BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1631

In the Matter of Marquam Creek Solar, LLC, Petition for Waiver of OAR 860-082-0025(1)(c)	MARQUAM CREEK SOLAR, LLC'S RESPONSE TO STAFF REPORT

I. INTRODUCTION AND SUMMARY

Marquam Creek Solar, LLC ("Marquam Creek Solar") respectfully submits this Response to the Staff Report filed with the Public Utility Commission of Oregon ("OPUC" or "Commission") on April 14, 2021. Although Portland General Electric Company ("PGE") states that it does not support or oppose Marquam Creek Solar's Petition for Waiver of OAR 860-082-0025(1)(c), Staff recommends rejection of the Petition.

Staff's proposal is unreasonable because it would subject Marquam Creek Solar to lengthy and expensive contested proceedings to cure a problem that could be easily resolved by giving Marquam Creek Solar the opportunity to make a very minor reduction in its proposed nameplate capacity. Staff overlooks the realities of project development and the need for resolution in the near term for Marquam Creek Solar. Marquam Creek Solar expects that it could indeed prevail in a litigated or arbitrated proceeding over PGE's flawed studies and unjust proposal to unilaterally amend or revoke the parties' fully executed Generator Interconnection Agreement ("GIA"). In fact, in the past day Marquam Creek Solar has received a report from the community solar program's ("CSP") third-party engineering firm confirming that PGE's proposed need for 3V0 sensing and transfer trip is flawed even without a capacity reduction from

2.0 megawatt ("MW"), which certainly suggests that Marquam Creek Solar would be likely to prevail in a dispute. But the point of the Petition for Waiver is to save Marquam Creek Solar the expense and delay of doing so. Thus, Marquam Creek Solar continues to respectfully request that the Commission grant its Petition, which would give Marquam Creek Solar the option to elect to minimally reduce its capacity to the extent necessary to avoid cost-prohibitive interconnection upgrades identified in PGE's interconnection re-studies.

In the alternative, if the Commission determines Marquam Creek Solar must be confined to one of the contested processes or other test case proposals made by Staff, Staff's proposal to allow only 60 days to do so is insufficient and inconsistent with the applicable rules. Instead, the Commission should provide 60 days to file a complaint or other dispute resolution process and prevent PGE from withdrawing Marquam Creek Solar from the interconnection queue until such proceeding is finally resolved, which would allow time to attempt to continue to work with PGE as Staff suggests.

II. RESPONSE COMMENTS TO STAFF REPORT

The Commission should grant a waiver of OAR 860-082-0025(1)(c) to allow Marquam Creek Solar to make a relatively limited reduction in its nameplate capacity necessary to maintain economically feasible interconnection costs. Marquam Creek Solar respectfully disagrees with Staff's recommendation to deny the Petition.

A. Marquam Creek Solar Has Already Pursued the Third-Party Engineering Solution, which Confirms the Flaws in PGE's Interconnection Studies

The major flaw in Staff's Report is its assumption that the various contested proceedings and dispute resolution options available to Marquam Creek Solar are the best path forward. Staff proposes Marquam Creek Solar engage in arbitration of interconnection disputes under OAR 860-082-0080, alternative dispute resolution under OAR 860-002-0000, a complaint to enforce its GIA under OAR 860-082-0085, or engage the CSP third-party engineer in a review of PGE's interconnection analysis and engineering requirements.[1] But none of these options are going to be binding on PGE without substantial expense and delay, which could be fatal to this community solar project. The reality is that this project has been in the interconnection queue for four years and needs to find the fastest path to secure interconnection at reasonable cost.

Furthermore, the logic of Staff's proposal is inconsistent and flawed. The premise of Staff's proposal to deny the request for a minor reduction in the capacity of Marquam Creek Solar is the apparent concern that allowing such reduction will harm the lower queued customer on the feeder, SPQ0247. But SPQ0247 is only going to avoid expensive transfer trip costs if Marquam Creek Solar completely withdraws from the queue and eliminates PGE's requirement than anyone pay for 3V0 sensing. As PGE's comments explain, if Marquam Creek Solar proceeds with its project without reducing its capacity, it could do so only by paying for 3V0 sensing, which would then subject SPQ0247 to also supply transfer trip protection.[2] In that case, SPQ0247 would still pay a preliminary estimated interconnection cost of $762,058, which is almost certainly cost-prohibitive for its small facility.[3] On the other hand, if Staff's proposal is adopted and Marquam Creek Solar successfully prevails in a dispute resolution process or test case, SPQ0247 will likely be in no better position given the interconnection of the higher queued generator utilizing the free capacity on the feeder. Unless the Commission orders Marquam Creek Solar's GIA terminated at the public meeting, it is far from clear how Staff's proposal will actually benefit SPQ0247 in the real world.

