interconnection matters could doom the state's slow implementation of community solar, as those projects will also use the Oregon state jurisdictional interconnection process.[3] As the interconnection process is the gateway for independent power producers to bid into utility requests for proposals, any failure to address interconnection issues will also significantly limit the resources available to submit bids.[4] Thus, interconnection matters

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2 PGE's Monthly Status Report in UM 1854 shows only about a half dozen projects that have submitted complete information in 2018-2019 and are still pursuing PPAs. Despite this extremely low level of new PPA requests, the Commission elected to surprise the industry and implement on its own motion a rate decrease and considered lowering the size threshold to 100 kW earlier this year in UM 2001.

3 NIPPPC/REC/CREA's understanding is that community solar will use the state jurisdictional interconnection process. See Rules Regarding Community Solar Projects, AR 603, Order No. 17-232 at 10 (June 29, 2017); Rules Regarding Community Solar Projects, AR 603, Department of Justice Interoffice Memo from S. Andrus to M. Breish (Jan. 26, 2017).

4 Most independent power producer bids into requests for proposals will use the Federal Energy Regulatory Commission rather than state jurisdictional interconnection process. However, some projects will begin or have completed their interconnection under the state jurisdictional process, and problems with the state jurisdictional queue, informational requirements, etc. will at least indirectly impact the federal jurisdictional interconnections.

are one of the cornerstones to an independent and competitive power supply in this state, and the Commission should view these interconnection issues in that context.

II. COMMENTS

NIPPC/REC/CREA provide the following comments on the specific interconnection data and information that the Commission should require from utilities.

A. Interconnection Study Reports

The utilities should immediately begin posting on their Open Access Same-Time Information System ("OASIS") site all interconnection study reports on a going forward basis and should immediately begin processing, reviewing, and redacting (where needed) old studies and posting those as they are completed. PacifiCorp already provides these studies on its OASIS site and it is appropriate for Idaho Power and PGE to provide the same information.

1. The Only Confidential Material Contained in Interconnection Studies Are Customer Identification Information

Redactions are appropriate where it protects truly confidential applicant information. NIPPC/REC/CREA remain unconvinced that any information produced in the studies qualify as Critical Infrastructure Protection ("CIP") or Critical Energy Infrastructure Information ("CEII"). At the May 17, 2019 workshop, PGE expressed that it may have some information in its studies that qualify, but was unable to provide any specific examples other than that it does not cover system upgrades that are approved and budgeted. If a utility comes forward with a specific example or a concrete proposal for classifying certain specific requirements or information as CIP/CEII, then NIPPC/REC/CREA will respond at that time regarding the appropriateness of the

CIP/CEII classification. The parties are not likely to resolve the CIP/CEII issue without specifics (which the utilities have not provided), and the Commission should at this time demand that the utilities explain what information, if any, in their interconnection studies could be CIP/CEII.

2. Historic Studies Should Be Provided Back to Before the Current Breakdown in PGE's and PacifiCorp's Processing of Interconnections

Old studies should be posted as far back as is necessary to meaningfully inform the policy decisions that will be made in the UM 2000 Investigation into PURPA Implementation. The industry has raised concerns over the studies including:

- The study process and time for completing studies;
- The construction timelines detailed within the studies;
- The studies' compliance with the generator interconnection rules or guidelines;
- The cost estimates detailed in the studies;
- The interconnection requirements detailed in the studies, possible alternatives, and the changes in interconnection requirements in subsequent studies;
- The mistakes made in studies or accuracy of information provided; and
- The changes that the utilities have made to their interconnection studies over time (i.e., earlier studies were performed more quickly, with lower costs, and quicker construction timelines, etc.)

It is understandable that some issues and delays may arise when the market is favorable for development and there are more projects in the interconnection queues with contracts to sell power to PGE (both on and off-system). However, the Commission will be unable to weigh the utilities' legitimate challenges against the industry's concerns without appropriate access to historical studies. Further, if the generator interconnection rules or guidelines need to be amended to remedy the above noted issues, then the Commission will need to make appropriate factual findings upon which to support its decision. Access to the historical studies themselves is the best way to achieve this.

The ultimate goal for producing historical studies should be to go far enough back in time to enable a comparison of studies performed *before* the interconnection process began experiencing the issues described above with the studies that occurred over time. Presumably the interconnection process worked better at some point in time in the past, and it has only recently begun experiencing more significant issues. It would be most informative to policy-making to know what worked previously and how the studies have changed over time.

NIPPC/REC/CREA anticipate that this would mean that PGE should produce studies from the last 5 years and PacifiCorp should produce the last 7 years[5]; it is not clear at this time how far back that would be for Idaho Power. Different time periods are warranted because PGE began experiencing significant interconnection problems more recently (within the last 3 years) than PacifiCorp (within the last 5 years). We are proposing that interconnection studies be posted from at least two years prior to the time the utilities started experiencing significant interconnection issues. Additionally, the older years are likely to be much easier to produce because the utilities had fewer interconnection requests in those years. However, if the 5 and 7 years is not sufficiently

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5 While we understand that PacifiCorp already posts all of its studies, this time period becomes relevant in the later discussion on historical interconnection milestones.

far back in time to enable a meaningful pool of information *before* the utilities began experiencing interconnection issues, then the time period should be longer.

Finally, the data described herein should be the minimum amount necessary to inform the UM 2000 policy docket; however, there is no reason why PGE and Idaho Power cannot continue to review and post older historical studies beyond that which is detailed herein. Ideally, their OASIS queues would end up looking similar to PacifiCorp's. Making all interconnection studies available would serve the goal of transparency just the same as on a going forward basis so long as the project is still interconnected and in-service. As such, the Commission should require that the utilities immediately post studies on a going forward basis, produce sufficient historical studies (5-7 years, or more if needed) to inform the UM 2000 policy decision by a date certain, and continue processing older historical studies.

B. Utility System Information

The system information provided by the utilities should serve the goal of providing a baseline of data to enable a potential interconnection customer to make appropriate siting decisions before getting too far down the development path and discovering constraints on the system. Staff's list of utility system data detailed in their Initial Interconnection Data Transparency Proposal is appropriate and useful in this regard.

1. Additional Specific Information

Each of the undisputed items from Staff's list are not discussed here. However, NIPPC/REC/CREA support the refinements discussed at the May 17, 2019 workshop to:

- Provide the county or other location identifier for each substation;

- Define the substation voltage to be provided as the low-side feeder voltage rather than the high-side transmission voltage;
- Provide two "yes/no" items under the communications line item for the utilities to state whether there is SCADA at the substation and whether there is fiber to the substation;
- Define the feeder line capacity to be provided as the capacity at the head of the feeder; and
- Provide all generation on a feeder, regardless of type (QF, non-QF, net metering, etc.).

2. Daytime Minimum Load Information Should Be Provided

Daytime minimum load is highly valuable to determining whether a site is viable because additional requirements are often triggered when a project will result in more generation on a feeder than there is load to absorb it. Therefore, without daytime minimum load the remainder of the system data provided will be virtually useless.

PacifiCorp and PGE expressed concern that the daytime minimum load would be difficult to provide. However, Idaho Power did not seem to have the same difficulty. The information should not be difficult to provide, and if PacifiCorp and PGE are using a less efficient process, then the Commission should require them to switch to the process used by Idaho Power. Further, the utilities noted that the daytime minimum loads are often calculated in the study process. It would not be difficult to, and the utilities should simply update the daytime minimum load for the feeder at the time that a study is performed on that feeder and provide a date for when the data was "refreshed." At a minimum, the daytime minimum load should be updated quarterly.

3. The Utilities Should Be Allowed to Inform Interconnection Customers that the Data Is Outdated or Old

NIPPC/REC/CREA to not object to the utilities posting a reasonable disclaimer. It would be appropriate to simply require the user to check a box on the disclaimer in order to access the utility data.[6] Other steps such as providing an email address or validation link may be appropriate so long as it is an automatic process that allows the user to access the data nearly immediately after requesting the access. The interconnection data workgroup should discuss the specifics of the utility system disclaimers.

4. Information Should Be Easily Accessible

The data should be easily available online, user-friendly, and with the option to download the data into an excel spreadsheet for the user's convenience. The utilities should post a user-friendly map similar to the NYSEG/RE&G site linked above on a publicly available website and linked from their OASIS sites. Additionally, there should be a link to download a table of the data so that the user can filter and sort the data for their needs. While it may not be feasible to develop an interactive map in the short term, a table will be sufficient in the interim while an interactive map is being developed. Finally, each utility should add additional columns in its interconnection queue for each of the data points detailed herein.

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6 The disclaimer available on this New York State Standardized Interconnection Requirements ("NYSEG")and Rochester Gas and Electric Corporation ("RG&E") site is one example: https://iusamsda.maps.arcgis.com/apps/webappviewer/index.html?id=2f29c88b9ab34a1ea25e07ac59b6ec56

C. Interconnection Metrics

It is necessary for the utilities to produce interconnection metrics both on a going forward basis and for historical interconnections. The purpose for these two subsets of data is different; therefore, there are slightly different data points for each, as detailed below.

