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Renewable Systems Interconnection Study:

Distributed Photovoltaic Systems Design and Technology Requirements

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Abstract

To facilitate more extensive adoption of renewable distributed electric generation, the U.S. Department of Energy launched the Renewable Systems Interconnection (RSI) study during the spring of 2007. The study addressed the technical and analytical challenges that must be addressed to enable high penetration levels of distributed renewable energy technologies. Interest in PV systems is increasing and the installation of large PV systems or large groups of PV systems that are interactive with the utility grid is accelerating, so the compatibility of higher levels of distributed generation needs to be ensured and the grid infrastructure protected. The variability and nondispatchability of today's PV systems affect the stability of the utility grid and the economics of the PV and energy distribution systems. Integration issues need to be addressed from the distributed PV system side and from the utility side. Advanced inverter, controller, and interconnection technology development must produce hardware that allows PV to operate safely with the utility and act as a grid resource that provides benefits to both the grid and the owner.

Preface

Now is the time to plan for the integration of significant quantities of distributed renewable energy into the electricity grid. Concerns about climate change, the adoption of state-level renewable portfolio standards and incentives, and accelerated cost reductions are driving steep growth in U.S. renewable energy technologies. The number of distributed solar photovoltaic (PV) installations, in particular, is growing rapidly. As distributed PV and other renewable energy technologies mature, they can provide a significant share of our nation's electricity demand. However, as their market share grows, concerns about potential impacts on the stability and operation of the electricity grid may create barriers to their future expansion.

To facilitate more extensive adoption of renewable distributed electric generation, the U.S. Department of Energy launched the Renewable Systems Interconnection (RSI) study during the spring of 2007. This study addresses the technical and analytical challenges that must be addressed to enable high penetration levels of distributed renewable energy technologies. Because integration-related issues at the distribution system are likely to emerge first for PV technology, the RSI study focuses on this area. A key goal of the RSI study is to identify the research and development needed to build the foundation for a high-penetration renewable energy future while enhancing the operation of the electricity grid.

The RSI study consists of 15 reports that address a variety of issues related to distributed systems technology development; advanced distribution systems integration; system-level tests and demonstrations; technical and market analysis; resource assessment; and codes, standards, and regulatory implementation. The RSI reports are:

- *Renewable Systems Interconnection: Executive Summary*
- *Distributed Photovoltaic Systems Design and Technology Requirements*
- *Advanced Grid Planning and Operation*
- *Utility Models, Analysis, and Simulation Tools*
- *Cyber Security Analysis*
- *Power System Planning: Emerging Practices Suitable for Evaluating the Impact of High-Penetration Photovoltaics*
- *Distribution System Voltage Performance Analysis for High-Penetration Photovoltaics*
- *Enhanced Reliability of Photovoltaic Systems with Energy Storage and Controls*
- *Transmission System Performance Analysis for High-Penetration Photovoltaics*
- *Solar Resource Assessment*
- *Test and Demonstration Program Definition*
- *Photovoltaics Value Analysis*
- *Photovoltaics Business Models*

- *Production Cost Modeling for High Levels of Photovoltaic Penetration*
- *Rooftop Photovoltaics Market Penetration Scenarios*.

Addressing grid-integration issues is a necessary prerequisite for the long-term viability of the distributed renewable energy industry, in general, and the distributed PV industry, in particular. The RSI study is one step on this path. The Department of Energy is also working with stakeholders to develop a research and development plan aimed at making this vision a reality.

Acknowledgments

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- John Bzura, National Grid
- Tom Key, Electric Power Research Institute.

Acronyms

AC	alternating current
ADSL	asymmetric digital subscriber line
BPL	broadband over power line
DG	distributed generation, distributed generator
EMS	energy management system
GE	General Electric
IEC	International Electro-technical Committee
IEEE	Institute of Electrical and Electronics Engineers
LAN	local area network
LTC	load tap changing
LV	low voltage
MPP	maximum power point
MTBF	mean time before failure
MV	medium voltage
NDZ	nondetection zone
NREL	National Renewable Energy Laboratory
OF	over frequency
OV	over voltage
PLCC	power line carrier communications
PV	photovoltaic
RSI	Renewable Systems Integration
SEGIS	solar energy grid integration system
SFS	Sandia Frequency Shift
SVC	static VAr compensator
SVR	step voltage regulator
SVS	Sandia Voltage Shift
UF	under frequency
UPS	uninterruptible power supply
UV	under voltage
VAr	volt-ampere reactive
VPCC	point of common coupling voltage
WECC	Western Electricity Coordinating Council

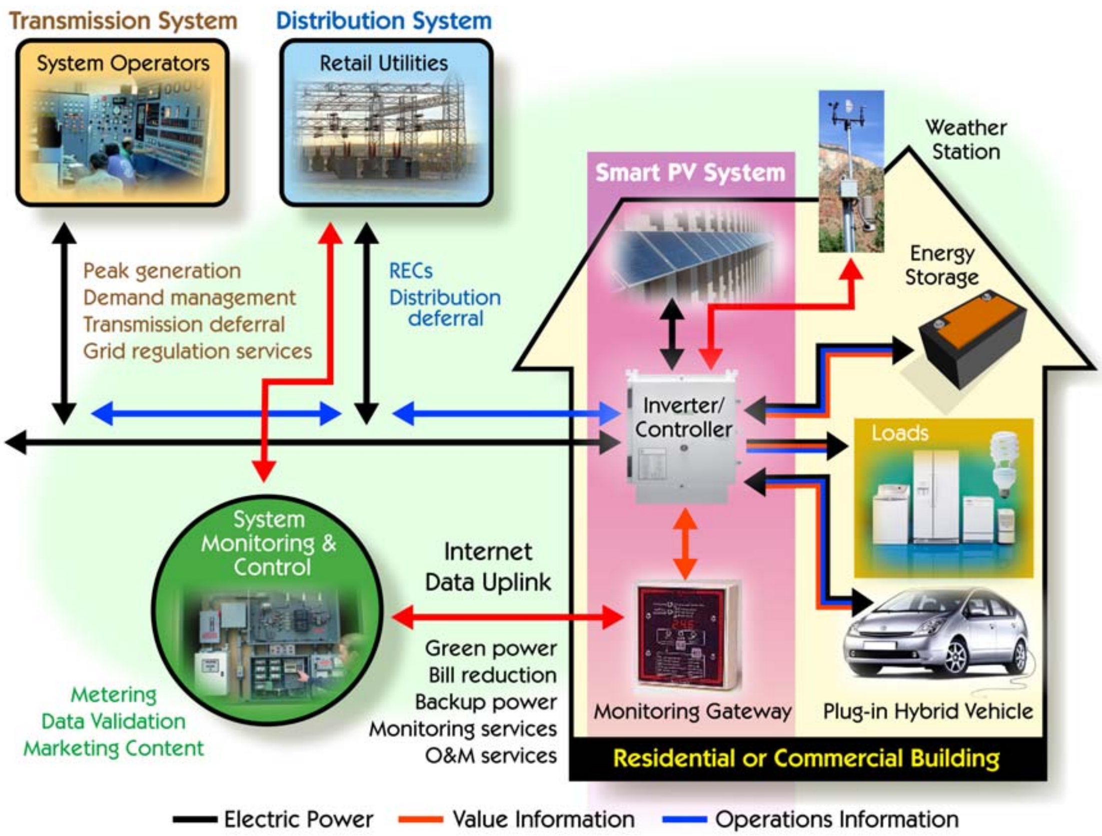
Executive Summary

Distributed photovoltaic (PV) systems currently make an insignificant contribution to the power balance on all but a few utility distribution systems. Interest in PV systems is increasing and the installation of large PV systems or large groups of PV systems that are interactive with the utility grid is accelerating, so the compatibility of higher levels of distributed generation needs to be ensured and the grid infrastructure protected. The variability and nondispatchability of today's PV systems affect the stability of the utility grid and the economics of the PV and energy distribution systems.

Integration issues need to be addressed from the distributed PV system side and from the utility side. Advanced inverter, controller, and interconnection technology development must produce hardware that allows PV to operate safely with the utility and act as a grid resource that provides benefits to both the grid and the owner. Advanced PV system technologies include inverters, controllers, related balance-of-system, and energy management hardware that are necessary to ensure safe and optimized integrations, beginning with today's unidirectional grid and progressing to the smart grid of the future.

Recommendations

- Develop solar energy grid integration systems (see Figure below) that incorporate advanced integrated inverter/controllers, storage, and energy management systems that can support communication protocols used by energy management and utility distribution level systems.
- Develop advanced integrated inverter/controller hardware that is more reliable with longer lifetimes, e.g., 15 years mean time before failure and a 50% cost reduction. The ultimate goal is to develop inverter hardware with lifetimes equivalent to PV modules.
- Research and develop regulation concepts to be embedded in inverters, controllers, and dedicated voltage conditioner technologies that integrate with power system voltage regulation, providing fast voltage regulation to mitigate flicker and faster voltage fluctuations caused by local PV fluctuations.
- Investigate DC power distribution architectures as an into-the-future method to improve overall reliability (especially with microgrids), power quality, local system cost, and very high-penetration PV distributed generation.
- Develop advanced communications and control concepts that are integrated with solar energy grid integration systems. These are key to providing sophisticated microgrid operation that maximizes efficiency, power quality, and reliability.
- Identify inverter-tied storage systems that will integrate with distributed PV generation to allow intentional islanding (microgrids) and system optimization functions (ancillary services) to increase the economic competitiveness of distributed generation.



The solar energy grid integration system integrated with advanced distribution systems

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1. Introduction

The installed capacity of grid-connected photovoltaic (PV) power system installations has grown dramatically over the last five years (see Figure 1-1). The capacity is still less than 1% of the peak electricity load on the utility grid, but at this growth rate, a 5% or 10% level may be less than a decade away. Such penetration levels are significantly higher than the currently-assumed limits under which net energy metering is allowed, and reaching those levels is likely to require significant changes to current inverter technology and regulations to maintain reliable and economical grid operation.

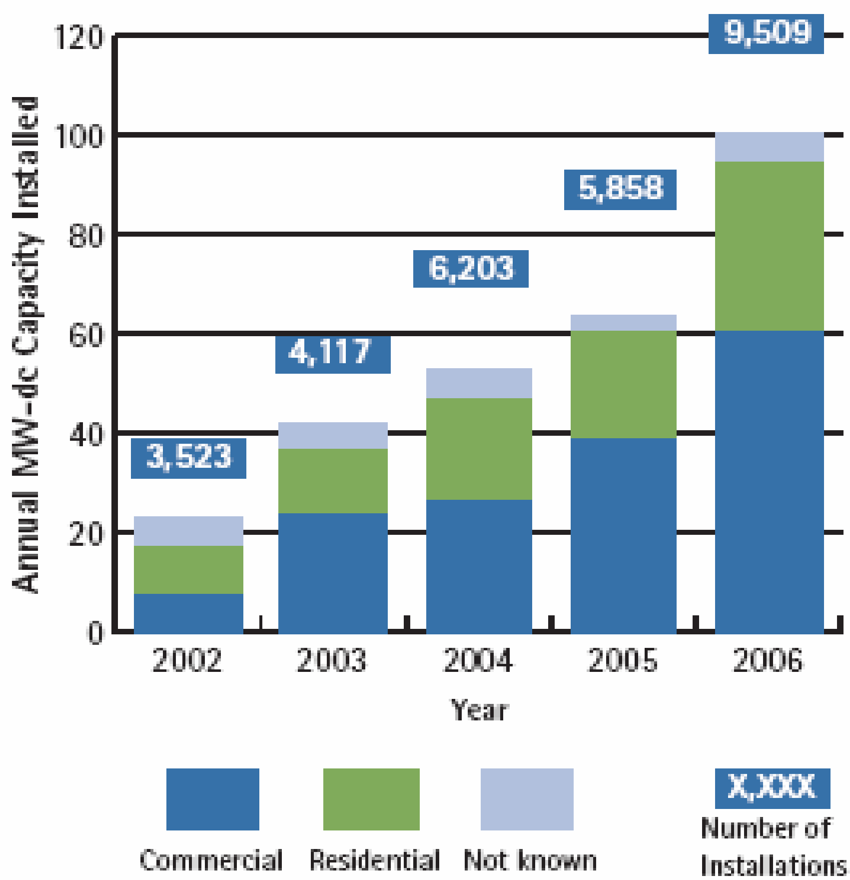

Figure 1-1. U.S. grid-tied PV installations

At the scale of the entire interconnected electric power grid, generated electric power must be consumed within milliseconds of being generated. Excess power can be accumulated with energy storage systems such as pumped hydro, but conventional energy storage systems respond much more slowly than the load changes, so peaking generation is throttled back to stabilize the power flow into and out of the grid. In addition, when the load on the utility grid reaches new peak levels, the system operators must start activating every available generating source, and even minor throttling back of generation may cause the grid voltage to collapse.

Grid-connected PV power system designs focus on converting as much irradiant power as possible into real power (current flowing into the grid in phase with the utility-defined voltage). This design goal is appropriate for a technology that has insufficient installed capacity to approach the typical loads supplied by the electric power utility infrastructure. However, as the installed capacity of this technology grows, this assumption will at some point no longer hold true; in some small areas of the electric power distribution system (for example, some rural feeders), solar electric power generation has already approached or exceeded the local daytime load and the electric utilities have begun to modify their physical infrastructure (e.g., wire size and voltage control settings) to adapt to this new power flow pattern. If this trend continues, PV power systems will be required to provide increasing levels of grid support services and to participate to a greater extent in utility dispatch and operations processes.

Stand-alone PV power systems must already deal with issues of this type, albeit on a much smaller scale. Inverters in stand-alone systems must regulate their output alternating current (AC) bus voltages by supplying current as needed to maintain voltage. Battery energy storage is usually included to address power demand surges, store generated power during low demand, and continue to supply power to the load during cloudy or nighttime conditions. The technology is available to incorporate similar features into grid-tied PV inverters, but doing so would drive up the cost of PV electric power compared to real-power-optimized grid-connected PV power systems.

The parallels are striking between the surge and demand variability characteristics of off-grid PV power systems and the peaking load and demand variation concerns faced by an electric power grid's system operator. However, there are some significant differences between these systems. One difference is that the off-grid PV power system has a relatively small number of loads, many of which are significant by comparison with the generating capacity, so variations in load tend to be relatively large and abrupt [1]. Conversely, the electric power grid has billions of loads that are tiny by comparison with the generating capacity, so variations tend to be smooth. The other difference is that the conventional electric power grid can store energy by reducing consumption of generating plant fuel. Solar power cannot be conserved this way for later use, so the off-grid PV power system usually includes an energy storage subsystem to keep some of that unused power for later low-light conditions. When the storage is full the PV power conversion is throttled back and available energy is discarded. Grid-connected PV power systems avoid the capital costs and roundtrip inefficiency of electric power storage in favor of dependence on conventional power sources as the backup power supply, because there are no incentives or regulations directing them to do otherwise.

If grid-connected PV power systems were negligibly cheap, the system operator would prefer to curtail power production (and waste available irradiant power) when demand drops. However, all generating plants have some capital cost and their owners would prefer to operate them at full capacity to maximize revenue per year (or month or day). The system operator must throttle back generation or increase the rate of storage (e.g., water pumping) when demand drops, or the frequency will climb too high. This condition is managed by the system operator, who uses a combination of carrot (pricing) and stick (regulation) actions. As these types of actions that curtail power production are applied to grid-connected PV power systems, designers will have to choose between discarding available power and adding storage.