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1 *Staff Report* at 10.
2 *PGE's Comments* at 7-8.
3 *PGE's Comments* at 8 n. 8.

Notably, it appears that SPQ0247 has development problems beyond any interconnection issues that granting the Petition for Waiver might cause. Marquam Creek Solar contacted the Marion County Planning Department and confirmed that the only application for a conditional use permit for the parcel identified in PGE's studies for SPQ0247 was withdrawn after an appeal by neighbors. Thus, the lower queued project has already experienced development flaws that would preclude it from moving forward in the near term.

Additionally, at Staff's suggestion a few weeks ago, Marquam Creek Solar has already engaged the use of the CSP third-party engineering firm, EN Energy Engineering ("EN"), and the report supplied just this week confirms that Marquam Creek Solar's concerns with PGE's flawed studies and analysis are valid. Specifically, the report, which is provided at Attachment 1 to this Response explains, in pertinent part:

> In the case of the proposed [Marquam Creek Solar] 2 MW solar project interconnecting to the Scotts Mills 13.2 kV distribution circuit, there would be no reverse power either through the 13.2 kV circuit breaker or the Scotts Mills substation transformer based on the MDL of 2.105 MW stated by the 10/27/20 letter from the PGE Legal Department.[4]
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> EN believes these PGE interconnection study guidelines are extremely conservative and should be questioned because of the considerable additional interconnection costs required by PGE especially in the [Marquam Creek Solar] project case.[5]
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> In addition, PGE in the 10/27/20 letter from their Legal Department stated 7 net metering DER projects with a total name plate capacity of 89 kW (or 0.089 MW) interconnected to Scotts Mills – Scotts Mills 13.2 kV feeder from 9/1/17 to 3/9/20, a period after MC's initial interconnection application to PGE was made. In several communications with GKS, PGE stated the 7-net metering DER's would not be responsible for any substation upgrades even though their generation interconnections contributed to lowering the Scotts

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[4] Attachment 1, EN Energy Engineering Report at 4.
[5] *Id.* at 5.

> Mills MDL by 0.089 MW. EN is not agreement with PGE's comments regarding the net metering DER's impact based on other DER interconnection processes in the USA.[6]
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> Since there is no reverse power expected through the Scotts Mills substation transformer, EN is questioning why PGE is requiring a 3VO protection scheme which includes installing a 115 kV circuit breaker and 67 kV voltage transformers when no reverse power was determined through the substation transformer in the study.[7]

The third-party report also concludes that even if transfer trip were required, PGE's insistence on use of fiber communication unreasonably inflates costs to Marquam Creek Solar over the use of more cost-effective solutions.[8]

While the third-party report certainly confirms the flaws Marquam Creek Solar and others have experienced with PGE's studies over the past several years, there is no guarantee PGE will agree with the report and change its requirements without a protracted dispute. Staff also encourages PGE to agree to reconsider its study findings, but Marquam Creek Solar's experience over the past several years does not make Marquam Creek Solar very optimistic that PGE will voluntarily do so. Staff was also apparently unable to convince PGE to seriously reconsider its studies in discussions during the three-month pendency of this Petition for Waiver.

Assuming PGE will not agree to revise its engineering analysis to keep costs reasonably within the range of those in the fully executed GIA, Marquam Creek Solar would still be confined to some form of contested proceeding with PGE. The point of the Petition for Waiver is to provide Marquam Creek Solar a certain and expeditious path forward. While Marquam Creek Solar agrees that PGE's flawed interconnection processes should be corrected, it is not realistic to expect individual developers of 2-MW community solar facilities to engage in

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6 *Id.* at 4-5.
7 *Id.* at 5.
8 *Id.* at 5-6.

protracted one-off litigation to overturn PGE's technical electrical engineering standards. Nor is it reasonable to hold up Marquam Creek Solar's development until such matters can be resolved.