1. The Utilities Should Provide Information on Prospective Metrics

On a going forward basis, the reporting of metrics is necessary to hold utilities accountable for meeting the requirements in the generator interconnection rules and guidelines and to increase transparency into the parts of the process that may be more problematic. The industry raised concerns that the utilities are not meeting the required deadlines in the rules, or that the interconnection queues are delayed or moving slowly. A number of interconnection disputes could be resolved by simply requiring utilities to do what the rules already require. Currently, the only method for interconnection customers to raise issues to the Commission is to file a complaint. Rather than each affected applicant filing an interconnection complaint, the Commission could simply require that the utilities make this information public. While posting their compliance may not ensure that, in every case, the utilities will now strictly comply with the rules, it at least offers an incentive to do so.

A similar effort is underway at FERC with the updated Large Generator Interconnection Procedures, Order No. 845. Recognizing that delays are an issue in many interconnection queues, FERC will require quarterly posting of summary statistics detailing the number of interconnection requests withdrawn and number completed, the proportion of studies completed within the tariff timeframe, and average time to complete a study.[7] While FERC's reporting only requires the summary to be reported, the utilities will necessarily need to track the underlying metrics in order to prepare the summary. For example, in order to state the proportion of studies completed within the tariff timeframe, the utilities will need to track the date each study agreement is received and the date completed.

In this case, the data the utilities should track is similar to the data the they will need to track for FERC, but modified slightly for consistency with Oregon's rules. Staff proposed a number of interconnection tracking fields in attachment 2 to Staff's Initial Interconnection Data Transparency Proposal. NIPPC/REC/CREA support that proposal with the addition of a few additional data fields:

- The application date;
- The dates each study begins;
- The dates each study is completed; and
- The number of hours spent on each study.

Under Docket No. AR 521, the small generator interconnection rulemaking, each utility developed form interconnection study agreements which provide that the studies shall be completed and results transmitted within 30 days unless otherwise agreed to by the parties. Then the utilities are free to put a different schedule in the appendix and under the rules must make "reasonable efforts" to meet those self-imposed deadlines. There is a very high level of frustration in the industry with this process. The form

[7] Reform of Generator Interconnection Procedures and Agreements, 83 Fed. Reg. 21342, 21377 ¶ 290 (May 9, 2018).

agreements give potential applicants an expectation about how long a study should take and how long the entire application processing phase should take. Applicants make investment decisions based on their reasonable expectations and are later blindsided by study agreements that expect the study to take much longer and by studies that remain incomplete even beyond the projected completion date in the agreement. It is for these reasons that it is necessary to track the start and finish dates for the studies and the number of hours spent performing the study.

The utilities should begin tracking and posting prospective interconnection metrics for applications complete as of July 1, 2019 as recommended in Staff's draft initial proposal. PGE indicated that it has already begun tracking interconnection metrics with the roll out of its new interconnection software. PacifiCorp expressed a desire to coincide the interconnection tracking with the implementation of FERC's Order No. 845 in early 2020.

NIPPC/REC/CREA disagree that compliance should be synced up with Order No. 845. The utilities have known for at least a year that they will need to begin tracking and posting data in compliance with that order. Even more important, Oregon is about to embark on its UM 2000 journey and re-evaluation of its interconnection rules. It is essential that metrics be provided and available to inform that process. Any delays in providing interconnection information will necessarily delay UM 2000. Also, Order No. 845 was initially issued in April of 2018 and has been stalled due to reconsideration requests, and may be further delayed.

2. The Utilities Should Provide Information on Past Interconnection Metrics

Historical metrics are necessary to inform the policy decisions in the UM 2000 Investigation into PURPA Implementation and should go far enough back in history to capture at least a couple years prior to the utilities experiencing issues in their interconnection queues (when they began experiencing a higher volume of applications).[8] While this historical data includes some dates and timelines detailed above, there is some of the prospective tracking data that may not be necessary and may be more difficult to obtain (such as the number of hours spent on a study). As such, that data is not requested. However, the retroactive data should capture cost trends and should be organized in a manner that enables meaningful comparisons. The historical data produced in this process should include existing data from OASIS or existing internal utility tracking mechanisms, and data that is easily pulled from the studies or other documents. While much of this data would technically be available when the utilities publish their studies, it will be more useful to the Commission and stakeholders if the utilities pull the data out and present it in a table for easy review, sorting, filtering, and comparison.

Attachment A includes a proposed spreadsheet detailing the data that should be produced retroactively. In addition to the data in Attachment A, the utilities should also

[8] As discussed above in the Interconnection Study Reports section, the NIPPC/REC/CREA believe this to be somewhere between 5 to 7 years, but should be longer if the utilities experienced a higher volume of applications and/or queue processing issues at an earlier date, in which case the period should include at least two years of data before these queue changes.

include in their individual report any data reported on their OASIS or tracked internally. First, basic information about the project/interconnection should be provided. This includes the name, queue number, date of application, applicable rules (FERC or State and which tier applies), whether the project is an energy resource or a network resource (or being analyzed under both), the size, generation type, project type (QF, non-QF, utility owned, etc.), the requested in-service date, and the voltage. These data are necessary meaningful comparisons. For example, there is concern regarding the cost differences between energy resource interconnections and network resource interconnections. If the Commission considers changing Oregon rules and policies on this point in UM 2000, then the comparisons between the two will inform their decision-making. Further, other factors such as the size, generation type, and voltage will enable parties to compare the trends of similar interconnections over time.

Second, the utilities should also produce a minimum amount of timing and cost data that can be easily pulled out of the study agreements and reports. The timing data includes the dates the study agreements were executed by the interconnection applicant and the utility, the date of the study report, the scheduled number of days to complete the studies and actual number of days to complete it, and whether a restudy was needed. Unlike in the prospective metrics recommended above, it is probably not necessary to produce the date when the scoping call occurs or the dates when the study agreements were provided to the applicant for signature. This data may be more difficult for utilities to gather because they may need to search employee emails or other correspondence to verify these dates. Additionally, by knowing the dates of the prior study reports and the date the next study is executed by the interconnection applicant, parties can narrow down the date the agreement was provided.[9] However, should the utilities already track these dates internally, they should provide them to better inform the process.

These timelines will assist parties in reviewing changes in the interconnection processes over time. The industry is concerned that the time to process an interconnection application takes longer than it did several years ago. The requested dates will break out the trend of lengthened timelines, and the other requested project information will help show whether there are differences in processing timelines between projects with different characteristic such as by generation type, size, or QF/non-QF interconnections. Without getting into any specific policy recommendations at this time, this data can be extremely valuable in determining where there are issues and where there are not, facilitating discussion over possible improvements.

The utilities should also provide some basic information about the study itself. This includes the organization (i.e., PGE or a third party contractor) and individuals who performed the study (the utility, a third-party hired by the utility, or a third-party hired by the applicant), whether there were any re-studies, and whether there were any alternative studies (such as an independent third-party study supplied by the applicant). These metrics will assist the Commission in determining whether any policy changes are needed in regards to the utilities use of third-party consultants to perform studies, to ensure that studies are being performed by engineers with the competent technical background to

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[9] Additionally, under the rules an interconnection application is deemed withdrawn if the study agreement is not returned within 15 business days, so parties will generally know that the agreement was provided sometime within 15 business days of when it was executed.

appropriately apply all relevant engineering design and protection safety standards, and can also help explain some delays if, for example there were restudies or alternative studies.

The utilities should also provide the total estimated upgrade costs in each study. The industry has also raised concerns about increasing interconnection costs, large changes to interconnection costs between studies (both increases and decreases), and differential costs between energy resource interconnections and network resource interconnections. There have been a few suggested policy fixes such as allowing restudies if a project would like to switch its designation, or adopting clear policies and rules to reimburse interconnection customers for system upgrades that benefit the entire system. The Commission will need to decide these issues in the UM 2000 policy docket. Without asserting what the result should be, this data will inform that Commission decision.

Finally, the utilities should produce some basic information including timing and cost data at the interconnection agreement stage and upon completion of the project. This includes the date the interconnection agreement was signed by the customer, date signed by utility, interconnection facility costs detailed in the agreement, network upgrade costs detailed in the agreement, the agreement deposit, and the in-service date in the agreement. Further, the utility should also provide who performed the construction (the utility or a third party), the actual interconnection facility costs, the actual network upgrade costs, any network upgrade costs allowed as refundable, and the actual in-service date. Similar to the data provided on each of the studies, the timing and cost data provided here will enable parties to review changes over time as well as compare the final costs with the earlier estimates, or comparing the applicant's requested in-service date, with the date ultimately achieved.

All of the data detailed in this section should be relatively easy to pull out of existing documents such as interconnection studies, interconnection agreements, and interconnection invoices. Should the utilities also post other data on their OASIS sites or internal tracking mechanisms, those data should also be included in that utility's individual reports generated for this process.

It would also be helpful for the Commission, Staff and stakeholders if the utilities provide a summary of the above metrics. This would include totals, averages, and minimums/maximums. Attachment B details a number of these metrics that would be helpful. While most of this could be calculated by the stakeholders themselves once the utilities provide the raw data, by having the utilities produce this, all parties can refer to the same data.