Localized voltage regulation issues will be one of the first impacts on grid operation as penetration grows. Power flowing toward the substation can result in increased voltage levels. In particular, capacitor banks and voltage regulators that normally boost voltage slightly may now push voltages above standard voltage limits. The power level at which such effects become detrimental may vary greatly from one feeder to the next, depending on the size and location of capacitor banks and voltage regulators, as well as on the resistance and impedance of the distribution system wires (a long or undersized power line is more likely to be sensitive to power variations). Possible approaches to resolving this issue are to curtail real power generation during peak times (with diversion to storage or power dissipation, wasted or otherwise used) and to control reactive power (voltage regulation, which is currently prohibited for distributed generation [DG]).

Another issue that could become significant as penetration of PV power production increases is voltage flicker. This effect occurs when one generating source reactive power output increases or (more commonly) decreases faster than the remaining generators can compensate. Rapid changes in irradiance (up to 15% per second) as clouds pass over will lead to PV power transients that are expected to tax the ability of rotating machine generators to react and restore system voltage.

One architectural change that is anticipated in the grid of the future is microgrid operation, in which campus- to neighborhood-sized areas served by common distribution system equipment are designed to disconnect and run independently from the rest of the grid if a supply disruption occurs. Technical solutions to certain grid-connected problems such as voltage regulation and power throttling are also useful for operating a microgrid.

Finally, with so many additional functions allocated to the inverter, the inverter becomes ever more critical to the system function, and the reliability of current technology inverters becomes a significant issue. Combining discrete components into prepackaged integrated components, reducing operating temperatures of components, and increasing electrical rating margins are expected to be key steps for increasing the mean time before failure (MTBF) from fewer than 10 years to 15 years or more.

2. Status of Photovoltaic System Designs

Major categories of PV system designs include grid-connected without storage, grid-connected with storage, and off-grid.

2.1 Grid-Connected with No Storage

The major elements of a grid-connected PV system that does not include storage are shown in Figure 2-1. The inverter may simply fix the voltage at which the array operates, or (more commonly) use a maximum power point (MPP) tracking function to identify the best operating voltage for the array. The inverter operates in phase with the grid (unity power factor), and generally delivers as much power as it can to the electric power grid given the sunlight and temperature. The inverter acts as a current source; it produces a sinusoidal output current but does not act to regulate its terminal voltage in any way.

The utility connection can be made by connecting to a circuit breaker on a distribution panel or by a service tap between the distribution panel and the utility meter. Either way, the PV generation reduces the power taken from the utility power grid, and may provide a net power flow into the utility power grid if the interconnection rules permit.

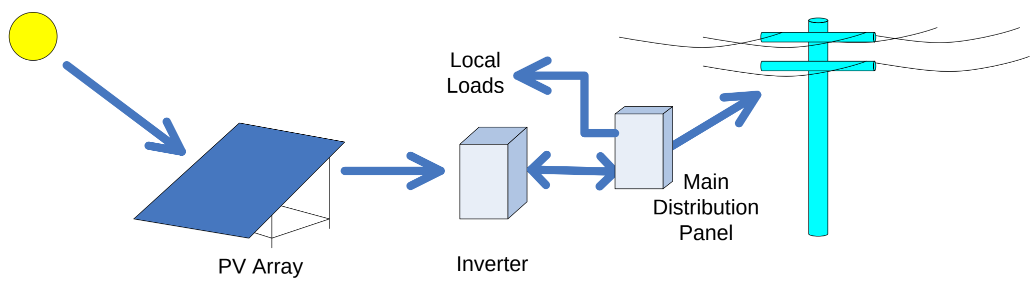

Figure 2-1. Grid-connected PV power system with no storage

A simplified equivalent circuit of the same basic grid-connected system is shown in Figure 2-2. The PV system typically appears to the grid as a controlled current source, local loads may consist of resistive, inductive, and capacitive elements, and the utility source is represented by its Thevenin-equivalent model (voltage source Utility_V with series impedance Utility_Z). The local loads within a single residence rarely include much capacitance, but if a whole neighborhood is modeled at once, voltage support capacitors maintained by the utility may contribute significantly to the local load mix. This leads to conditions that could fool the inverter into running, even if the utility becomes disconnected (unintentional islanding). The utility source impedance models such things as the impedances of transformers and cables. The inverter handles all grid interface functions (synchronization, over/undervoltage [OV/UV] and over/underfrequency [OF/UF] disconnects, anti-islanding) and PV array control functions (MPP tracking).

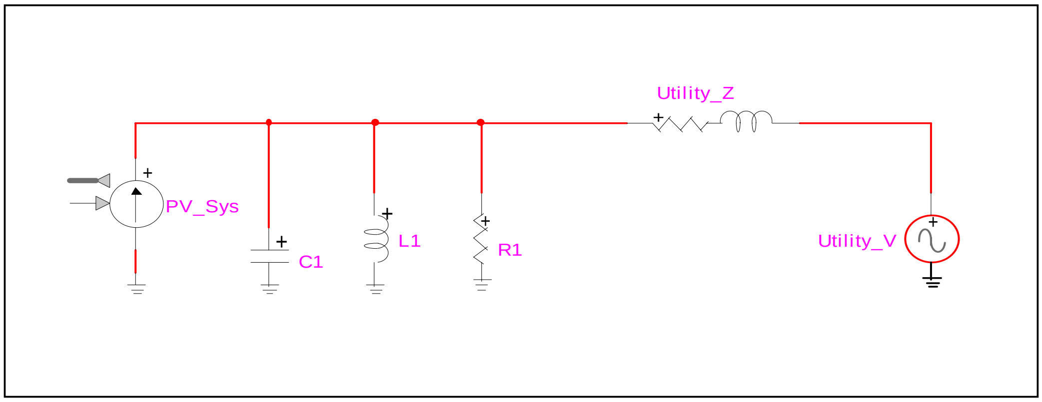

Figure 2-2. Schematic drawing of a modern grid-connected PV system with no storage

The ratio of PV system size to local load demand may be small enough that reverse power flow from the PV to the utility never occurs, but at high penetration the magnitude of the reverse power flow at midday is likely to exceed the magnitude of the nighttime load power. As shown in Figure 2-3, if we try to make the generation energy (area of red hump) equal to the load energy (blue area), the daytime power production (peak of red generation hump at solar noon) is likely to exceed the peak load power flow because most loads draw power all night when the PV system cannot supply power. For this residential load example, the peak load power flow is a double peak in late evening, which highlights the time misalignment that can occur between residential load and PV generation. Fortunately, commercial loads peak in the early afternoon, so the total PV generation in a utility system can reduce the peak system load, even though it may have no impact on the peak load at the residence where the PV is installed.

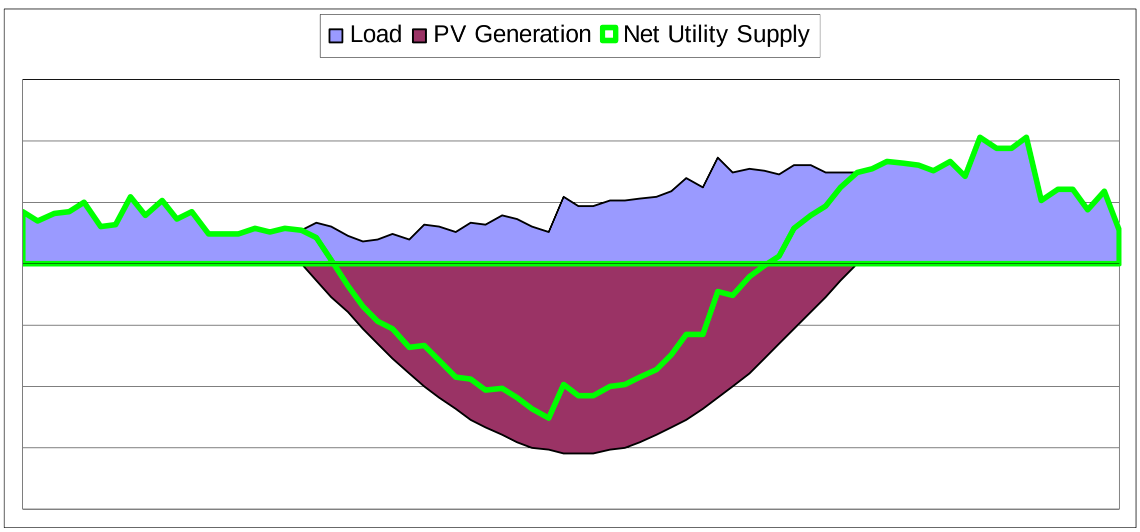

Figure 2-3. Power flows required to match PV energy generation with load energy consumption

As part of this work, an extensive literature search was conducted to assess the current body of knowledge of expected problems associated with high penetration levels of grid-tied PV. The results of that literature survey are presented here.

Several studies have been conducted to examine the possible impacts of high levels of utility penetration of this type of PV system. One of the first issues studied was the impact on power system operation of PV system output fluctuations caused by cloud transients. A 1985 study [2] in Arizona examined cloud transient effects if the PV were deployed as a central-station plant and found that the maximum tolerable system-level penetration level of PV was approximately 5%. The limit was imposed by the transient following capabilities (ramp rates) of the conventional generators. Another paper published in that same year [3] about the operating experience of the Southern California Edison central station PV plant at Hesperia, California, reported no such problems, but suggests that this plant had a very stiff connection to the grid and represented a very low PV penetration level at its point of interconnection.

In 1988, another study dealt with voltage regulation issues with the Public Service Company of Oklahoma system when clouds passed over an area with high PV penetration levels, if the PV were distributed over a wide area (south Tulsa, Oklahoma) [4]. At penetration levels of 15%, cloud transients caused significant but solvable power swing issues at the system level, and thus 15% was deemed to be the maximum system-level penetration.

In 1989, a paper describing a study on harmonics at the Gardner, Massachusetts, PV project was released [5]. The 56 kilowatts (kW) of PV at Gardner represented a PV penetration level of 37%, and the inverters (APCC SunSines) were among the first generation of true sine wave pulse width modulation inverters. All the PV homes were placed on the end of a single phase of a 13.8 kV feeder. This was done intentionally:

> Selection of the houses comprising the Gardner Model PV Community was predicated on establishing a high saturation of inverters as may become typical on New England distribution feeders in the next century. [6]

The PV contribution to voltage distortion at Gardner was about 0.2%, which was far less than those made by many customer loads [5]. Thus, harmonics were not a problem as long as the PV inverters were well designed. This paper also mentions the potential value of PV systems being able to provide reactive power to keep the power factor of a feeder approximately constant.

A 1989 paper [7] indicates that the PV community was aware at that time of potential issues involving interactions between PV systems and automatic tap-changing transformers (load tap changing [LTC] transformers). This paper describes a computer model used to study the problem, and found that cloud-induced PV output fluctuations could cause excessive operation of LTCs, but no maximum penetration level was suggested. (See 8, pp. 2–3, for more information about this problem.)

Another cloud transient study was released in March 1990 [9]. This one used a utility in Kansas to quantify the impact of geographic distribution of PV on allowable PV penetration level at the system level. This utility was described as having only very small amounts of fast-ramping generation capacity; most of its generation was in the form of slow-responding coal-fired units. The authors concluded that under the conditions studied, the utility's load-following capability limited PV penetration to only 1.3% if the PV were in central-station mode; the limitation was caused by unscheduled tie-line flows that unacceptably harmed the utility's economics. However, the allowable penetration rose to 18% if the PV were spread over a 100-square-kilometer (km^2) area, and to 36% if the PV were scattered over a 1000-km^2 area, because of the smoothing effect of geographic diversity.

Also in March of 1990, an important Electric Power Research Institute report on the Gardner, Massachusetts, PV project was released [6]. This study looked at four areas:

- The effect on the system in steady state and during slow transients (including cloud transients)
- How the concentrated PV responded under fast transients, such as switching events, unintentional islanding, faults, and lightning surges
- How the concentrated PV affected harmonics on the system
- The overall performance of distribution systems, in which the total impact of high-penetration PV was evaluated.

This study reports a number of interesting findings:

- The authors measured the rate of sunlight change caused by cloud passages. They report measured values of 60 to 150 $W/m^2/s$.
- Spatially distributing PV systems significantly reduces the system impacts of slow transients caused by clouds, and at Gardner no unacceptable voltage regulation problems occurred as a result of cloud passages. However, the authors do note that unacceptable voltage excursions could be possible if more PV were added, and if "…the circuit is lightly loaded and var [sic] compensating capacitors are connected."
- The inverters used at Gardner used the slide-mode frequency shift (SMS) method of unintentional islanding prevention [10]. The authors of [6] report on a series of anti-islanding tests that use five of the inverters at Gardner, including tests that use a 10-horsepower induction machine running in parallel with the five inverters. In none of these tests were the authors able to cause the inverters to run for more than one cycle. (These are believed to be all R-L load tests; no RLC load tests of the type required by IEEE-1547 and UL-1741 were reported.)
- The fault current provided by the inverters was limited; the maximum observed fault current was "…no more than 150% of rated converter current."

The final conclusion of this EPRI report is that the 37% penetration of PV at Gardner was achieved with no observable problems in any of the four areas studied.

The impact of high penetrations of PV on grid frequency regulation appeared in a 1996 paper from Japan [11]. This study used modeled PV systems that respond to synthetically generated short-term irradiance transients caused by clouds. The study looked at system frequency regulation and the break even cost, which accounts for fuel savings when PV is substituted for peaking or base load generation and PV cost. This paper reaches three interesting conclusions: (1) the break-even cost of PV is unacceptably high unless PV penetration reaches 10% or so; (2) the thermal generation capacity used for frequency control increases more rapidly than first thought; and (3) a 2.5% increase in frequency control capacity over the no-PV case is required when PV penetration reaches 10%. For PV penetration of 30%, the authors found that a 10% increase in frequency regulation capacity was required, and that the cost of doing this exceeds any benefit. Based on these two competing considerations, the authors conclude that the upper limit on PV penetration is 10%.

Between 1996 and 2002, a series of reports was produced by an International Energy Agency working group on Task V of the Photovoltaic Power Systems Implementing Agreement. Unintentional islanding, capacity value, certification requirements, and demonstration project results were all the subjects of reports, but the one that is of primary importance here dealt with voltage rise [12]. This report focused on three configurations of high-penetration PV in the low-voltage distribution network (all PV on one feeder, PV distributed among all feeders on a medium-voltage/low-voltage (MV/LV) transformer, and PV on all MV/LV transformers on an MV ring). This study concludes that the maximum PV penetration will be equal to whatever the minimum load is on that specific feeder. That minimum load was assumed to be 25% of the maximum load on the feeder in [13], and if the PV penetration were 25% of the maximum load, only insignificant overvoltages occurred. Any higher PV penetration level increased the overvoltages at minimum loading conditions to an unacceptable level. This study assumed that the MV/LV transformers do not have automatic tap changers (they are assumed to have manually set taps).

In August 2003, two major studies dealing with this topic by General Electric (GE) (under contract from the National Renewable Energy Laboratory [NREL]) were released [13, 14]. The first concentrated on DGs interfaced to utilities through inverters; the second focused on larger scale system impacts and rotating DG, but still with several results on inverter-based DG. Both were simulation-based studies: the first used GE's Virtual Test Bed model and focused on a simulated distribution system; the second used positive sequence load flow and examined the entire Western Electricity Coordinating Council footprint. Key conclusions of the first study [13] include:

- For DG penetration levels of 40%, such that the system is heavily dependent on DGs to satisfy loads, voltage regulation can become a serious problem. The sudden loss of DGs, particularly as a result of false tripping during voltage or frequency events, can lead to unacceptably low voltages in parts of the system.
- The simulated distribution system was assumed to employ step voltage regulators (SVRs), which are essentially autotransformers with an automatically adjustable tap on the series winding [15]. During periods of low load but high generation and with certain distribution circuit configurations, the reverse power flow condition could cause the SVRs to malfunction. Again, voltage regulation becomes a problem.
- A voltage regulation function, implemented through reactive power control, would significantly increase the benefits of inverter-based DGs to the grid. Unfortunately, this function would interfere with most anti-islanding schemes as they are presently implemented.
- Inverter-based DGs do not contribute significantly to fault currents, and thus did not adversely affect coordination strategies for fuses and circuit breakers. The study notes that the short-duration fault current contribution of small distributed inverter-based DGs is smaller than that of distributed induction machines. However, it also points out

that this might not always be true if the DG is connected at a point where the utility series impedance is unusually high. These conclusions may not remain valid if the voltage regulation controls suggested earlier are implemented.

