February 13, 2017

Solar Industry Responses to ITWG Questions on New Monitoring and Control Requirements

<u>Question 1</u>: What are the top 5 items / concerns associated with Monitoring and Control that the solar industry wish to address in relation to interconnections in NYS (Wish List)

First among the top five issues for the solar industry is our primary concern relating to the proposed implementation of dramatically lower thresholds for monitoring and control as proposed by the Joint Utilities (JU). Specifically, our concerns include:

1. The solar industry agrees with and supports in principal the long-term goal of increased monitoring and control of distributed generation, as this will be essential at higher levels of penetration to animate new distribution-level DER markets. However, as currently envisioned, the cost burden for systems below 1 MW from monitoring and control are such that projects in this range could rapidly be made non-viable by lowering the current threshold. Thus, lowering the threshold at this time could risk the virtual elimination of the small scale commercial solar market in the State.

   As detailed in section 4.3 below, we believe that the current state of the solar industry in New York as compared to other states across the U.S. and in Europe does not support a technical requirement for the kind of significantly lower threshold proposed by the JU. In light of this, the solar industry would be deeply concerned with any consideration of lowering the threshold for monitoring or control until there has been time for the JU and solar industry to develop, test, validate, and deploy a sufficiently low cost option for monitoring which would not create undue barriers to the deployment of smaller systems. We view any consideration before this occurs as premature and it would raise serious issues for the industry.

In addition to our principal concern, we have two critical questions for the Joint Utilities concerning their near and medium term plans and their views on the how these relate to requirements for monitoring and control that would be very valuable to the solar industry to have explored.

2. Most importantly, in order to better guide the development of lower-cost monitoring only strategies, the solar industry would be interested in understanding more about the use cases envisioned by the JU for the data that they would like to ultimately see collected from solar systems below 1 MW. For example:

    - Over what time frame would each of the individual Utilities be looking to make systematic use of this data and integrate it into their routine operations? Is this new monitoring data viewed as a necessity today for their existing operations platforms or are the Utilities requesting monitoring now in anticipation of future needs when their Advanced

Distribution Management System (ADMS) / Distributed Resources Management Systems (DERMS) are implemented and/or when higher penetrations of solar PV are actually deployed on the circuits?

- Would the data be used for general "operational awareness," or as part of their efforts to further the goals of REV by animating distribution-level DER markets? If so, what specifically are those distribution-level DER markets (e.g. voltage regulation)?
- How would the real-time nature of the data be significant to the Utility and what additional functionalities would it enable in the near-term as opposed to a slower temporal scale used by monitoring systems other than SCADA?
- How would the monitoring data be used differently by the Utility than that which could potentially be made available through Advanced Metering Infrastructure (AMI)? If the Utilities are not pursuing AMI, why do they not consider this a valuable potential option?
- Assuming the cybersecurity requirements are adequately addressed, under what conditions would communications over existing Internet connections such as PJM's 'Jetstream'[1] or other uses of existing customer monitoring equipment be viewed as acceptable to the JU in lieu of separate Utility specific monitoring systems?

3. In order to further guide the development of monitoring only solutions, the solar industry would like to better understand what the conditions and potential system thresholds / screening conditions are under which the Utilities could see receiving monitoring data alone for systems under 1 MW as being acceptable and what the technical rationales are for the conditions they feel would necessitate the need for control of such systems as well?

Finally, we have two more open-ended questions for the Joint Utilities concerning their views of the efforts of other utilities including those in Hawaii and California and how they are approaching the need for expanded communications, monitoring, control, and automation that would be very valuable in exploring possibilities over the medium to longer-term.

4. The Hawaiian Electric Companies' *Near-Term Action Plans* for the period 2017–2021 as set forth most recently in their *Power Supply Improvement Plan (PSIP)* from December 2016 is designed to advance Hawaii's goal of getting 100% of its electricity from renewable energy by 2045. As part of this action plan in the PSIP, the Hawaiian Utilities are engaged in a number of advanced monitoring and control efforts aimed at achieving the very high penetrations of solar PV needed to reach a 100% renewable grid which may provide valuable experience for the future design of systems in New York under REV and the Clean Energy Standard. These Hawaiian efforts include:

> Starting in 2017, we plan to pilot a plug-in collar device that is integrated with the standard utility meter slot called ConnectDER that through cellular

[1] http://www.pjm.com/markets-and-operations/etools/jetstream.aspx

communications (with capability to accommodate other communication protocols, including the Company's proposed Smart Grid Foundational Project network) can provide remote monitoring, visibility, configurability and on/off control of PV systems. Pilot is leveraging federal grant funding from US DOE and Energy Excelerator.
Plans to develop autonomous advanced inverter control for excess energy conditions. Through the Grid Modernization Lab Call, we are studying if frequency-watt functionality can be developed and configured to mitigate excess energy conditions without the need for remote communication and control. We expect to complete this study work in September 2017.

Continue collaboration with Siemens, Alstom, AWS Truepower, Referentia Systems, DNV GL, Apparent Inc., Stem, Gridco, Western Balancing Authority, and Utilities Advisory Team under the US DOE grant-supported System to Edge of-Network Architecture and Management (SEAMS) for SHINES (Sustainable and Holistic Integration of Energy Storage and Solar PV) project. Deployment of standardized communication and control infrastructure can provide system-level benefits of enhanced utility visibility and control of distributed systems and edge-of-network electrical resources thus providing grid-informed support services and monitoring.

Maui Electric and Hawaiian Electric will also continue its collaboration with Hitachi, Maui Economic Development Board (MEDB), County of Maui, HNEI, DBEDT, and the New Energy and Industrial Technology Development Organization (NEDO) on the Hitachi JUMPSmart Pilot Project on Maui. In Phase 2, DMS-based aggregation and control of the distributed resources are being evaluated to assess this functionality to manage high renewable energy penetration and to demonstrate a "virtual power plant" concept. The project leverages over $50 million from NEDO and supported by numerous international and local stakeholders. A key component of the project is the aggregation and control of distributed resources, including electric vehicles. About 12 months of data collection has occurred under Phase 1 with Phase 2 pilot testing scheduled to occur until February 2017.[2]

The solar industry would be interested to hear the JU position on the (1) direction of these efforts by the Hawaiian utilities, (2) the technology choices they are pursuing, and (3) the applicability of their potentially lower cost monitoring and control options to New York's medium to longer-term future.

5. Finally, it is clear that distributed generation developers cannot – and should not be expected to – bear the full cost burden of building out the entire level of communications, monitoring, control, and automation infrastructure that will be needed to achieve the CES goals of getting 50% of New York electricity from renewables by 2030 much less the longer-term goal articulated by Governor Cuomo of finding a "rapid, cost-effective, and responsible pathway to reach 100 percent renewable energy statewide."[3]

   California has similarly aggressive mandates for achieving high penetrations of renewable electricity. To achieve these goals, the utilities were ordered by the

[2] HECO 2016 p. 7-5 to 7-6
[3] https://www.governor.ny.gov/news/governor-cuomo-presents-25th-proposal-2017-state-state-nations-largest-offshore-wind-energy

Public Utilities Commission to identify the need for new investment (including new infrastructure) that would be needed to integrate higher levels of distributed generation. As part of their initial *Distribution Resources Plan* filed in July 2015, Southern California Edison, sought authorization to spend substantial resources through 2015-17 which would be recovered through their 2018 general rate case (in which they anticipated further requests for the years 2018-20).