D. Interconnection Standards

The utilities should also be required to post interconnection standards applicable to Oregon jurisdictional interconnections. At the May 17, 2019 workshop, PacifiCorp and Idaho Power indicated that they already have standards that they can provide. PGE indicated that it has not previously publicly posted any standards, but that it is in the process of developing its policy now and is not opposed to providing it. NIPPC/REC/CREA expect that this document would be somewhat similar to the one

PGE has posted on its OASIS site for FERC jurisdictional interconnections, but be applicable to Oregon state jurisdictional interconnections.[10]

Finally, the IEEE 1547 standard in the Oregon small generator interconnection rules should be updated to the most current standard. The Commission hosted a workshop on March 13, 2019 on recent ongoing research at the National Renewable Energy Laboratory and the Western Interstate Energy Board regarding mitigating perceived barriers to distributed solar PV deployment related to the interconnection process. In that presentation, the IEEE 1547-2003 standard was referred to as "pessimistic."[11] This is the standard currently imbedded in the Oregon small generator interconnection rules. By simply updating this reference to the most recent 2018 version of the standard, the Commission can meaningfully improve state jurisdictional interconnections.[12] As such, the Commission should immediately open a rulemaking to update that standard.

E. Interconnection Data Workgroup

The interconnection data workgroup should also include a representative from NIPPC and the Coalition, a representative from the Oregon Solar Energy Industries Association, and two to three individual developers with particular expertise and interest in this interconnection data process. The workgroup should work to resolve any issues

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10 Available at: http://www.oasis.oati.com/PGE/PGEdocs/PGE_Gen_Requirements_(07-12-2013).pdf

11 See Attachment C, slides 36-37.

12 Or alternatively, instead of referencing the specific standard, the rule could be modified to refer to the IEEE 1547 standard "as it is updated from time to time," or something similar to protect it from becoming outdated again.

regarding the CEII/CIP data that may come up as utilities begin publishing this data, the specific wording of any utility disclaimers, and any other issues that may arise.

III. CONCLUSION

NIPPC/REC/CREA support Staff's draft recommendations but seek additional and or clarified information where noted. The interconnection data made public in this process should hold utilities accountable for meeting the requirements in the OPUC's generator interconnection rules and guidelines, provide a baseline of utility system information to inform interconnection customer siting decisions, and inform the policy decisions that will necessarily need to be made in the broader UM 2000 OPUC Investigation into PURPA Implementation.

Dated this 31st day of May 2019.

Respectfully submitted,

Marie Barlow

Irion A. Sanger
Marie P. Barlow
Sanger Thompson, PC
1041 SE 58th Place
Portland, OR 97215
Telephone: 503-756-7533
Fax: 503-334-2235
irion@sanger-law.com

Of Attorneys for NIPPC and the Coalition

Gregory M. Adams (OSB No. 101779)
RICHARDSON ADAMS, PLLC
515 N. 27th Street
Boise, Idaho 83702
Telephone: (208) 938-2236
Fax: (208) 938-7904
greg@richardsonadams.com

Of Attorneys for the Community
Renewable Energy Association

Attachment A

OR Interconnection Milestones Tracker

PROJECT INFO										
Project Name	**Queue Number**	**Date of Application**	**Applicable Rules FERC/State (Tier 1-4)**	**ER/NR**	**Size**	**Generation Type**	**Project type (QF, non-QF, utility owned, etc)**	**Requested In-Service Date**	**Interconnection voltage at POI**	**Status (in-progress, withdrawn, in construction, active)**

Feasibility Study									
Date Feasibility Study Agreement signed by customer	Date Feasibility Study Agreement signed by utility	Date of Feasibility Study Report	Scheduled number of days for completing the study	Actual number of days to complete the study	Number of Days Early/Late	Who performed study (utility, 3rd party hired by utility, 3rd party hired by applicant)	Restudy? (Y/N)	Alternative Studies?	Feasibility Study total estimated upgrade costs

System Impact Study									
Date System Impact Study Agreement signed by customer	**Date System Impact Study Agreement signed by utility**	**Date of System Impact Study Report**	**Scheduled number of days for completing the study**	**Actual number of days to complete the study**	**Number of Days Early/Late**	**Who performed study (utility, 3rd party hired by utility, 3rd party hired by applicant)**	**Restudy? (Y/N)**	**Alternative Studies?**	**System Impact Study total estimated upgrade costs**

Facility Study									
Date Facility Study Agreement signed by customer	Date Facility Study Agreement signed by utility	Date of Facility Study Report	Scheduled number of days for completing the study	Actual number of days to complete the study	Number of Days Early/Late	Who performed study (utility, 3rd party hired by utility, 3rd party hired by applicant)	Restudy? (Y/N)	Alternativ e Studies?	Facility Study total estimated upgrade costs

Interconnection Agreement						
Date Interconnection Agreement signed by customer	Date Interconnection Agreement signed by utility	Interconnection Facility Upgrade Costs in Interconnection Agreement	Network Upgrade Costs in Interconnecton Agreement	Total Costs assigned to customer (in agreement)	Interconnection Agreement Deposit	In-service date stated in Interconnection Agreement

Final/Actual Data					
Who constructed (utility, 3rd party hired by utility, 3rd party hired by customer)	Actual Interconnection Facility Upgrade Costs	Actual Network Upgrade Costs	Actual Network Upgrade Costs Applied/Allowed as Refundable	Total Costs assigned to customer	Actual In-Service date

Attachment B

NIPPC/REC/CREA Additional Specific Information

Totals

- # applications
- # for study process, all steps, (and # started & finished): a) scoping meeting; b) feasibility study; c) system impact study; d) facilities study
- # that started post-studies a) engineering; b) construction
- # interconnected/energized
- # QF vs non-QF
- # utility-associated vs non-utility-associated

Summary Info / Initial Analytics

- <u>Costs</u>:
  - Provide: A) Max, Min, Average; B) QF vs non-QF; C) Utility-associated generation vs not.
    - By Voltage
    - By Year
    - NR vs ER
    - By Size
  - Summarize
    - NU: Reimburse; non-reimburse
    - NU: Benefits to ratepayer ($MM); total, average, by year, QF/non-QF)
    - NU vs ER, % splits
    - Cost reduction if no NU

- <u>Timelines</u>: For each study phase step, provide:
  - For the following:
    - Tariff timeline
    - Actual timeline
  - Provide:
    - A) Max, Min, Average;
    - B) QF vs non-QF;
    - C) Utility-associated gen vs not;
    - D) NR vs ER
    - % achieved schedule
    - % missed schedule
    - Average days early/late
  - Summarize by:
    - All
    - By Application Year
    - By Voltage
    - By MW
    - By QF/non-QF
    - Utility-associated vs non-utility associated
  - Trend Summaries

Attachment C

Mitigating or Removing Interconnection Barriers to Distributed PV Deployment

Public Utility Commission of Oregon

March 13, 2019

Mitigating or Removing Interconnection Barriers to Distributed PV Deployment

Public Utility Commission of Oregon; March 13, 2019

NATIONAL RENEWABLE ENERGY LABORATORY

Western Interstate Energy Board

Agenda Overview

- Introductions
- Overview of the Western Interstate Energy Board (WIEB)
- DOE Solar Energy Technologies Office Cooperative Agreement Overview
- Distributed Solar PV Interconnection Process Research Project
- Emerging Interconnection Issues and Recommended Policies
- Upcoming Analysis
- Discussion and Wrap-Up

Western Interstate Energy Board

Legal Basis: the Western Interstate Nuclear Compact (PL 910461).

Purpose: to provide the instruments and framework for cooperative state efforts to "enhance the economy of the West and contribute to the well-being of the region's people."

Board Members

UT - Dr. Laura Nelson, Governor's Office of Energy Development
NV - Angela Dykema, Governor's Office of Energy
AZ - Brian Goretzki, Arizona Department of Health Services
CA - Janea Scott, California Energy Commission
CO - Kathleen Staks, Colorado Energy Office
ID - John Chatburn, Governor's Office of Energy Resources
MT - Jeff Blend, Department of Environmental Quality
NM - Ken McQueen, Energy, Minerals & Natural Resources Department
OR - Janine Benner, Oregon Department of Energy
WA - Tony Usibelli, Washington State Energy Office
AB - Christine Lazaruk, Alberta Energy
BC - Les MacLaren, Ministry of Energy, Mines & Petroleum Resources

* Appointed by Governors and Premiers.