- The inverter-based DGs did not respond adversely to high-speed transients such as those caused by capacitor switching, and thus did not degrade the system's response in such cases.
- For widely dispersed DGs, modern positive feedback-based anti-islanding appears to eliminate unintentional islands without serious impacts on system transient performance, but the complexity of the subject indicates that more study is needed.

In the second study [14], significant impacts were observed when DG penetration levels were 10% to 20%. Although this study concentrates on large DGs, which would probably not include much PV, two of the study's conclusions are relevant here.

- It echoes the sentiment that aggressive voltage and frequency trip set points will become a problem at high DG penetration levels. The study documents one case (see page 29) in which a significant transient event becomes a full-blown cascade failure because of underfrequency tripping of DGs after a major mainline generator is lost. (A similar result has been observed in the field; an official investigation committee concluded that the Italian blackout of 2003 was made significantly worse by underfrequency tripping of DGs [16].)
- It suggests that active anti-islanding, particularly involving positive feedback on frequency, has a negative but minor impact on system dynamic behavior.

Neither GE study indicates a maximum allowable DG penetration level, but the first study suggests that on the system simulated there, the maximum level is less than 40% because significant problems appeared at the 40% level.

A 2006 study [17] examined the impact of DGs on distribution system losses, as a function of penetration level and DG technology. It concluded that distribution system losses reach a minimum value at DG penetration levels of approximately 5%, but as penetration increases above that level, distribution system losses begin to increase. The reasons for this are not entirely clear, but the general result (there was a penetration level at which distribution losses were minimized) was consistent across all DG technologies. The penetration level at which minimum losses occurred was nearly doubled if voltage regulating, variable power factor inverters were used.

Yet another 2006 study focused on high penetrations of distributed generators in distribution systems [18]. This report was produced by a European consortium called Distributed Generation with High Penetration of Renewable Energy Sources (DISPOWER) that includes universities, research institutes, manufacturers, and representatives of several segments of the utility community. This report examined many types of DG in many configurations. Items in the DISPOWER report that are of specific interest here include:

- The report describes a Power Quality Management System, which is a centralized control scheme for distributed generators that has been in field tests since 2005. This system uses transport control protocol/Internet protocol and Ethernet cables as the physical communications channel. Initial field tests appear to be promising.

- One section of the report deals specifically with problems expected as DGs approach high penetration levels. The authors studied both radial and mesh/loop distribution system configurations and conclude that the mesh/loop configuration has significant advantages for mitigating the problems associated with high DG penetration. They also noted that harmonics increased slightly when the DGs were present, but never did they reach a problematic level. This study does not suggest a maximum penetration level.
- One section of the report discusses safety and protection. It notes that the practice most commonly adopted by DGs today is to disconnect at the first sign of trouble. This report, like the earlier GE reports, suggests that this approach will no longer be acceptable when penetration levels become significant, although no specific penetration level is given. Instead, ride-through must be implemented, without creating problems with unintentional islanding.

A recent study [19] reached some striking conclusions. This study examined the impact of PV penetration in the United Kingdom, where utility source series impedances are typically higher than in the United States. It examined the probability distributions of voltages in a simulated 11-kilovolt (kV) distribution system with varying levels of PV penetration, using an unbalanced load flow model. PV output was simulated using measured data with one-minute resolution. As expected, the probability density functions shown indicate that PV causes the distribution to shift toward higher voltages, but only by a small amount. The mean point of common coupling voltages increased by less than 2 V (on a 230-V nominal base). The study's conclusions include:

- If one employs a very strict reading of the applicable standard in the United Kingdom (BS EN 50160), PV penetration is limited to approximately 33% by voltage rise issues. However, at 50% penetration, the voltage rise above the allowed limits was small, and so the authors suggest that the 33% limit is somewhat arbitrary.
- Reverse power flows at the subtransmission-to-distribution substation did not occur, even at 50% PV penetration.
- Contrary to the results in [17], the authors of [19] found that at 50% penetration distribution system losses were reduced below the base-case values, largely because of reductions in transformer loading.
- Voltage dips caused by cloud transients might be an issue at 50% penetration, and the authors suggest further study of this issue.

Table 2-1 summarizes the PV penetration limits found in the literature.

Table 2-1. Summary of Maximum PV Penetration Levels Suggested in the Literature

Reference Number	Maximum PV Penetration Level	Cause of the Upper Limit
2	5%	Ramp rates of mainline generators. PV in central-station mode.
4	15%	Reverse power swings during cloud transients. PV in distributed mode.
5	No limit found	Harmonics.
6	> 37%	No problems caused by clouds, harmonics, or unacceptable responses to fast transients were found at 37% penetration. Experimental + theoretical study.
8	Varied from 1.3% to 36%	Unacceptable unscheduled tie-line flows. The variation is caused by the geographical extent of the PV (1.3% for central-station PV). Results particular to the studied utility because of the specific mix of thermal generation technologies in use.
10	10%	Frequency control versus break-even costs.
11	Equal to minimum load on feeder	Voltage rise. Assumes no LTCs in the MV/LV transformer banks.
12,13	< 40%	Primarily voltage regulation, especially unacceptably low voltages during false trips, and malfunctions of SVRs.
16	5%	This is the level at which minimum distribution system losses occurred. This level could be nearly doubled if inverters were equipped with voltage regulation capability.
18	33% or ≥ 50%	Voltage rise. The lower penetration limit of 33% is imposed by a very strict reading of the voltage limits in the applicable standard, but the excursion beyond that voltage limit at 50% penetration was extremely small.

2.2 Grid-Connected with Storage

Figure 2-4 shows two basic storage architectures commonly found with grid-connected PV systems. Figure 2-4(a) shows an architecture that many older systems have used, where a separate battery charge control device controls power collected from the PV array. This arrangement leaves the inverter to provide backup battery charge control from the utility power grid when insufficient PV power is available, but does not allow efficient extraction of excess PV power for supply to the grid when the batteries are fully charged. Figure 2-4(b) shows an architecture that is more common in modern grid-connected PV power systems that allows the PV array power to be directed optimally by the inverter to batteries or the utility power grid as appropriate.

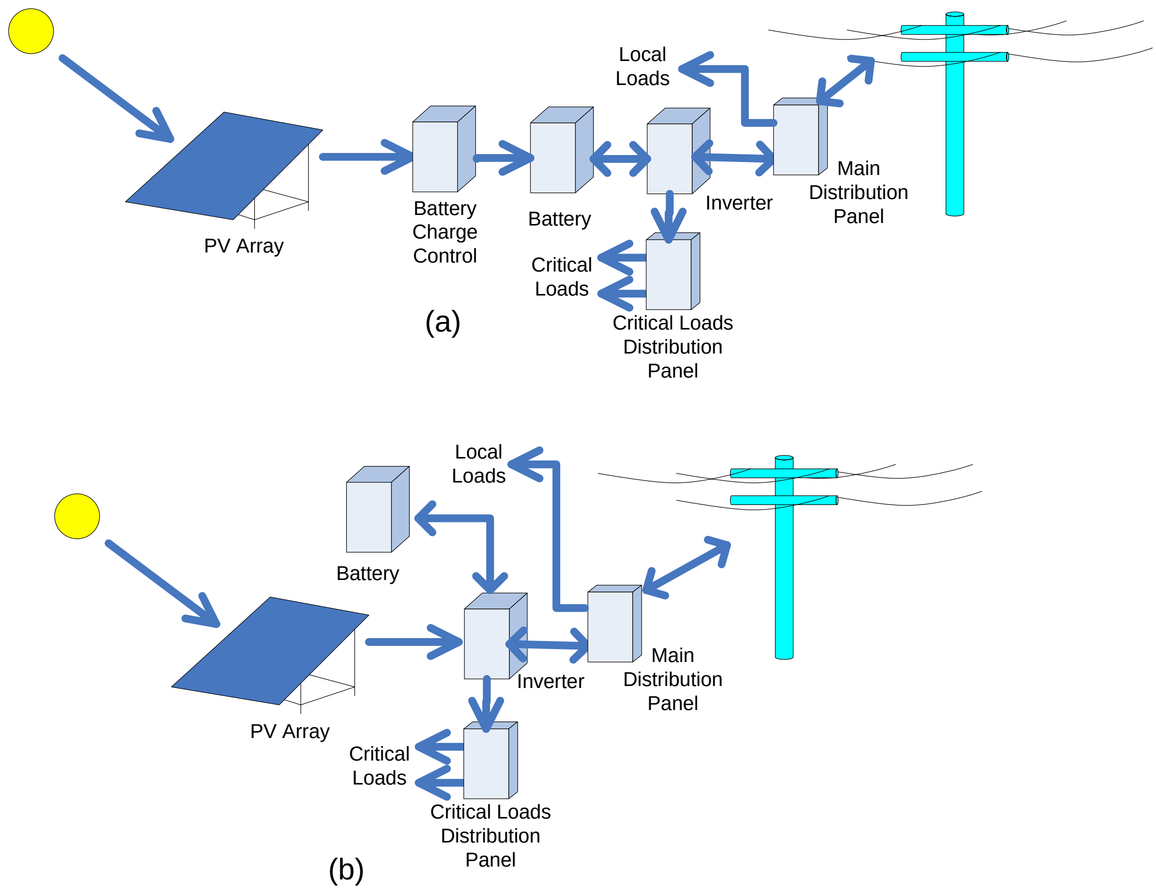

Figure 2-4. Grid-connected PV systems with storage using (a) separate PV charge control and inverter charge control, and (b) integrated charge control

In both cases, storage provides the opportunity to supply power to critical loads during a utility outage. This feature is not available without storage.

As with the grid-connected only configuration described previously, PV generation reduces the power taken from the utility power grid, and may in fact provide a net flow of power into the utility power grid if the interconnection rules permit. Storage has been traditionally deployed for the critical load benefit of the utility customer in the United States, but the Ota City High Penetration PV project [20] deployed local storage as an alternate destination for energy collected during low load periods to prevent voltage rise from reverse power flow in the distribution system.

2.3 Off-Grid with Storage

Off-grid PV systems may include electricity or other storage (such as water in tanks), and other generation sources to form a hybrid system. Figure 2-5 shows the major components of an off-grid PV system with electricity storage, no additional generators, and AC loads. In a system of this type, correctly sizing the energy storage capacity is a critical factor in ensuring a low loss-of-load probability [21].

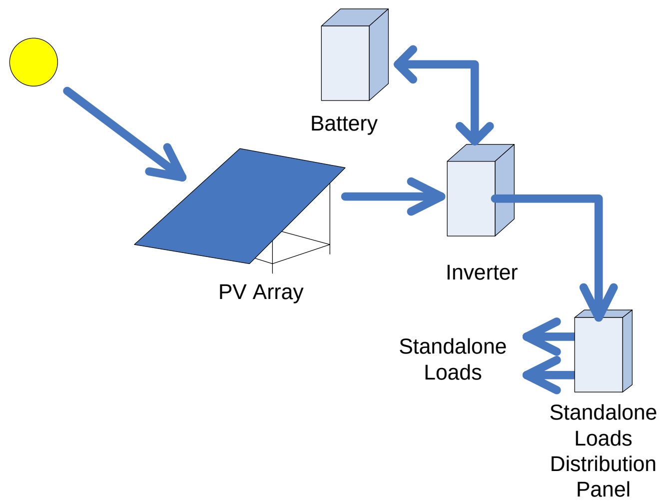

Figure 2-5. Off-grid PV system with storage

In this system configuration, the inverter acts as a voltage source, which is in contrast to the grid-tied system. The stand-alone inverter determines the voltage wave shape, amplitude, and frequency. To maintain the voltage, the inverter must supply current surges, such as those demanded by motors upon startup, and whatever reactive power is demanded by the loads.

Many stand-alone PV systems include engine-generator sets. In most cases, the generators are thought of as backup generators that are operated only during periods of low sunlight or excessive load that deplete the energy storage to some minimum allowed state of charge. The inverter senses a low battery voltage condition and then starts the generator. The generator usually produces 60-hertz (Hz) AC power directly, and thus when it starts, it powers the loads directly (the power to the loads does not pass through the inverter). The inverter operates as a rectifier and battery charger, drawing generator power to recharge the batteries. The system continues in this mode until the batteries are recharged. The generator is then stopped, and the inverter resumes regulation of the AC bus voltage, drawing power from the PV and batteries.

3. Project Approach

As part of the work done under this task, in addition to the aforementioned literature review, a limited survey of utility engineers and a limited amount of computer modeling were carried out. Those results are presented below.

3.1 Survey of Utility Engineers

A survey of utility engineers was conducted as a part of the RSI work. The survey developed for this work is attached as Appendix A. Survey responses were solicited from engineers at nine utilities. Eight engineers representing seven of the utilities responded, and their responses are summarized below. The utilities who submitted responses were:

- Salt River Project (Arizona)
- National Grid (Massachusetts, including the Gardner Project)
- Public Service Company of New Mexico
- Tucson Electric Power Company
- Southern California Edison
- Sacramento Municipal Utility District
- San Diego Gas and Electric.

PV penetration levels reported by the respondents varied widely. Some utilities have experienced PV penetration lower than 3% on any feeder to date, but there are high-penetration examples. For example, the Gardner, Massachusetts, project included PV at a 37% penetration level in distributed mode, and the 4.6-megawatt (MW) central-station PV plant near Springerville, Arizona, represents almost 58% penetration on its feeder. The highest system-level PV penetration reported (total PV as a fraction of total system peak demand) was about 0.2%. Three of the respondents indicated that they could not accurately state their PV penetration levels because they have only begun the process of mapping very small customer-sited PV to specific feeders. However, all three reported that they are in the process of performing such mapping.

As might be expected from the low PV penetration levels, most respondents reported having not yet seen any adverse effects from high PV penetration. Notably, the respondent from National Grid, who has in-depth knowledge of the Gardner, Massachusetts, project, reported no problems. Two problems were mentioned by other respondents as having been observed in the field: (1) voltage fluctuations during cloud passages over very large central station PV plants, caused by the slow following characteristics of the utility’s thermal generation; and (2) voltage fluctuations caused by mass tripping of PV, which resulted from system events involving momentary voltage or frequency dips; some of the dips were initiated by events thousands of miles away.

Respondents were also invited to share their concerns about the possible future effects of high levels of PV penetration. Table 3.1 summarizes their concerns, and the number of respondents expressing each one.

Table 3.1 Summary of Utility Engineers' Concerns about Potential Future Problems Associated with High Penetrations of PV*

Potential Problem	Number of Mentions
Excessive cumulative harmonic distortion	3
False trips	3
Need for PV inverters to incorporate voltage regulation	2
Potential for unintentional islanding	2
Need to reduce impacts of cloud transients	1
Need for improved modeling tools to facilitate distribution system planning/analysis with PV	1
Need for utility control of PV inverters	1

*The number of mentions is the number of respondents (of a possible 8) mentioning each problem.

Two respondents reported a high degree of confidence in the protection afforded them by standards like UL-1741 and IEEE-1547. These utilities expect to rely on UL-1741 and IEEE-1547 compliance to ensure that high penetrations of PV will not cause severe problems. This comment illustrates the importance of continuing the evolutionary process these standards are undergoing, to allow them to adequately deal with future PV system topologies and maintain their success with legacy systems. One respondent also mentioned that inverter testing programs, such as the one conducted by Distributed Utility Associates in California, are helpful to utilities.

