DEMONSTRATION OF INVERTER BASED GRID VOLTAGE SUPPORT FUNCTIONS ON 19 MW (DC) PV GENERATING FACILITY

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ABSTRACT

As the size of photovoltaic (PV) systems increase, and the interconnect voltages rise from distribution level to sub-transmission levels and higher, there is increasing pressure from utilities to provide the same level of grid stability control as rotating machine equipped generators. New inverter designs combined with specialized control systems allow generating assets to control real power output and dynamically supply and absorb reactive power (VARs), thereby allowing the generator to contribute to voltage and frequency stability of the grid. This paper presents a 19 MW (DC) PV facility where a plant-wide control system utilizes only the plant's primary solar inverters to provide dynamic real-time VAR, Power Factor, and Automatic Voltage Regulation (AVR) support, demonstrating the unification of fifteen separate inverters operating as a single Static Synchronous Compensator (STATCOM). The system is also demonstrated providing STATCOM functions at night, with no solar irradiance. The use of the PV inverters for this role saves the cost and complexity of additional infrastructure, while providing utilities with real time, on-demand VAR support.

1. Introduction

The solar generating asset here presented is located outside Phoenix, Arizona. The facility consists of 15 one megawatt Power-One (now ABB) (MW) rated inverters connected via a 12.47kV AC collection system to an Arizona Public Service (APS) 69 kV substation. The system was designed and constructed by juwi solar Inc. (JSI), and the plant is owned by PSEG Solar Source. The author of the paper managed the team responsible for the design, testing, and implementation of both the Supervisory Control and Data Acquisition (SCADA) system and the control system as described for this facility.

This paper begins with a basic discussion of what grid support functions entail, and then describes the basic plant topology. Next, the control interface used by JSI operators is presented. Finally, the bulk of the paper discusses the implementation and verification of this system. The paper covers items required by APS as part of their Site Inspection Checklist. This is appropriate, as passing the site inspection indicates acceptance of the plant to perform as specified by the Interconnect Agreement (IA).

For each item on the list, the full test procedure includes varying the plant real power output to verify control loop stability across the plant's real power output range.

- Plant Real Power Output Control (Curtailment)
- VAR Control Mode, demonstrating the plant's ability to supply and absorb specified amounts of reactive power.
- Power Factor Control Mode, demonstrating that plant's ability to maintain a constant, non-unity power factor under varying conditions.
- AVR (Automatic Voltage Regulator) Mode, demonstrating that the control can rapidly and automatically maintain a voltage setpoint specified by operators.

Finally, the paper closes with the presentation a single inverter at this site providing voltage support resources that start during the day and last well past sunset, making the case that solar inverters are capable of providing VAR support at night.

2. Basic Reactive Power and Grid Support

Reactive Power (VAR) Support has been a common feature of AC transmission and distribution systems since the very beginning. Reactive power comes from the phase shift between voltage and current waveforms in AC systems. A power factor of Unity indicates that voltage and current are in phase, meaning that all the power placed into the system is available to do real work. If the power factor is 0, then the voltage and current waveforms are 90 degrees out of phase, meaning that the sum of voltage (V) and current (I) at any point on the sine wave is zero.

Inductance and capacitance are chiefly responsible for shifting power factor in electrical power transmission and distribution systems, as these systems are comprised of large coils of wires in transformers, and long runs of wire to move power to customers, in addition to customer loads. If a system gets too capacitive, then inductors in the form of large coils of wire can be switched in. If a system is too inductive, then capacitors can be switched in. These devices do not consume real power, as such, as they provide no electrical work, but they act to "scoot" the voltage and current waveforms closer together.

If more dynamic control is required, for example near a large factory with rapidly changing loads, switching discrete elements in and out of a circuit may not be sufficient. In this case, other technologies can be used, such as Static VAR Compensators (SVC), STATCOMs, or synchronous condensers. The applications and operation of these devices are beyond the scope of this paper.