DOE Solar Energy Technologies Office Cooperative Agreement Overview

Cooperative Agreement with U.S. DOE

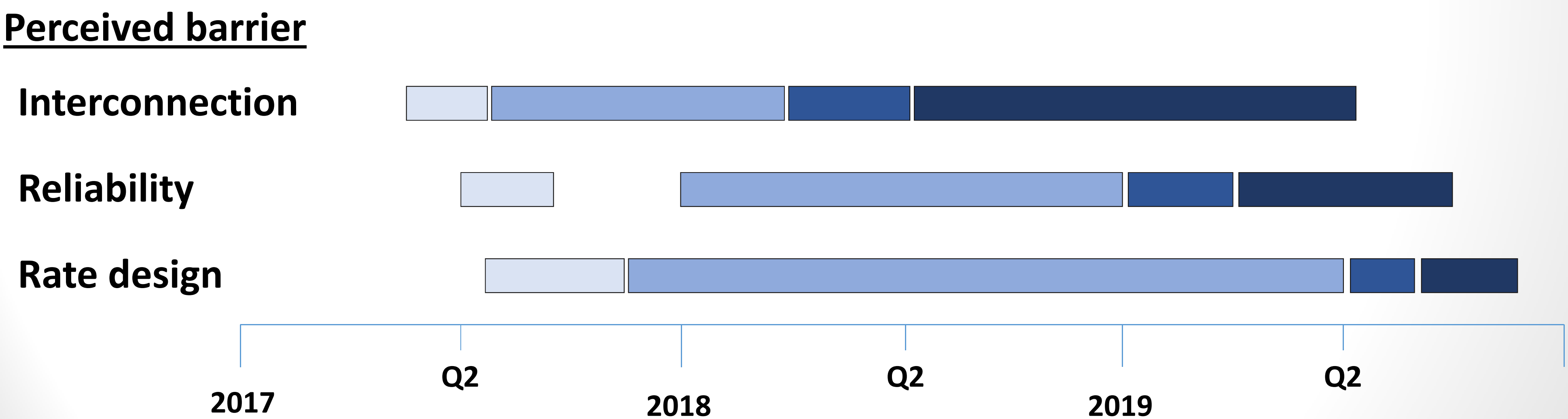
- Goal: To mitigate or even remove barriers to distributed solar PV deployment in the West
- Perceived barriers:
  - concerns with interconnection process
  - potential reliability concerns
  - concerns with utility rate design

Project Stages and Timeline

Led by national laboratories:
1. Develop research plan
2. Conduct research/modeling and write final report

Conducted by WIEB:

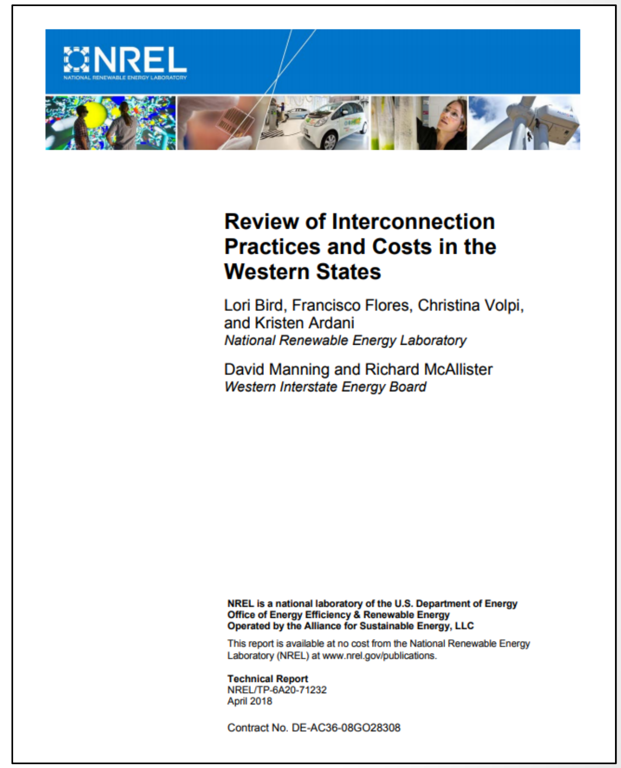
3. Develop outreach strategy and materials
4. Perform western state outreach



Distributed Solar PV Interconnection Process Research Project

Interconnection Project

- Focus on state interconnection requirements
- Research methodology:
  - Utility and developer interviews
  - Compile and analyze data on state interconnection standards, requirements, processes; and utility practices
- Research reports:
  - "Interconnection Practices and Costs in Western States"
  - "New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues"



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Review of Interconnection Practices and Costs in the Western States

Lori Bird, Francisco Flores, Christina Volpi, and Kristen Ardani
National Renewable Energy Laboratory

David Manning and Richard McAllister
Western Interstate Energy Board

NREL is a national laboratory of the U.S. Department of Energy Office of Energy Efficiency & Renewable Energy Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Technical Report
NREL/TP-6A20-71232
April 2018

Contract No. DE-AC36-08GO28308

Report links: https://www.nrel.gov/docs/fy18osti/71232.pdf
https://www.nrel.gov/docs/fy19osti/72038.pdf

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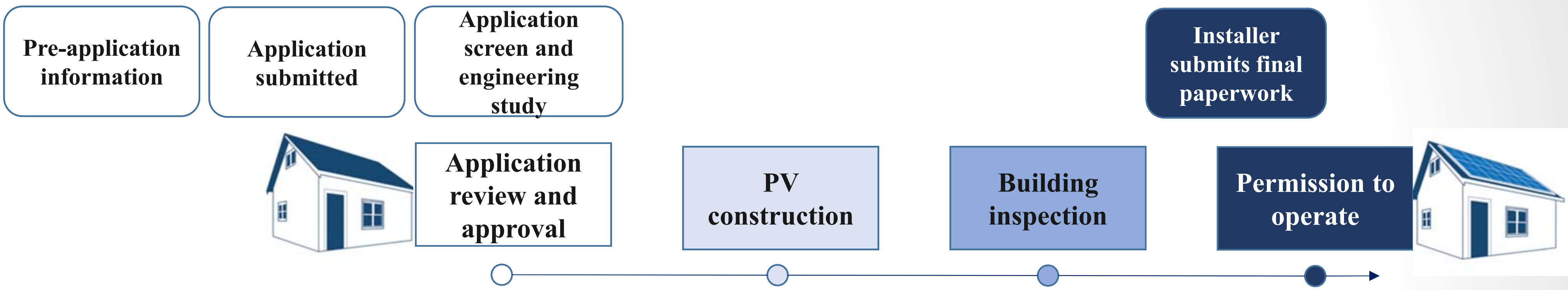
Interconnection Process Overview



* Project focuses on state interconnection standards

Benefits of State Interconnection Standards

- Benefits
  - Best practices that facilitate economic deployment of distributed generation
  - Reduce interconnection time and costs, improve process efficiency
  - Consistency between states to lower barriers
  - Helps address challenges and leverage opportunities of new technologies (e.g. storage, advanced inverters)

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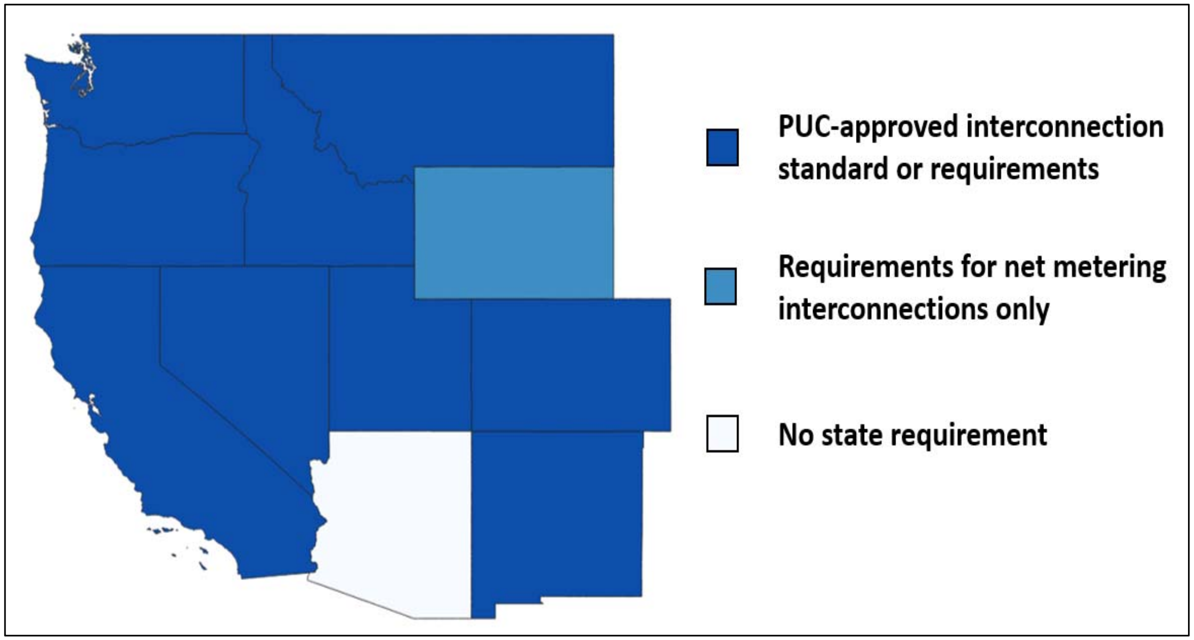
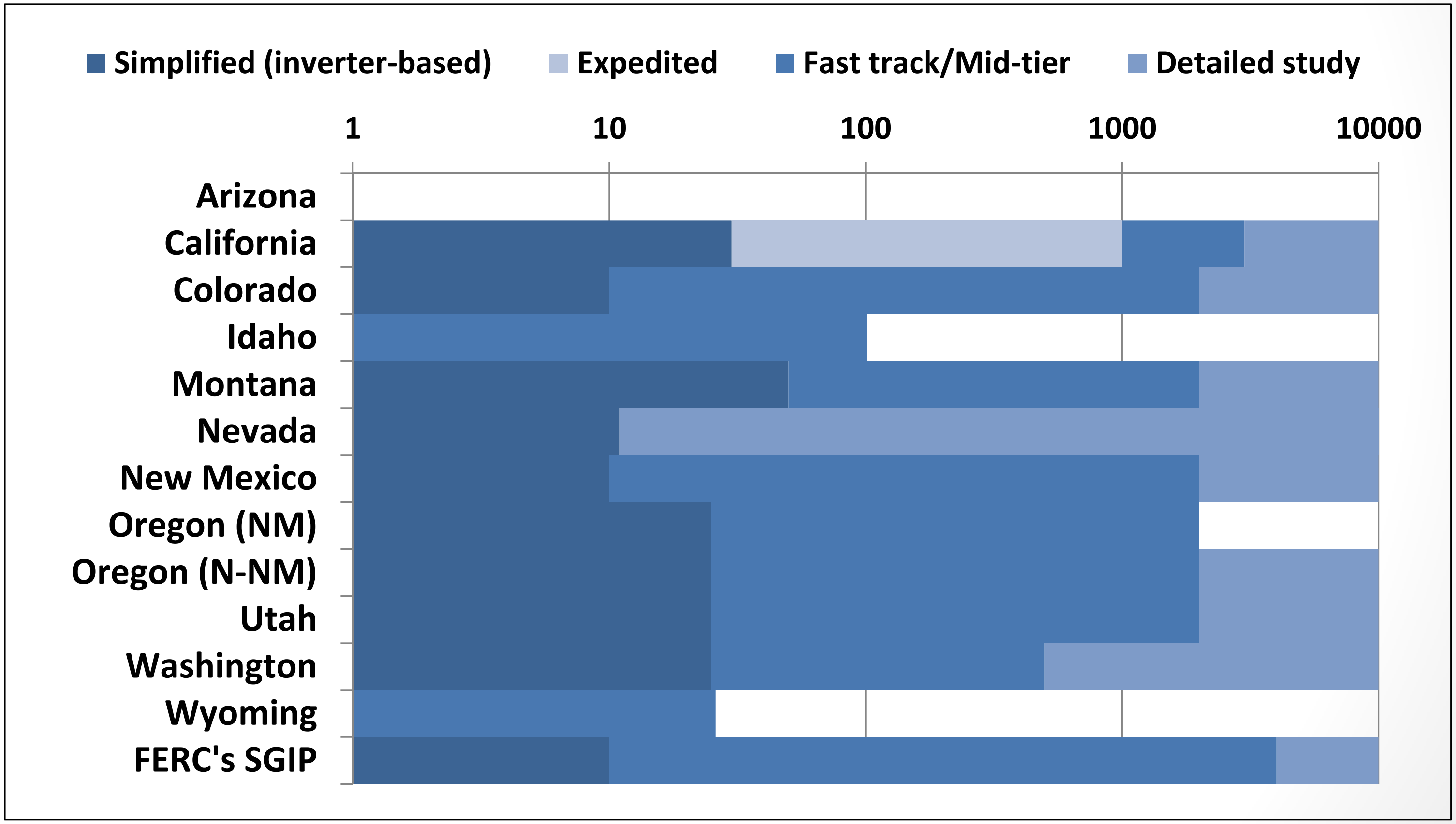
State Interconnection Standards