Another respondent mentioned that his utility has policies that he interprets as limiting the total allowable DG penetration on a feeder to 30%.

One respondent stated: "Appropriate planning methodologies are needed for emergencies when the PV will be disconnected from the distribution system." This could be interpreted as an anti-islanding concern, but contextual clues from elsewhere in this respondent's answers suggested that standard operating protocol required a visible lockable disconnect to isolate the PV from the utility during service. Thus, this response is not included in Table 3.1 as being related to anti-islanding.

3.2 Model Results

The modeling performed specifically for this work was limited because of the available time. One author has developed a detailed system-level model of a grid-tied PV system, and extensively experimentally verified the model with assistance from the Distributed Energy Test Laboratory at Sandia National Laboratories. This model runs in the MATLAB Simulink environment and is designed to examine issues related to islanding prevention, operation of MPP trackers, and system-level impacts resulting from tripping (or failure to trip) grid-tied PV. The harmonics produced by PV inverters are not modeled.

This model was used to study the simulated distribution system shown in Figure 3-1, which models one phase of a 13.2 $kV_{\text{line-line,RMS}}$ distribution system.

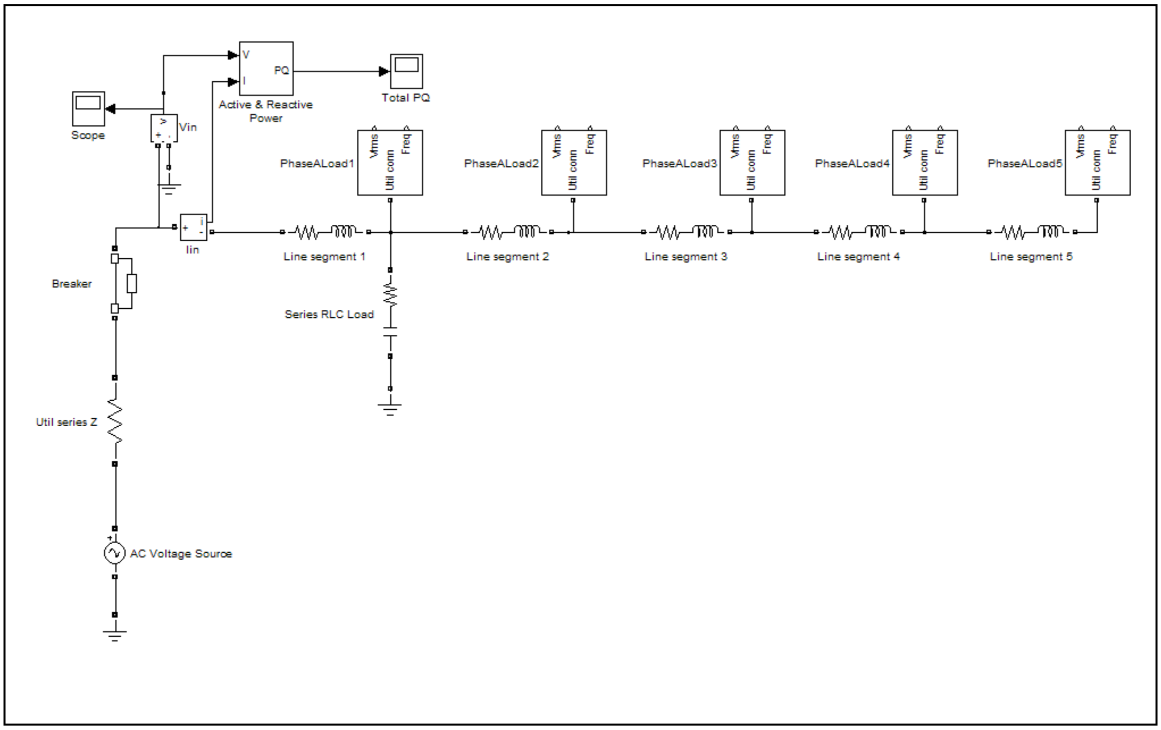

Figure 3-1. Example simulated distribution system

Five PV systems with their local loads are shown, but any number of PV + load blocks can be simulated. A power factor correction capacitor was included as shown and was used to compensate the reactive power demands of the distribution transformers and lines. Typical parameters for distribution system components were taken from [15] and [22]. Loads were modeled as parallel RLC circuits with a real power consumption of 5 kW (11.52 Ω at 240 V_{rms}), a Q factor of 0.5, and a resonant frequency of 60 Hz. All the PV systems and loads were single-phase. This model was used to examine the effectiveness of the Sandia Frequency Shift (SFS) and Sandia Voltage Shift (SVS) methods of islanding prevention in the multi-inverter case. First, for a single PV/load block, the generation-to-load ratio was adjusted to 1 (real power balanced) by adjusting the PV system output, and the reactive powers were balanced using the power factor correction capacitor. The run-on time (time between the tripping of the utility breaker at the left in Figure 3-1 and the deactivation of the PV system) was recorded. Then, PV/load blocks were added one at a time with interconnecting impedances as shown in Figure 3-1, and the real and reactive powers were rebalanced. This process was repeated for a utility with a low series impedance (0.5 Ω, purely resistive) and a high-impedance case (5 + j37.7 Ω). Figure 3-2 shows the results for SFS, and Figure 3-3 shows the results for SVS.

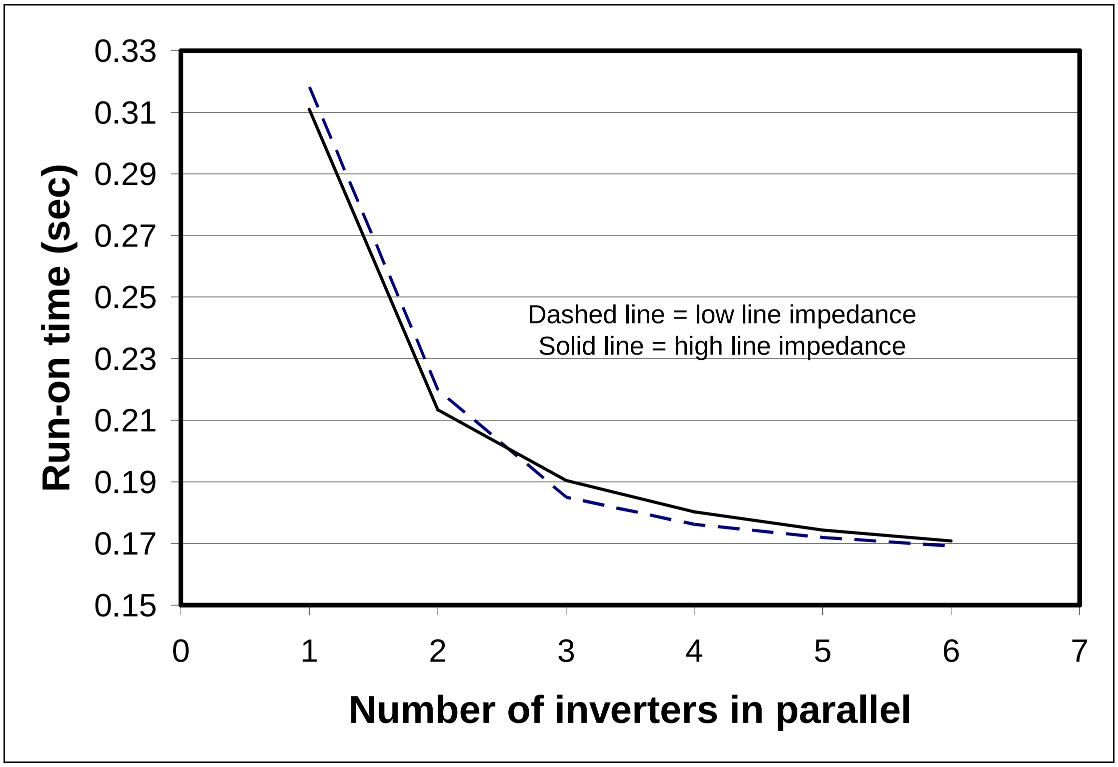

Figure 3-2. Results of simulations to test the effectiveness of the SFS active anti islanding method in the multi-inverter case

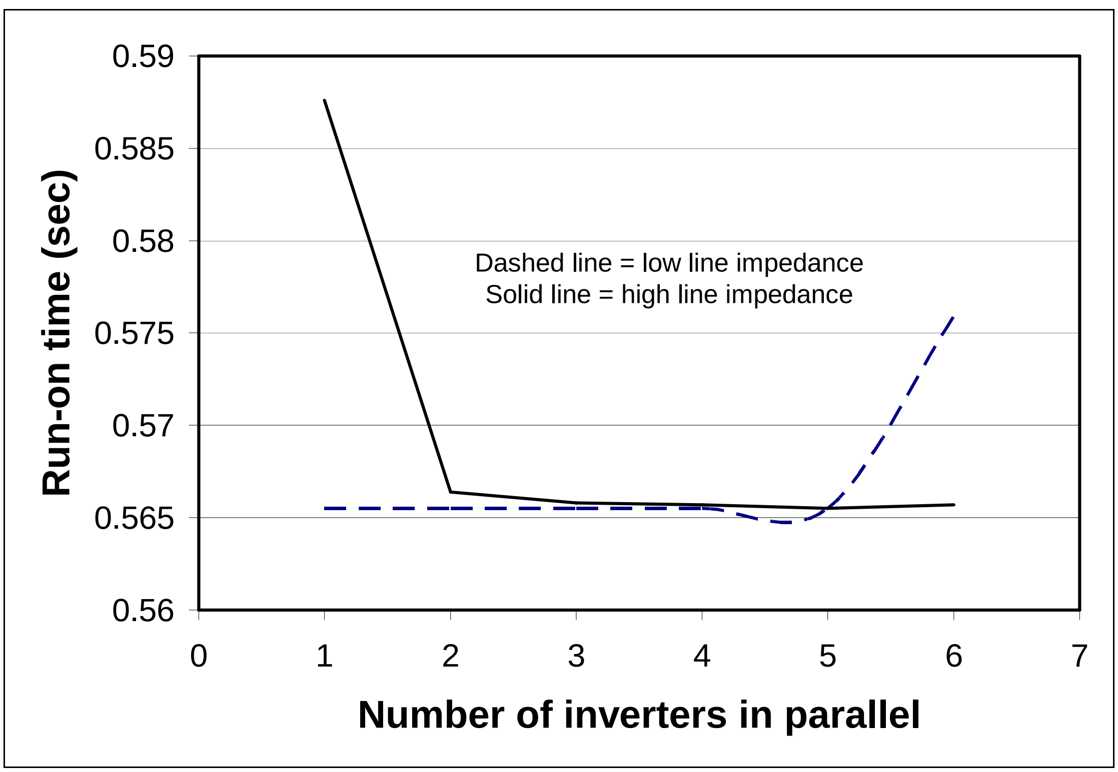

Figure 3-3. Results of simulations to test the effectiveness of the SVS active anti-islanding method in the multi-inverter case

The simulation results suggest that neither SFS nor SVS loses effectiveness in the multi-inverter case; in fact, they improve slightly as inverters are added. At least for these two methods, loss of anti-islanding effectiveness at high penetration with multiple inverters is apparently not a concern. The apparent increase in run-on times from five to six inverters in Figure 3-3 in the low line impedance case is an artifact caused by numerical chattering [23].

The model was also used to observe the effect of a loss of PV generation during a low-voltage event on the utility. A simulated three-phase distribution system is shown in Figure 3-4. Again, “typical” distribution parameters were taken from [15] and [20], along with suggestions from experienced colleagues. The generation to load ratio in this specific case was 0.833, and the power factor of the aggregate load as seen from the three-phase utility source was 0.95 lagging. A simulation was performed in which the utility source dropped to 92% of nominal voltage, followed by a sag to 80% of nominal voltage (see Figure 3-5). During the first sag, the PV systems do not trip because the voltage does not fall below the UVR trip threshold, and when the sag ends the voltage returns to its pre-sag level. During the second sag, all of the PV trips almost immediately. The post-sag voltage is 2 V lower than the pre-sag voltage because of the loss of generation, and the frequency did not deviate by more than 0.05 Hz. The effect of the mass trip of the PV on the system is almost negligible because the utility source impedance is low and because the source is considered to have infinite inertia.

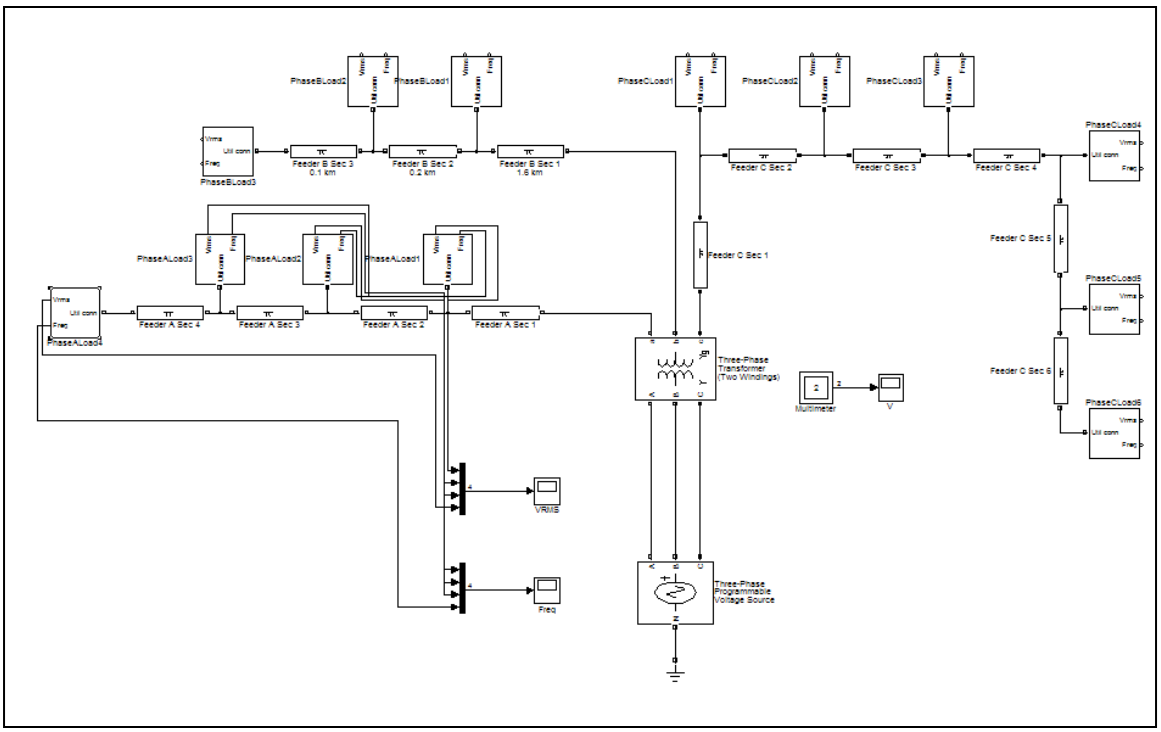

Figure 3-4. Simulated distribution system used in the modeling reported here

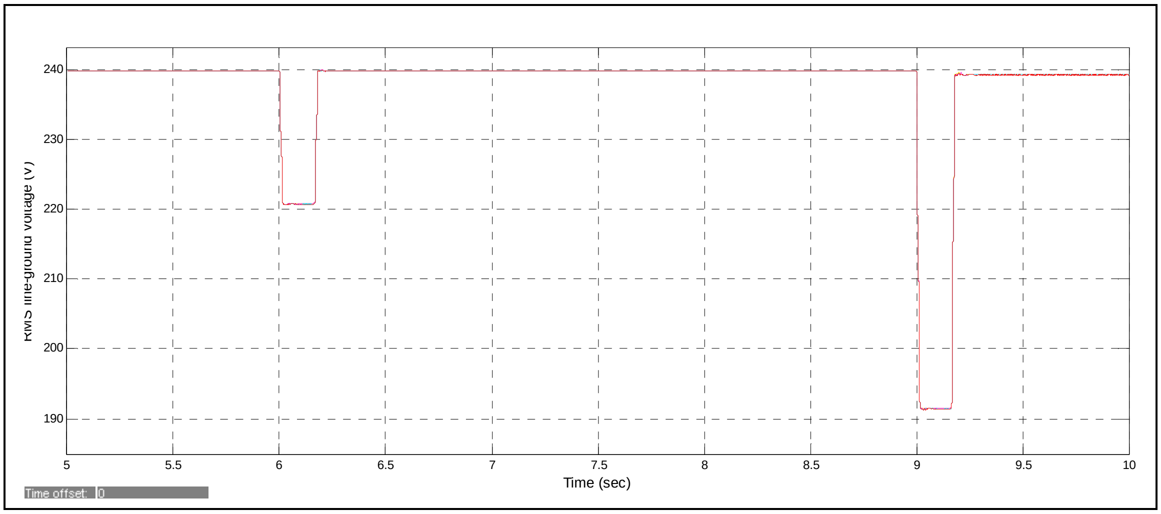

Figure 3-5. RMS voltages on Phase A during two utility voltage sags

3.3 Description of Issues

3.3.1 Voltage Excursions

Voltage rise refers to the increase in voltage at the DG (PV) end caused by the PV system sending current back through the power system impedance. Power systems can be modeled as shown in Figure 3-6; the utility is represented by its Thevenin equivalent (voltage source and series impedance). Usually, the series impedance of the utility ("Utility_Z" in Figure 3-6) is quite small, and the voltage drop across it is not significant. However, in some areas the load current can become high enough, relative to this impedance, that the resulting voltage drop could cause the load node voltage (what utilities refer to as service voltage) to become unacceptably low. The usual solution to this problem is to increase the sending-end voltage (Utility_V in Figure 3-6) so the voltage at the load node remains within an acceptable range. Of course, this means that under light loading conditions the load node voltage can be fairly high [**Error! Reference source not found.**].