B. Staff Ignores the Fully Executed GIA

In recommending the Petition should be denied, Staff's Report incorrectly ignores the executed GIA. As was demonstrated in the Petition, Marquam Creek Solar has already secured a fully executed GIA that identifies interconnection upgrades with a cost estimate of $268,350, and that GIA does not state that such cost estimates are contingent upon completion on any higher queued interconnection facilities.[9] Marquam Creek Solar has not agreed to amend the GIA, and Marquam Creek Solar has the right to enforce the GIA if the Petition for Waiver is denied.

As with most contracts, the GIA can only be amended by a mutually executed written instrument and its integration clause excludes consideration of prior communications and studies. The GIA states:

> **8.2 Amendment**
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> The Parties may mutually agree to amend the Agreement by a written instrument duly executed by both Parties in accordance with provisions of the Rule and applicable Commission Orders and provisions of the laws of the State of Oregon.
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> * * * *
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> **8.5 Entire Agreement**
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> The Interconnection Agreement, including any supplementary Form attachments that may be necessary, constitutes the entire Agreement between the Patties with reference to the subject matter hereof and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of the Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Patty's compliance with its obligations under the Agreement.[10]

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9 *Marquam Creek Solar's Petition* at Exhibit 1 (containing the GIA).
10 *Id.* at §§ 8.2 & 8.5.

However, by ignoring Marquam Creek Solar's contractual rights under the GIA, Staff's Report finds that Marquam Creek Solar is no different from any other interconnection customer. In support of this conclusion, Staff relies on the January 11, 2019 email from PGE stating that after completion of re-studies "we can make any necessary changes to the Interconnection Agreement," as well as PGE's ensuing re-studies that contain similar assertions that PGE will update the cost estimate.[11] However, Marquam Creek Solar has reserved its rights under the GIA throughout the re-study process, and neither party has executed PGE's January 19, 2010 email or any of the PGE's ensuing re-study results as an amendment to the GIA. These documents are therefore irrelevant to Marquam Creek Solar's contractual rights under the GIA.

Similarly, Staff is incorrect in finding that Marquam Creek Solar "is similarly situated to the five higher-queued generators proposing to interconnect in the same area at the time Marquam Creek Solar submitted its interconnection request."[12] None of these prior interconnection customers proposed to reduce their capacity through a petition for waiver to the Commission. Thus, those prior projects on the feeder serve as no meaningful precedent for denying the Petition. In any event, it is unlikely any of those higher queued customers on the feeder could have avoided PGE's forecasted upgrades with a minor reduction to their capacity because PGE's measure of daytime minimum load on the Scotts Mills feeder before 2019 was

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11 *Staff Report* at 9; *see also Marquam Creek Solar's Petition* at Exhibit 2 (containing email).
12 *Staff Report* at 8.

substantially lower.[13] The higher daytime minimum load to identified during the re-study process of 2.105 MW for 2019, caused Marquam Creek Solar to propose a minimal reduction to its capacity to meet PGE's requirements.

Thus, Staff is incorrect that Marquam Creek Solar is similarly situated to previous customers in the queue or that there is any precedent supporting Staff's proposal.

C. Rigidly Implementing OAR 860-082-0025(1)(c) Is Inconsistent with Best Practice in the Industry; Staff Errs to Assert Otherwise

Staff's Report is incorrect to assert "Marquam Creek Solar has not demonstrated that 'rigidly' implementing OAR 860-082-0025(1)(c) is inconsistent with best practices."[14] The Commission's small generator rules are unique in their failure to allow for reasonable capacity reductions as a matter of right, and therefore a waiver of OAR 860-082-0025(1)(c) should not be unreasonably withheld. Staff's proposal is adverse to distributed renewable energy development.