The choice of which technology to use is a complicated process of engineering design, system response time analysis, cost analysis, and system requirements. The use of PV inverters for grid control is only now coming under serious consideration. In the past, it was assumed the PV systems would either stay connected at near unity power factor, or else disconnect. This may be appropriate for small-scale systems, but contributes to grid instability when operating large utility-scale plants, as it is possible for the PV facility, generating at unity power factor, to push line voltage up as irradiance increases, as all the power that leaves the site is in the form of real power under the unity generating requirement.

This can also cause undue wear and tear on tap changers and capacitor controls. However, if the solar plant is allowed to respond to its own voltage, maintaining the utility's specified voltage at the point of interconnection (POI), regardless of plant real power output, the PV plant can operate as a "stiff source", providing stability against other changing loads in the system. Rotating machines are not naturally stiff sources, as controlling their VAR or real power output requires changing physical properties or varying currents in excitation systems.

Modern solar inverters are solid-state devices that generate sinusoidal AC power by turning on and off at great speed, over 20 KHz in some cases. This enables inverters to respond rapidly to changing grid events, showing response times as statically excited rotating machines. Changing output of an inverter involves varying the duty cycle of a fast switching waveform, rather than performing tasks that effect large rotating masses. In addition, because solar inverters are not limited by the physical constraint of power angle, which relates to the physics of magnets rotating in coils of wire, they are able to stay connected at power factors which would cause conventional rotating machines to lose synchronization with the grid.

It will be demonstrated that a properly controlled PV generating facility can offer real time variability in VAR supply and absorption without any additional equipment required.

3. Basic Plant and Control Topology

The plant described here is comprised of 19 DC MW of single-axis tracked arrays powering 15 one megawatt Power One ULTRA inverters. The AC is collected via two 12.47kV circuits into a 69kV APS substation. The inverters communicate using the Modbus protocol over RS485 at 19.2 kbps to the central plant controller through serial device servers at each inverter pad.

Each inverter pad is also equipped with fiber ring networking equipment, an LCD Interface for diagnostics, controls for the tracker equipment, and an appropriate Uninterruptable Power System (UPS) to ensure the network and communications systems stay serviceable in any loss of AC event.

The communications system employed allows for a very low latency message transit time throughout the facility. Modbus commands originated by the controller get to the inverters in better than 15 ms even under a heavily loaded network. All machines receive their commands within 10 ms of each other, generally within two AC cycles of the input being read by the controller. This extremely fast communications speed, combined with the inverter's own rapid response time, contributes to the simplicity of the controller's implementation. Commands are issued to the appropriate Modbus power control registers in each of the fifteen inverters at intervals determined by settings in the plant controller.

The plant controller itself is implemented as a software routine running in a deterministic real-time automation component included with the site's data aggregation software. The only additional hardware required is a sufficiently fast Power Quality Meter (PQM), in this case a SEL-735. Such meters are generally included as check meters on JSI constructed plants. No additional computational, PLC, or RTU hardware or software is required for the controller implementation demonstrated here. The hardware running this software is a standard off-the-shelf 61850-rated substation automation computer. The control inputs to the plant control come mainly from the SEL-735, although the APS RTU meter data is used as well.

The ULTRA inverters support a Q(U) mode, allowing the amount of VAR output (Q) to be determined as a function of grid voltage (U) measured at the inverter's terminals. This functionality is not utilized on this site, as it was found through testing that control based on the PQM at the POI resulted in more stable behavior under all power output and irradiance conditions. Additionally, the behavior of the site's transformers and collection system are more accurately modeled using the control algorithm developed, allowing closer agreement between command values and response. Additionally, the use of central command inputs and broadcast-style outputs allow for multiple inverters to be taken offline or fail without significantly impacting the function of the controller.

The ability to compensate automatically for missing inverters comes from the control loop's input data coming from the point of interconnect metering. A loss of an inverter, whether it be for fusing, ground fault, or maintenance, looks the same at the point of interconnect as a change in irradiance. The controller will automatically command the appropriate response from other machines, regardless of the numbers of inverters available, up until the limit of available capacity on the site.