Of particular relevance here is the fact that they anticipated the use of this money to make significant investments in greatly expanded communications, monitoring, control, and automation throughout their system. Specifically, their plans included:

> The first prong of this approach, "grid modernization," includes investment in information technology (IT) and automation focused on better monitoring and control capabilities. The initial set of investments is aimed at providing enhanced system-wide planning tools to support the DRP and grid analytics capabilities that leverage grid data to improve operating efficiency, such as leveraging smart meter data to identify potential grid performance problems. IT investments also consist of enhanced communications and control capabilities to provide grid operators increased ability to operate a more complex grid and interact with DERs. These IT investments will be combined with enhanced circuit and substation automation. The purpose of automation technologies is to improve protection, real time data acquisition, and flexibility. Examples include remote fault indicators (sensors) to provide more information about grid status and remote intelligent switches to improve isolation and operations.[4]
>
> Increased levels of substation and distribution automation will result in more data, such as voltage, current, and power flow at substations and along the distribution circuits. Such automation will also provide remote control of devices within the substation and more precise switching operations throughout distribution circuits. This will support increased levels of DERs by providing more information to operators regarding system performance and the effect of DERs on the grid. This will also give operators more flexibility to remotely operate the system and increase the ability of DERs to provide grid benefits, such as meeting peak demand and supporting voltage and reactive power needs. As part of substation automation, modern protection relays combined with high-speed communication will be installed to enable bi-directional load flows using more complex protection schemes. Advances in communications and control systems will be needed to support the increased levels of automation as well as the increased levels of DERs. A large amount of data such as voltage, current, and power flow will be generated by the new automated devices as well as the DERs themselves. This data must be transmitted securely to operators in real-time so that operators can evaluate and react quickly to mitigate problems if they arise. In addition, new technology platforms and applications will enhance analytics and modeling capabilities for planners to evaluate the capability of DERs to meet reliability functions as well as develop statistical models necessary to improve load forecasting.[5]

[4] SCE 2015 p. 204
[5] SCE 2015 p. 206-207

SCE's plan requested spending between $38.5 and $66 million between 2015 and 2017 on distribution automation, $31.6 to $56.6 on substation automation and $130 to $198 million on technology platforms and applications. In their 2018 to 2020 requests, these figures rose to $185 to $320 million for each of the automation upgrades and $270 to $470 million for technology platforms and applications.[6] In their 2018 general rate-case filings, SCE noted that these expenditures benefit their customers by improving "system reliability and outage restoration while supporting increasing levels of DERs and two-way flows of energy", by supporting "customer choice of new technologies and services in an expedient and cost efficient manner", and by enabling "opportunities to obtain optimal value from DERs through wholesale and distribution grid services."[7]

In light of ongoing efforts like those at SCE, the solar industry would be interested to hear the JU position on (1) SCE's arguments for including substantial investments in communication, monitoring, control, and automation within their general rate-case, (2) their choices of technology for achieving the level of monitoring and control abilities that they pursuing, and (3) the potential applicability of their approach to New York over the near to medium term as a means of achieving the JU's desired level of monitoring and control without posing insurmountable barriers to DG development.

<u>Question 2</u>: After listening to presentations and discussion on this subject at the January 2017 ITWG meeting, what are the Solar Industries proposed thresholds for Monitoring (ie, Projects Size & Voltage) requirements? Same question for Control requirements?

Based on our review of the experiences in other high States across the U.S. as well as those in Germany, we would strongly recommend the adoption of the generally applicable threshold of 1 MW based on nameplate capacity for monitoring and control via SCADA enabled PCC recloser as the standard for all Utilities in New York at the present time with the option to include a 300 kW threshold (again based on the facility's nameplate capacity) for systems connected at line voltages of 5 kV or less as is currently done by National Grid.[8] The supporting evidence for this recommendation is detailed below in Section 4.

<u>Question 3</u>: Identify any potential lower cost equipment and/or communication alternative options for both Monitoring and Control. Include

[6] SCE 2015 p. 2013
[7] SCE 2016b p. 5-10
[8] National Grid 2015 p. 19

details on costing information and any known deployment of these alternatives elsewhere in the US or elsewhere within your response.

Work on the identification of lower cost options for monitoring and control that could be validated and deployed by New York utilities is in its early stages in New York. We are aware of and support the ongoing efforts of NYSEG to identify such options and note that they have achieved a monitoring only solution with a cost of $27,500 for the RTU as opposed to $65,000 - $85,000 for a recloser with SCADA communications. While still too high to be sustained by smaller systems, this work is a commendable effort and the solar industry would be interested to learn more about NYSEG's system and to explore options to further lower its cost.

In general, there are possibilities that the solar industry are aware of that may have the potential to provide lower cost monitoring and communication such as:

- Secure data transfer systems that use public Internet as the primary communications medium (e.g. PJM Jetstream)
- SEL Real-Time Automation Controller (RTAC)[9] are reasonably priced, but may have meaningful costs for programming, commissioning and testing.
- A paired down version of the Smart Grid Solutions (SGS) Element product which is being used for the Flexible Interconnect Capacity Solution REV demonstration project is currently being developed.[10] The Element Lite is expected to cost roughly $15,000 to $20,000 with an additional $10,000 in costs to interface the product with Utility SCADA systems. The use of a SEL RTU or similar product could further lower the costs. In addition, the Element Lite may allow remote disconnect capabilities via the PV metering circuit breaker.

In addition, there may be the potential to use the functionality of Advanced Metering Infrastructure (AMI) to provide cost-effective monitoring capabilities for smaller systems where Utilities are planning to deploy AMI anyway.

Finally, there are projects the solar industry is aware of such as that in Hawaii such as the pilot project to test "a plug-in collar device that is integrated with the standard utility meter slot called ConnectDER that through cellular communications (with capability to accommodate other communication protocols, including the Company's proposed Smart Grid Foundational Project network) can provide remote monitoring, visibility, configurability and on/off control of PV systems."[11]

However, until the industry has a clearer sense of the JU requirements and perspectives as requested in our questions two and three in Section 1 above, we feel it is likely premature to propose specific technologies for monitoring only solutions. Our recommendations detailed in Section 4 are to defer any consideration of lowering the monitoring or control threshold below the current generally applicable 1 MW limit based on facility nameplate capacity. During that deferral, it will be possible to work

[9] https://selinc.com/products/3505/
[10] http://www.smartergridsolutions.com/us/products/anm-element-autonomous-real-time-secure/
[11] HECO 2016 p. 7-5

with the JU to better understand their goals and requirements and to jointly explore technologies in depth that have the potential to be piloted, tested, validated, and ultimately deployed.

Question 4: The NY Joint Utilities (JU's) are looking to lower the Monitoring and Control threshold down to 100 kW to address increased Distributed Generation (DG). From the Solar Industry perspective, (1) why shouldn't such provisions be required now or at this time and (2) when should the additional or lower Monitoring and Control threshold be implemented in NY for DG interconnection projects associated with the SIR?

