*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Substation Transformer Backfeeding:

Substation Transformer Backfeeding	Joint Utilities
Common Definition	Reverse power flow through substation power transformers from the distribution system as a result of ~~excess generation on~~ generation sources from the distribution system.
Existing allowances for substation backfeeding	Currently allowed for all overhead radial systems in NY with necessary modifications
Criteria for neutral overvoltage protection~~3Vo~~	Needed for substations comprised of delta-wye transformers that are radially fed or tapped from a single transmission source where backfeeding is expected~~expected and islanding may be sustained for some time~~. ~~3Vo~~ Neutral overvoltage protection reduces prolonged over voltage from phase to ground faults on delta-wye connected transformers. Substations with multiple transmission sources are already protected against over-voltage conditions resulting from phase to ground faults.
If neutral overvoltage protection~~3Vo~~ is required, explain the function of the ~~3Vo~~ neutral overvoltage scheme	~~3Vo~~ Neutral overvoltage protection schemes protect~~s~~ Delta-Wye connected transformers and transmission system equipment from zero sequence voltage issues like over-voltage from a phase to ground fault. 3V0~~o~~ is one of the most common ~~a~~ protection scheme applications designed to reduce the duration of long term overvoltage conditions. In general, protection schemes are established to detect and mitigate safety and reliability issues but ~~but~~ do~~es~~ not reduce the risk of the fault from occurring. These overvoltage conditions have the potential to exceed insulation levels (BIL) of the substation and transmission line equipment, and maximum continuous operating voltage of surge arresters. Zero sequence voltage protection (or another ~~fast~~high speed detection method) on the primary side of the transformer is required in order to detect these overvoltage conditions. ~~3Vo~~ This protection will disconnect the generation ~~from~~source from the ~~substation transformer~~fault condition, and stop the ~~DER and substation transformer~~source from contributing to the transmission side overvoltage condition. ~~3Vo~~ Neutral overvoltage protection would serve as protection at locations that were previously not susceptible to these kinds of issues until transformer backfeeding became an issue due to localized generation on the distribution side. Alternative solutions outside of 3V0~~o~~ may be available, however this will vary by each utility and substation.
Criteria and values to determine amount of backfeed allowed before additional protection is required	Substation transformer backfeeding is analyzed on an individual basis. The minimum load of a substation transformer during normal system condition and also during N-1 contingency scenario is identified and reviewed. If the aggregate generation is equal to or greater than the minimum loading value identified, additional transformer protection may be required.
How is minimum daytime load determined without actual transformer loading information	To estimate a minimum load level for circuits/feeders, where data is unavailable or needs to be estimated at a more granular level, a value of approximately 25% of the substation or feeder peak load is used; however, these values can range from less than 15% (or much less in specific cases) up to -30% based on varying substation configuration and circuit/feeder topologies.

Formatted: Font: 8 pt

Formatted: Font: 8 pt

Formatted: Font: 8 pt

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Substation Transformer Backfeeding:

Substation Transformer Backfeeding	National Grid	Central Hudson	AVANGRID	Con Ed	Orange and Rockland
Criteria and values to determine amount of backfeed allowed before additional protection is required	National Grid's criteria for determining the need for ~~3Vo~~ neutral overvoltage protection compares the maximum generation of a feeder to the minimum load and then assumes an N-1 contingency. If that ratio exceeds 67%, National Grid begins the evaluation of requiring ~~3Vo~~ protection of the substation power transformer and transmission system components.~~since the substation bus could be in an unintentional island operation.~~ These criteria are conservative good utility practice. ~~Since max output for solar PV DG systems does not occur in non-daylight hours, daytime loading is deemed appropriate and is defined between 8AM and 8PM.~~ Further criteria are being developed to address concerns for transformer continuous loading. Presently National Grid's approach for continuous thermal loading of a transformer is to limit the aggregate connected DG to not exceed the nameplate ratings of the transformer.	Central Hudson analyzes substation transformer backfeeding on an individual basis. Central Hudson typically reviews the minimum load of a substation transformer during normal system condition and also during N-1 contingency scenario. If the aggregate generation is equal to or greater than approximately 85% of the ~~this~~ minimum value identified (this may vary based on system conditions), additional transformer protection may be required.	AVANGRID analyzes substation transformer backfeeding on an individual basis. AVANGRID analyzes the potential for substation transformer backfeed and the potential of the distribution system to provide fault current contribution for a sustained fault on the transmission system. AVANGRID compares the size of the DER system to the feeder demand at time of peak production of the DER system.	Con Edison has not experienced elevated penetration that causes substation transformer backfeeding and has not developed any criteria or set any limits.	Orange & Rockland analyzes substation transformer backfeeding on a case by case basis. Orange and Rockland typically review the minimum load at the substation transformer and determines the loading for both base case and N-1 contingency scenarios (L/O feeder on bus with all load, or L/O feeder from adjacent station that automatically flops more generation than load to bus). If the aggregate generation is equal to or greater than this minimum value identified, additional transformer protection may be required.
How is minimum daytime load determined without actual transformer loading information	National Grid's long standing best practice for the feeder demographics in the upstate NY service area for the minimum load estimate of stations that are manually recorded is 25% of the seasonal peak load. Where SCADA is available at stations, 12-month historical Energy Management System ("EMS") data is used to determine minimum load levels.	Central Hudson has minimum load data available for approximately 78% of distribution feeders. To estimate a minimum load level for circuits/feeders, where data is unavailable or needs to be estimated at a more granular level, a value of approximately 25% of the substation or feeder peak load is used; however, these values can range from less than 15-30% based on varying substation configuration and circuit/feeder topologies.	AVANGRID has very limited minimum load data available for their distribution circuits/feeders. Based on various transformer bank loading analysis AVANGRID have determined that distribution circuits' minimum loads can vary from 9% to 30% of system peak load. AVANGRID uses 15% of system peak to determine minimum loads.	Con Edison has minimum load data for all of their transformers and circuits/feeders. ~~Con Edison normally considers the circuit/feeder load between 11:00am and 2:00pm to identify daytime minimum loads~~. It is important to note that when minimum load data is collected, it is generally only available for analysis through extensive manual data mining. It is not considered readily available	Orange and Rockland has minimum load data for over 99% of their distribution circuits/feeders. ~~Where data is available, the minimum per phase daytime load is collected between 8:00am and 6:00pm~~. For the single station where data is not available, the minimum load of the 34kV circuit that feeds the station is retrieved. Using the station's percentage of the 34kV circuit, the load of the single-bank station is determined. Applying the responsibility factor and percent imbalance for the respective circuits fed from this bank, the minimum daytime load per phase is derived for each circuit.
What is the minimum daytime loading time-frame?	Since max output for solar PV DG systems only occurs in daylight hours, daytime loading is deemed appropriate and is defined between 8AM and 8PM.	Where data is available, the minimum daytime load is collected between 8:00AM and 6:00PM	Where data is available, the minimum daytime load is collected between 10:00AM and 6:00PM	Con Edison normally considers the circuit/feeder load between 11:00am and 2:00pm to identify daytime minimum loads.	Where data is available, the minimum per phase daytime load is collected between 8:00am and 6:00pm
Typical cost for installing 3V0~~o~~ protection	National Grid's ground fault overvoltage protection ("3V0~~o~~") has an average cost of approximately $300,000-$450,000 each, for substations 69kV and above. Average cost of approximately $250,000-$350,000 each, for substations below 69kV.	Central Hudson estimates the cost of 3V0 protection to be approximately $225,000. However, 3V0 is infrequently required and this is Central Hudson's first cost estimate for 3V0~~Central Hudson has not experienced a need to install 3Vo protection for DER (to this date).~~	AVANGRID has not experienced a need to install 3Vo protection for DER (to this date).	3Vo protection is at all Con Edison substations already as part of their normal substation design criteria. All Con Edison substations have multiple sources and thus must be protected against over-voltage conditions.	Orange and Rockland has not installed 3Vo protection (to this date) but estimated cost of installation to be in the range of $350k to $450k

Formatted: Font color: Auto

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Anti-Islanding Protection:

Anti-Islanding Protection	Joint Utilities
What is the common criteria for identifying the need for Direct Transfer Trip (DTT) protection?	1. Aggregate AC rating of all DER does not exceed 2/3 of the minimum feeder loading. 2. QPV + Qload is not within 1% of the total aggregate capacitor rating or feeder power factor is never >0.99 (lagging or leading) for an extended period of time. 3. If an island consists of both rotation and inverter based DER, sum of all rotating machine AC ratings is less than 25% of the total DER. 4. A minimum of 2/3 of the DER inverters in the system are from the same manufacturer. If the first criterion is met, DTT protection is not needed and there would be no need to test the other three criteria. If the first criterion is not met, failing any one of the other three criteria would indicate unintentional islanding is a risk and might require DTT installation. The JU is currently consulting with industry experts and will continue to evolve their position on this topic.
How and where is minimum feeder loading determined if actual feeder loading information is not readily available?	JU will provide the data, estimations, and methodology used to determine minimum daytime loading on a per utility basis. (See response to question 5 on substation transformer backfeeding.)
What is the State-wide project size criteria for when the SANDIA criteria is or isn't applied to a project for review?	All applications >50kW are evaluated by SANDIA criteria. However many applications between 50kW to 300kW will quickly pass the screens based on the JU minimum load criteria.

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Anti-Islanding Protection:

Anti-Islanding Protection	National Grid	Central Hudson	AVANGRID	Con Ed	Orange and Rockland
If DTT protection is determined to be required, explain the different types of communications used and reasoning for using each type.	National Grid requires a dual channel DTT scheme between their EPS protective device(s) and the DER facility, if DER interconnection projects have NERC reliability requirements. The two channels use diverse communications media from each other such as digital microwave for one and leased telephone line for the other. For distribution system interconnected projects where NERC reliability does not apply to the DER customer, a single channel telecommunication may be used. The single channel telecommunication requirements for the DTT application normally consists of a leased telephone circuit, or other National Grid approved communication circuit.	Central Hudson allows customers to choose their preferred method of communication. Typical Central Hudson DTT installation channels include leased telephone lines via audio tone or fiber optic cable. Central Hudson is also evaluating power line carrier and wireless radio applicability for DTT.	AVANGRID employs fiber and copper. Dedicated fiber is preferred however third party fiber path may also be an option. AVANGRID has not incorporated radio up to this point.	Con Edison does not have large enough penetration of inverter based DG in their system to cause them to evaluate DTT (for this type of DG). For large synchronous generation, Con Edison is evaluating monitoring frequency and phase orientation at the DER site and comparing it to a reference point in its system. If the reference point and phase angle is similar to the DER, the DER is allowed to generate.	Orange and Rockland monitors sectionalizing devices (breakers and reclosers to identify islanding conditions and sends DTT signal to isolate DER. Orange and Rockland plans to install digital relays for monitoring faults and islanding conditions. Currently Orange and Rockland uses leased phone lines for DTT communication. However, wireless communication may be implemented for new installations after analyzing the requirements of repeaters and installation feasibility based on site location.
What is a typical/standard range in cost for installing direct transfer trip (DTT) protection?	National Grid's direct transfer trip (DTT) has an average cost of approximately $250k each.	Central Hudson's estimated cost of DTT installation is $270k. However, it has been over twenty years since Central Hudson has completed an installation of DTT for distributed generation. As Central Hudson gains new experience with recently submitted CDG projects, they will develop a better understanding of DTT installation cost.	AVANGRID estimated DTT installation cost in the range of $200k to $250k.	For con Edison, the cost is generally in the range of $700k to $800k, but the cost reflects DTT installation for multiple feeders in a network installation. Installation cost vary with each site.	Orange and Rockland estimated DTT installation cost in the range of $200k to $300k.

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Monitoring and Control:

Monitoring and Control Definitions	Joint Utilities
What is the common or standardized definition used by the electric utilities for "control" of distributed generation?	Control at the distribution level refers to signaling and mobilization of distribution assets (disconnect or re-connect), placed into a setting for live line work such as non-reclosing/one shot to lock out/ Hot Line Tag (HLT) to satisfy system operational goals in real-time. The ability to control distribution system assets is vital to the reliable and efficient operation of the distribution grid. Utilities would require direct control of the assets for disconnection for the use case of maintaining system safety and reliability during abnormal system conditions. The dispatch-able component of control can be completed through the DER control center. The term 'control' signifies the utility having complete discretion over operation of the asset. Whereas, the term 'dispatch' indicates that the utility sends control signals to the asset owner who have discretion over operation of the asset. The term 'dispatch' is used for signals sent to DER providers i.e. the ability to ramp up or ramp down kW and/or kVAR output.
What is the common definition used by the electric utilities for "monitoring" of distributed generation?	Monitoring of a facility is the ability to receive feedback on specific points or data, at pre-determined intervals. Monitoring of the distribution assets and DERs in the distribution system is essential for maintaining the reliability of the grid. At the point of generation the monitoring of the energy source must include metering values on a per system basis, the phase, voltage, current, watts, VARs, and power factor. Status at the point of generation shall include trip, close, live-line protection status (i.e. HLT), and power flow set points. There is a need for expansion and improvement in visibility and communication protocols to interact with and observe DER providers.

