June 27, 2017

Solar Industry Responses to Questions from May 10, 2017 ITWG Meeting

EPRI REPORT / SIR SCREENS / CESIR:

1. Is there a need for a "Simplified Voltage Rise at the POI" screen or test in the preliminary review? If Yes, propose a screen and explain in detail. If no, still provide explanation.

In general, the 15% penetration screen included in the preliminary review is intended to be adequately conservative to address concerns regarding voltage rise caused by DG systems. For example, as noted in a 2012 study from NREL

> The 15% threshold is based on a rationale that unintentional islanding, voltage deviations, protection miscoordination, and other potentially negative impacts are negligible if the combined DG generation on a line section is always less than the minimum load.[1]

As such, the 15% penetration screen has been successfully relied on in the initial review process in California, Massachusetts, and Hawaii to address any potential concerns over voltage impacts from DG. Such reliance can be seen, for example, in the description of the significance of the 15% penetration screen in California's Rule 21 which notes that "[l]ow penetration of Generating Facility capacity will have a minimal impact on the operation and load restoration efforts of Distribution Provider's Distribution System." Similar justification for relying on the 15% penetration screen is included in Hawaii's Rule 14H. Thus, the addition of a "Simplified Voltage Rise at the POI" screen is unlikely to meet a need for additional protection relative to the penetration screen and we would recommend that it not be included as a new screen in the preliminary review.

However, the solar industry does recognize the value for projects that fail the 15% penetration screen to have additional information concerning the stiffness of the circuit. In particular, having information about the electrical stiffness of the circuit in the form of the short circuit current would be of value in two key ways. First, for systems that failed preliminary review, having an estimate of the voltage rise the system could potentially cause at the site would help the developer to determine if the project should move forward with Supplemental Review, a CESIR, or neither, helping to direct the project most efficiently through the application process and avoid using utility resources to study projects that have little chance of avoiding major upgrades or significant downsizing to stay within required voltage limits. Second, if the developer has other projects in their portfolio that were looking to interconnect to the same circuit, this information could similarly help them to determine whether or not to submit further applications.

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[1] M Coddington et al., "Updating Interconnection Screens for PV System Integration", NREL/TP-5500-54063, February 2012 (p. 2)

Thus, given its potential usefulness in reducing the study of systems unlikely to move forward and in directing those that do have potential to the most efficient next step (i.e. Supplemental Review of CESIR), the solar industry would request that the short circuit current at the POI be provided with the results of the preliminary review as a point of information for all projects that fail preliminary review.

2. Is there a need for a voltage flicker screen in the supplemental review? If yes, propose a screen and explain in detail what standard(s) the screen should comply with (IEEE 1453 or 519). If no, still provide explanation.

Due to extensive experience with systems in the real world as well as analyses of solar irradiance data, the solar industry believes that it is very unlikely that visible flicker (i.e. the impact of voltage variation on lighting as embodied in IEEE 1453 or 519) will be a concern for solar PV installations. In the context of supplemental review, passing the simplified methodology used to test the compatibility of the system with ANSI voltage limits provides adequate protection for all voltage related concerns thus avoiding the complexity and time required for accurate time domain analysis of the impact of solar fluctuations for systems that do not require it. As a result, if a system passes the simplified ANSI voltage limit test within supplemental review, the solar industry does not see a reason to include any further screen for visible flicker at this stage. If a system fails the simplified ANSI voltage limit test, or if its results raise concerns regarding the potential impact of voltage variations on regulation devices on the circuit or substation, then this system would likely fail supplemental review and would require further study using a time domain analysis within the CESIR process.

In combination with this recommendation to remove an a priori study of visible flicker, the solar industry would again express its support for a post facto process to address flicker as detailed in comment 1.3 from our April 28, 2017 responses to the original EPRI proposals. Specifically, in the unlikely event that a complaint was to arise following installation of a solar system, the limits imposed by IEEE 1453 can be directly and accurately evaluated via the use of a flickermeter and the root cause of any violations can then be identified. If it is found that the solar facility is to blame for the power quality issues, the interconnection contract would provide the necessary process for the system to be taken offline pending mitigation.