4.1 – Introduction and Summary

The solar industry agrees with and supports in principal the long-term goal of the JU of increased monitoring and control of distributed generation, as this will be essential at higher levels of penetration to animate new distribution-level DER markets and is consistent with the overall goals of REV and efforts at the NYISO to transition to such a future. However, until the utilities can integrate price competitive market solutions, the level of monitoring and control envisioned in the current JU proposal will be cost-prohibitive for systems smaller than 1 MW and appears inconsistent with the thresholds used in other States including those with far higher penetrations of DER. As such we believe that it is premature to consider such a dramatic change in the current requirements for monitoring and control.

As noted above, based on our view of the IEEE guidance as well as the experience in numerous other jurisdictions and high penetration States, we would strongly recommend a continuation of the use of the generally applicable threshold of 1 MW based on a facility's nameplate capacity for both monitoring and control at the present time. We would also support the inclusion at the Utility's discretion of a 300 kW threshold (again based on the facility's nameplate capacity) for systems connected at line voltages of 5 kV or less as is currently done in New York by National Grid.[12] Our recommendation for the use of nameplate rather than aggregate capacity, is consistent with the requirements in other states California, Hawaii, Nevada, Massachusetts, and Oregon.

In addition to our benchmarking analysis, we believe that the three examples cited by the JU in relation to their proposed lowering of the threshold (Germany, Hawaii, and the FERC NOPR) do not strongly support the JU position as stated. The German experience that led to the imposition of monitoring and control on 100 kW systems is substantively different than that in New York with Germany having far higher penetrations dominated by a large number of smaller systems.[13] Hawaii is, and has been, implementing new communications and control systems throughout their grid,

[12] National Grid 2015 p. 19

[13] For example, as of December 2016, systems ≥1 MW make up more than 96% of the proposed capacity from all pending facilities in the New York interconnection queue for National Grid, NYSEG/RG&E, Central Hudson, and Orange & Rockland.

but appear to be targeting 2019 for new requirements on individual DG facilities. Finally, the recent FERC NOPR does not appear to have a universal mandate for monitoring or control on 100 kW systems and instead explicitly and repeatedly notes the need to balance the need for monitoring with that of avoiding unsustainable cost burdens on small systems.

Finally, given the success of similar standards in other jurisdictions at enabling high penetrations of solar to be interconnected safely and reliability, we would recommend that no substantive changes to the above standard be considered until (1) the level of PV penetration approaches that of other leading States that relied on the 1 MW threshold as detailed in Section 4.3 and (2) a suitably low cost option for monitoring and control can be developed that does not pose an unsustainable burden on smaller systems. Based on our review of the New York market, this is likely to take at least two years at a minimum. In making this proposal, we feel that the evidence supports our conclusion that there is very likely to be sufficient time for New York to defer the imposition of a radically lowered threshold for monitoring and control without significantly impacting system planning or creating an undue risk of potential retrofit requirements. During such a deferral, the solar industry would be strongly supportive of and seek to engage with efforts by the JU to develop, test, validate, and deploy lower cost monitoring only solutions that could interface with their distribution management systems as they are developed, come online, and expand under the ongoing REV proceedings. If an acceptably low cost option that met Utility needs could be developed sooner than expected, the solar industry would support reconsideration of the 1 MW threshold at that point.

The evidence and analysis that supports our conclusions is detailed below.

4.2 – Significance of the Proposed Requirements to the Solar Market

The proposal to move the threshold for monitoring and control to 100 kW (and to 50 kW once there is at least 100 kW in aggregate installed on a feeder) would have profoundly negative impacts on this market segment. To illustrate the critical importance of this issue to the viability of smaller projects, Figure 1 below shows a comparison of the costs per watt-AC of a 100 kW system attributable to the inverters and solar panels themselves and that which would be attributable to the SCADA enabled recloser which the current JU proposal would mandate.

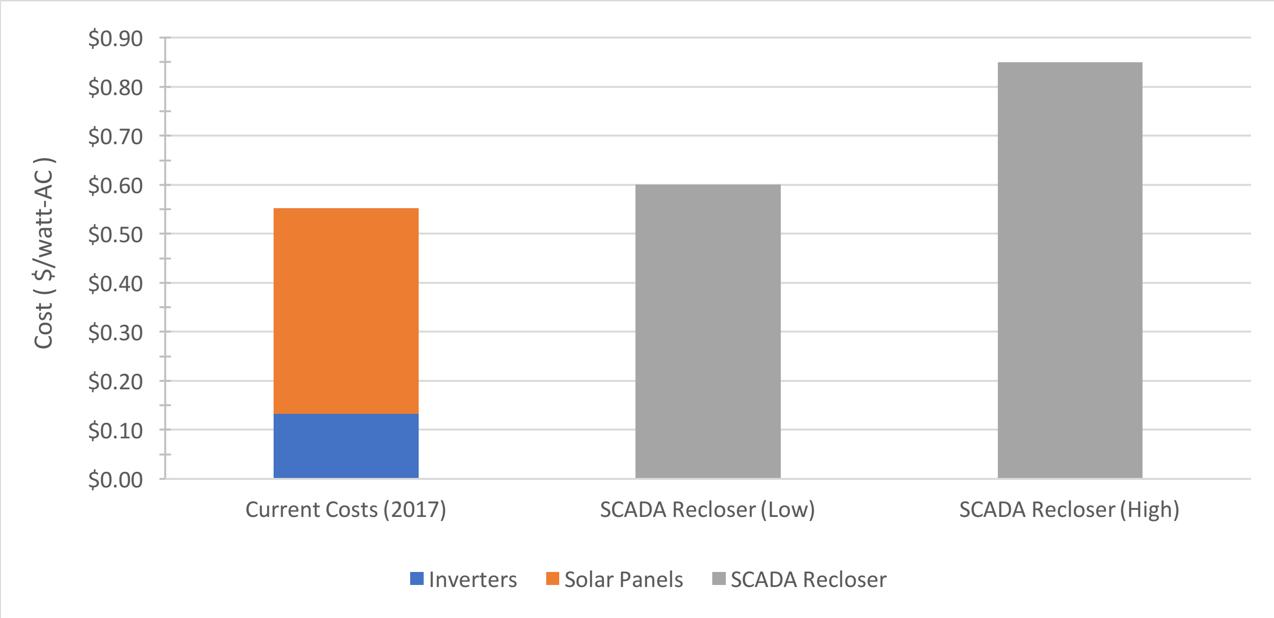

Figure 1: Comparison of the costs for the inverters and solar panels drawn from recent industry experience to the costs associated with the addition of a SCADA reclosers taken from the JU data provided in the latest ITWG Matrix (12/13/16).[14]

Thus, regardless of any potential for such monitoring and control requirements on small systems to expand the hosting capacity of distribution circuits, no projects of this scale would be able to sustain this type of high cost interconnection upgrade. As a result, the imposition of the JU proposal would effectively put an end to the market for such systems. This market is not insignificant in New York when considered by total number of projects. For example, based on the list of pending projects in the interconnection queue as of December 2016, there were more than 315 proposed projects between 100 kW and 500 kW and more than 380 between 100 kW and 1 MW in National Grid, NYSEG/RG&E, Central Hudson, and Orange & Rockland's service territories. Together, these projects make up 15 to 18 percent of the total number of projects in the interconnection queue by number and many would likely become uneconomical if SCADA reclosers were to now be required.