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Rationale for Requiring Control &/or Monitoring:

Rationale for Requiring Control &/or Monitoring	Joint Utilities
What is the minimum project size threshold at which control of new DG projects is required?	DERs will require standard control above a certain size threshold, although control may be required for DERs below the size threshold. The size threshold for Control is set at 1 MW and above. This criteria may be modified to include PVs below 1MW In the future. The level of control for DER's below the 1MW threshold will be decided by each utility based on system, locational and other constraints. DERs will be expected to comply with evolving control standards which will be applied retroactively. This size threshold will be determined based on prior and future utility experiences so that the safety and reliability of the distribution system is maintained.
Are there any additional criteria besides size that would require control of new DG projects?	JU may require control depending on the following : • The level of system impact • Locational or system constraints • Number of aggregated smaller systems • Feeder containing multiple large PV systems • If minimum daytime load is below 1 MW or if it's a standalone generating assets. • For network system consider the native load and system configuration (spot network, isolated network, high tension, non-network) • Voltage Threshold (4kV, 13kV, 27kV, et cetera) • Existing utility local controls and curtailment options • Low-visibility sub transmission system • In the future, where the DG is required to help meet local distribution capacity under contingency conditions, JU may require control
What is the minimum project size threshold at which monitoring of new DG projects is required?	DERs will require standard monitoring above a certain size threshold, although monitoring may be required for DERs below the size threshold. The size threshold for Monitoring is set at 1 MW and above. This criteria may be modified to include PVs below 1MW In the future. The level of monitoring for DER's below the 1MW threshold will be decided by each utility based on system, locational and other constraints. DERs will be expected to comply with evolving monitoring standards which will be applied retroactively. This size threshold will be determined based on prior and future utility experiences so that the safety and reliability of the distribution system is maintained. For aggregated DER systems, visibility of individual DERs monitoring data in the aggregate will be required at the primary feeder level.
Are there any additional criteria besides size that would require monitoring of new DG projects?	JU may require monitoring for multiple facilities on a single feeder, for locations where the utility may have opted not to require a marginal system upgrade and where PV inverter PF adjustment has been allowed for mitigation.

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Description of Monitoring Equipment and Functions:

Description of monitoring equipment and functions	Joint Utilities
What are the required monitoring points/data for a new project that reaches the minimum project size threshold and criteria?	For the safety and reliability of the distribution system, utilities will require information on DER/circuit parameters such as, but not limited to - power factor, real power, reactive power, phase current and voltage, hot line tags, device status (open, close or lock-down) that can aid monitoring and verification for future potential market settlements. The JU may also request information from DER aggregators on parameters of individual DERs that form a part of aggregated DER systems. As markets and technologies evolve, the JU may require a size threshold (minimum and maximum) for the size of an aggregated DER system.
Describe the equipment used to collect the monitored data.	Equipment for collecting monitoring data would include, aggregators, reclosers, and RTU's either connected through SCADA at the PCC or through cell or radio communication. Future monitoring and control may include Stakeholder's Distributed Energy Resource Management System (DERMS) or similar system passing location based DG data to the utility's monitoring and control system
Describe typical communications methods, data collection intervals and data storage used for such monitoring requirements.	Polling Frequency: Real time monitoring is required for individual DERs – standalone or part of an aggregate. However, the sampling rate for DER performance can range from 2 seconds – 1 minute, depending upon the technical capabilities of the DSP system (for e.g.: SCADA scan rate), DER size and the type of grid service provided by the DER. Communication Protocol: Standalone DERs and DERs comprising of an aggregate, will communicate with utility systems by means of generally accepted, industry-established communication protocols such as DNP, Modbus, IEC 61850 etc. However, the exact protocols specified may differ depending on the utility's technology infrastructure. Future system may include Encrypted VPN tunnel between Stakeholder's NERC compliant monitoring and control system and the Utility NERC compliant monitoring and control system
Describe the software applications that are used to show status of the monitored data.	See utility specific response below
Is the monitoring software application able to exchange information with the software application(s) used for control? Describe any analytical capabilities of the monitoring software.	See utility specific response below
Describe any additional software or hardware systems that are connected to or need access to the software or hardware described above.	See utility specific response below
What is a typical / standard range in cost for implementation and	See utility specific response below