3. Propose and explain in detail how voltage flicker should be studied / reviewed as part of the utility CESIR. Again, explain in detail what standard(s) the screen should comply with (IEEE 1453 or 519)

As noted above, the solar industry believes that it is extremely unlikely that visible flicker presents a concern for solar PV installations that justifies the effort and complexity involved with conducting an accurate time domain analysis and is better addressed via a post facto process using actual measurements with a flickermeter. In this, we remain in agreement with the initial recommendations of EPRI and our comments of April 28, 2017.

If, however, our recommendations to eliminate the study of visible flicker from both the Supplemental Review and CESIR steps are ultimately not adopted, then the solar industry would stress that the only applicable standard, in our view, is IEEE 1453 and would strongly argue that no consideration should be given to the application of the outdated and now superseded methodology of the pre-2014 versions of IEEE 519. This point is addressed further in the attached annex to these comments.

Finally, unlike and separate from visible flicker, if the simplified voltage screening methodologies used to determine compliance with ANSI limits raise concerns regarding the impact of transient voltage variations on any regulation devices present, then this issue is one we feel should be studied further within the CESIR process. Specifically, in such cases, the solar industry would recommend the use of long-term dynamics modules that represent the impact of an intermittent DG by varying their output with realistic levels of ramping and that can take appropriate account of the geographic diversity of systems on a circuit. Such a recommendation is consistent with that of a 2013 report from Sandia National Laboaratory which concluded that

> QSTS [Quasi-Static Time Series] analysis is necessary to accurately quantify the effects of PV on voltage regulation device operations. The analysis should be an estimate of the long term, e.g. annual, difference in operations that can be expected due to PV. It is necessary to run both the base case and the PV case for comparison in order to quantify the impact due to PV.[2]

<u>MONITORING & CONTROL:</u>

1. Compile data and information analysis on economic impact of Monitoring & Control requirements on PV projects in the 0-50kw and above 50kw up to 1MW ranges.

Context and Uncertainty

At the current time, it is difficult to arrive at a definitive assessment of the costs that solar projects in the above two ranges can bear for monitoring and control requirements going forward because it is a time of particular change and uncertainty in the market. While we expect most of these uncertainties to be settled in the next year, they include:

1. Awaiting finalization of the NY VDER tariff, especially for non-CDG solar projects, but also for CDG projects in a few key components

[2] Robert J. Broderick, Jimmy E. Quiroz, Matthew J. Reno, Abraham Ellis, Jeff Smith, and Roger Dugan, *"Time Series Power Flow Analysis for Distribution Connected PV Generation"*, Sandia National Laboratories, January 2013 (SAND2013-0537) p. 18

2. The widely varying PILOT rates and default property tax assessment approaches currently being used across the state
3. The declining NY Sun MW Block incentive, which is soon to be in its last block for the C&I Rest of State Region
4. Lack of market data concerning both the minimum required discount need to acquire customers, and the amount of customer churn for CDG projects and the resulting impact on project economics
5. Finally, there are larger unknowns not modeled or included here like the pending Suniva/Solar World U.S. International Trade Commission trade case that has threatened to add a $0.40/W tariff to foreign made module prices.

Assumptions

With all of these uncertainties in mind, for the purposes of presenting a model based on our current best understanding, we evaluated the question using a set of realistic inputs for several example projects sizes in all of the utility territories to arrive at a range of potentially bearable additional costs for monitoring and control requirements. Given the uncertainties of VDER finalization concerning storage, we looked just at solar-only projects. The standard assumptions used for each analysis were:

1. Total capex project costs by size (including EPC, Development, etc) of $1.50 Wdc for 750 kW, $1.60 Wdc for 500kW, $1.70 for 250kW, and $2.00 for 50 kW based on the latest industry data
2. No base project interconnection costs beyond addition of a new service
3. Project revenue based on default VDER Tranche 2 and 3 VDER tariff rates for CDG projects by utility (and Tranche 1 was included for National Grid), which we consider conservative, as the compensation for this project type is expected to be the greatest and most financeable value available under the new tariff.
4. Property tax PILOT rates in line with NYSERDA's new recommended PILOT ranges and use of a revenue-based assessment methodology (for all projects regardless of size)
5. NY MW Block incentive levels continuing at the lower final levels being approached, which are around $0.03/kWh
6. The project must offer at least a 10% discount below current retail rates to acquire and retain customers
7. Standard land lease rates are used for all projects by region, ranging from $1,000/acre/year upstate to $1,500-2,000/acre/year downstate
8. Standard solar resource data by region
9. Projects typically use financing, and have access to competitive rates on debt and standard tax equity costs.

Modeling and Results

1. For the range of potential additional bearable costs by project, the low end was modeled using the VDER tranche 3 compensation, the higher end of NYSERDA's recommended PILOT range, and a 5% customer churn that results in unusable credits.
2. The high end of the range in contrast was modeled using VDER tranche 2 compensation (or tranche 1 in the case of National Grid), the lower end of NYSERDA's recommended PILOT range, and a 0% customer churn that results in unusable credits.
3. The results of this analysis for each utility and project size are below:

Table 1: Example Potential Additional Bearable Costs By Project Size and Utility Territory Location ($/W)

	50 kWac	250 kWac	500 kWac	750 kWac
NYSEG West	$0.00	$0.00	$0.00	$0.00
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RGE	$0.00	$0.00	$0.00	$0.00
National Grid	$0.00	$0.00	$0.00	$0.00
Central Hudson	$0.00	$0.00	$0.00-0.01	$0.00-0.08
ORU	$0.00	$0.00-0.18	$0.02-0.27	$0.10-0.34

Conclusion

From the above analysis, we find that:

- Projects above 200kW in ORU and over 750kW in Central Hudson are potentially able to bear some modest additional costs for monitoring and controls while remaining minimally economically viable. For Central Hudson, this would only possibly be the case for projects over 750 kW. For ORU, this may be possible for projects in the range of 250kW-1MW, but this is still pending all of the above mentioned uncertainties in the opening section, any one of which could irrevocably change this conclusion and eliminate the ability to bear the additional cost. In this context, it is also important to note the assumption of zero addition interconnection costs other than those associated with the addition of a new service. For most projects, the addition of even modest interconnection upgrades could also have significant impacts on these conclusions.

- Projects under 1MW in National Grid, NYSEG, and RGE are typically not able to bear any additional costs and are in fact, having difficulty remaining economically viable today at this scale. In fact, the only way smaller projects in these later utility territories are expected to remain viable going forward are if you can do some combination of the above: large volumes to scale and further drive down costs below industry standards, combine projects in portfolios with downstate projects, build on-site with no lease payments, build on-site with no new electrical service from the utility, secure projects with no property tax, and/or have customer able to supply their own capital and use tax credits and so no additional financing costs for these elements. While these are possible solutions, they should definitely not be assumed to be possible or probable for these smaller size projects and thus relied on to assume that they could bear any additional costs for monitoring and/or control.

- As a result of this more detailed modeling, we continue to have serious concerns regarding the impact of any new monitoring and/or control requirements for systems below 1 MW. As a final note, we would like to highlight that the timeline for resolution of many of the major uncertainties in project financing highlighted above is consistent with the timeline for deferring action on new monitor and/or control requirements the solar industry has recommended previous to enable time for the development, testing, and deployment of lower cost options. As such, the financial modeling continues to support our recommendation that action on new mandates in this area be deferred at this time to allow the uncertainties to be resolved and new, more economically viable hardware options for monitoring and/or control to be developed.

IOAP / AUTOMATION:

1. Solar Industry – Poll the industry to determine what the overall goal is for the IOAP / Automation. What specific areas of the application process do you anticipate will improve with automation? Is full automation required rather than just utility compliance with SIR timelines?