Finally, while the number of projects is not insignificant and they serve an important sector of New York ratepayers with some solar companies specializing in the development of systems in this range, the continuation of current practice to generally exempt systems below 1 MW from additional monitoring and control requirements should not pose insurmountable constraints on near-term Utility planning. Based on the list of pending projects in the interconnection queue, systems at or over 1 MW make up 97% of the proposed capacity from facilities over 100 kW by system size, and thus using our proposal to maintain the current threshold will very probably capture the vast majority of generation capacity that is likely to be put on the grid in the coming years.

[14] The data in this figure assumes a AC/DC ratio of 1.2 for the 100 kW-AC system when calculating the cost of the panels and inverters.

4.3 – Comparison of New York's Solar Penetration to Other Leading States

In their ITWG presentation, the JU put forth the justification that "[m]onitoring at lower levels of PV is needed to meet the Joint Utilities current and future system needs due to elevated level of PV adoption"[15]. While significant progress has been made in the last few years, the solar industry does not believe that the current penetrations of solar PV in New York are sufficient to justify the near-term imposition of radically lower thresholds for high-cost monitoring and control equipment than have been typically applied in many parts of the U.S. When compared to other leading States that used or continue to use the more generally applied threshold of 1 MW (modified by line voltage in some cases) to safely and reliability interconnect high penetrations of solar PV, New York has substantially lower levels.

For example, we considered the top nine States in terms of overall installed solar capacity as of the end of 2015 and compared their levels of penetration with that of New York based on three different metrics including: (1) the percentage of the total state-wide nameplate generating capacity of all scales and technologies that was solar, (2) the number of watts of installed solar per MWh of electricity production in the State, and (3) the number of watts of installed solar per retail electric customer. These results are shown in Figures 2, 3, and 4 below, and the average value for all the states in each figure is marked with a horizontal line.

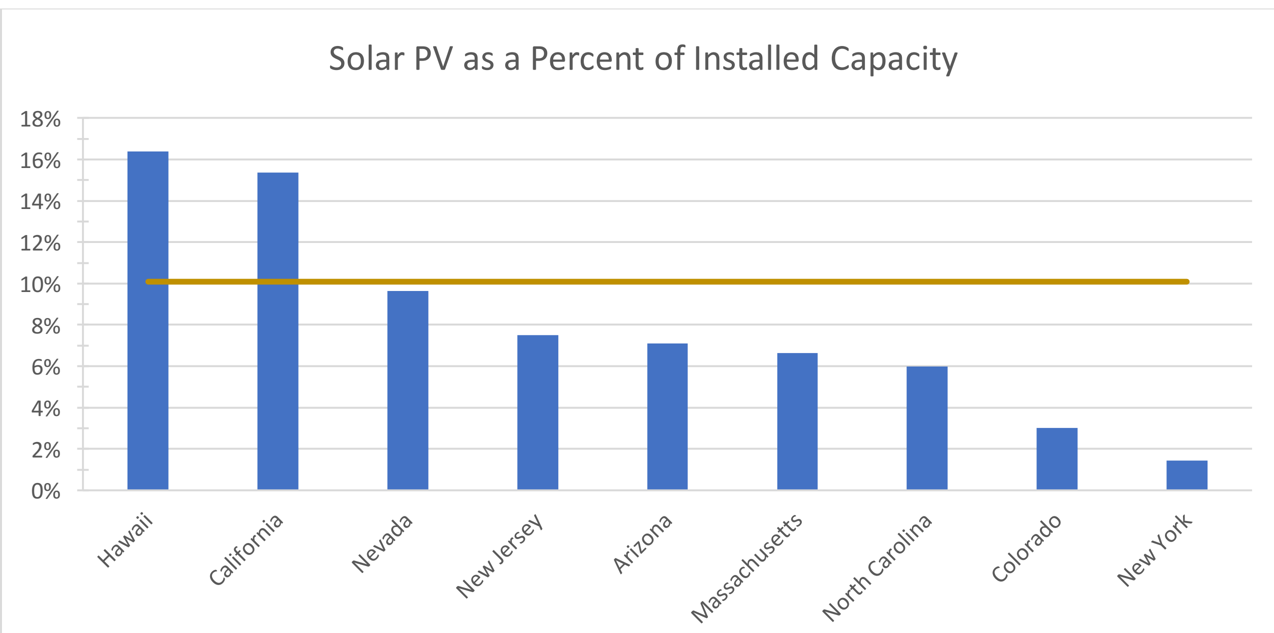

Figure 2: Comparison of the level of solar PV penetration at the end of 2015 in the nine States with the highest total amounts of solar deployed as measured by the percent of installed generating capacity that was solar.[16]

[15] JU Presentation slide 6
[16] SEIA 2016 and EIA 2016

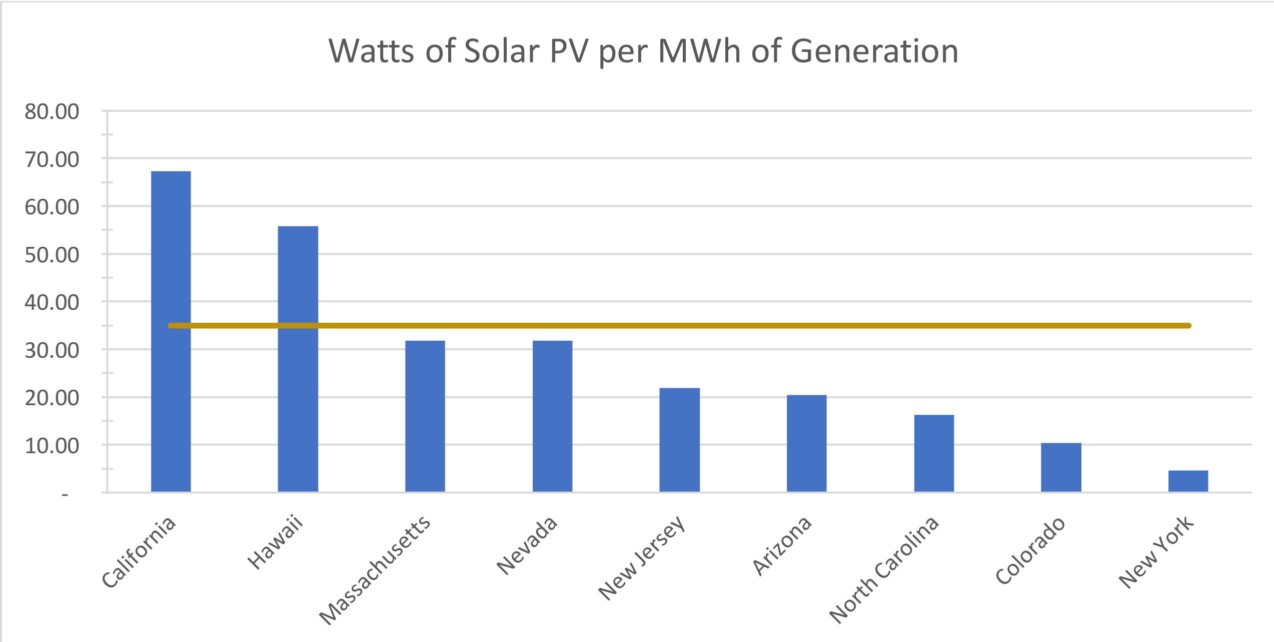

Figure 3: Comparison of the level of solar PV penetration at the end of 2015 in the nine States with the highest total amounts of solar deployed as measured by amount of solar per unit of total electrical generation in the State.[17]