If a PV system produces more power than the local loads require, the resulting reverse power will flow through the series impedance. The voltage drop across the series impedance will now be negative because of the reversal in the direction of power flow, so the voltage at the PV end becomes the utility voltage plus the voltage across the series impedance. If the utility voltage were already set fairly high, it is easy to envision a situation in which the PV array can push the load node voltage over the utility regulation limits defined in American National Standards Institute C84.1 or even the allowed overvoltage threshold [24].

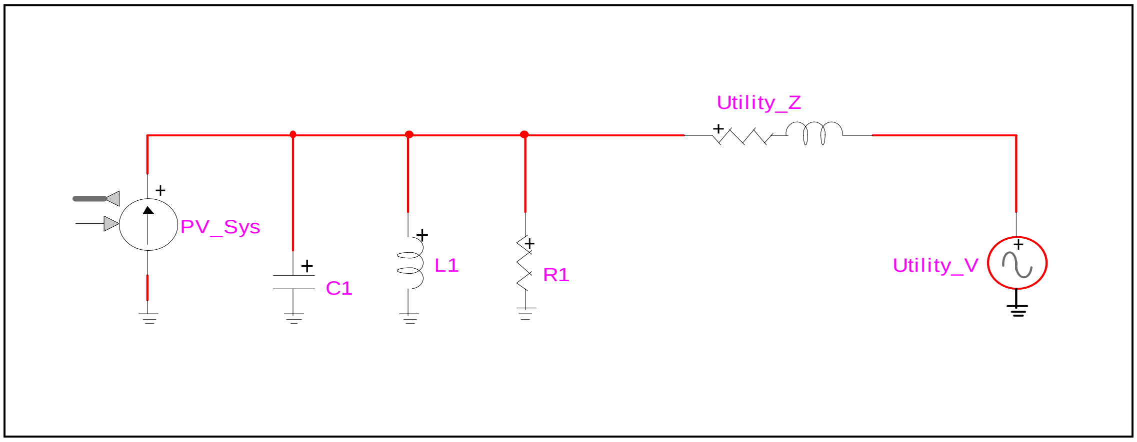

Figure 3-6. Schematic of a utility source (right) with its series impedance, feeding a node with an RLC load and a PV system

The literature search suggests that voltage rise is a significant issue because it sets some of the lowest limits on allowable PV penetration, but there is not universal agreement on what those limits are.

Voltage increase can be lessened, and the upper limit it imposes on PV penetration eased, in the following ways:

- Decrease the utility's series impedance. Probably the most logical solution to the voltage rise problem is to design service drops and distribution systems to have very low impedances (low voltage drops), which suggests larger or multiple conductors, and larger derating factors on transformers or the use of more transformers. One obvious impact of such a redesign is increased capital cost, but another less obvious effect would be an increase in the system short-circuit current strength at the point of common coupling, and overcurrent protection would have to be modified accordingly. This approach reduces voltage drop problems in both directions and reduces losses. Theoretically, reconfiguring conductors to reduce parasitic capacitances and inductances might also help in some cases, but this is likely to be of little importance in distribution systems.
- Use energy storage. PV energy could be diverted from the utility line to a storage medium for later use when voltages are too high. The many benefits of energy storage are described elsewhere in this report.
- Use nonunity power factor operation to give PV inverters voltage control capability. Inverters can phase-shift their output to supply volt-amperes reactive (VArs) to (or draw them from) the utility. However, to significantly reduce voltage increase, the PV inverter would need to be designed for additional apparent power capability (e.g., a 5-kilowatt inverter might need a 6- to 7-kilovolt-ampere rating). For additional details and analysis, see the RSI Report titled, *Distribution System Voltage Performance Analysis for High Penetration PV*, Section 4.3. Some flexibility is allowed for utilities to make special arrangements for nonunity power factor operation, but changes to IEEE 1547 that specifically address this strategy would eventually be needed for standardization and universal adoption.

- Require customer loads to improve their power factors. Again, this would allow the utility to reduce its sending-end voltage, leaving more headroom for the PV.
- Program PV inverters to fold back power production under high voltage. This approach has been investigated in Japan, and though it can reduce voltage rise, it is undesirable because it requires the PV array to be operated off its MPP, thus decreasing PV system efficiency and energy production. It also interferes with today's positive feedback-based anti-islanding, because folding back has a voltage regulation effect and could reduce an overvoltage that might otherwise indicate islanding or another abnormal condition.
- Customers downstream of the DG or on adjacent feeders originating from the same substation bus (in other words, those who cause the low voltage condition that requires increased substation voltage) could use an energy management system (EMS) that incorporates a load-shedding scheme. Noncritical loads could be equipped with load-shedding switches activated by either a low voltage threshold or a communications signal (power line carrier or otherwise). Then, the utility's voltage setting at the substation could be reduced, leaving more headroom at the PV end. This is likely to be a very cost-effective solution, but it requires the customer to put up with the occasional loss of load caused by low voltages.
- Use diversionary or dump loads at times of high PV power production and low load. This is essentially the dual of a load-shedding regimen under low-voltage conditions; one switches in extra loads at times of very high voltage. From the grid's perspective, it provides the same effect as the storage and fold-back methods above. Facility EMS controls could also be integrated with the PV system controls to provide a more robust solution that could operate discretionary loads as needed. For example, the system could automatically start and stop a washing machine and clothes dryer during peak PV generation/peak voltage conditions. However, in many grid-connected PV applications, suitable dump loads may not be easily identified.

Looking to the distribution system of the future, additional solutions to the voltage rise issue based on power electronics may be possible. For example, power electronic transformers in substations or along distribution feeders could regulate voltage, control fault current, and improve power quality [25]. To realize this, the cost and reliability of power electronic transformers must improve. Alternatively, distributed SVCs and SVRs, centrally controlled via a communications bus, could be used to regulate distribution system voltages [26]. Another solution to the voltage rise issue that has been suggested by Japanese researchers is to consider a new distribution system architecture based on loops or meshes, instead of radial feeders [27]. The loops or meshes would be interconnected by using power electronics similar to the power electronic transformers just mentioned that would precisely control the loop power flows. These power converters could also be centrally controlled as discussed in [23]. The added degree of control provided by the power electronics and the loop architecture could effectively eliminate voltage rise.

3.3.2 Peak Load Support

Utility infrastructure costs are driven largely by the need to serve loads during high demand. To help manage loads, utility rate structures typically include charges tied to the customer's peak monthly demand. Future tariffs may be based on real-time pricing – such as hourly – and these would also reflect the cost of service during periods of peak demand.

Customers can thus incur a significant cost related to on-peak loads. These loads must be managed to lower energy costs. EMS and storage could be employed to limit customer peak loads, benefiting both the customer and the utility.

3.3.3 Distribution Outages

Most utility outages occur at the distribution level. Outages may be momentary – a few cycles or seconds – or longer term. Advanced utility automation systems may help to prevent such outages by automatically isolating sections of the line and reconfiguring sources such that the outage is confined to a small number of customers. However, the capacity of alternate sources is often limited by voltage or ampacity constraints, limiting the viability of this solution.

If a DG or storage source could be included in the utility planning, the source could be used to support a temporary, independent island until the outage could be resolved.

3.3.4 Spinning Reserve

Historically, spinning reserve has been provided by large idle power plants, kept spinning for faster response to outages by other units. The capacity of such units is therefore untapped, and the capital and operating costs of these units must be allocated to the customer base through electricity rates.

This service could be provided (or supplemented) by DG sources. When aggregated, the effective reserve provided by DG could be comparable to the plants they would displace. This would free the capacity of the larger units for ongoing energy needs.

3.3.5 Frequency Regulation (and Area Regulation)

Though the VAr control method described above is clearly a voltage regulation scheme, in this context we refer to the need for the power system to respond to rapid changes in load and PV output, and can include amplitude and frequency regulation. Rapid variances of PV output, usually caused by cloud transients, interact with the ramp rates and response times of the generating plants and voltage regulation equipment that must follow changes in load.

The literature and the survey results suggest that voltage regulation is still a concern. For central-station PV plants, voltage regulation is a particularly great concern; the lowest values of allowable PV penetration level mentioned in the literature are all for central-station PV plants, and are in the low single digits.

Voltage regulation caused by cloud transients, especially over large central station PV plants, can be improved by:

- Using fast-acting energy storage that levels the PV output during cloud transients. If one assumes that a cloud transient that cause the PV system output to dip has a linear ramp-down period, a constant low-power period, and a linear ramp-up period, the cloud transient could be leveled by an energy storage system that can produce the power profile shown in Figure 3-7. Typically, during the constant portion of the cloud transient, the PV system's output is assumed to drop to about 20% of its value under clear sky conditions. Thus, the storage system must supply the other 80%. Assuming that the irradiance ramps at a rate of 200 W/m^2/s [28], the amount of energy storage required to level a cloud transient is shown in Figure 3-8, as a function of PV system size and duration of cloud transient (time period t_2 in Figure 3-7). This is the storage amount required to eliminate the cloud transient. The PV ramp rate could be reduced with considerably less storage.

- Integrating high time resolution cloud transient forecasting into utility dispatch and control. This is similar to wind forecasting proposals for large wind farms. Satellite imagery could be coupled with knowledge of the PV plant locations to predict PV output dips caused by cloud transients. Using this information:
  - Utility voltage regulation means could be employed preemptively.
  - The PV plant could "soften" the transient by preemptively ramping down from MPP operation just before the cloud transient, and then resuming MPP operation slowly after the cloud passes. This leads to a loss of PV energy, but that loss could be minimized.

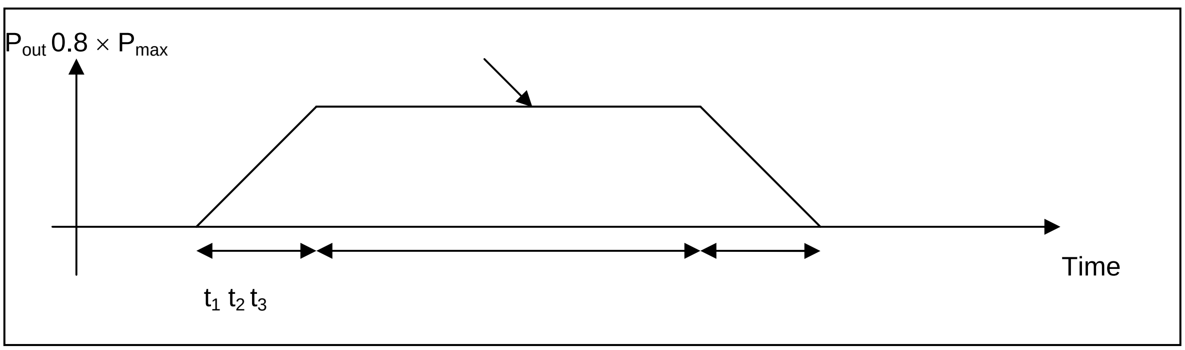

Figure 3-7. Power profile required of an energy storage unit to level a cloud transient in a PV system

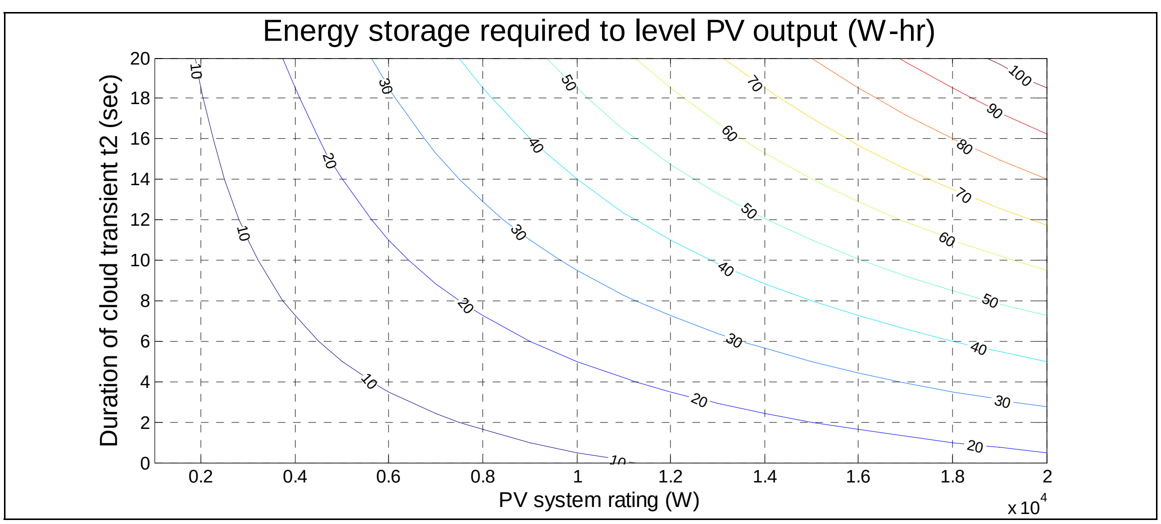

Figure 3-8. Energy storage required to provide the power profile in Figure 3-7, as a function of PV system rating and duration of the cloud transient

3.3.6 Problems Related to Active Anti-Islanding Methods

According to today's standards, all customer-sited DG are required to incorporate a means to detect loss of mains, to ensure that inverters do not feed utility faults or open utility lines.