The solar industry supports the near-term automation of those screens, such as the 15% penetration screen, that can be done readily, but does not see the full automation of the preliminary screening analysis as necessarily possible in the short-term nor a goal unto itself. In particular, the solar industry sees automation as a means of improving the accuracy and usefulness of the overall preliminary screening analysis by allowing the time within the existing SIR timelines previously spent on those automated screens to instead to be used for those steps which cannot yet be readily automated.

For example, as noted above the solar industry is requesting the provision of the modeled short circuit currents at the POI as a point of information in order to better enable decisions to be made on whether and how to move forward with projects that fail the 15% penetration screen in the preliminary review. While the provision of this information at the level of preliminary review is already done in some utility service territories as part of their interpretation of the current Screen F, the automation of as many steps as possible in the preliminary screens would free additional time for such analyses.

Finally, in delaying the implementation of full automation of the preliminary screening analysis, the solar industry would request that a deadline still be set for the initial automation of those screens for which automation is currently appropriate and practical and that additional discussions be held on future deadlines as situations that might enable further automation, such as the roll out of the initial hosting capacity analyses, occur.

2. Would you be more likely to use the Supplemental Screens if the cost and time applied towards the screens counted towards the CESIR cost and time requirement?

Based on experiences with a similar process in Massachusetts, the solar industry would be very interested in exploring such a proposal as part of a revamped supplemental review process. If the 20 business day timeline for the supplemental review could be rolled over into the CESIR process, leaving something on the order of 40 business days to complete the remainder of the full impact study following payment by the developer, than one of the major barriers to the use of supplemental review would be eliminated. In many cases where the usefulness of the current supplemental review process is in doubt, developers may bypass the supplemental review entirely and accept the higher cost of conducting a CESIR to avoid the potential for 80 business days to elapse before receiving the results, should they go for supplemental review and fail. The ability to apply at least a significant portion of the cost associated with supplemental review towards the CESIR would further lower the barriers to making use of this option for systems that may not need a full engineering study.

Within the framework for such a change, which we have seen put forward in the form of the proposal to cap the engineering hours allotted to supplemental review and allow its cost and timeline to roll into the CESIR, the solar industry feels it would be important at the conclusion of the supplemental review to be presented with the results of all completed analyses along with a summary of the issue or issues that arose requiring more time for engineering analyses, in order to provide transparency and enable decisions to be made on whether or not to move forward with a full CESIR. If such a proposal was to move forward, the solar industry would recommend that the technical discussions of what is to be included in the revised supplemental review and what results are to be provided remain with the ITWG, while requesting that the procedural questions of timeline and cost allocation questions be taken up by the IPWG contemporaneously.

Annex –Supplemental Comments on the Applicable Standards for Setting Limits on Visible Flicker

While the solar industry does not believe that visible flicker present a concern for solar PV that warrants the need for the type of detailed time domain analysis necessary to accurately model this phenomenon and that no simplified screens should be adopted, we do wish to clarify here that the only standard that should be applied in any case is that in IEEE 1453.

In 2014, the latest version of IEEE 519 removed any reference to the so-called "Flicker Curves" in their entirety. Thus, the previous version of IEEE 519 from 1992 (now nearly 25 year old) was officially superseded. This change in IEEE 519, left the updated methodology in IEEE 1453 as the only active IEEE standard for use in evaluating the impact of visible flicker. In addition, we note that the adoption of limits based on the IEEE 1453 methodology are also likely to be included in the revised power quality section of IEEE P1547 currently under consideration.