4. User Interface

The operator interface to the plant's control system is shown in Fig 1. This screen is accessible by operators at any time, and utility partners can interface directly with the controller via DNP3, OPC, or other protocols as required. The top button at the top of the screen with the plant's name serves as a navigation button through the rest of the mimic screens in the system. The graph at lower left shows key plant interconnection measurements, including line voltage, kVAR, MVA, and power factor. The data displayed comes directly from the Remote Terminal Unit (RTU) connected to the APS Energy Management System (EMS) Meter. The control inputs to the controller are not visible on this screen, as it serves only to inform the operators of the current status of the system.

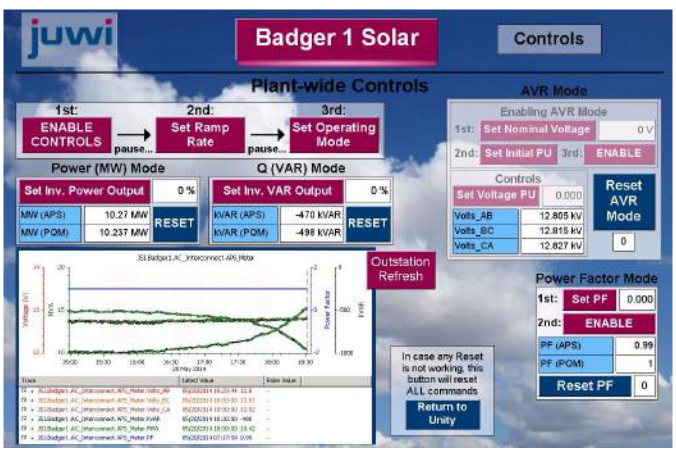

Fig 1. Plant grid support control screen

There are three steps to enabling the control modes of the facility, as shown in the upper left of **Fig 1**. First, qualified operators click the "ENABLE CONTROLS" button, which turns on the plant controller. Then the "Set Ramp Rate" control is operated, which inputs a control-loop wide ramp rate. Finally, the "Set Operating Mode" button allows the operator to set the control mode (VAR, Power Factor, or AVR). The "Power Mode" controls are always operable, as curtailment functions with any of the other options active. Once the operating mode is set, the operators can chose to set a VAR output percentage via the Q (VAR) Mode, set the Power Factor to a commanded value, or setup the AVR mode in Per-Unit (pu) terms.

All control modes have a "RESET" mode, which leaves the controller active but sets the facility back to Unity power factor. To disable the plant controller, and set the system back to the set-points programmed in non-volatile storage in all fifteen inverters, the "Return to Unity" button is available.

5. Operating Modes and Output Graphs

This section covers the operating modes of the site, with control inputs and system responses discussed in each section. The metering directions here are as follows: The absorption of reactive power (+ VAR, +power factor) causes voltage to rise. The supply of reactive power (- VAR, - power factor) causes a reduction in line voltage.

The operating modes are:

- Plant Real Power Output Control (Curtailment)
- VAR Control Mode, demonstrating the plant's ability to supply and absorb specified amounts of reactive power.
- Power Factor Control Mode, demonstrating that plant's ability to maintain a constant, non-unity power factor under varying conditions.
- AVR (Automatic Voltage Regulator) Mode, demonstrating that the control can rapidly and automatically maintain a voltage setpoint specified by operators.

Historic low-speed trends come from the JSI SCADA System. The transient time graphs come courtesy of Arizona Public Service (APS). The equipment used to capture the data for the JSI Graphs is the SEL-735 PQM meter, using a combination of polled DNP3 values and the meter's real time data, displayed via the MET (meter) command. The effective PT ratio for all voltage channels was 60:1 (12470 V to 207.8V). The current sense elements are 1000:5 Class 0.5 CT's. Those CT leads were tapped with 5A clamp-on CTs for the data acquisition equipment supplied by APS to gather transient time data presented in the AVR section.