In general, two levels of loss of mains detection are employed in modern PV inverters. First is the traditional response to abnormal conditions affected by OV/UV and OF/UF trips. Consider the case shown in Figure 3-9, which is the same as Figure 3-6 except that a breaker was added (which could represent any current interrupting device). It is relatively straightforward to show [29, 30] that if the breaker opens at a time when the PV system's output power (real or reactive) and the RLC load's P and Q demand are not equal, there will be a detectable change in the amplitude or frequency of the point of common coupling voltage (VPCC, marked in Figure 3-9). Thus, if one sets the OV/UV and OF/UF operating windows to be very narrow, the OV/UV and OF/UF will provide effective loss-of-mains detection in most fault or open-line cases. Partly for this reason, IEEE-1547 specifies that DG should trip offline if the RMS voltage at the inverter's terminals is 10% above or 12% below the nominal value for more than two seconds (and faster at wider limits), or if the frequency is not between 59.3 Hz and 60.5 Hz.

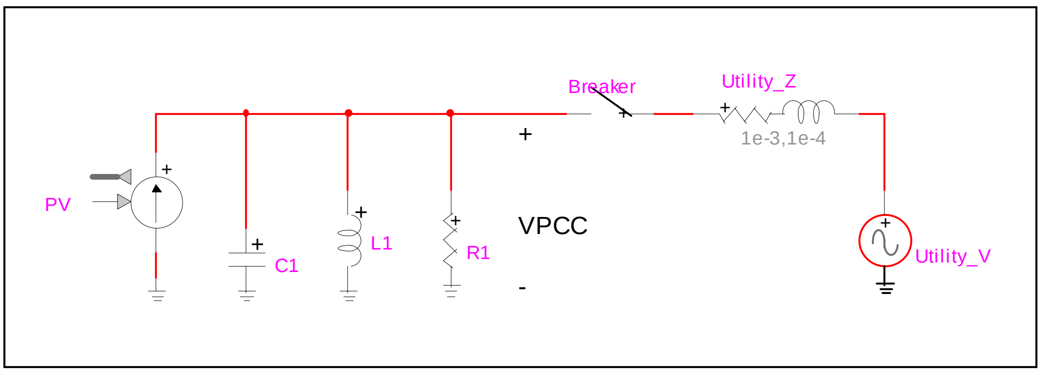

Figure 3-9. Simplified system configuration for understanding loss-of-mains detection

With static inverter-based DG, there will remain a narrow range of RLC loads, called a nondetection zone (NDZ) [31], for which the OV/UV and OF/UF alone would fail to detect a loss of mains. Although the spontaneous occurrence of these tuned circuit loads and other conditions necessary for an unintentional island to form and remain stable are extremely improbable, inverter controls typically employ any of a number of active anti-islanding algorithms to further reduce the NDZ and have helped allay concerns of utility protection engineers and line workers.

The results of the literature search suggest three reasons why it is desirable to replace current active anti-islanding schemes with alternatives that facilitate the implementation of grid support functions in inverters.

- Allowing PV and other inverter-based DG to ride through voltage sags or frequency disturbances is highly desirable. This is not possible with the aggressive UV and UF tripping of PV used today. These aggressive low voltage or frequency trips can (and have been observed to) cause DGs to disconnect at a time when their continued operation would provide extremely high value to the host utility. Thus, using aggressive OV/UV and OF/UF settings to improve the detection of and response to line faults and loss of mains, has limited the ability of PV to be a "good citizen" on the grid [13]. Until a few years ago, similar trip settings were used with large scale wind farms. The advent of low-voltage ride through requirements [32, 33] signaled a change in utility perspective towards large wind, and many utilities with PV experience are suggesting that a similar change in perspective needs to follow for PV and other DG as they reach high system-level penetration.
- Most of the highly effective islanding prevention techniques used in commercially available PV inverters use some type of destabilizing positive feedback [34] to help ensure that either the amplitude or the frequency of VPCC goes beyond the OV/UV or OF/UF limits upon loss of mains. Although they prevent islanding, these types of controls require PV inverters to generally perform an anti-regulation function: they act in such a way as to attempt to make any excursion in voltage or frequency worse. The literature indicates that this type of control has a minor but negative impact on the grid.
- The literature and survey responses make clear that voltage regulation capability in PV inverters is desirable from a system-level perspective. This capability also conflicts with and reduces the effectiveness of certain anti-islanding functions.

There are other reasons why active anti-islanding as implemented today is undesirable at higher penetration levels. For example, certain active anti-islanding techniques can cause power quality problems at very high penetration levels, under certain conditions. Impedance detection can cause flicker and power system noise, if certain precautions are not taken [21, 35]. However, most real-world inverters do take those precautions. Also, almost all active anti-islanding methods require some distortion of the PV system's output current waveform [23], but that distortion can be minimized under normal operating conditions, and inverters are required to meet the harmonic limitations in [24] while their anti-islanding controls are active. The literature reports no field observations of either problem.

Today's active anti-islanding methods are also not suitable for use in microgrids. A microgrid is a collection of electrical sources and loads, along with their interconnections and associated equipment such as transformers, that can operate in parallel with the utility or in stand-alone mode as needed [36]. The defining characteristic of a microgrid is its capability to separate from its host utility and power its own loads. Some experts believe microgrids could become an important part of the utility system of the future [37, 38]. Microgrids would require a loss-of-mains detection scheme that allows them to know when to switch from utility-parallel to islanded mode, but methods that rely on creating a voltage or frequency transient are not amenable to smooth transitions between these two modes. The method used in much of today's microgrid work requires the microgrid to always import power from the utility; the loss of that import power can then be used to detect the onset of islanding [39]. This restriction would prevent future microgrids from exchanging power with each other or exporting power to support the host system.

Finally, there is some concern that certain anti-islanding methods might lose effectiveness in the high-penetration case where there are large numbers of inverters. There is not yet a consensus on this issue [40].

Based on this discussion, the need for alternative loss-of-mains detection methods is clear. These alternative methods should not use destabilizing positive feedback, but rather facilitate the implementation of grid support functions, without losing islanding detection effectiveness for any combination of local loads, DGs, or system configurations. Potential solutions to this problem include:

- Use power line carrier communications (PLCC) [26, 27, 41, 42]. Any of several types of communication system could be used to replace active anti-islanding, but PLCC has a number of significant advantages for this application. If the PLCC signal meets certain criteria, such as having a continuous carrier, and if other well-known challenges to PLCC communications can be adequately solved, loss-of-mains, fault, and islanding detection could all be achieved with the PLCC signal as a continuity test of the line. If there is a fault, the PLCC signal will be lost at the PV system's end of the line. A test for the PLCC signal can then be used to detect islanding; its presence indicates that the utility is still there, and its absence indicates a condition that requires shutdown or separation from the utility. The inverter would thus "know" when it was islanding and could react appropriately, and active anti-islanding would be unnecessary. Voltage and frequency trip settings could be widened to better accommodate utility transients and provide better ride-through, or even adjusted dynamically depending on whether the inverter were in grid-tied or stand-alone mode. The PLCC receiver need not be in the inverter; the loss-of-mains detection function could be implemented at the point of common coupling, which would facilitate AC modules and microgrids.

  Almost no information content is required in the PLCC signal. It can still be used for other control functions without interfering with the loss-of-mains detection function. In addition to being continuous, the PLCC signal must be available at all endpoints, which means it must propagate well through distribution system impedances. This generally restricts the usable frequency range of the PLCC signal, and thus the available bandwidth. Subharmonic and low-frequency (< 1 kHz) systems have been successfully tested for this application, but PLCC transmitters in this frequency range tend to be expensive. Broadband over power line (BPL) might be useful in this application if issues related to propagation, generation of interference, and noise immunity can be addressed [43]. A number of commercial PLCC-based automatic meter reading systems operating in the 1-6 kHz range are also available, and some of these may be suitable. The main challenges for PLCC in this application are to develop a rugged, low-cost PLCC transmitter and identify or develop a low-cost (and preferably noninvasive) means of ensuring reliable signal availability at all endpoints.

- Integrate PV inverters into utility supervisory control and data acquisition systems or AMI systems. Inverters could be tied into utility communications systems, which would issue a warning to inverters in sections of the utility isolated from the mains. Any available channel, such as BPL, DSL, or coax, could be used. This would require that utility communications systems reach to all distribution-level endpoints, which is not presently the case. There may be other reasons to connect inverters to AMI systems, such as enabling PV systems to respond to real-time pricing signals. This would require the inverters to be connected to a high-bandwidth communications system that could, if properly configured, handle the anti-islanding function as well.

- Use other passive islanding detection techniques. One promising candidate for such a technique is harmonic signature detection [44], but at this time it has not been proven to be universally applicable in real-world power systems.

4. Project Results

The results imply that future generations of grid-tied PV inverters should incorporate a number of features, as described below. Incorporation of these features would move today's grid-tied PV system architecture toward the Solar Energy Grid Integration System (SEGIS) architecture shown in Figure 1-1.

4.1 Voltage Regulation

A PV inverter or the power conditioning systems of storage within a SEGIS could provide voltage regulation by sourcing or sinking reactive power. The literature search and utility engineer survey both indicated that this is a highly desirable feature for the SEGIS.

Implementing this feature would require modifications to the traditional PV inverter hardware design. For example, the required rating of the PV power electronics would have to be suitably oversized to support reactive needs and maintain full real power service. Also, the inverter's energy storage capacitors must be suitably sized so that excessive ripple does not reach the PV array during periods of high VAr production or absorption. The inverter's control software would also have to be suitably modified.

Technology drawn from stand-alone inverters and motor drives is sufficient for all of these requirements. However, adding this capability would increase inverter cost. The market mechanisms that would lead to acceptance of this additional cost are less clear. The problem of pricing ancillary services from DG, such as voltage regulation and VAr support, has not yet been fully solved.

Significantly enhanced communications capabilities in PV inverters must be a part of SEGIS development. These communications capabilities would allow inverters to receive and respond to market pricing signals sent from the utility, and to maintain proper coordination of their actions with those of other utility voltage regulation equipment. Communications for future PV inverters are discussed more fully below.

4.2 Backup Power (Islanding)

A utility that uses automated switching and sectionalizing could use a SEGIS to serve loads in a microgrid that operates in stand-alone (islanded) mode. In this context, the SEGIS would have to provide all the services normally provided by the utility, including load following and frequency control, and it would have to be able to resynchronize with the utility before reconnection.

SEGIS storage systems could be sized to cover momentary interruptions (one minute or shorter) or longer term, such as 15 minutes, depending on the customer's budget and required level of reliability. The system would be similar to a conventional uninterruptable power supply (UPS), except that it would be controlled by the utility and would serve multiple customers. To maximize its effectiveness, the utility could employ a parallel load management system to shed noncritical load in the island.

In general, PV improves the performance and feasibility of microgrids in two ways: (1) by reducing fuel use, thereby either extending the length of time that a microgrid can stand alone without fuel inputs from the outside, or reducing the amount of fuel that must be stored on-site; and (2) by reducing the emissions of the DG mix, which in many cases are restricted by law. Microgrids must generally be justified economically before they will be installed [45]. A full discussion of the economics of microgrids is beyond the scope of this paper. Two technical challenges associated with microgrids will be discussed here.

- Loss-of-mains detection must be provided at the point of common coupling between the microgrid and the host utility. The microgrid needs to be able to enter the stand-alone mode (sometimes called the intentional islanding mode) seamlessly upon loss of utility, and to reconnect automatically when the utility comes back online. The destabilizing active anti-islanding techniques used in inverters today are unsuitable for this purpose because they cannot readily be implemented at the point of common coupling, and they work by creating a voltage, phase, or frequency transient when the utility is lost. These transients work against a seamless transition between grid-parallel and stand-alone modes. Two suitable replacements, a passive method such as harmonic signature detection, or some form of communications, were identified earlier. PLCC is a preferred candidate because of the unique match between its properties and the needs of the application. Also, unintentional islanding within the microgrid would also have to be dealt with; that is, a SEGIS within a microgrid must be equipped to act appropriately if the section of the microgrid becomes isolated from the rest of the microgrid [35]. This problem could also be solved by communications.
- A SEGIS within a microgrid must be equipped with control software that enables it to operate in an environment where it must interact with other generators, possibly where no single generator has enough capacity to carry the entire load. The SEGIS and other generators must therefore work cooperatively to maintain voltage stability and power quality and meet cost goals.

Inverter control in microgrids is an active research topic today, and many questions remain unanswered [36, 46, 47]. Techniques for controlling DGs in a microgrid can be broadly grouped into centralized control and distributed control techniques, although in practice some combination of both is almost always used. Centralized control relies on high-speed communication channels between DGs and a central control computer, which may be an EMS. Distributed control schemes [48] such as agent-based controls do not have centralized control; instead, the DGs must work cooperatively to control the system, and EMS functions would be provided by this same cooperative action between sources, storage, and loads. One form of distributed control is local variable-based control, which uses only the information available in the DG’s terminal voltage. Generally, either power versus frequency droop controls or active output impedance emulation are used to regulate voltage and share loads between the DGs, and the need for communications between the generators is minimized [35, 49, 50]. Other distributed control concepts go in the opposite direction, relying on high-bandwidth communications channels between the DGs, and between the DGs and other power system elements [51]. De Brabandere et al. propose a distributed control strategy that combines a low-bandwidth communication strategy based on identification of the ratio of resistance to reactance with a modified droop control applied to both frequency and voltage [52, 53].

Debate continues about whether distributed or centralized controls are preferred. In reality a combination of both will probably continue to be used. Distributed control based on local variables is robust in the face of grid disturbances, and is inherently plug-and-play in the sense that theoretically any combination of generators with the correct droop controls can be easily paralleled, and new generators can be added to the system at any point without changing the set points of the controls of the other generators. Local variable-based control is therefore ideally suited to the fast control functions of voltage regulation and maintenance of stability, and to enable generators to continue to function in the event of a failure of a communications channel. Communications-based techniques can much more easily implement financially motivated energy management functions, could eliminate the need for inverter-based active anti-islanding, and can coordinate all power system elements much more easily than local variable-based techniques. Communications standards like IEC-61850 or LonTalk may eventually facilitate this process. These techniques are thus best suited to the slower-speed control functions of energy management and system coordination.

Additional research is needed in the area of SEGIS integration into microgrids. Agent-based controls have been successfully demonstrated in certain circumstances [54, 55, 56, 57, 58]. These early results demonstrate the great potential of agent-based control, but more broadly applicable solutions are still needed. Droop controls are being actively investigated by a number of research teams, but implementing a microgrid with droop controls seems to require a very large engineering effort; true plug-and-play functionality seems far off.

4.3 Spinning Reserve

Energy storage has been used for spinning reserve at the transmission level. Smaller DG units could likewise be used, with an aggregate capacity comparable to conventional thermal units used for this service. The storage would be sized with about 15 minutes of storage, depending on the ancillary market design. This is enough time to start up gas turbines and dispatch power.

4.4 Frequency Regulation (and Area Regulation)

Distributed storage could be used to regulate system frequency (or control area flow) by charging and discharging in response to signals sent by the system operator. Initial demonstrations using flywheel technology have been used for this purpose. Storage would have to be sized at about 15 minutes of full power to provide this.

4.5 Possible Directions for System Design Evolution

4.5.1 Communication of Price and Generation Control Signals

As described in the introduction, grid-connected PV power systems are given stringent requirements not to introduce negative impacts to the grid and are ignored for power load matching. According to work done at NREL, an economic incentive that seems to disable solar generation for limited periods appears at system penetration levels as low as 7%. [59] One possible way to adapt the control strategy for grid-connected PV system operation is to introduce communication with one or more central control or price sources. Since distribution system control communication is generally oriented toward system protection, and is usually implemented with dedicated copper circuits, conventional communication technology is not likely to scale up for application to distributed PV generation. The following sections describe the characteristics of communication systems in general, and of modern digital communication systems in particular. Its aim is to identify key features of the communications systems of the future for distributed PV.

4.5.1.1 Communication Systems

Communication systems are the means by which information is transferred between a sender and a receiver. The study of such systems is the subject of a broad academic discipline. A brief review of the capabilities of communication systems in general and the capabilities of some promising candidates for near-term implementation are presented here.