As with PGE, Staff identifies no other jurisdiction in the country where this type of de minimis downsizing is not routinely allowed. Staff states it would like to better understand the New York and California policies referenced by Marquam Creek Solar, but it is not necessary to even look that far. As previously explained, even this Commission's own Large Generator Interconnection Procedures ("LGIP") allow for such reductions.[15] As with Oregon's small

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[13] For example, PGE's System Impact Study for SPQ0037, dated June 5, 2018, measured a daytime minimum load of 1.62 MW for 2017, it and evaluated a 2.2 MW facility. PGE's System Impact Study for SPQ0046, dated April 16, 2019, measured a daytime minimum load of 2.06 MW for 2018, and it evaluated a 2.5 MW generator. The remaining two interconnection customers (SPQ0073 and SPQ0074) that were in the queue at the time Marquam Creek Solar applied for interconnection were each 2.97 MW and thus significantly in excess of the daytime minimum load measured by PGE at the time. Staff appears to suggest there was fifth higher queued customer on the feeder that was also sized at 2.0 MW, which would appear to be SPQ0054, but that customer withdrew from the queue before Marquam Creek Solar even entered the queue in 2017 and is therefore irrelevant. These studies and information are all available on PGE's OASIS website at https://www.oasis.oati.com/pge/.

[14] *Staff Report* at 9.

[15] OPUC Order No. 10-132, App. A at pp. 20-22 (containing OPUC-approved LGIA § 4.4).

generators, lower queued large generators would be impacted by such downsizings and are not typically offered refunds for network upgrades.[16] Therefore, Staff's Report and PGE's comments are wrong to assert that the other interconnection processes cited by Marquam Creek Solar "are specific to large generators facing network upgrades that will not be borne directly by the lower queued generators."[17]

There is nothing in PGE's Comments or Staff's Report that in any way suggests that it is typical or reasonable in the industry to impose a complete bar to any reduction in capacity, as Staff apparently recommends by proposing to never grant waivers to OAR 860-082-0025(1)(c). There was no expression of strong policy barring small reductions in capacity through a properly filed petition for waiver in the order that adopted the small generator rules, which provided no explanation for the basis for the rule in the first place.[18] To the contrary, such a policy is far outside of the norm and ignores the practical realities of project development, where minor capacity reductions are expected during the development process for a number of reasons, including to avoid major system upgrade costs.

D. Marquam Creek Solar Agrees that PGE Should Not Be Allowed to Remove It From the Queue if the Petition Is Denied, But 60 Days Is Unlikely to Be Sufficient to Resolve Such Dispute

Staff's Report recommends the Commission grant a "temporary waiver of OAR 860-082-0025(7)(e), and any other relevant timelines, which would otherwise require Marquam Creek Solar to execute an interconnection agreement and make milestone payments or be removed

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16 *See* OPUC Order No. 10-132 at 3 (allowing the possibility of a refund to the large interconnection customer only in the case "quantifiable system-wide benefits"); OPUC Order No 09-196 at 5 (discussing the possibility of refunds for small generators).

17 *Staff's Report* at 6.

18 *Marquam Creek Solar's Petition* at 11-12 (discussing AR 521 and change to the rules to bar such reductions at PacifiCorp's request without responding to Oregon Department of Energy's assertion that such capacity changes should be allowed).

from the queue" for 60 days.[19] While Marquam Creek Solar appreciates Staff's concern that PGE will attempt to withdraw it from the queue, Staff misreads the applicable rules, which provide PGE with no such right, and Marquam Creek Solar urges the Commission not to suggest PGE has such a right. Instead, if the Commission denies the Petition for Waiver in favor of Staff's suggestion that Marquam Creek Solar pursue various dispute resolution and test case processes, the Commission should bar PGE from removing Marquam Creek Solar from the queue until such processes are complete.

First, as noted above, Marquam Creek Solar has not agreed to amend its executed GIA to incorporate the results of any interconnection re-studies and there is no deadline for it to agree to do so. Marquam Creek Solar has offered to consider such an amendment if PGE were to cooperate to achieve acceptable interconnection re-studies and a reasonable scope of work for the project, but to date, PGE has not done so.