5.1. Plant Real Power Output Control

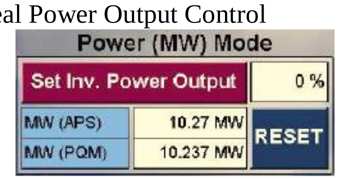

Fig 2. Power output percentage set-point

The plant controller allows the operators to set a percentage output of total plant capacity. The operator interface shown in

Fig 2 shows their interface to this functionality. The operators sees real time MW value from both the PQM and APS meter, as well as the current set point. An output of 0% is set when the system is turned on, as the default conditions are not set unless the control mode is enabled.

The available AC MW capacity is ultimately determined by inverter hardware limits, firmware settings and available DC capacity. A setting of 100% plant output corresponds to the maximum limit set in the inverters according to the interconnect agreement. In the case of this site, the 100% output is limited to 15MW, a value which can never be exceeded using operator controls or inverter command signals.

5.2. VAR Control Mode

Fig 3. VAR percentage Output

In VAR control mode, the plant operators specify a percentage of total plant nameplate VAR capacity. The operator mimic, shown in **Fig 3**, provides visibility into the APS and PQM kVAR reading in real time. The values are different due to the polling rate of the meters: The PQM meter provides data much faster than the APS meter. Although direct control of VAR output percent would not normally be used by operators, the infrastructure and systems to send VAR controls is the basis by which the controller sends commands to the inverters to implement both the power factor and AVR control modes.

During the VAR mode tests, the plant was required to stay within +/- 0.95 pf and maintain voltage within 10% of nominal.

Table 1: Summary of VAR mode results

VAR Percent Command	3-phase MW	3-phase MVA	3-phase MVAR	Voltage (%NOM)	VAR Percent Actual
+25%	13.709	14.464	4.612	108%	+30%
0%	13.995	13.995	0	105%	0%
-50%	13.462	15.494	7.669	99.2%	-51.1%

The voltage on the 69kV line was higher than nominal during the test, resulting in the site's 12.47kV feeder system operating closer to 13.1kV at unity power factor. The acceptance testing values are shown in Table 1, with the voltage of 105% of nominal and no VAR control enabled. The controller responded with a +30% VAR actual output when commanded to operate at 25%. It was later discovered this was due to a further layer of VAR compensation employed inside the inverters to compensate for internal filtering which was not accounted for in the plant controller's initial internal model. The controller responded with -51.1% VAR output on a -50% command, or 7.7 MVAR, before the power factor hit the 0.95 and testing was halted. The inverter's internal filters, combined with the reactance of the transformer, resulted in the refining of the controller's internal model to adjust this difference out in the final system.

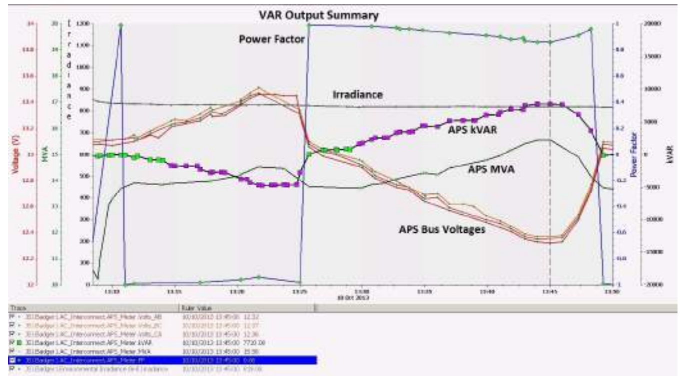

Fig 4. VAR command results spanning 40 minutes of constant irradiance of 820 watts/square meter.

Having completed official testing, permission was granted to test the VAR control system more completely, provided the plant's output voltage stayed below 13.5kV. The result of a range of VAR commands is summarized in Fig 4.

The plant's VAR output was changed to -4.6 MVAR with a power factor of -0.95, and a voltage of 13.46kV. Then the VAR output was increased to 7.7 MVAR at a power factor of 0.86, with a voltage output 12.32 kV. The irradiance was constant during this test, at 820 watts per square meter.