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

maintenance of such monitoring requirements for a new project	

Description of Monitoring Equipment and Functions:

Description of monitoring equipment and functions	National Grid	Central Hudson	AVANGRID	Con Ed	Orange and Rockland
Describe the software applications that are used to show status of the monitored data.	ABB for control center EMS	Today, it is the Sensus RTM software. Control points are modified through the electronic recloser's software program. In the future, status will be viewed through the Schneider DMS and communications will occur through the ABB Tropos radios backhauled to a fiber/microwave communications system	Siemens Spectrum system at Energy Control Center	PI Historian includes Coresight, Datalink, Processbook and System Explorer (Asset Framework).	Distribution SCADA System at Distribution Control Center. Future system may include Distribution Management System (DMS) modules and a DERMS interface.
Is the monitoring software application able to exchange information with the software application(s) used for control? Describe any analytical capabilities of the monitoring software.	Control is a manual command issued remotely from ABB system EMS operator.	Same application	Siemens Spectrum system is capable but at this point alarm limits set with operator making discussions.	The distribution management system pushes data out to the PI Historian in real-time, but does not accept data back from it. The analytical capabilities of PI Historian are very strong – it can implement all analytics we would need.	The SCADA system has monitoring and control over the recloser at the PCC. The local settings on the recloser control must be modified locally by the control vendor's software.
Describe any additional software or hardware systems that are connected to or need access to the software or hardware described above.	n/a	n/a	At this point alarm limits set with operator making discussions	We use OSI servers that are fully redundant with disaster recovery and cyber security features.	None at this time. As the DG penetration increase and the utilities gain more experience interacting with them we will reevaluate current software and hardware technologies (ADMS, DERMS, AMI).
What is a typical / standard range in cost for implementation and maintenance of such monitoring requirements for a new project?	**$30-40k estimate for RTU**	The cost for installing and programming an Electronic recloser with a Sensus radio (or future, ABB Tropos radio) is approximately $55,000 – $65,000.	Recloser w/ SCADA communications - $65k RTU w/ SCADA communications - $27.5k	This SCADA solution is on our isolated 120/208V or 277/480V networks for net metered PV. Current costs around $100-$120K.	Recloser with SCADA Communication. $80k

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Description of Control Equipment and Functions:

Description of control equipment and functions	Joint Utilities
What are the required control (points/functions) for a new project that reaches the minimum project size threshold and criteria	For the safety and reliability of the distribution system, utilities will require information on DER/circuit parameters such as, but not limited to - power factor, real power, reactive power, phase current and voltage, hot line tags, device status (open, close or lock-down) that can aid monitoring, control and verification for future potential market settlements. Trip and close functionality at the point of common coupling (PCC) will also be needed.
Describe the equipment used to exercise the control functions	An electronic recloser with SCADA or cellular communications is used to control systems 1 MW and above. For systems below 1 MW, a SCADA connected RTU may be required. Future monitor and control may include Stakeholder's Distributed Energy Resource Management System (DERMS) or similar system passing location based DG data to the utility's monitoring and control system
Describe typical communication methods, data collection intervals and data storage used for such control requirements	Polling Frequency: Real time control is required for individual DERs – standalone or part of an aggregate. However, the sampling rate for DER performance can range from 2 seconds – 1 minute, depending upon the technical capabilities of the DSP system (for e.g.: SCADA scan rate), DER size and the type of grid service provided by the DER. Communication Protocol: Standalone DERs and DERs comprising of an aggregate, will communicate with utility systems by means of generally accepted, industry-established communication protocols such as DNP, Modbus, IEC 61850 etc. However, the exact protocols specified may differ depending on the utility's technology infrastructure. Future system may include Encrypted VPN tunnel between Stakeholder's NERC compliant monitoring and control system and the Utility NERC compliant monitoring and control system
Describe the software applications that are used to show status of the monitored data.	See utility specific response below
Is the monitoring software application able to exchange information with the software application(s) used for control? Describe any analytical capabilities of the monitoring software.	See utility specific response below
Describe any additional software or hardware systems that are connected to or need access to the software or hardware described above.	See utility specific response below
What is a typical / standard range in cost for implementation and	See utility specific response below