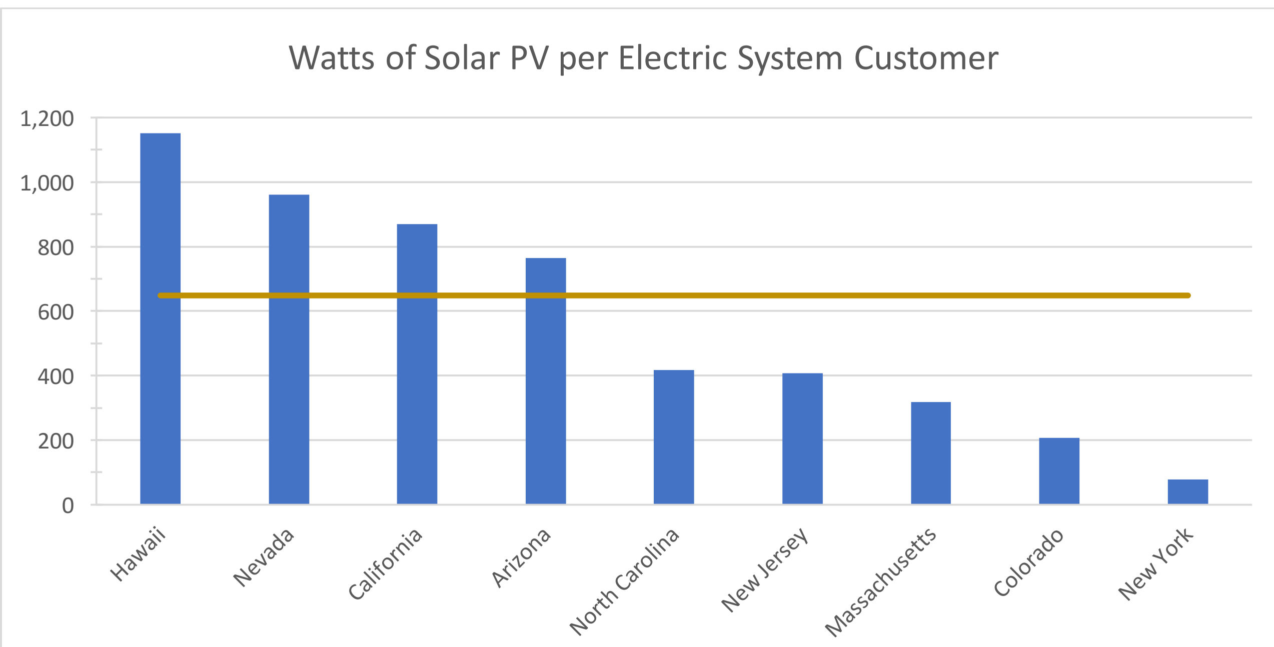

Figure 4: Comparison of the level of solar PV penetration at the end of 2015 in the nine States with the highest total amounts of solar deployed as measured by the amount of solar installed per retail electric customer.[18]

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[17] SEIA 2016 and EIA 2016b
[18] SEIA 2016 and EIA 2016c

Compared to other top States with significant amounts of solar, New York's level of penetration at the end of 2105 was just 12 to 15 percent of the weighted average of these States (78 versus 650 watts of solar PV per retail customer, 1.4 percent versus 10 percent of installed capacity from solar, and 4.6 versus 35 watts of solar PV per MWh of generation). At recent rates of deployment (207 MW in 2015 for example according to SEIA), New York would require a minimum of 17 years to catch up to the average penetration that was already present in these States by the end of 2015. Even compared to the next closest State, it would require an additional two years of development at minimum from the current date before New York would reach the same levels of penetration as Colorado had at the end of 2015.

Thus, while New York's advancement to date has placed it in the top 10 States in terms of overall development and the efforts under way to expand the State's solar market through the creation of community distributed generation (CDG), and the Clean Energy Standard will further enhance that development, there is substantial room for growth in the State before we begin to approach the levels of PV penetration seen in other regions. As will be discussed below, a number of these States reached these higher levels of penetration using the commonly applied monitoring and control threshold of 1 MW (again, modified by line voltage in some cases).

4.4 – Benchmarking of Monitoring and Control Requirements in U.S.

First, the general guidelines governing monitoring and control of DER today are those contained in IEEE 1547.3(2007). In this guide, the IEEE define facilities under 250 kW as Class 1 and note that "[b]ecause installations in this class are relatively small, it is unlikely that the AEPSO will require monitoring" and that "[i]n rare instances, the AEPSO may want to know the connection status of the DR unit."[19]

For Class 2 facilities between 250 kW and 1.5 MW, the IEEE guide notes

> As DR installations approach output levels of 1 MW, the DR owner may be required to communicate the DR's connection status and output to the AEPSO. A Class 2 DR installation of 1 MW may need to communicate its status and output to an independent system operator.

The guide goes on to note that

> Class 2 DR installations are unlikely to impact system voltage at the PCC. Therefore, it is highly unlikely that the AEPSO will require voltage monitoring.

It is only Class 3 facilities (i.e. those over 1.5 MW) for which the IEEE guide concludes that more detailed monitoring will likely be required. Specifically, it notes that

> DR installations in this class could have a significant impact on the area EPS system to which it is connected. As a minimum for most DR installations of this class, the AEPSO is likely to require status of the DR. Commonly, the DR's real and reactive power will be monitored and telemetered to the AEPSO. In such a case, the AEPSO's SCADA system may be used.

[19] IEEE 1547.3(2007) p. 19

Thus, the current JU proposal to extend monitoring and control requirements to all systems over 100 kW (and to many systems over 50 kW once the aggregate penetration on a line exceeds 100 kW) would appear inconsistent with the currently applicable expectations from the IEEE in their guidelines for implementing the "provisions for monitoring" requirements in standard 1547 (Section 4.1.6).

Second, as we noted in our presentation to the ITWG, the use of a threshold for monitoring and control of 1 MW (occasionally modified by line voltage) is a common one still in use by many jurisdictions and should not be viewed as an outdated relic of a low DG penetration past. Significantly, a number of the high-penetration States highlighted above in Section 4.3 as well as a number of other jurisdictions continue to use this type of standard and one of the utilities with the largest amount of solar in the U.S. (PG&E) has recently returned to this threshold for most facilities in its supplemental anti-islanding protection scheme. Even utilities that have recently reduced their thresholds more monitoring and control, such as two Utilities in Massachusetts, did so only to 500 kW, well above the current JU proposal.