Second, even absent the executed GIA, the OPUC's Division 82 rules do not require any interconnection customer to agree to utility's facility study results within any deadline. The applicable deadline upon receipt of the facilities study is contained in OAR 860-082-0060(8)(h), which states: "*If the applicant agrees to pay* for the interconnection facilities and system upgrades identified in the facilities study, then the public utility must approve the application within 15 business days of the applicant's agreement." In turn, OAR 860-082-0025(7)(e) – the rule cited by Staff's Report – then provides: "A public utility must provide an executable interconnection agreement no later than five business days after the date of approval of an interconnection application. . . . The applicant must return an executed interconnection

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19 *Staff's Report* at 11.

agreement to the public utility or request negotiation of a non-standard interconnection agreement within 15 business days of receipt or the application is deemed withdrawn."

As applied here, Marquam Creek Solar has not "agree[d] to pay" for the ten-fold increase in interconnection facilities and system upgrades identified in PGE's latest Facilities Re-Study, as contemplated in OAR 860-082-0060(8)(h). Thus, there is no basis to trigger the deadline for Marquam Creek Solar to execute a new GIA or an amendment to existing GIA. The lack of such deadline makes good sense because the rules accommodate discussion between the customer and the utility to ascertain any unexplained costs and requirements of the facilities study before committing to pay for such costs – such as the ten-fold increase in costs since the time of GIA which the CSP's third-party engineer has already found to be unreasonable. Leaving a customer exposed to the risk of being removed from the queue in this circumstance would render meaningless the right to use of the CSP's third-party engineering review.

Finally, even if there were a deadline that could apply, Staff's proposal of 60 days is not sufficient to resolve this dispute if the Petition for Waiver is denied. Further, the arbitration rules Staff cites prevent the utility from withdrawing the interconnection customer from the queue without a 60-day time limit, and thus Staff's proposal would appear to leave Marquam Creek Solar in a worse position than the default treatment under those rules.[20] Therefore, if the Petition for Waiver is denied, the Commission should provide 60 days to file a complaint or other dispute resolution process and prevent PGE from withdrawing Marquam Creek Solar from the interconnection queue until such proceeding is finally resolved. That would provide time to

[20] *See* OAR 860-082-0080(5) ("The filing of a petition for arbitration of a dispute arising during the review of an application to interconnect a small generator facility does not affect the application's queue position").

work with PGE and the CSP's third-party consultant before resorting to such dispute resolution process.

III. CONCLUSION

For the reasons set forth above and prior filings, the Commission should grant the requested waiver of OAR 860-082-0025(1)(c).

Respectfully submitted on this 16th day of April 2021.

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Attachment 1

EN Energy Engineering
Marquam Creek Solar Project Study Review

April 16, 2021

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Marquam Creek Solar Project Study Review

GreenKey Solar (GKS) through Energy Solutions has requested EN Engineering (EN) to review and comment on policies and methods used in various Portland General Electric (PGE) System Impact and Facility studies involving the 2 MW Marquam Creek (MC) solar photovoltaic project in Clackamas County, Oregon.

EN reviewed the PGE Distributed Energy Resources (DER) interconnection procedures, policies and methods to determine the following:

- Are the planning assumptions made by PGE generally reasonable compared to other utilities, such as the threshold for the use of transfer trip relaying and the goal of preventing back-feeding at the feeder and the substation level?
- Does PGE methodology involving minimum daily load (MDL) appear reasonable and in line with other utilities?
- Are the solutions and associated costs proposed by PGE in line with those made by other utilities?

DER Interconnection Planning Assumptions Compared to Other Electric Utilities

PGE overall have very similar DER interconnection policies with other electric distribution utilities (EDU) in the USA and is consistent with the most current version of IEEE Std 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems.

PGE follow similar national DER interconnection policies and practices with regards to the following:

- **Electronic Reclosers** – Nearly all EDUs in the USA require electronic reclosers to be installed and to work remotely in any inverter based DER's greater than 500 kW. If a recloser is present and a fault is temporary, the recloser will close after a set time delay and remain closed. As a result, inverter based DER can come back on line much more quickly with a recloser present than without one.

  PGE requires as a minimum an electronic recloser for every inverted based DER interconnection. IEEE Std. 1547 require voltage sensing, relaying and communication capabilities only provided by an electronic recloser. In addition, in the case of the MC project, PGE followed a consistent Good Utility Practice of replacing any upstream hydraulic recloser with an electronic recloser. The estimated costs of the MC electronic recloser at $77,000 are approximately $10,000 above the current national average for an installed 15 kV class electronic recloser.