The inverters responded in less than a second to each commanded VAR setting, moving at the programmed ramp rate to the new VAR output setting.

This demonstrates the ability of the plant to change the output voltage from 12.32 kV to 13.46kV, with a VAR output swing from -4.6MVAR to 7.7MVAR, while maintaining constant real power output around 13.8 MW. The VAR mode provides the basis of how commands are sent to inverters by the pf and AVR control loops, described in the following sections.

5.3. Power Factor Control Mode

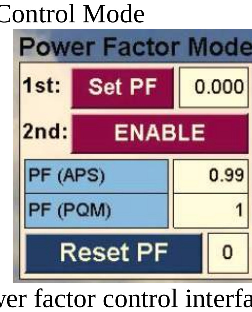

Fig 5. Power factor control interface

Fig 5 shows the operator interface for the Power Factor control mode. The operator can see the current pf set point. To enter a new power factor set point, the operator enters the desired signed power factor and clicks set PF, then clicks enable to send the control command. Once enabled, new set point commands can be issued in real time by clicking “Set PF”. The controller implements bounds checking on control inputs and clamps them at values appropriate for the site if out-of-bounds commands are sent.

Table 2: Summary of power factor mode test results

Power Factor Command	3-phase MW	3-phase MVA	3-phase MVAR	Voltage (%NOM)	Power Factor Actual
0.944	13.812	14.564	4.619	108.31	0.95
1.00	13.988	13.988	0	105	1.00
-0.955	13.798	14.565	4.663	101.77	-0.95

The power factor control mode test was also influenced by the line running above nominal voltage during the test. At Unity power factor, the voltage was already at 105% of nominal. The plant was able to operate from 0.95 lag to 0.95 lead without trouble. The control system accepts three digit commands for power factor, making a command of 0.944 valid. The SEL-735 as configured only reported two significant figures for power factor.

The power factor control mode is implemented as a set of calculations which simulate the AC collection network of the plant, calculating each inverter’s desired VAR output. These VAR commands are then sent to the inverters via VAR set point commands. Although the inverters support their own, internal, standalone power factor control system, experiments showed that using the plant controller’s mathematical model to account for line lengths and transformer characteristics allowed for better control of power factor at the POI, when compared to the inverters controlling their power own power factor at their AC terminals.

The model runs based on a deadband based around the value of the power factor read at the SEL-735. If the power factor differs by more than this value, the model is evaluated under current plant conditions, and new VAR values are sent to the inverters. The total time for this observe, calculate, and send can be less than 15 msec. Combined with the network lag, the total command response time can be as low as 30 msec.

5.4. AVR Control Mode

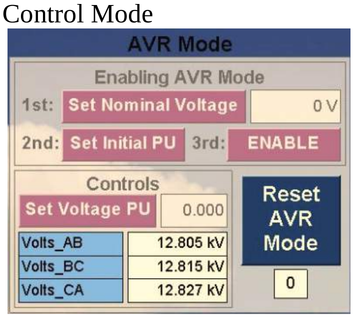

Fig 6. Automatic Voltage Regulator (AVR) mode interface

Automatic Voltage Regulator (AVR) Mode uses internal VAR commands to control for a per-unit voltage specification. As part of this test, the AVR system was set to operate at a number of voltage steps, measuring the dynamic system response at each step. To use this control mode, the plant operator initially sets a baseline nominal voltage, and then specifies the voltage to be maintained as per-unit (pu). Fig 6 shows the interface for this control mode.

The operation of this control loop involves the calculation of the desired per-unit voltage set-point compared to the current per-unit voltage set point, and calculates appropriate inverter-level VAR commands, which are then sent to the appropriate inverter control registers. This uses the same AC plant model as the power factor mode to generate appropriate VAR commands based on plant operating conditions. The calculations are wrapped in a voltage deadband, so that the model only runs when the voltage diverges sufficiently from the commanded voltage to justify new commands being sent.