For example, California's Rule 21 governing interconnection, states

> If the nameplate rating of the Generating Facility is 1 MW or greater, Telemetering equipment at the Net Generation Output Metering location may be required at Producer's expense. If the Generating Facility is Interconnected to a portion of Distribution Provider's Distribution System operating at a voltage below 10 kV, then Telemetering equipment may be required on Generating Facilities 250 kW or greater. Distribution Provider shall only require Telemetering to the extent that less intrusive and/or more cost effective options for providing the necessary data in real time are not available. Distribution Provider will report to the Commission or designated authority, on a quarterly basis, the rationale for requiring Telemetering equipment in each instance along with the size and location of the facility.[20]

In implementing this requirement, Southern California Edison requires that for systems between 1 MW and 10 MW "real time SCADA telemetry of watts and vars only are required for total generation and customer load" while only units larger than 10 MW are required to provide "unit gross MW and MVAR, generator status, generator circuit breaker status, and generator terminal voltage" as well as "real time telemetering of project net MW and MVAR."[21]

In addition, it is noteworthy that Pacific Gas and Electric (PG&E) recently changed its protection practices in the context of supplemental anti-islanding protection so that systems between 40 kW and 1 MW will now only require a SCADA equipped PCC recloser if the DG exceeds 50% of the line segment minimum load <u>and</u> the "line section total machine and uncertified generators to total certified DG" exceeds 10 percent.[22] This change in policy took place in early 2016 following efforts from CalCom

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[20] CPUC 2016 Section J.5
[21] SCE 2016 p. 53-60
[22] PG&E 2016

Solar (a developer with a specialization in agricultural systems) who had challenged PG&E's requirement for expensive reclosers on its smaller systems.[23]

A similar set of thresholds as those used in California are found to be common in many other jurisdictions as well. These include (in alphabetical order):

Arizona

> 8.8.2 Remote Trip
> (a) A Remote Trip is a manual trip signal issued by the APS Control Center to trip the generation off line and isolate it from the APS Distribution System. This signal will normally be communicated via fiber optic cable originating at the APS substation or communicated via a VG36 leased telephone line provided by the local telephone company. It will generally trip the generator breaker(s) via a Customer installed breaker control circuit. Any GF that is 1 MW or greater shall be equipped for Remote Trip capability.
>
> A GF with an aggregate generator nominal nameplate rating less than 1 MW will not typically require remote trip capability as specified above. However, depending upon the GF's impact on the APS System, APS may require remote trip and remote monitoring capability. The Remote Trip function will be accomplished via a Remote Terminal Unit (RTU) provided by APS at Customer's expense and installed by Customer at Customer's Facility.
>
> 8.8.3 Remote Monitoring
> (a) Any GF rated at 1MW or greater shall be equipped for remote monitoring by the APS Control Center. APS will install, at Customer's expense, a bi-directional EMS meter (in addition to the billing meter) along with communication wiring in the SES incoming metering section to provide instantaneous Watts, VARS, Volts and cumulative kWh readings to the RTU. For all installations, Customer must provide two meter sockets and two sets of test switches at the SES metering compartment in accordance with the APS ESRM – one set for the EMS meter and the other for the billing meter. APS may elect to install, on a temporary basis, and at APS' expense, transducers in lieu of the EMS meter, in the event such meter is not available at the time of the GF start-up. Once the EMS meter becomes available, APS will coordinate with Customer to install it and remove the transducers.[24]

Hawaii

> Supervisory Control: For generating facilities with an aggregate capacity greater than 1MW, computerized supervisory control shall be required to ensure the safety of working personnel and prompt response to system abnormalities in case of islanding of the generating facility. Supervisory control may be required for generating facilities with an aggregate capacity greater than 250 kW and up to 1 MW, but shall not be required for generating facilities with an aggregate capacity of 250 kW or less.
>
> Supervisory control shall include monitoring of: (a) gross generation by the

[23] CalCom Solar 2016
[24] APS 2013 p. 36

generating facility; (b) feedback of Watts, Vars, WattHours, current and voltage; (c) Vars furnished by the utility; and (d) status of the interrupting device. In addition, the supervisory control will allow the utility to trip the interrupting device during emergency conditions.[25]

Iowa and Wisconsin

The Company shall require the continuous telemetry of power quantities, breaker statuses and alarms for all aggregate generation for the following criteria:

- The aggregate generation output capability is greater than 1 MW and less than or equal to 10 MW (Iowa) or 15 MW (Wisconsin) connected to the Company's electric distribution system at a voltage 35 kV or less.
- Any customer-owned generation involved in wholesale power transactions.[26]

Massachusetts

National Grid requires the installation of an RTU for non-Independent Power Producer DG applications at the following thresholds:

5kV: DG > 500kW
15kV: DG > 1MW
+15kV: DG > 1.8MW

The RTU is intended for the company's use in monitoring and remote control of the customer DG interconnection. Communication is achieved via a customer owned leased line from the local telecommunications vendor. Remote control is installed to operate the generator breaker, parallel to the load. At the request of the customer, it is permissible to control the main breaker of their site, in series with the load. Either approach is acceptable, provided that the ultimate goal of disconnecting the DG from the company power system is achieved. In addition to the RTU, the PCC recloser will be controlled through telemetrics. Any device capable of DNP3 can be used in lieu of the RTU.[27]

PCC Recloser Requirements – Threshold DG Size (National Grid)
For independent power producers and non-independent power producers:

- 5kV: Interconnections greater than or equal to 500kW
  - For sites between 250kW and 500kW, it is the discretion of the company given the unique circumstances of the interconnection as to whether or not a recloser is required.
- 15kV: Interconnections greater than or equal to 1000kW
  - For sites between 500kW and 1000kW, it is the discretion of the company given the unique circumstances of the interconnection as to whether or not a recloser is required.[28]

Nevada

If the Net Nameplate Rating of the Generating Facility is 1,000 kilowatts or greater, Telemetering equipment at the Net Generator Metering location may be required at the Producer's expense to allow the Utility and the Customer's

[25] HPUC 2011 Section 3.f
[26] Alliant Energy 2016 p. 17-18
[27] MA TSRG 2016 p. 10-11
[28] MA TSRG 2016 p. 13

scheduling coordinator to monitor such large Generators for their impact upon the distribution system. The costs for Telemetering, including equipment, installation, and any costs for leased telephone lines are separate and in addition to other Metering costs addressed in Section G.7 below. If the Generating Facility is interconnected to a Distribution System operating at a voltage below 10 kV, then Telemetering equipment may be required on Generating Facilities 250 kilowatts or greater. The Utility shall only require Telemetering to the extent that less intrusive and/or more cost effective options for providing the necessary data in real time are not available. Charges will be included in an applicable Interconnection and Operating Agreement.[29]

Ohio, Pennsylvania, New Jersey, and West Virginia

4.4.13.2 Generator interconnections rated 2000kW or larger, individually or in aggregate shall provide access to their Supervisory Control and Data Acquisition (SCADA) Remote Terminal Unit (RTU) which will be connected via an appropriate, Connecting Party supplied, dedicated digital cellular circuit to FE's Transmission System Control Center. Details of the communication requirements begin in Section 4.13.5. The RTU must communicate with the FirstEnergy EMS via DNP 3.0 protocol.