- **Group Operated Disconnect Switches** – For safety reasons, a group operated disconnect switch is required for the majority of DER interconnections in the USA greater than 25 kW. The switch shall, at minimum, provide a visible break, be lockable in the open position and be accessible by the utility 24/7 at all times of the year. PGE and the vast majority of EDUs in the USA require group operated disconnect switches for all DER interconnection studies provided. The costs of the group operated disconnect switches are included in the estimated PGE (primary service) interconnection costs of the MC DER project and are within reason.

- **Metering** – All EDUs require either primary metering or recently technology improved low metering for any inverter based DER greater than 100 kW interconnecting to a distribution level feeder 12 kV or greater. The majority of EDUs utilize primary metering but recently many EDUs have utilized low voltage metering which account and compensate for generator step-up transformer and distribution line losses. An approximate savings of $5,000 can be achieved if low voltage metering be utilized instead of the traditional primary metering. In addition, the accuracy of low voltage and primary metering are similar based on the recent technology improvements made. The primary metering costs in the MC DER project is within reasonable for similar applications.

- **Power Flow and Voltage Stability** – PGE follows similar planning assumptions regarding power flow and voltage stability with regard to power quality standard ANSI C84.1-2016 and the most recent version of IEEE Std 141 – Recommended Practice for Electric Power Distribution for Industrial Plants.

  In the case of the MC project, the voltage regulator at the Scott Mills substation will need to have the voltage set point adjusted from 120V to 118V to account for a peak load case. The costs of the adjusting the voltage set point are included in the estimated PGE (primary service) interconnection costs of the MC DER project and are within reason.

- **DER Impact at Light Load Condition** – With regard to any inverter-based solar DER considering interconnection to the Scotts Mills substation, a facility with only a single 9.4 MVA rated substation transformer and a single outgoing 13.2 kV distribution feeder documenting the daytime light load of the distribution feeder is very critical. Documenting the date and time when the daytime light load on a distribution feeder and distribution substation transformer is a requirement for system impact analysis. Daytime light load typically occurs during the Spring and Fall throughout EDUs in the US.

Typically, PGE inverter based DER interconnection system impact studies (SIS) provide the date and time when the daytime light load condition occurs for both the distribution feeder and distribution substation transformer. Based on this consistent information, SCADA load information is available for PGE distribution feeders and distribution substation transformers. The vast majority of US EDUs provide the date and time when light load occurs at both the distribution feeder and distribution substation transformer level similar to what PGE is providing in in their SIS's.

The 10/27/20 letter from the PGE Legal Department to Irion A. Sanger (Sanger Law PC), PGE states that the measured minimum daytime load (MDL) for the Scotts Mills – Scotts Mills 13.2 kV feeder for the period 6/1/19 and 6/1/20 and was measured at 2.105 MW. The minimum daytime (9 AM – 5 PM) load which occurred on 9/25/19 at 1 PM was correctly provided by PGE. The methodology to determine the MDL period provided by PGE was similar to what other the majority of EDUs in USA provide in a similar DER analysis:

- Load information over the most recent 12-month period.
- Minimum load information along with date and time provided through SCADA.
- Actual light load information provided. No reduction of minimum light occurred with regard to future inverter based solar projects.

PGE reported in the MC 3/15/21 Facility Study, the 2020 MDL for Scotts Mills – Scotts Mills 13.2 kV feeder increased from the 2019 MDL level at 2.105 MW (9/25/19 @ 1 PM) to a 2.35 MW level (6/18/20 @ 1 PM).

Based on the information provided in the 10/27/20 PGE letter, EN believes the measured MDL for both the Scotts Mills 13.2 kV feeder and the Scotts Mills substation transformer was stated correctly at 2.105 MW by PGE.