The response time of the system can be tuned in various ways, allowing for the system to follow the voltage of the utility slowly, or rapidly respond to voltage step changes, depending on the setup of the loop control timers. Automatic interactive inputs into the AVR set point could also enable a solar inverter to regulate a line on its own.
Table 3 shows the results of the step test. The original procedure required the output to step up and down from the 12.47kV nominal, until power factor approached 0.95 leading and lagging. However, because the line was 13.1kV nominal, the test by was performed by stepping down in 0.01 per unit voltage steps, then doing a larger step from 0.97 per unit to 1.00 per unit to test transient response. All inverters were online, operational, and participating in the control strategy for this test.

Table 3: AVR Step Test Results

Step	Voltage per-unit command	Voltage (kV)	Power factor	MW	MVA	MVAR
1	1.00	13.075	1.00	13.681	13.681	0
2	0.99	12.869	0.99	13.696	13.847	2.038
3	0.98	12.662	0.96	13.710	14.321	4.137
4	0.97	12.493	0.92	13.721	14.835	5.639
5	0.96	12.497	0.93	13.731	14.834	5.612
6	0.97	12.482	0.92	13.749	14.872	5.667
7	1.00	13.012	1.00	13.787	13.787	0

The data presented in **Table 3** satisfied the acceptance requirements for the facility. The APS solar commissioning specification had no requirement for transient response to voltage step changes, but APS personnel were curious, so a 4% step change was tested. The APS data acquisition equipment was configured to gather high-speed transient data, and the plant controller was configured for the most rapid ramp rate possible. The APS data acquisition system samples three voltage and three current channels, all at 2 KHz per channel. The data presented was calculated from these raw measurements. All fifteen inverters were online and operating under the control of the plant controller. The real power output of the facility was approximately 80% of its capacity, due to the available irradiance when the test was performed.

The AVR system was set for a nominal voltage of 13kV. The voltage was then stepped down in 1% steps to reach 12.47kV. The system was then commanded to raise the voltage in a single 4% step, the results of which are shown in Fig 7 and Fig 8.

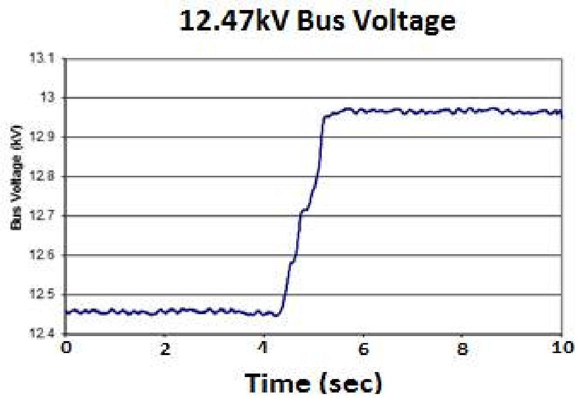

Fig 7. Bus Voltage transient response to 4% voltage step change

Fig 7 illustrates the step change in bus voltage from 12.47 kV to 12.95kV. The voltage ramps up 480V (3.6% of 13kV) in around 1.5 seconds, with no overshoot and clean damping, a ramp rate of 320 volts per second. This shows that all machines were able to get their commands rapidly enough to respond in unison. The use of VAR commands to the inverters means that the inverters do not need to seek voltage or currents at their own terminals, allowing all machines to react very quickly without oscillation.