In general, communication systems all share features that will be discussed for each candidate system: latency, bandwidth, reliability, accuracy, distance limits, capital cost, and operating cost.

Latency refers to the delay between sending and receiving information. For example, with the use of satellite communications the speed of light traversing the distances involved can introduce noticeable delays during telephone conversations. Another example of latency can be found in e-mail, which may normally take only a few seconds, but if any of the e-mail relays are busy or disabled the delay to delivery may take minutes or days. Reaction times for some safety-related events are about 160 milliseconds, and real-time pricing signals may become stale after an hour.

Bandwidth refers to the rate at which data can be transferred. Returning to the satellite telephone example, a single satellite may be able to handle thousands of telephone calls simultaneously and may be upgraded to handle tens of thousands, but it cannot shorten the time-in-transit for any words spoken during any telephone call. In the area of grid-interactive DG, most data items currently considered as possible messages are very small (a few bytes each). A central management server (aggregator) will need extra data to keep each message uniquely identifiable (network overhead) and may communicate with tens to thousands of DG systems, so bandwidth at the server could be a bottleneck that limits the number of DG units that can be aggregated by one server.

Communication accuracy refers to how many messages are received in an altered form; measurement accuracy refers to how close the reported value is to the actual value. Most digital communication systems pad the data with enough information to identify unintentional alterations (errors) of a few bits in each message and depend on the sender to repeat the transmission if no acknowledgment is received. This involves time delays, which can add uncertainty to the overall time-in-transit.

Reliability indicates how frequently the communication channel will fail to transmit a message accurately. An error may be detected as such by comparison with the redundant data (checksum), so some errors that occur may be transformed into longer delays while the message is resent. A message with undetected errors is passed on as accurate, even though it is different than the one that was sent. The large bandwidths commonly available today mean that redundancy is added to the message; thus, the probability that incorrect data may be sent is reduced to vanishingly small values. However, this method of achieving reliability has a cost in increased effective latency as information is sent and resent multiple times.

Some communication methods have inherent distance limitations that are often linked with their available bandwidths. Commonly available twisted-pair 100-Mbps Ethernet has a defined distance limit of 100 m (328 ft) [60]; an asymmetric digital subscriber line (ADSL) can connect a telephone company central office to homes up to about 1.5 miles away. PLCCs also have distance limits that can vary by orders of magnitude, depending on the properties of the specific signal and power system.

Communication system capital costs will affect decisions regarding methods of communications employed. For example, dedicated copper communication conductors are commonly used for distributed utility protection systems. However, as more signals are required, the installation of large numbers of wires for communication becomes prohibitive. Wireless (usually digital radio signaling) communication options allow new wiring to be omitted entirely. Digital packet switched communication systems allow piggybacking of information over one new medium or even using extant infrastructure (for example, reprovisioning telephone service to include ADSL removes any need to install new conductors). Reuse of electrical power distribution wires for communication is appealing, but most implementations of this strategy are designed for in-home use, and there is a tradeoff between bandwidth and distance limitations.

Communication systems operating costs are primarily driven by power consumption and maintenance. A signal propagated through the variety of impedances found in utility power distribution systems will usually require more transmitting power than a dedicated closed medium such as ADSL or cable modem. One strategy for addressing power consumption is to use low-power-short-haul technologies (which typically have low bandwidth) to reach signal gateways that collect information together and retransmit all data on higher bandwidth dedicated communication media. Maintenance costs arise from communication media (conductor or insulation degradation by corrosion or mechanical means such as digging) and transmit-receive equipment.

4.5.1.2 Open Standards Institute Seven-Layer Model

To realize the benefits of communications between distributed resources, open system standards and definitions must be used. The Open Standards Institute has promoted a model of communication that separates the elements of communication systems into layers [61], where the upper layers are more conceptual and the lower layers are more physical. For example, a postal letter containing a birthday card conveys personal greetings at a very high level. The envelope provides information about the source and destination and is one level below the concept of birthday greeting. Further levels might be analogous to the bag that the envelope is placed in at the postal service, and another level could be analogous to the truck driven from one town to another that happens to carry the bag.

This analogy is useful because, just as trucks made by different manufacturers may be used to transport the birthday card with no difference in the delivery of the greeting (as long as the trucks meet their deadlines), the choice of how a particular hour-ahead price update or utility fault/disconnect now signal is delivered can involve several communication standards that apply to different aspects of the communication system. However, the latency requirements of some applications may preclude certain communication technologies. For example, satellite communications may bypass the need for dedicated communication wires, but it has too much delay to be useful for a transfer trip application.

4.5.1.3 *Candidate Communication Solutions*

Table 4-1 identifies basic characteristics of several communication options for communicating protective signals and price signals to the grid-connected PV power system.

Table 4-1. Communication Technology Characteristics

Technology	Latency	Bandwidth	Reliability	Accuracy	Distance Limits	Capital cost	Operating Cost
Dedicated copper wire (dry contact)	< 3 ms	200 bps	High	High	2-20 miles	High	Low
Ethernet (10BaseT, etc)	2-10 ms	10-1000 Mbps	Medium	High	100 m	Medium	Low
Continuous carrier PLCC	0.2-10 ms (loss of mains)	Low	Unknown	High (loss of mains)	< 100 miles	High	High
Broadband (BPL) PLCC	< 30ms	Medium to High	Unknown	Unknown	2000ft per hop	Medium to High	Medium
Spread-spectrum wireless	5-50 ms	10-50kbps	Variable	High	300m	Medium	Low
Bluetooth (Class 1)	50 ms	1-3 Mbps	Variable	High	<100m	Medium	Medium
ZigBee (IEEE* 802.15.4-2003)	> 16ms	20Kbps or 250Kbps	Unknown	High	<100m per hop (can relay)	Low	Low
IEEE 802.11 Wireless Ethernet	2-10 ms	10-54 Mbps	Medium	High	30m	Medium	Low

*Institute of Electrical and Electronics Engineers

Dedicated leased lines are a traditional technology for transmitting dry-contact signals for supervisory and protective functions to transmission-connected generators. These lines are often multiplexed with continuous carrier signals. However, installing leased lines into residence-sited PV systems would be prohibitive.

Ethernet wiring is commonly used for local area networks (LANs), which are becoming common for Internet sharing in residential applications. However, this technology must be connected to a wide-area-network technology such as ADSL or a cable television system, and reliability of these networks is maintained only at a convenience level, such that protective functions would be inappropriate for transmission this way.

Continuous-carrier power line communications is most often applied to automated meter reading systems. This has the advantage of being inherently coupled to the connection whose continuity is of concern for islanding. This makes using the presence of this carrier appropriate for broadcasting a transfer trip signal from the feeder circuit breaker. Unfortunately, this technology is relatively expensive and power hungry, so it has not gained momentum in the utility market. It also has a fairly low bandwidth, so it may not be appropriate for transmitting real-time pricing signal data.

BPL is a general description of several technologies that have been offered in competition with ADSL and cable TV Internet connectivity options. Unfortunately the BPL technologies tend to be sensitive interference by loads (reduced reliability) and broadcast signals that interfere with other radio spectrum users (particularly amateur radio). These concerns have so far prevented BPL from becoming widely available.

Spread-spectrum wireless radios cover various frequency bands, but to avoid interfering with other signals they usually do not provide very wide signal bandwidth. Unfortunately, these radios are not well standardized for interoperability between manufacturers, so they may not be appropriate for use in a wide variety of PV system equipment.

Bluetooth and Zigbee are normally intended for very short-range communications (the quoted distance limits are rather optimistic), and are not very stable standards. However, in so-called solar subdivisions, the communications relay feature of ZigBee may make it a practical technology for real-time price signals.

IEEE 802.11g (Wi-Fi or wireless Ethernet) has a somewhat longer track record than Bluetooth, and is becoming a common LAN implementation technology. This may make it practical to piggyback on customer Internet connections to access real-time pricing data.

Of these options, the continuous-carrier PLCC option would be technically advantageous for islanding prevention, but it is comparatively expensive to install and operate. For real-time pricing data (a function primarily in the interest of the customer and less sensitive to latency), interconnection with the customer’s LAN to share an Internet connection is an attractive, low-cost option.

4.5.1.4 Signal Classes

Voltage Regulation
The line voltage can use control algorithms like droop control or output impedance synthesis to determine voltage regulation needs. These types of control can handle voltage regulation and fast (shorter than 1 s) electrical control. However, for control in slower response situations, a centralized dispatch of reactive power could provide significant advantages in some cases, and could be provided instead based on local line conditions. Communication would need to occur only every few cycles, so bandwidth requirements are minimal.

Peak Shaving (Demand Response)
Tariffs use demand charges to discourage peak loads. Under this scenario, no communications would be required from the utility.

Future systems will likely use real-time pricing schemes in which the price paid by the customer for electricity is not constant, but is determined by the market in real time. During a time of generation shortage, supply and demand would dictate that the electricity price would increase. In a real-time pricing system, the communications system would be used to send a price signal to the customer indicating that electricity rates were rising. An EMS might then operate to shut down certain noncritical loads, especially those with built-in storage such as tank water heaters, to minimize utility bills. Systems with local energy storage might switch to these local stores, depending on the relative price of energy from storage versus energy from the utility. Either scenario would reduce the peak load for the utility.

The real-time pricing signal may be generated on time scales ranging from 1 to 60 minutes, depending on utility. Communications bandwidth requirements would depend on what level of device participates in the market. In an ideal case, every electricity load and source might participate in the real-time pricing market. However, that would require communications and intelligence capabilities in every device plugged into the wall. BPL probably could not provide enough bandwidth to realize such a system. Thus, it is more likely that EMS will integrate these functions at the facility level. The EMS would then communicate with loads, sources, and storage under its control.

Backup Power (Intentional Islanding)

The presence or absence of the utility could be signaled via communications. PLCC has unique advantages, as the presence or absence of the signal could be used as a continuity test of the line. Intentional islanding must be coordinated with automated sectionalizing switches to ensure that faults are external to the island and that the DG source is internal.

These sectionalizing switches must therefore have high-speed communication and controls. They also must have detection and control logic to ensure that the intentional island is synchronized with the utility before reconnection.

Furthermore, the utility could require customers to drop noncritical loads during an island protection operation. In this case, the utility would have to provide communications to the customers to indicate the intentional island.

Communications must provide instantaneous (subcycle) status and response must likewise be subcycle.

Spinning Reserve

The ramp up of spinning reserve units—triggered by a lost unit or a frequency excursion—is initiated by a signal from the system operator. The signal is sent approximately every second, but may differ between independent system operator territories. Thermal units responding to this signal normally reach full output over a few minutes. If this same signal were available to distributed EMS, they could dispatch generators or storage under their control to relieve the pressure on remaining mainline generation units, or activate load-shedding schemes. Theoretically, the real-time pricing scheme could achieve the same goal, if the market were updated often enough. The loss of generator would trigger a price spike, to which an EMS would respond by dispatching sources or storage, or by shedding load.

Frequency Regulation (and Area Regulation)
Signals from the system operator (generally calculated values derived from frequency and average frequency) control units to ramp up and down as necessary to ensure that the average system frequency over time is 60 Hz. These signals are sent every few seconds, and response time is several minutes.

In the case of DG, response time can be much faster, even on the millisecond scale. In principle, this would provide greater value than an equivalent rated thermal unit. More thermal units have to be combined to provide comparable ramp rates. Also, the faster response provided by DG would mitigate frequency excursions faster, reducing the effective capacity needed for the service.

However, DG has not historically been used and is unproven in this application. Also, the added benefit of fast DG response is not well quantified.

Control Fault Current Modes
Today’s PV inverters typically do not contribute significant levels of fault current. This is often a desirable property, because it should mean that the addition of distributed PV to utility systems will not adversely affect the coordination of utility protective devices. However, the SEGIS may require more sophisticated control over its fault current contribution, and communications that allow the SEGIS to know whether it is in grid-parallel or microgrid mode would be important.

First, consider the SEGIS’s grid-tied behavior. Because the SEGIS would incorporate voltage regulation capability, its fault current contribution will likely be much larger than that of today’s unity pf PV inverters. The SEGIS will thus need a way to determine when it is feeding a fault, and limiting its fault current. PLCC-based loss-of-mains detection should be effective in the case of a hard (low-impedance) fault, because such a fault should lead to a loss of the PLCC carrier, signaling to the SEGIS to disconnect from the grid. High-impedance faults present a greater challenge: reliably differentiating high-impedance faults in distribution systems from poorly behaved loads and other normal distribution system conditions is a subject of ongoing research [62, 63].

However, in the intentionally islanded (microgrid) case, the utility’s contribution to fault current is not available. The SEGIS could increase its fault current contribution, so that standard protective devices will reliably operate in the event of a fault. Communications could be used to determine whether the SEGIS is in grid-parallel or microgrid mode, and the inverter’s surge current capability could be used to momentarily increase its fault current capability in this case. Again, reliable differentiation between a high-impedance fault and a noisy load is a key capability.

4.5.1.5 Example Command Sets To Be Sent via Communications
Some potential signals from the utility distribution control system to the PV system might be:

- Use wide voltage-frequency range. This would enable low voltage or low frequency ride-through capabilities.

- Ramp to x% power. This signal might be used in a case in which the voltage frequency in a section of the system began to rise excessively.
- Switch offline. This signal might be thought of as the utility's E-stop button on the inverter.

Some potential signals from the price aggregating clearinghouse might be:

- Hour-ahead real energy price
- Maximize real power generation
- Hour-ahead reactive power price

The International Electrotechnical Commission Technical Committee 57 Working Group 17 is developing IEC-61850-7-420 for distributed energy resources to define relevant data and use cases describing typical uses for those data. This standard is a part of a large group of standards being developed under the overall IEC-61850 standard for power systems of the future.

4.5.2 Energy Management Systems

The SEGIS should be designed to work with an EMS that takes into consideration anticipated PV energy available, pricing signals, storage system availability and performance, and other factors. For example, PV energy could be delivered to the grid during high-priced periods or to storage during low-price periods. If prices over the coming hours are expected to increase by a factor greater than the battery efficiency losses, the energy could be stored.

4.5.2.1 Peak Shaving (Demand Response)

EMS and SEGIS can be used to lower peak customer loads and reduce demand charges. Certain non-time-critical loads, such as thermal loads, can be timed to minimize peaks. EMS controllers can be programmed so peak loads are managed without compromising customer processes. SEGIS storage would be charged during periods of low demand and dispatched during peaks by the EMS that can receive and respond to real-time pricing signals.

SEGIS storage systems would be sized based on the load profile (or net load profile), specific to each customer. Typically, the system would need to have several hours of storage, which can be kept to a minimum by smart dispatch in which the storage device follows the load in real time under the direction of the EMS. Such smart dispatch could use predictive capabilities to determine the threshold above which dispatch would occur. Under a real-time pricing scenario, the historic hourly prices could also be taken into account.

4.5.2.2 Other Energy Management System Functions

This report deals primarily with integrating the SEGIS with an EMS, but the EMS could perform a number of important grid support functions, including shedding of noncritical loads during peak demand times, fast-acting load shedding during system emergencies, and load shifting for loads with inherent thermal storage. As noted earlier in this report, realizing these capabilities would require the development of:

- High-speed communications reaching all endpoints in the distribution network
- High-speed real-time market mechanism that monetizes all aspects of power system operation, including both the market rule base and the physical communications and computational infrastructure to realize real-time market participation by all EMS and SEGIS-equipped facilities.

5. Gap Analysis

5.1 Voltage Regulation Coordination

PV inverters and power conditioning systems could be used to vary reactive power, but current grid interconnection standards are not compatible with this function. The validation of voltage regulation using a large number of generators has not been demonstrated.