4.4.13.3 In situations where the existing aggregate generation is approaching the minimum loading on the FirstEnergy substation transformer or where the aggregate generation on a distribution circuit is approaching the maximum generation for the circuit, at the discretion of FirstEnergy, generators rated less than 2,000 kW may be required to furnish a SCADA remote terminal unit (RTU) in order to connect and provide access to this data by FirstEnergy.[30]

Oregon

Except as provided in subsection 3(b), a public utility may not require an applicant or interconnection customer with a small generator facility with a nameplate capacity of less than three megawatts to provide or pay for the data acquisition or telemetry equipment necessary to allow the public utility to remotely monitor the small generator facility's electric output.[31]

Significantly, we note that many of these requirements including those in California, Hawaii, Massachusetts, Nevada, and Oregon specifically apply the monitoring and control thresholds to systems based on their nameplate capacity and not on the aggregate generation on the line and only FirstEnergy has an explicit caveat that "may" require generators under 2 MW to provide monitoring if the aggregate DG approaches the maximum circuit load or the minimum substation load.

In addition to the above jurisdictions, we note that the two utilities in Massachusetts that have recently lowered their thresholds for monitoring and/or control (Unitil and Eversource MA, previously NSTAR and WMECO) had previously been using a standard

[29] NPUC 2009 Section G.5
[30] FirstEnergy 2014 Section 4.4.13
[31] OPUC 2009 Section 860-082-0070. The exception in subsection 3(b) is "is for systems less than 10 MW that do not export to the grid and have protective relays to prevent feeding into the grid." [OPUC 2009 Section OAR 860-082-0055]

1 MW threshold for both monitoring and control.[32] Significantly, in the 2016 revision these utilities reduced their threshold only to 500 kW, well above the cut-off envisioned in the current JU proposal.[33] In the context of this reduction, it is important to recall that the levels of solar penetration in Massachusetts are well above those in New York. Specifically, through the end of 2015 (i.e. before the lowering of the monitoring thresholds was published by the Technical Standards Review Group), Massachusetts had a penetration that was more than 4.5 times higher than New York as measured by the metrics in Section 4.3. At recent rates of deployment, it would take more 10 years for New York to achieve parity with where Massachusetts was at the time the new, lower thresholds for monitoring and control were published.

Finally, it is of note that even in States with lower thresholds, such as Minnesota that require some form of monitoring only solutions for systems over 250 kW, that they still only require SCADA enabled monitoring (as opposed to slower, less real-time monitoring systems) and "Direct Control via SCADA by Area EPS of interface breaker" for systems over 1 MW.[34]

4.5 – Reply to Three Examples Cited by the JU in Support of their Proposed Changes (Germany, Hawaii, and the FERC NOPR)

First, the JU note in their presentation that "Germany requires remote monitoring and control for all DG over 100 kW."[35] This has been true as a general requirement across Germany since 2012 when amendments to the Renewable Energy Sources Act became effective.[36] However, the context of this requirement and the relative state of the solar and broader renewable energy markets in Germany in 2011 as compared to New York today appear to make this precedent inapplicable to our situation.

For context, the change to the monitoring and control requirements for small systems in Germany was accompanied by a change in how they were to be compensated. Specifically, systems between 100 and 750 kW are now required to "sell their energy by direct marketing" where compensation "is received in the form of flexible market premiums."[37] As part of this change, all systems over 100 kW required to have the ability for the utility to control their output and to curtail their power output remotely. Systems below a given size were allowed to avoid this requirement by accepting a limitation of their output power that could be fed into the grid at 70 percent of their rated capacity.[38]

Even more important for this discussion, this level of monitoring and control and the associated changes to compensation for systems at the level of 100 kW in Germany was driven in large part by the high penetrations of solar and by a desire to more economically achieve future increases in deployment. By comparison, through the end

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32 MA TSRG 2013 p. 8-10
33 MA TSRG 2016 p. 12-14
34 MPUC 2004 p. 13 of 29 to 16 of 29
35 JU Presentation slide 10
36 SMA 2012 and IEA 2016
37 Wirth 2017 p. 10
38 SMA 2012, IEA 2016, and Wirth 2017 p. 34 and 37

of 2015, New York was still at less than 1/10th of Germany's 2011 solar penetration as measured by installed watts per capita, as a percent of installed capacity, and as a percent of annual generation. When the intermittent renewables are combined, at the end of 2011 when the new rules in Germany went into effect, the country had more than 35 percent of its installed capacity coming from solar and wind as compared to less than 5.5 percent in New York as of 2015.

At recent levels of development for solar in New York, it would take us more than 25 years to catch up to where Germany was at the end of 2011. In addition, the need for large scale retrofits of small systems in Germany was largely a product of the very rapid pace of Germany's development of a solar market and the incentive structure of their feed-in-tariff resulting in very large amounts of small scale generators coming online very rapidly.[39] For example, the total amount of solar in Germany rose from 2,060 MW in 2005 to 25,430 MW in 2011 and to more than 41,000 MW by 2017. By 2016, solar accounted for 7.4 percent of the net electricity consumption in Germany with PV supplying up to 35 percent of total system demand on sunny weekdays and up to 50 percent of system demand on some weekends.[40] Of this impressive total, solar facilities with nameplate ratings over 1 MW in Germany accounted for just 15 percent of the total installed capacity in 2017.[41] This type of development is markedly different from the New York market with its lower penetrations and greater emphasis in the current queue on projects between 1 and 2 MW. As such, we feel that there is likely to be sufficient time for New York to substantially defer the imposition of a radically lowered threshold for monitoring and control without significantly impacting system planning or creating an undue risk in the future of unsupportable retrofit requirements.

Second, the JU note that in Hawaii

> They plan to add intelligence and controls throughout the distribution circuit and substation along with two-way communications to monitor and control inverter operation, switching, regulation of voltages and management of power flows on distribution feeders.[42]

The implication of this quote appears to be that Hawaii's plans are a precedent for their current proposal to mandate monitoring and control of all facilities over 50 kW once a feeder reaches 100 kW of aggregate DG.

While it is true that Hawaii is aggressively pursuing a more dynamically monitored and controllable grid along the lines of where Germany has been moving, it does not appear that they have finalized their plans for new requirements on individual facilities as the JU are currently proposing for New York. Specifically, in their December 2016 *Power Supply Improvement Plan*, the Hawaiian Electric Companies note

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[39] Specifically, the retrofits were designed to enable the large amounts of PV on the grid to modulate their power output in a frequency-dependent manner to address over-frequency events, to enable low-voltage ride-through, and to able to supply or absorb active and reactive power in either a static or dynamic manner. [SMA 2012]

[40] Fraunhofer 2015 and Wirth 2017 p. 6

[41] Wirth 2017 p. 32

[42] JU Presentation slide 11

> We plan to propose communication, monitoring, and reporting requirements for DER by 2019. Monitoring, configurability, visibility, and appropriate command and control of DER assets, whether through direct or aggregated communication, are a key component in the PSIP Resource Plans and Grid Modernization efforts. The Companies have taken the first step by revising Rule No. 14, Paragraph H, on October 21, 2015 to include remote connect/disconnect and configurability functionality for advanced inverters, in a signal to the manufacturing industry of our intent to require that functionality in the near future.[43]

HECO goes on to highlight a pilot project starting in 2017 aimed at lowering the cost and complexity of future monitoring and control requirements using "a plug-in collar device that is integrated with the standard utility meter slot called ConnectDER that through cellular communications" which has the ability to "provide remote monitoring, visibility, configurability and on/off control of PV systems."[44]

Finally, as with the case of Germany discussed above, it is crucial in our perspective to keep in mind the far higher penetrations of solar on the Hawaiian grid than in New York. For example, based on the penetrations as measured in Section 4.3 and recent rates of deployment, it would take a minimum of 33 years for New York to achieve the same level of solar penetration as Hawaii had by the end of 2015.