- **DER Direct Transfer Trip Protection Scheme Requirements** – Once the daylight light load levels for the distribution feeder and distribution substation transformer have been documented, reverse power flow through the distribution feeder breaker and distribution substation transformer can be determined. For example, if an inverter based DER injects 2 MW into a distribution feeder with an existing light load level of 1 MW at the feeder breaker and 1.8 MW at the substation transformer level, reverse power flow will occur at both distribution feeder breaker and at the substation transformer level. Since the DER capacity exceeds the possible feeder and transformer light loads, a possible "islanding condition", a mismatch of load and DER generation capacity can occur during a fault condition. As with most US EDUs, all Oregon EDUs would require a Direct Transfer Trip (DTT) protection scheme to be installed at the DER electronic recloser relaying and at the distribution feeder breaker relaying to avoid a possible "islanding condition". Anytime there is a possible reverse power flow through the feeder breaker or substation transformer, the DTT protection schemes during various fault conditions will trip the DER recloser off-line separating the DER from the electric power system.

In the case of the proposed MC 2 MW solar project interconnecting to the Scotts Mills 13.2 kV distribution circuit, there would be no reverse power either through the 13.2 kV circuit breaker or the Scotts Mills substation transformer based on the MDL of 2.105 MW stated by the 10/27/20 letter from the PGE Legal Department. PGE is justifying the DTT protection scheme at the Scotts Mills 13.2 kV circuit breaker by the following statement in the 10/27/20 letter:
"Per protection guidelines, if the nameplate of the proposed generating facility in addition to the existing generation on the feeder is within 90% of the associated feeder's consumption, then the proposed generating facility will be asked to be responsible for the associated substation upgrades. In this case. MC solar may increase that generation-to-consumption ratio to 95% or more. This does not take into consideration any unforeseen events which may occur on the system that may further reduce daytime minimum load and temporarily place the substation and distribution system at risk."

EN does not agree the above PGE statement regarding "… within 90% of the associated feeder's consumption…" is currently in the PGE Distribution Interconnection Standards - June 17, 2019. Instead of PGE's comment of "… within 90% of the associated feeder's consumption…" the following statement is in the PGE interconnection standards: "When an inverter based DER is above the 90% of the minimum load hot line indication is required. On feeders with reclosing, the hot line indication is used to do hot line blocking" (refer to Section 2.2.3.1 Hot Line Indication of 6/17/19 PGE Distribution Interconnection Standards). Since the 2 MW MC solar project is within 95% of the 2.105 MW MDL, PGE is implying in the 10/27/20 letter, GKS is responsible for a DTT protection scheme per protection guidelines even though PGE's distribution guidelines don't specifically include this requirement.

If an unforeseen event occurs that may further reduce the daytime minimum load EDU's have the right to take a DER temporarily off-line if reverse power occurs through the distribution circuit breaker and/or substation transformer and avoid any risk to the distribution system and substation. This practice is very common in the US for inverter based DERs to be taken off-line if a partial outage of the distribution feeder occurs and reverse power is occurring through the distribution circuit breaker, if no DTT protection scheme is available.

EN reviewed several other EDU DER interconnection study guidelines in the USA and found no similar PGE requirements such as the following:

- A DTT protection scheme is required when the distribution circuit breaker power flow is within 90% of the feeder's consumption during MDL conditions.
- PGE reserves the ability reduce minimum loading in any interconnection study by 50% to account for unplanned events that may occur on the distribution system during a light load condition such as a tap line or a recloser lockout.

In addition, PGE in the 10/27/20 letter from their Legal Department stated 7 net metering DER projects with a total name plate capacity of 89 kW (or 0.089 MW) interconnected to Scotts Mills – Scotts Mills 13.2 kV feeder from 9/1/17 to 3/9/20, a period after MC's initial interconnection application to PGE was made. In several communications with GKS, PGE stated the 7-net metering DER's would not be responsible for any substation upgrades even though their generation interconnections contributed to lowering the Scotts Mills MDL by

0.089 MW. EN is not agreement with PGE's comments regarding the net metering DER's impact based on other DER interconnection processes in the USA.

EN believes these PGE interconnection study guidelines are extremely conservative and should be questioned because of the considerable additional interconnection costs required by PGE especially in the MC project case.