Statewide interconnection requirements in the western states



Application Processing Tracks

State technical review threshold by system size (kW)



Non-Exporting PV Systems

Treatment of Non-exporting Systems

	AZ	CA	CO	ID	MT	NV	NM	OR NM|N-NM	UT	WA	WY
Is there different treatment for non-exporting PV systems?		•			•	•	•	|•			

Example Procedures for Non-exporting Systems

	California	Montana	Nevada	Oregon
Methods for Non-Exporting	Under-sizing or relays	Relays or other protective equipment	Undersizing or relays	Relays or other protective equipment
Changed Treatment in Screening	Qualifies for fast-track; bypasses certain screens	Expedited review	Non-export status required for simplified review	Specific review track for non-exporting projects

Storage and PV plus Storage

State Requirements for Storage

	AZ	CA	CO	ID	MT	NV	NM	OR NM|N -NM	UT	WA	WY
Interconnection standards specifically address energy storage systems		•	*			•	•	|			
Interconnection Standards Address PV plus Storage		•	*			•		|			

* Xcel Energy CO agreed to adopt guidance for interconnecting storage as part of a settlement agreement

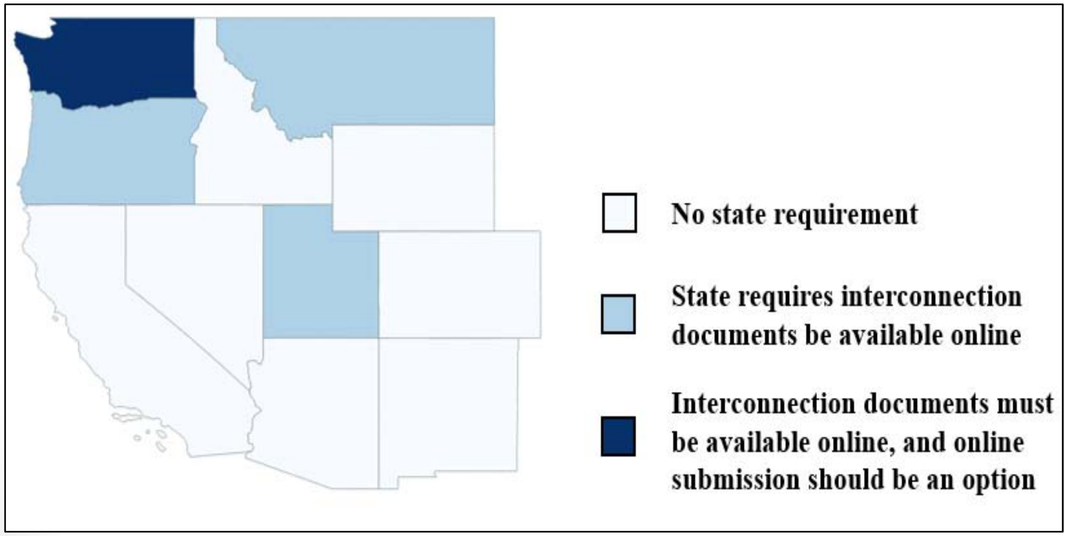
Storage and PV plus Storage Policy Issues

Implementation issue	Including storage in interconn. standards	Storage operation and control	Net metering compensation	Inadvertent export
Example policies	• Explicitly include storage in the definition of a generator (CA, NV, NM)	• Ongoing policy discussions • Operating restrictions (e.g. through software) can reduce net capacity of PV + storage (Xcel SA, NV) • Storage control can restrict charging behavior to reduce technical review of load (CA)	• Estimation methodology for ≤ 10kW (CA) • Storage either cannot export or can only charge from NEM generator (Xcel SA, NV)	• Ongoing policy discussions • Project Authorization Request IEEE P1547.9 (standard for storage)