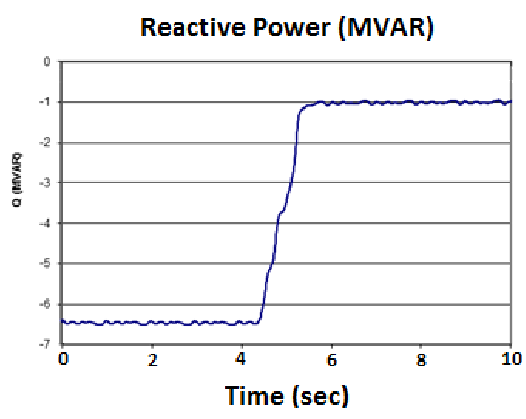

Fig 8. MVAR output change in response to 4% voltage step change

Fig 8 illustrates the MVAR output change at the point of interconnection for the 4% step in voltage commanded to the AVR control system. The plant VAR output changed from -6.5 MVAR to -1 MVAR, a change of 5.5 MVAR in 1.5 seconds, for a ramp rate of 3.6 MVAR per second. This graph shows the VAR output changing cleanly to its new output, without overshoot or oscillation.

The implementation of the AVR control demonstrated above is fairly straightforward. The AVR control figures out where the voltage needs to be, based on a per-unit input. It then calculates the VAR output needed from each of the fifteen inverters using a model internal to the control loop, and sends those commands to the inverters. The inverters are then responsible for delivering the commanded VARs according to their own internal control strategy. This strategy keeps the relatively low speed (measured in milliseconds to seconds) plant control system out of the way of the very high speed (kilohertz-level) switching control implemented in the inverter.

6. Night Time VAR Support

Solar inverters generally sleep at night, using as little power as possible while waiting for the sun to rise. Advances in power electronics and inverter design means it is feasible to operate an inverter as a 24-hour a day STATCOM device, even with no irradiance to produce real power from the PV arrays.

In the time between commissioning and final acceptance, plant personnel had time to run a small experiment on night time VAR support in collaboration with Power One, the manufacturer of the inverters. With the permission of APS, one of the inverters on site was temporarily modified, enabling night VAR support. The plant controller was then configured in VAR mode, and a static 10% VAR output percentage was set for that machine starting during solar noon, and left that way through sunset. The main focus of the test was to see how the inverter VAR output varied as the irradiance went to zero. The results of this test are shown in Fig 9. The data were gathered from an SEL-735 PQM attached to the inverter’s AC output terminals.

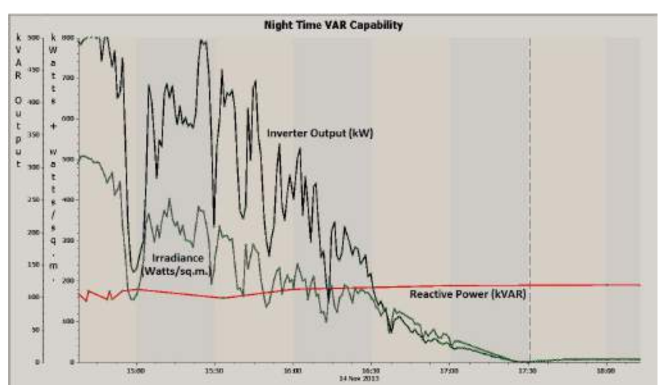

Fig 9. Night time VAR Operation of single inverter

At night, on a site not equipped for night time VAR support, both real and reactive power will go to zero as irradiance goes to zero. Fig 9 shows 15:00 to 18:00 on November 14. The 110kVAR output is clearly maintained throughout the entire day, remaining solid even as irradiance drops to zero. The vertical dashed line in Fig 9 represents the sunset time.

If this functionality was deployed across the entire solar facility, the VAR, AVR, and power factor control modes presented in this paper could be made available 24 hours a day, regardless of irradiance.

7. Conclusion

This paper demonstrated the successful implementation of a plant-wide controller enabling the use of 15 inverters on a 19MW DC PV facility for voltage support functions, including VAR output control, power factor control, and Automatic Voltage Regulation (AVR) control. Results of an experiment showing VAR support at night was also presented.

8. Credits

The plant controller demonstrated here was developed by juwi solar, Inc., which provided much of the data. Transient time data, as well as a very successful and fun-filled plant commissioning experience, were provided by Arizona Public Service (APS). Power-One (now ABB) provided support for inverter configuration, as well as access to their laboratory and test facilities to test the control strategies prior to deployment on the site.