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

maintenance of such control requirements for a new project	

Description of Control Equipment and Functions:

Description of control equipment and functions	National Grid	Central Hudson	AVANGRID	Con Ed	Orange and Rockland
Describe the software applications that are used to show status and modify the control points	See response for same question monitoring	Today, it is the Sensus RTM software. Control points are modified through the electronic recloser's software program. In the future, status will be viewed through the Schneider DMS and communications will occur through the ABB Tropos radios backhauled to a fiber/microwave communications system.	Siemens Spectrum system at Energy Control Center	Distribution management system.	Distribution SCADA System at Distribution Control Center. Future system may include Distribution Management System (DMS) modules and a DERMS interface
Describe the analytical capability of the control software		The analytical capability through Sensus RTM is limited, but the Schneider DMS will included a full historian.	Not enable to this point but used for operational contingencies	PI Historian is not used for control purposes – just for monitoring. No real analytics at this point.	None at this point.
Describe any additional software or hardware systems that are connected to or need access to the software or hardware described above			At this point alarm limits set with operator making discussions All analog, status and control are stored in a offline database	n/a	None at this time. As the DG penetration increase and the utilities gain more experience interacting with them we will need to reevaluate current software and hardware technologies.
What is a typical/ standard range in cost for implementation and maintenance of such control requirements for a new project	See response for same question monitoring	The cost for installing and programming an Electronic recloser with a Sensus radio (or future, ABB Tropos radio) is approximately $55,000 – $65,000.	Recloser w/ SCADA communications - $65k RTU w/ SCADA communications - $27.5k	Recloser – in range with Avangrid costs. SCADA etc for isolated networks - $100 - $120K.	Recloser with SCADA Communication. $80k

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.

Future Practices (REV):

Future Practices (REV)	Joint Utilities
Explain the electric utilities position on whether or not full control and/or monitoring are needed in every location across NYS independent of size.	For DERs 50 kW or above enrolled in a NYISO Tariff, the DSP may limit the operation or disconnect or require the disconnection of the DER from a utility's distribution or transmission system at any time, with or without notice, in the event of real or predicted abnormal operating conditions. For planned and scheduled maintenance events, prior notice (typically, 48-hours in advance) may be provided. For DERs not enrolled in a NYISO Tariff, irrespective of size, the DSP may limit the operation or disconnect or require the disconnection of DER from a utility's distribution or transmission system at any time, with or without notice, in the event of real or predicted abnormal operating conditions. For planned and scheduled maintenance events, prior notice may or may not be provided.
Explain in detail how the answers above change or vary as we move forward into REV and its initiatives associated with DER and DG interconnections.	Monitoring and control will be required to participate in future markets. Additionally, the capabilities, testing, and deployment of smart inverter technology, and data sharing from developers, may change these requirements.
Are there expected to be additional requirements for increased communications and data sharing among various software applications and hardware platforms? Describe.	Standalone DERs and DERs comprising of an aggregate, will communicate with utility systems by means of generally accepted, industry-established communication protocols such as DNP, Modbus, IEC 61850 etc. However, the exact protocols specified may differ depending on the utility's technology infrastructure. The level of Monitoring and Control, irrespective of the threshold, will be decided by each utility based on system, locational and other constraints. DERs will be expected to comply with evolving monitoring and control standards, which will be applied retroactively.
Are there expected to be additional types of monitoring or functionality required (such as solar irradiance sensors or solar forecasting)? Describe.	Utilities have the right to require a short term (e.g. week ahead / day ahead / real time) forecast for individual facilities expected output. Such forecasts may be required for use as input to the day ahead planning process to secure the distribution systems for local reliability. A breakdown of aggregated forecasts may be required for the DSP to determine impacts on local reliability, where local reliability issues are not effected an aggregated forecast may be acceptable.
Are there expected to be additional requirements for additional data or higher resolution monitoring of loads?	Yes. Oscillography data will be needed information for the DSP to monitor and mitigate electric system power quality disturbances.

*Matrix is designated for PV use only. Further revisions would need to be made to accommodate and reflect other technologies.