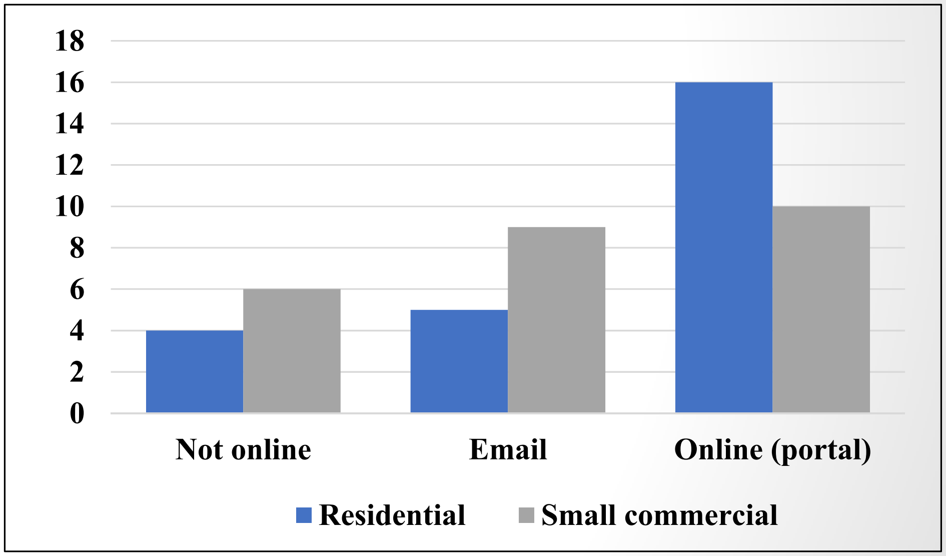
Customer Service Practices

Application Access and Submission

Map of state requirements concerning application material accessibility

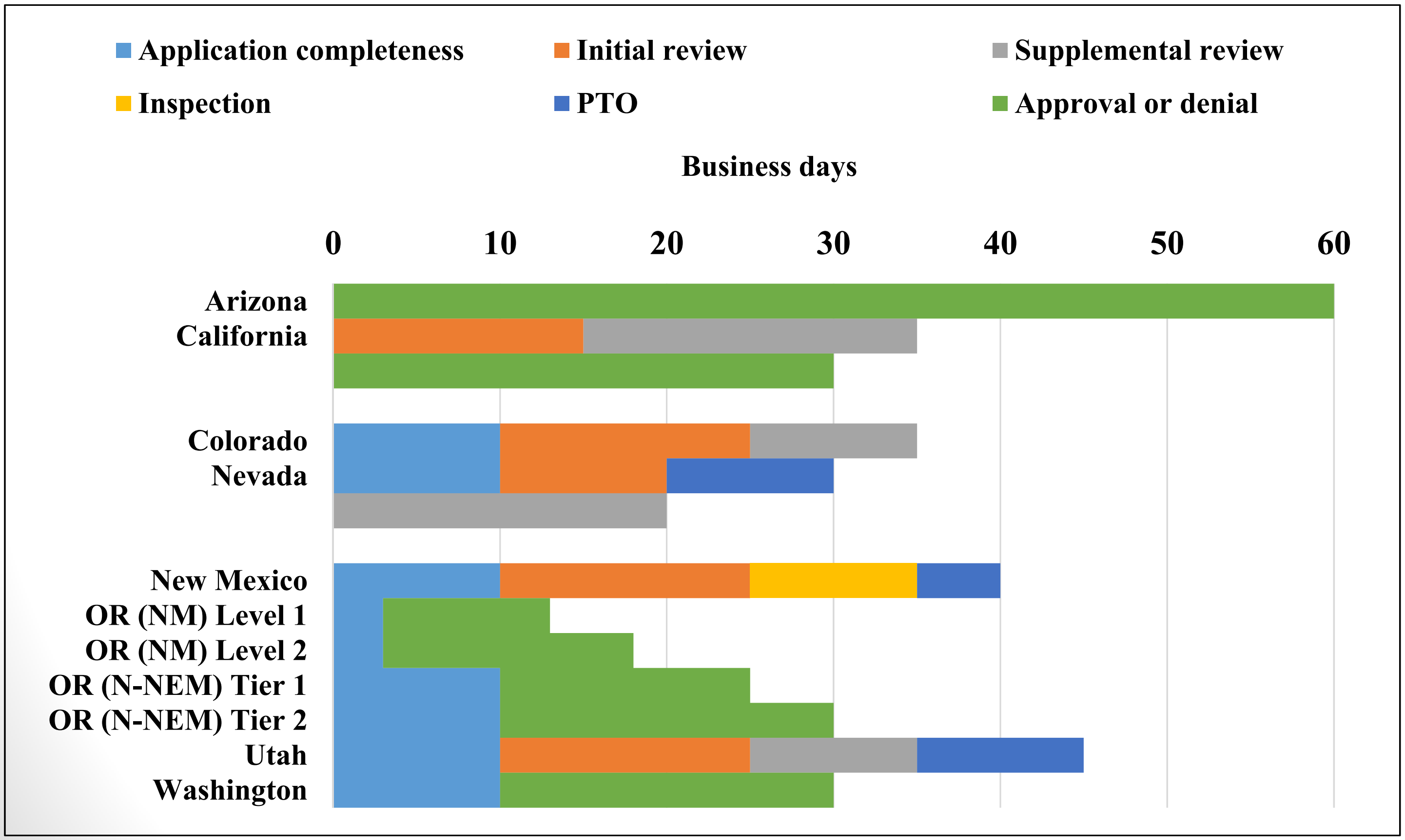


Select western utility application submission method (n=25)



Timeframe Requirements

State timeframe requirements for application processing



- Timeframe requirements vary from state to state
- Corrective action varies by state, typically light lift
- Only one state (California) requires utilities to report timeline performance

Cost-Related Provisions

Application Fees
- Standard fee for processing an application

Pre-Application Reports
- Avenue for developer to request technical information about system impacted by a proposed project

Cost Certainty Provisions
- Study or upgrade cost envelope

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Application Fees

California	• Standard fee required for NEM <1 MW • $800 for non-net metered systems and systems >1 MW.
Nevada	• No application fee for NEM
New Mexico	Fee is graduated by proposed system size: • $50 for systems ≤10 kW • $100 for systems 10 kW to 100 kW • $100 + $1/kW for systems larger than 100 kW.
Oregon	• $100 for simplified review (free for simplified NEM) • $500 for fast-track review.

Pre-Application Reports

	AZ	CA	CO	ID	MT	NV	NM	OR NM|N-NM	UT	WA	WY
Pre-application reports required to be made available		•	•					•			

- Pre-application reports help developers better understand potential costs and grid impacts of a selected site
- CA and FERC SGIP requirements are specific about information that should be included in a pre-application report

Takeaways

1. Incorporate verbiage on storage and PV plus storage, if exporting
2. Mandate interconnection timeline performance reporting
3. Require reporting of interconnection upgrade cost estimates and actual costs

Emerging Interconnection Issues and Recommended Policies

Cost Certainty

- Supplemental review cost limits
- Fixed costs In CA, NEM projects < 1 MW pay a single upfront fee that covers any potential study and upgrade costs
- Cost envelope

States with cost envelopes

State	Envelope	Entity financially responsible
Massachusetts	• 25% upgrade cost envelope after impact study estimate • 10% upgrade cost estimate after detailed study estimate	Utility shareholders
California	• 25% upgrade cost envelope. • To opt in, a developer must pay a $2,500 deposit and allow the utility additional study time.	Utility shareholders or ratepayers
Utah	• A customer's liability for studies is limited to 25% above the utility's study cost estimate.	Ratepayers

Transparency and Cost Reporting

Unit cost guides – costs for common upgrades

Reporting of interconnection costs

Example System Equipment Costs (from PG&E Unit Cost Guide)

Equipment	Unit Cost
Grounding/Stabilizing Transformer- Pole Mounted	$30,000
Grounding/Stabilizing Transformer- Padmounted	$51,000
Conductor (Per feet) - Overhead-Urban	$220/ft

Example Cost Variance Report

Project #	Estimated cost	Actual Cost	Variance	Explanation
1	$67,500	$129,966	93%	Distribution required additional mobilization. Telemetry needed.
2	$12,800	$12,797	0%	Within 20%
3	$1,351,000	$1,029,599	-24%	Distribution was complete at a shorter route. Telemetry used cellular technology.
4	$192,750	$220,941	15%	Winter construction. Telemetry used cellular technology.

Example Xcel MN Monthly Cost Variance Report (Nov 2017) filed in Docket E002/M-13-867.

Cost allocation

Cost Allocation Challenges

- Typically grid upgrade costs paid by system that triggers upgrade
- Subsequent projects may benefit but not share costs
- As deployment grows, this approach may become more problematic

Potential Policy Solutions

- **<u>Cluster study approaches</u>** evaluate impacts of a group of projects on the grid and split costs across projects
  - e.g. California distribution group study process, under Rule 21 (for IOUs)
- **<u>Sharing costs with future projects</u>**
  - e.g. National Grid Pilot. Upgraded two substations and costs are spread over current and future DERs larger than 50 kW on per kW basis.
- **<u>Utility line extension policies</u>**

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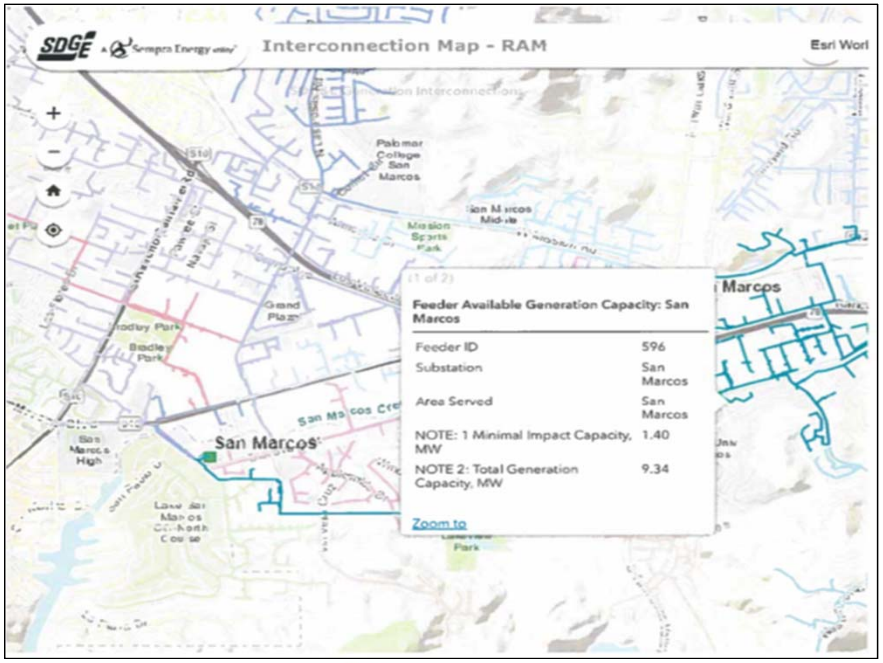
Fast Track Screens

State Use of FERC SGIP Fast-Track Review Screens

FERC Fast-Track Review Screen	AZ	CA	CO	ID	MT	NV	NM	OR NM|N-NM	UT	WA	WY
Subject to Tariff			●								
15% of Peak Load		●	●		●	●	●	●|●	●	●	
Secondary Networks		●	●		●			●|●	●	●	
Maximum Fault Current			●		●			●|●	●	●	
Short Circuit Capability		●	●		●	●	●	●|●	●	●	
Service to Transformer Compatibility		●	●		●	●	●	●|●	●	●	
20 kW Shared Secondary			●		●			●|●	●		
Split Neutral 20% Limit		●	●		●		●	●|●	●	●	
Transient Stability Limitations		●			●			●|●	●		
No Construction Screen			●		●			|●	●		