5.2 Distribution-Level Intentional Islanding (Microgrid)

The use of storage to provide short-term intentional islanding support on a distribution feeder serving multiple customers has not been demonstrated. Communication and control related to isolation has not been demonstrated. A demonstration of such a system on a real utility circuit would help to validate this as a distribution planning option.

5.3 Controlling Facility Demand and Export by Emergency Management System Integration

The use of storage to mitigate problems arising from the export of power from the customer facility to the grid has been demonstrated in the Ota City PV-integrated distribution system. However, effectively using storage to eliminate backfeed would require a control algorithm to be developed that could intelligently manage storage capacity. The algorithm would take into account historical PV output and load to predict optimum load dispatch set points to capture demand charge savings. It would have to apportion stored energy over the course of the week. The algorithm would have predictive capabilities based on ambient temperatures, and solar output to forecast net loads (loads less expected PV output).

Similar control strategies would need to be developed in response to demand-response or real-time pricing scenarios. Stored energy would most effectively be managed with estimates of future hourly pricing and PV output. Algorithms could be developed, for example, to forecast anticipated prices based on historical signals received by the EMS system. Storage could be charged in anticipation of needed energy during periods of high prices. The dispatch of stored energy would take into account anticipated PV output in future hours. The algorithms for forecasting pricing and PV availability could be based on statistical analysis using diurnal patterns.

An example of an integrated EMS/PV/Storage system is described in Table 5-1. The optimization problem would be to minimize the monthly cost of electricity service to the customer. This cost is a combination of demand charges and energy charges, including real-time energy charges in which future pricing is unknown.

Table 5-1. Example EMS Optimization Parameters

Parameters	Loads (by Circuit or Device)	PV	Storage	Pricing
Fixed Parameters	Critical versus noncritical Thermal set points (such as chiller water temperature range)	Rated power System output versus meteorological values	Rated power Transient power Energy storage capacity as a function of discharge rate Turnaround efficiency	Demand charges (fixed or tiered) Energy charges (real-time and fixed tiers)
Measured Parameters (real time)	Actual loads Temperatures (air, chiller water, process heat, etc.)	Actual power Ambient temperature Insolation (from instrument or satellite data)	Actual power State of charge (measured or calculated)	Real-time price (if used) Meter read status (demand ratchet)
Forecasted Parameters (minutely or hourly)	Loads	Power		Price
Output/Control	Noncritical loads (on/off)	(None)	Charge or discharge power	(None)

The EMS would take into account fixed and measured parameters to control outputs. Using available PV power (in this assumed case) is always beneficial, so PV power is not a controlled output. Only loads and storage are controllable. The key to optimization would be to determine when and how to manage loads and when to charge or discharge the storage.

The problem is a combination of deterministic and stochastic effects. For example, the cost to the customer is easily calculated if the monthly loads and utility prices are known. The PV output could likewise be calculated from its design characteristics and known insolation. Such models are deterministic and readily available.

The stochastic effects, however, are more complicated. For example, charging the storage in advance of high real-time energy prices would be desirable. However, under a real-time pricing scenario, the prices are not known and must be forecast. Likewise, the availability of PV energy and thermal load requirements would have to be forecast. Historical measured data and historical forecasting errors could be used to forecast, so the respective forecasting models learn through experience.

The decision to charge or discharge storage in a given hour would therefore require a knowledge of all system states at every hour of the month, and these would be forecast based on the best available data. Forecasts might include insolation, ambient temperature, and energy prices. Deterministic models would use these forecasts to predict PV output and thermal loads. Finally, the decisions to control noncritical loads and dispatch storage would be made to minimize monthly energy cost.

5.4 Backup Power (Intentional Islanding)

Utilities are obligated to provide nondiscriminatory pricing to all customers. The use of storage for enhanced reliability would give preferential reliability to certain customers connected to the island. It is not clear (1) how the regulatory agencies would view differential reliability; (2) whether the utilities would be willing to offer it; or (3) who would pay for this service.

Utilities can charge individual customers special facilities fees, but on circuits where some customers are willing to pay and others are not, how the regulatory rules would apply and how to recover the costs to install backup power for multiple customers are not clear.

Finally, our research has also demonstrated a need for an alternative to active anti-islanding that is compatible with microgrids and intentional islanding. Communications of several types seem to be one likely solution.

5.5 Spinning Reserve

Spinning reserve is normally performed at the transmission level. Storage at the distribution level would be effective only as spinning reserve when the distribution circuit is not taken out of service. During a major system-level outage, some distribution circuits would be curtailed in order to preserve system integrity. Circuits with substantial DG sources could be preserved for reserve service, but currently no mechanism is in place to do this. Therefore, it is not clear whether distribution sources are viable for this application.

In addition, spinning reserve is normally provided with units rated higher than 100 MW. The market for smaller units is not established.

5.6 Frequency and Area Regulation

Like spinning reserve, this service is normally provided at the transmission level. Unlike spinning reserve, which is limited to major disruptions, this service is provided continuously. During a distribution outage, the service would not be available.

Competitive markets are emerging throughout the country. Different ISOs have different minimum size requirements. Some allow systems rated at 10 MW and higher, some at 1 MW.

Energy storage or PV would provide significantly faster response times than conventional generation. Systems could respond in milliseconds (once the signal is received) relative to minutes for thermal plants. Therefore, DG provides this service more effectively than do conventional sources. This suggests that special control algorithms could be developed to take advantage of the fast response times.

Finally, energy storage or cloud transient forecasting for leveling or softening PV output during cloud transients appears to be desirable, but neither has been demonstrated.

5.7 Harmonics

Although two survey respondents mentioned cumulative harmonics as a source of concern for the future, and the topic arises in the literature occasionally, the literature, experimental results, and utility feedback indicate that harmonic pollution and excitation of power system resonances are not problems, as long as high-quality sinewave inverters are used. Even early studies [3, 5] suggest that this was not a problem with mid-1980s inverter technology, and with the introduction of IEEE-519 since then and the incorporation of those harmonic limitations into IEEE-1547, it appears safe to conclude that harmonics do NOT limit penetration levels if IEEE 519/1547-compliant inverters are used.

5.8 Effect of Distributed Generation on Coordination of Protective Relaying

The potential for PV inverters to change the conditions under which utility coordination schemes between fuses and circuit breakers are established has been raised as one possible adverse impact from high penetration levels of PV. Based on the literature search done for this work, this does not appear to be an issue with today's inverters because they contribute so little to fault currents, and thus are highly unlikely to cause fuses to melt or breakers to open out of their designed sequences. If voltage regulation controls are implemented, this issue may need to be revisited.

There is no universal agreement that PV inverters will not affect protection coordination. For example, see 8, pp. 2–10, where the authors describe a number of pathways through which high penetrations of PV could theoretically cause a protection coordination problem. Section 2 of that report details other potential issues, such as possible false tripping of protective relaying.

6. Recommendations for Future Research

Future research and development should account for the following issues:

6.1 Smart Photovoltaic Systems with Energy Management Systems

Hardware and algorithms will need to be developed that incorporate communication protocols used by EMS and utility distribution systems. When hardware is available that can accept input from advanced utility distribution systems and control loads and generation, algorithms can be developed that optimize economic use of energy sources.

The physical implementation of the EMS may be incorporated within the PV system or may be a separate device, depending on market forces. Small, limited-feature smart PV systems will likely incorporate a simplified EMS function; larger and more configurable designs may choose to create a separate EMS device.

6.2 Reliability and Lifetime of Inverter/Controllers

Inverter hardware currently available has an MTBF of 5 to 10 years. Since the MTBF of the PV modules that those inverters are connected to is closer to 20 to 30 years, inverters will have to be replaced once or twice during the life of the system. Also, an inverter failure incurs a missed-opportunity cost for energy that was not generated. Thus, increasing the usable life of inverters will most likely lead to lower energy costs.

6.3 Voltage Regulation Concepts

Interconnection policies such as IEEE1547 strongly discourage voltage regulation by DG sources in the utility distribution system. However, a cohesive technical and policy approach to allowing voltage regulation by DG will need to be developed to handle projected high-penetration scenarios. Slow regulation (for managing distribution system voltage profiles or microgrid operation) and fast regulation (for addressing flicker and cloud-induced fluctuations) will both be needed in high-penetration scenarios. Demonstrations of solid technical approaches for voltage regulating DG will provide support for updated standards that will streamline commercial product development and simplify utility interconnection.

6.4 Distribution-Level Intentional Islanding (Microgrid)

Further development is needed for control strategies to manage microgrids. This area is related to the grid-connected voltage regulation needs discussed earlier, but it will most likely need to be augmented with communications to coordinate the transition between grid-connected and isolated modes of operation.

Further investigation into the regulatory issues should be conducted. For example, the customers who would benefit from the intentional island as a secondary source would have increased reliability relative to customers who would not be connected to the microgrid. Could tariffs be increased for the customers who benefit to recover the capital costs of the storage system and associated controls? Would it be preferable (and legal) to collect premium revenues only during the island operation, and how would these prices be set? How would the utility address customers connected to the island who are not willing to pay for enhanced reliability?

6.5 Energy Storage

Energy storage subsystems need to be identified that can integrate with distributed PV to enable intentional islanding or other ancillary services. Intentional islanding is used for backup power in the event of a grid power outage, and may be applied to customer-sited UPS applications or to larger microgrid applications. Stored energy may also be applied to grid ancillary services such as spinning reserve or frequency regulation if aggregation is implemented.

7. Conclusions and Recommendations

In general, the idiosyncratic characteristics of PV as a DG have not yet caused any significant problems for utility systems. If PV penetration levels increase much more, the work conducted here suggests that the problems most likely to be encountered are voltage rise, cloud-induced voltage regulation issues, and transient problems caused by mass tripping of PV during low voltage or frequency events. Issues that are not expected to arise are power quality problems caused by active anti-islanding, excessive harmonic pollution, and major problems with coordination of protective relays and fuses.

Several short- and long-term solutions to the likely problems have been suggested in this report, but in conclusion the long-term view will be emphasized. The distribution system of the future will likely be characterized by a much greater proliferation of DGs, distributed storage, and much higher prevalence of power electronic converters, as illustrated the SEGIS concept. Major research efforts worldwide are attempting to produce power electronics transformers, new types of voltage regulators, more capable static VAr compensators, and the controls and communications required to coordinate all these power system elements. Certain control elements, such as fast electrical control, will be distributed, and economic dispatch and load control will likely be handled by a central EMS. When evolutionary steps produce this power system, most of the high-penetration PV issues discussed here will cease to be problems; the improved level of flexibility and control, coupled with the availability of distributed storage, will eliminate them.

The power converters within the SEGIS can be viewed as additional power electronics elements in this integrated system. Based on the work documented in this report, the most critical capabilities that SEGIS inverters of the future should have to be able to work within this system are ancillary-service and microgrid-ready controls, and communications capabilities to interface them to the power systems control communications bus. Hardware reliability concerns are important, but have not been specifically addressed in this report.

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Appendix A: High-Penetration PV Survey

High-Penetration PV Survey sent to utility engineers

Respondent name (optional):

1. What is the highest PV penetration level you are experiencing on your system? For purposes of this survey, take the definition of penetration level to be the ratio of nameplate PV power rating (W peak) to the maximum load seen on the distribution feeder (W).

2. What is the estimated total amount of PV (watts peak) installed on your system, and what is your peak system load (MW)?

3. What adverse impacts have grid-connected PV systems had on your system? Are these impacts worse in the higher penetration portions of your system?

4. What steps have you taken to mitigate the adverse impacts of PV penetration on your system?

5. What current or future issues most concern you as the level of PV system penetration increases?

6. Please offer any further comments you would like to add. Thank you very much for your participation in this survey.

Appendix B: Product Vendors

Identification of Product Vendors

A brief list of vendors that are active in the PV and storage markets

Photovoltaic Module Manufacturers

- Sharp USA: a manufacturer of poly-crystalline silicon and mono-crystalline silicon PV modules
- Kyocera Solar: a manufacturer of poly-crystalline silicon and mono-crystalline silicon PV modules
- Evergreen Solar: a manufacturer of poly-crystalline (string ribbon) silicon PV modules
- GE Energy: a manufacturer of poly-crystalline silicon and mono-crystalline silicon PV modules
- First Solar: a manufacturer of cadmium telluride thin-film PV modules
- United Solar Ovonic: a manufacturer of triple-junction amorphous silicon thin-film PV modules
- SolarWorld: a manufacturer of poly-crystalline silicon and mono-crystalline silicon PV modules
- BP Solar: a manufacturer of poly-crystalline silicon and mono-crystalline silicon PV modules
- Sanyo: a manufacturer of a broad range of industrial and consumer products, including heterojunction-with-intrinsic-thin-layer silicon modules (as well as amorphous silicon PV cells for consumer electronics applications)

Power Electronics and System Integration

- ABB Switzerland Ltd.: a manufacturer of a wide variety of electrical power generation, transmission, distribution, and consumption equipment.
- Exeltech: a manufacturer of on-grid and off-grid inverters
- Fronius AG: Austrian PV inverter manufacturer
- GridPoint: a supplier of energy management equipment designed to manage loads, storage, and renewable generation sources to optimize power flows for minimum cost
- PV Powered: a manufacturer of grid-connected PV inverters
- SatCon: a manufacturer of power system components for vehicles, machinery, and utility interactive power conversion systems.
- Sharp Electronics: manufactures a line of grid-tied PV inverters
- Siemens AG: major German manufacturer of PV inverters and other power equipment
- SMA America: subsidiary of a German manufacturer of grid-connected PV inverters
- Xantrex: a manufacturer of both grid-connected and standalone inverters

Short-Term Energy Storage

- Active Power, Inc.: a manufacturer of megawatt-scale flywheel-based energy storage equipment
- Axion Power Corporation: a manufacturer of lead-carbon batteries (an alternative battery technology)
- Beacon Power: a manufacturer of megawatt-scale flywheel-based energy storage equipment
- Electro Energy Inc.: a manufacturer of nickel-metal hydride, lithium-ion, and nickel-cadmium-based battery energy storage devices
- Exide: a manufacturer of stationary lead-acid and nickel-cadmium batteries
- Gaia Power Technologies, Inc.: a supplier of multi-technology energy storage solutions
- Honda: the auto manufacturer, also manufactures a line of ultracapacitors for vehicular applications (used in the FCX)
- Maxwell Technologies: manufacturer of energy storage capacitors
- S&C Electric Company: manufacturer of electric power transmission and distribution equipment, as well as lead-acid-battery-based uninterruptible power supplies and static VAR compensators
- Saft: a manufacturer of nickel-cadmium, nickel-metal-hydride, and lithium-ion batteries
- Trojan: specializes in deep-cycle lead-acid gel-cell batteries
- Varta: a manufacturer of portable, traction, and stationary batteries in multiple chemistries

Long-Term Energy Storage

- NGK Insulators Ltd.: a manufacturer of sodium-sulfur batteries
- VRB Power Systems Inc. : manufacturer of vanadium-redox electrolyte flow battery energy storage systems
- ZBB Energy: a manufacturer of zinc-bromine electrolyte flow battery energy storage systems

Distribution

1	MS1104	Margie Tatro, 6200
1	MS1104	Rush Robinett, 6330
1	MS1033	Charlie Hanley, 6335
1	MS1110	Jeff Nelson, 6337
1	MS1124	Jose Zayas, 6333
1	MS1108	Juan Torres, 6332
1	MS1033	Doug Blankenship, 6331
1	MS0734	Ellen Stechel, 6338
1	MS1108	Jason Stamp, 6332
1	MS1108	David Wilson, 6332
1	MS1108	Jaci Hernandez, 6332
1	MS1108	Michael Baca, 6332
1	MS0455	Shannon Spires, 6332
1	MS1108	Steven Goldsmith, 6332
1	MS1108	Jeff Carlson, 6332
1	MS 0899	Technical Library, 9536 (electronic copy)