Third, the JU highlight the FERC Notice of Proposed Rulemaking (NOPR) as support for their current proposal and state that "[m]onitoring and control is required for DER, Energy storage and DR at 100kW or above."[45] When considering requirements from FERC or the NYISO, it is important to note the important differences between DER aggregations that include energy storage and/or demand response capabilities (as addressed in the NOPR) which are intended to be dispatchable and receive control signals from the grid operator to participate in the wholesale capacity, energy and ancillary services markets, and DER facilities on the distribution grid that may (like many systems under 1MW) never opt to participate in new wholesale markets or markets made possible through REV.

In addition, the FERC NOPR appears far less definitive than the JU statement would imply even for systems that would be looking to participate in the new wholesale markets. Significantly, the FERC NOPR acknowledges explicitly that the high cost of monitoring and control equipment can pose substantial barriers to the development of smaller projects and that such considerations should be taken into account when setting requirements. Specifically, it notes

> 150. While the distributed energy resources in an aggregation will need to be directly metered, the metering and telemetry system, i.e., hardware and software, requirements RTOs/ISOs impose on distributed energy resource aggregators and individual resources in distributed energy resource aggregations can pose a barrier to the participation of these aggregations in organized wholesale electric markets. We recognize that RTOs/ISOs need metering data for settlement purposes, and telemetry data to determine a resource's real-time operational capabilities so that they can efficiently dispatch resources. However, metering and telemetry systems

[43] HECO 2016 p. 7-5
[44] HECO 2016 p. 7-5
[45] JU Presentation slide 6

> are often expensive potentially creating a burden for small distributed energy resources. While telemetry data about a distributed energy resource aggregation as a whole is necessary for the RTO/ISO to efficiently dispatch the aggregation, telemetry data for each individual resource in the aggregation may not be.
>
> 151. While we are not proposing to prescribe specific metering and telemetry systems for distributed energy resource aggregators, we propose to require each RTO/ISO to revise its tariff to identify any necessary metering and telemetry hardware and software requirements for distributed energy resource aggregators and the individual resources in a distributed energy resource aggregation. These requirements must ensure that the distributed energy resource aggregator will be able to provide the necessary information and data to the RTO/ISO discussed in Section III.B.4.d but also not impose unnecessarily burdensome costs on the distributed energy resource aggregators and individual resources in a distributed energy resource aggregation that may create a barrier to their participation in the organized wholesale electric markets.[46]

Thus, the FERC NOPR explicitly does not mandate new telemetry requirements for distributed generation aggregators or their constituent components but leaves this to the individual RTOs/ISOs to decide while giving specific guidance that these rules "not impose unnecessarily burdensome costs" on DER facilities such that the new rules would "create a barrier to their participation."

As a result, the final NYISO *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets* published in early 2017 noted that

> The NYISO is considering permitting aggregations of less than 1 MW to use real-time telemetered data from a sample set (at least 30%) of DER in a DCEA [Distributed Energy Resource Coordination Entity Aggregation]. This is primarily intended for residential and small C&I customers. **The purpose of sampling is to provide a representative view of the real-time performance of the entire DCEA without subjecting small DER to onerous metering requirements.** The NYISO will explore whether this sampled data can be used for settlement, billing, audit/verification and telemetry. The feasibility and associated requirements of this approach will be developed as part of the detailed market design phase of this initiative.[47]

Considering the above, the solar industry feels that the current direction of FERC and the NYISO is more aligned with our perspective on the importance of balancing the desire for monitoring and control with the need to avoid imposing unsustainable cost burdens on smaller generating facilities than with the view of the JU. Specifically, the JU's statement that "[m]onitoring and control is required for DER, Energy storage and DR at 100kW or above" by these entities does not appear to be universally true nor would we view such a mandate (if it existed) as a relevant precedent for their current proposal on individual facilities operating at the distribution level.

4.6 – Conclusions

As noted above, it is the view of the solar industry that it is premature to consider such a dramatic change in the current requirements for monitoring and control as

[46] FERC 2016 p. 112-113 (emphasis added)
[47] NYISO 2017 p. 21

currently proposed by the JU. As such, we recommend that New York continue with the application of a general threshold of 1 MW based on nameplate capacity for both monitoring and control for the near term. We would also support the inclusion, at the Utility's discretion, of a 300 kW threshold (based on the facility's nameplate capacity) for systems connected at line voltages of 5 kV or less as is currently the practice at National Grid. This view is based on our review of the experience in Germany and high penetration States in the U.S. as well as applicable standards and relevant technical standards from the IEEE.

Given the success of similar standards in other jurisdictions at enabling high penetrations of solar to be interconnected safely and reliability, we would recommend that no substantive changes to the standard be considered (1) until the level of solar penetration in New York approaches that of other leading States as detailed in Section 4.3 and (2) until the adoption by the JU of a sufficiently low cost option for monitoring and/or control which would not create undue barriers to the deployment of systems smaller than 1 MW. In support of this second condition, the solar industry would be strongly supportive of engaging with the JU on the development, testing, validation, and deployment of lower cost solutions that could interface with their distribution management systems as they are developed and expand in the coming years.

Based on our analysis of recent deployment rates and New York's penetration relative to other jurisdictions as well as of other differences in our respective markets, we feel that it will likely take a minimum of at least two years for the conditions to warrant any consideration of a new lower threshold. Finally, as an additional benefit, deferring adoption of a such an impactful new interconnection requirement in this manner would allow needed time for the State's solar market to mature and adapt to the significant changes that will occur over the coming years including (1) the implementation of the as yet unknown Phase One interim VDER tariff and the development of the expected Phase Two successor tariff, (2) the establishment and impact of the early phases of the Clean Energy Standard procurement process, and (3) the preparations for the ramping down of the investment tax credit starting in 2020.

Thus, we view our proposal for such a deferral in consideration of any dramatic changes to monitoring and control requirements as (1) consistent with the state of the New York's solar energy market and the experience of other jurisdictions, (2) unlikely to present insurmountable barriers to utility planning or to create a significant risk of future retrofit requirements as occurred in Germany, and (3) necessary to avoid a massive disruption of the market for systems under 1 MW that would result from the imposition of a requirement for SCADA enabled reclosers at the level of 50 or 100 kW.

Question 5: Recognizing that the lowest cost solutions are preferable, at what interconnection cost threshold are 100-500 kW projects commonly no longer viable?

While there are many important variations across the State in terms of project economics, a generally applicable consensus among the solar developers is that interconnection costs above roughly $0.10 per watt are sufficient to render projects in this size range unsustainable. To be clear, this figure is the maximum interconnection upgrade cost beyond the basic service cost that projects can bear in all regions of the state under net-energy metering (NEM). Please note though that if the new Phase One Tariff results in a lower value than NEM for small commercial systems, then even this level of interconnection costs may be difficult to bear in some regions. The solar industry is happy to provide more details about the assumptions and the modeling underlying these projects' economics at or before the next ITWG meeting if that is helpful.

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