Hosting Capacity Analysis

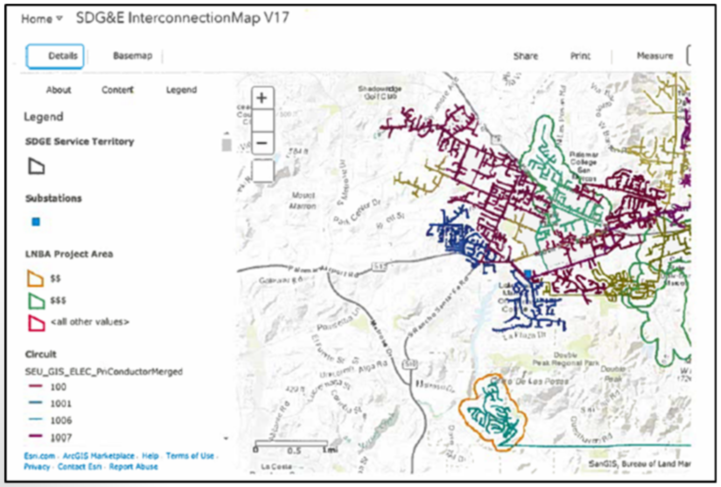
Hosting capacity: DER nameplate capacity that can be interconnected with a portion of a distribution system without the upgrading of system infrastructure



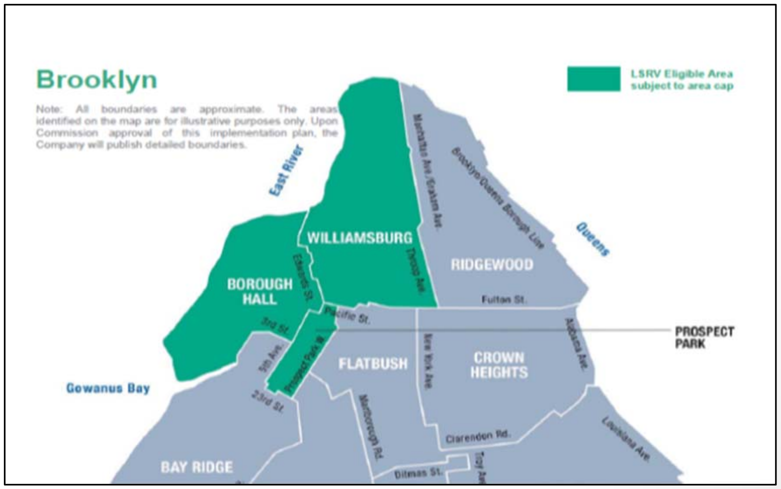
- States that employ hosting capacity analysis (HCA):
  - California (Integration CA)
  - Hawaii, Minnesota, New York
- Design and implementation considerations:
  - Capacity penetration measures vs. hosting capacity analysis
  - Streamlined vs. iterative methodology:
    - Costs (computation intensity, frequency of updating)
    - Accuracy (power flow simulations)
  - Public availability of hosting capacity data (maps)

Locational Net Benefits Analysis

- California:
  - Locational net benefits analysis (LNBA)
  - Developed during Demonstration Project B by IOUs, e.g., SDG&E – brown- v. green-encircled areas



- New York:
  - Locational system relief value (LSRV) is a factor in value stack compensation
  - ConEd (Borough Hall) LSRV-eligible area



Locational Net Benefits Analysis

<u>Locational value</u>: hosting capacity, deferral value, other factors?

- Locational value analysis:
  - Benefits, e.g., ↓ peak loading and defer infrastructure investment
  - Costs, e.g., transformer insulation aging, voltage regulator wear and tear
  - Net benefit analysis may only be positive for a minority of feeders, i.e., findings of Callaway et al (2016):

  https://erg.berkeley.edu/people/callaway-duncan/

- Design and implementation considerations:
  - Locational value, if derived using net benefit of DER deployment analysis, merits consideration
  - If net benefit is present at a given location, incentives for DER deployment could be considered

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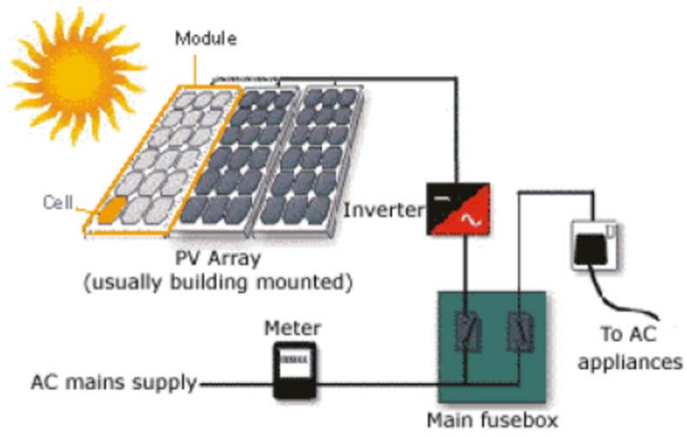
Advanced Inverters

<u>Advanced inverter functions</u>: low/high voltage ride-though, dynamic volt/var operations, DER – utility communication

- Jurisdictions that employ advanced inverter functions:
  - California
  - Hawaii
  - ISO-NE



- Design and implementation considerations:
  - IEEE Standard 1547 can be used to leverage advanced inverter functions that may enhance grid reliability
  - IEEE Standard 1547.1 (conformance testing) is currently under revision (late 2019/early 2020); until then, UL Standard 1741 SA certifies advanced inverters

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Upcoming Analysis

- Reliability Analysis (NREL):
  - Planning for High PV Penetrations
  - Analysis of DER Ride-Through Categories
- Rate Design Analysis (LBNL)

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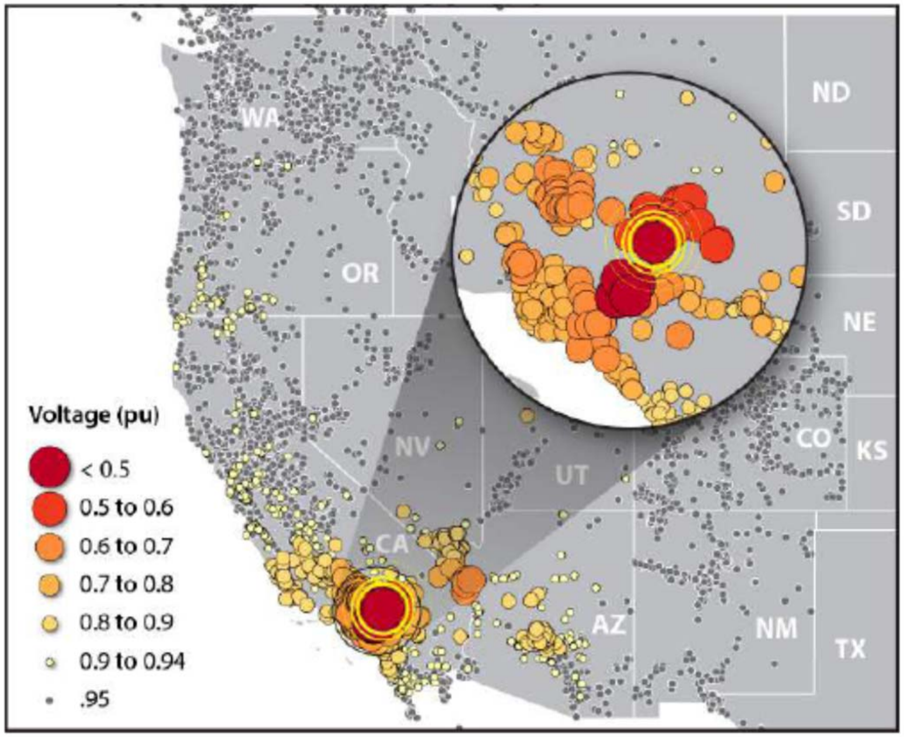
Analysis of DER Ride-Through Categories Modeling

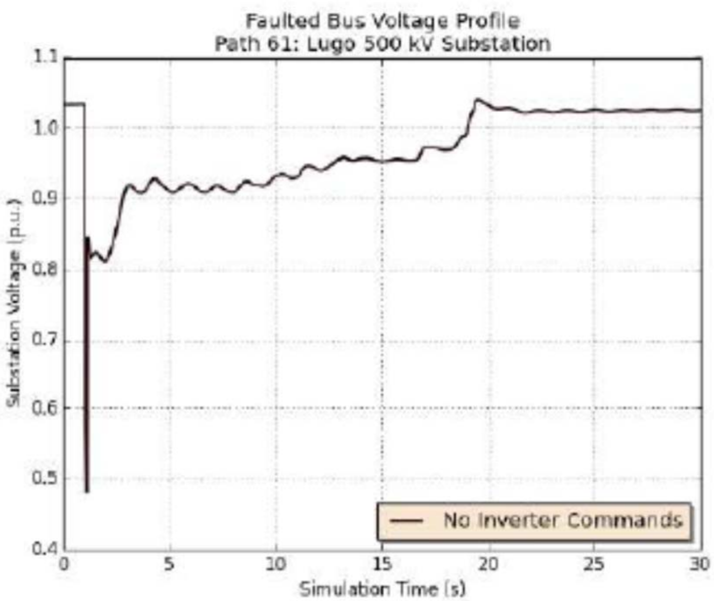
- Modeling:
  - PSLF, power flow at transmission level; OpenDSS, power flow at distribution level
  - PSLF → OpenDSS → PSLF . . . .
- Fault-Induced Delayed Voltage Recovery (FIDVR) severity metrics:
  - volt-sec metric (conventional) → Path 49 identification
  - volt-sec-DG metric (new) → Path 61 identification
- Path 61:
  - 10-mile transfer line
  - connects Victorville (LADWP) and Lugo (SCE) 500-kV lines