- **3V0 Overvoltage Protection** – A 3V0 protection scheme is also required on the high voltage side of the substation transformer to address the risk of damaging overvoltage introduced by a DER creating reverse power flow through the substation transformer and when there is a ground fault on the high voltage side of the substation transformer. The potential overvoltage of 173% of normal phase-ground voltage on the unfaulted phases creates a significant risk to damaging arresters, substation transformers, line insulators and other equipment. The majority of US EDU's install 3VO sensing protection equipment on high side of the substation transformer when there is reverse power flow possible through the substation transformer. Installing 3VO protection equipment includes installing 3 phase voltage transformers and circuit breaker on the high voltage side of the substation transformer and relaying to detect overvoltage on substation transformer and installing transfer trip at the DER. A 3VO protection scheme rapidly detects the overvoltage condition and removes the DER as a source.

  Since there is no reverse power expected through the Scotts Mills substation transformer, EN is questioning why PGE is requiring a 3VO protection scheme which includes installing a 115 kV circuit breaker and 67 kV voltage transformers when no reverse power was determined through the substation transformer in the study.

- **13.2 kV Circuit Breaker Replacement** – If the Scotts Mills 13.2 kV circuit breaker was installed before the 1990's the likelihood the circuit breaker is incompatible with the protective DTT relaying to be installed is very high. It may be more effective to replace the circuit breaker and associated relay protective scheme, rather than replacing only the protective relays in the aging circuit breaker. This is a common practice with the vast majority of US EDUs. However, if a DTT protection package is not required to be installed, then the Scotts Mills 13.2 kV circuit breaker will be required to be installed.

<u>DER Interconnection Communication Comparisons</u>

The one practice that could add considerable interconnection costs to any solar inverter based DER is the communication requirement between the DER and the interconnecting substation. If a DTT protection packages is required, communication between the applicant's equipment and the EDUs owned communicating device will be required.

PGE's current standard is to use fiber communication for DTT schemes. Many other EDUs in the USA also prefer fiber due to its lack of ongoing maintenance, long equipment life, low security risk, resistance to interference and easy adaptability to various technology platforms.

If an DER is in close proximity to the interconnecting substation (i.e., within a few hundred feet), the additional costs of fiber communication would not be a considerable incremental cost adder. However, if the DER is 2.7 miles from an interconnecting substation, as in the case of the MC project, the fiber communication line required by PGE is estimated to add $203,000 (for the fiber) and $2,677,000 (for structural sub-transmission pole replacements) to the DER interconnection costs.

Other national EDUs do not have the fiber communication requirements such as PGE. Many others only require Multipurpose Label Switching (MPLS) communication dedicated leased lines from the local telephone service provider between the DER site to the interconnecting substation. In this method monthly payments are required from the DER to the local telephone service provider. Based on the one Idaho Power Company (IPC) Oregon DER SIS analyzed; it appears IPC allows a MPLS dedicated leased line from the local telephone service provider between the DER site to the interconnecting substation as the allowed communication method.

Another communication application that many national EDUs use is radio-based communication. There have been many recent radio technology improvements that provide low security risk, resistance to interference and easy accommodations to various technology platforms. PGE in fact is considering this radio technology in a pilot program. Pending outcomes of the pilot tests, PGE may revise the DER communication standards and related interconnection costs in the future.

PGE Study Review Summary

PGE utilizes similar solutions with regards to many other EDUs in the USA with regard to requiring electronic reclosers, group operated disconnect switches, primary metering and determining voltage support requirements.

The most critical analysis for all EDUs is determining if there is any potential for reverse power flow through the distribution substation circuit breaker if the DER capacity is injected into the distribution system as proposed. A DTT protection scheme and along with communication infrastructure between the DER site and the interconnecting substation will be required to avoid an islanding condition. In addition, if there is potential for reverse power through the substation transformer a 3VO protection scheme will also be required to mitigate excessive voltage during a fault condition.

As stated previously, EN believes PGE's justification for installing the DTT and 3VO protection packages is questionable because the MC solar project is not expected to cause reverse power either through the Scotts Mills 13.2 kV distribution feeder and/or the substation transformer.

If the MC project DTT and 3VO protection packages are not justifiable, communication and the structural sub-transmission pole replacements between the applicant's equipment and PGE's owned communicating device will also not be required.

Overall, the estimated costs of $119,493 associated with the Distribution Modifications (100T Fuse, Electronic Recloser and Primary Service) in the 3/15/21 PGE MC Solar Facility Study are justifiable and are within reason.