Thus, the solar industry would argue that there is no longer a currently active IEEE 519 flicker standard to apply, and references to it should be eliminated. Such a conclusion that, when flicker is to be considered at all, that it should be evaluated under the limits of IEEE 1453 is consistent with the recommendations from the 2013 report from Sandia National Laboratories which noted

> The need for a formal flicker analysis should be established by evaluating the effect of a 100% change in PV output. If further study is justified, then a time series simulation can be performed, and the resulting voltage profile can be evaluated against the IEEE 1453 criteria.[3]

This was also the conclusion of the Independent Engineer who addressed the issue of visible flicker in a 2016 dispute between Xcel Energy and the developer of a Solar Garden facility in Minnesota. Specifically, the Independent Engineer concluded

> In this decision, the IE cites the Sandia-EPRI report and benchmarks three large North American entities comparable to Xcel Energy. All three entities use the IEEE Standard 1453-2015 to evaluate the impact of flicker on the distribution system. The IE also references a Case Study that demonstrates the effectiveness of using IEEE Standard 1453. The IE finds that Xcel Energy should be using IEEE Standard 1453 in the evaluation of flicker impact on the distribution system with the interconnection of DER.[4]

Finally, and most significantly in the current context, our conclusion that the only standard for evaluating visible flicker should be IEEE 1453 is consistent with the ruling of the Public Service Commission that adopted the most recent changes to the SIR in March of 2016. In their ruling the PSC noted that

> A new edition of IEEE 519, however, was adopted in 2014 and the [flicker] curves were eliminated from the guidelines; a streamlined document that

[3] Sandia 2013 p. 47

[4] Independent Engineer Decision, Community Solar Interconnection Engineering Dispute Between Xcel Energy and SEV MN1 LLC Seeking to Interconnect with Xcel Energy's Distribution System in Minnesota. Decision Resolving Solar Garden dispute with Xcel Energy, Date September 2, 2016 p. 1-2

contains recommended practices for harmonic measurements and limits for harmonic content is what remains of the previous edition. In order to conform the SIR to this recommended practice, any references to the curves are removed and the references to maximum harmonic content are adopted.[5]

Restricting any consideration of visible flicker to the use of the modern IEEE 1453 standard is particularly important as the now superseded flicker curves in IEEE 519 were originally designed to take into account the impact of square waveform fluctuations that occur with fairly regular and known frequency unlike the ramping of solar facilities due to transient cloud cover that produce fluctuations with more complex shapes and frequency distributions. In examining the impact of such differences the 2013 Sandia report noted

> The disadvantage of using the older IEEE 519 flicker curves for evaluating the voltage variation caused by PV is twofold. First, the flicker curve requires knowledge of not only the percent voltage dip caused by variation in PV plant output but also the frequency of the voltage dip. The frequency can be very difficult to quantify for cloud patterns that are not consistent. The second problem is the design of the flicker curve which was developed to address fast voltage changes such as motor starts and not the slowly changing voltage variation seen with PV. These problems with the IEEE 519 flicker curves often lead to an unnecessarily conservative approach for determining PV induced flicker impact.[6]

To illustrate this point, the Sandia report highlights a model circuit that was electrically weak and had a PV plant that was sized to 100% of the feeder's peak load and 240% of the feeder's minimum load. The largest ramp-rate occurred over a 5 minute period with a voltage dip of 2.65% at the PCC. However, the P_{st} was 0.07 for this event which was far below the planning level of 0.9. The report went on to conclude that "[t]his shows that the flicker associated with the largest delta V ramp, was not a problem for this feeder" and that "[n]one of the P_{st} exceeded the planning level of 0.9 and none of the P_{lt} approached the planning level of 0.7.[7]

Thus, to reiterate, the solar industry believes that it is extremely unlikely that visible flicker presents a concern for solar PV installations that justifies the effort and complexity involved with conducting an accurate time domain analysis and is better addressed via a post facto process. However, if our recommendations to eliminate the a priori study of visible flicker within the Supplemental Review and CESIR processes are not adopted, then the solar industry would strongly oppose the application of any standard other than IEEE 1453. Similarly, if our recommendations are adopted, the solar industry would strongly support the use of an actual flickermeter and the approach of IEEE 1453 alone for use in any retrospective analyses of visible flicker once systems are installed.

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[5] New York Public Service Commission, CASE 15-E-0557 - In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less., *Order Modifying Standardized Interconnection Requirements*, Issued and Effective March 18, 2016, p. 24

[6] Sandia 2013 p. 45

[7] Sandia 2013 p. 48-52