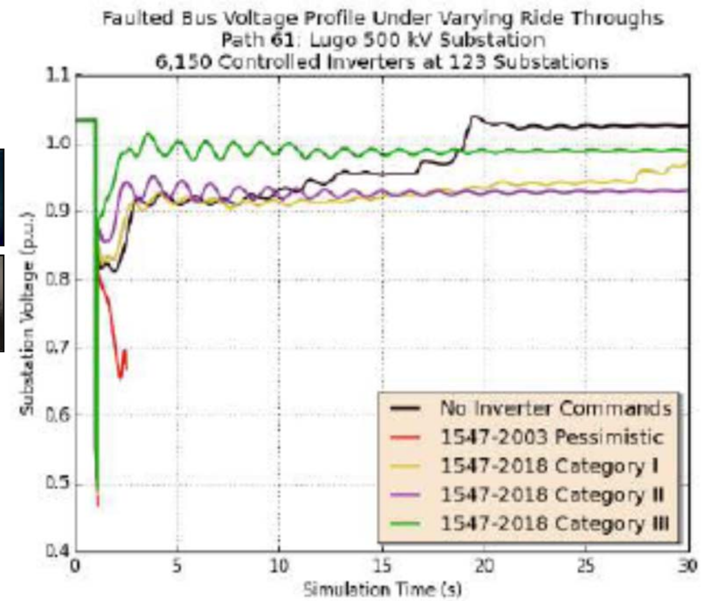
Distribution of Voltage Without Ride-Through



Geographic distribution of Western Interconnection buses with abnormal nominal voltages (categories of <0.5 through 0.90-0.94) with fault-induced delayed voltage recovery event on Path 61.

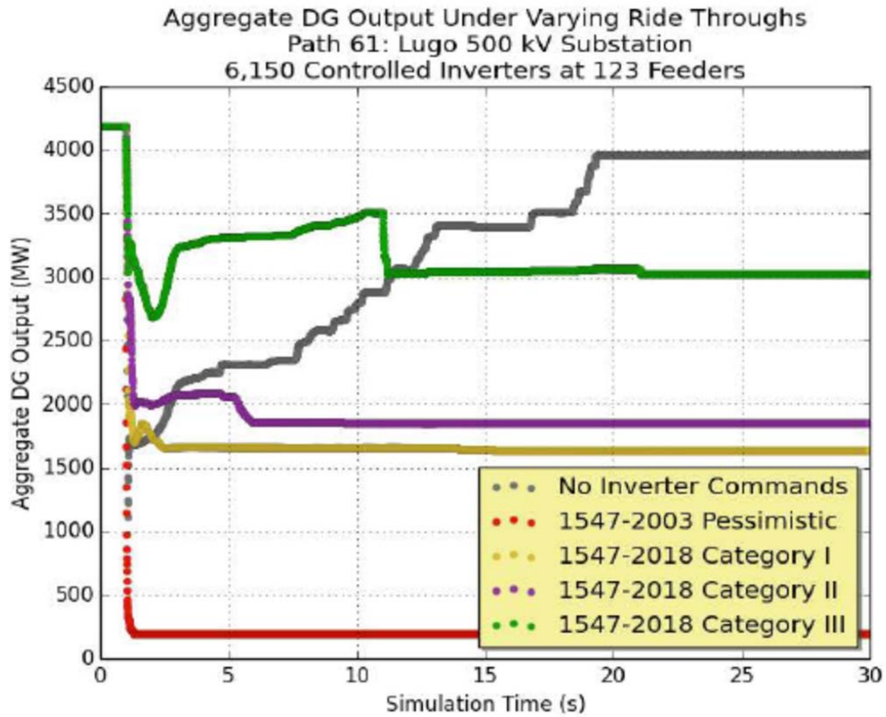
Voltage Without and With Ride-Through





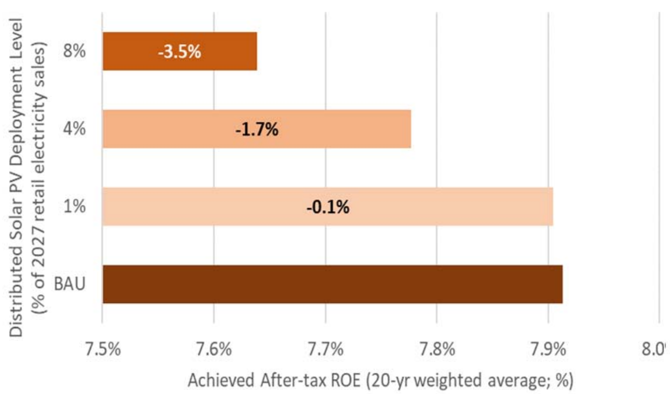
Voltage with fault-induced delayed voltage recovery event on Path 61, before (left) and after (right) OpenDSS-informed PSLF power flow modeling. Note that IEEE 1547-2018, Category III voltage ride-through mitigates abnormal voltage at Lugo Substation, in contrast to 1547-2003 and -2018, Categories I and II.

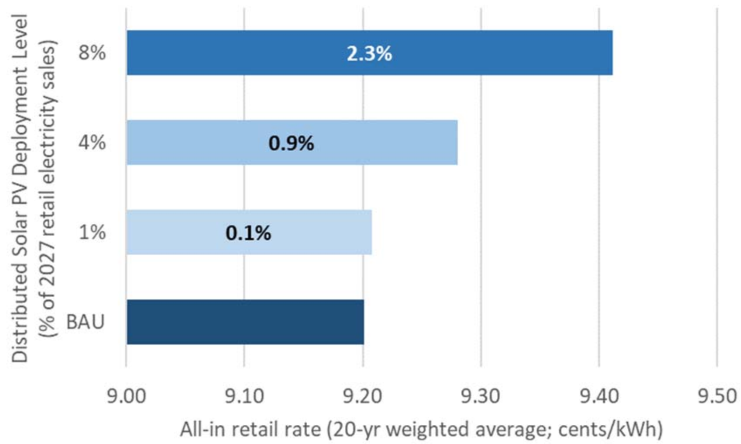
Aggregate DG Without and With Voltage Ride-Through



Aggregate distributed generation (DG) with fault-induced delayed voltage recovery event on Path 61. Note that IEEE 1547-2018, Category III voltage ride-through maintains DG at ~75% of normal level, in contrast to 1547-2003 and -2018, Categories I and II.

Impacts of NEM on Shareholders and Ratepayers





Return on equity (ROE, shareholder-specific; left) and retail rate (ratepayer-specific; right) in business as usual (BAU; no DPV), and with 1%, 4%, and 8% DPV penetration scenarios. Values inside bars represent decreases or increases relative to BAU. Revenue erosion between rate cases (reduced utility sales) and lost future earnings (deferred T&D CapEx) both contribute to decreased ROE. Increased retail rate is due to reduction in utility sales > reduction in utility cost growth.

Thank You

Maury Galbraith (mgalbraith@westernenergyboard.org)
Holly Taylor (htaylor@westernenergyboard.org)
Richard McAllister (rmcallister@westernenergyboard.org)

PROJECT INFO										
Project Name	Queue Number	Date of Application	Applicable Rules FERC/State (Tier 1-4)	ER/NR	Size	Generation Type	Project type (QF, non-QF, utility owned, etc)	Requested In-Service Date	Interconnection voltage at POI	Status (in-progress, withdrawn, in construction, active)

Feasibility Study										
Date Feasibility Study Agreement signed by customer	Date Feasibility Study Agreement signed by utility	Date of Feasibility Study Report	Scheduled number of days for completing the study	Actual number of days to complete the study	number of hours to complete the study	Number of Days Early/Late	Who performed study (utility, 3rd party hired by utility, 3rd party hired by applicant)	Restudy? (Y/N)	Alternativ e Studies?	Feasibility Study total estimated upgrade costs

System Impact Study										
Date System Impact Study Agreement signed by customer	Date System Impact Study Agreement signed by utility	Date of System Impact Study Report	Scheduled number of days for completing the study	Actual number of days to complete the study	number of hours to complete the study	Number of Days Early/Late	study (utility, 3rd party hired by utility, 3rd party hired by applicant)	Restudy? (Y/N)	Alternative Studies?	System Impact Study total estimated upgrade costs

Facility Study										
Date Facility Study Agreement signed by customer	Date Facility Study Agreement signed by utility	Date of Facility Study Report	Scheduled number of days for completing the study	Actual number of days to complete the study	Actual number of hours to complete the study	Number of Days Early/Late	(utility, 3rd party hired by utility, 3rd party hired by applicant)	Restudy? (Y/N)	Alternativ e Studies?	Facility Study total estimated upgrade costs

Interconnection Agreement						
Date Interconnection Agreement signed by customer	Date Interconnection Agreement signed by utility	Facility Upgrade Costs in Interconnection Agreement	Network Upgrade Costs in Interconnecton Agreement	Total Costs assigned to customer (in agreement)	Interconnection Agreement Deposit	In-service date stated in Interconnection Agreement

Final/Actual Data					
Who constructed (utility, 3rd party hired by utility, 3rd party hired by customer)	Actual Interconnection Facility Upgrade Costs	Actual Network Upgrade Costs	Actual Network Upgrade Costs Applied/Allowed as Refundable	Total Costs assigned to customer	Actual In-Service date