National Renewable Energy Laboratory
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Photovoltaic Systems Interconnected onto Secondary Network Distribution Systems – Success Stories

Technical Report
NREL/TP-550-45061
April 2009

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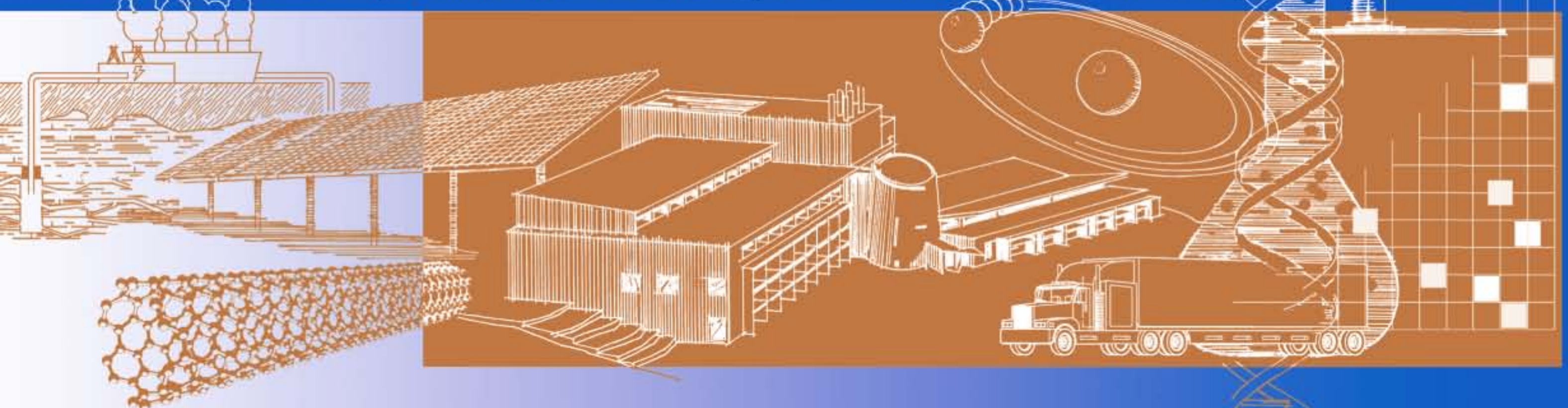

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Executive Summary

This report examines six case studies of photovoltaic (PV) systems integrated into secondary network systems. The six PV systems were chosen for evaluation because they are interconnected to secondary network systems located in four major Solar America Cities.

While the number of PV systems interconnected to the electric grid has increased significantly over the last decade, only recently have PV systems been installed in major metropolitan areas and tied to electric distribution secondary network systems (networks). Utilities use networks to distribute electricity to customers in areas where there are large concentrations of load and where reliability greater than that of a radial system is needed. Networks use multiple feeders that serve multiple transformers that in turn serve one or multiple electricity consumers. In contrast, radial distribution systems use single feeders that serve single transformers, each serving one or multiple electricity consumers. The main difference is that a customer on a network system is simultaneously served from multiple transformers connected to multiple feeders, where a customer on a radial system is usually served from one (or multiple) transformers connected to a single feeder. Therefore, customers served from radial systems will experience outages when the radial feeder is interrupted. Alternatively, customers served from a network system will not experience an outage if any of the network feeders are interrupted. It would require simultaneous outages on multiple network feeders for a network customer to experience an interruption. Therefore, as a general rule, a customer served from a network system enjoys a much higher degree of service reliability than the one served from a radial system.

Networks incorporate special protective devices at each network transformer. Such a device is known as a "network protector" (NP) and is designed to operate and open when electric power (both real and reactive power) is flowing back toward the utility. Network protectors are often considered a technical obstacle for utilities and their customers who wish to interconnect PV systems in areas served by secondary networks because the PV system may cause a reverse-current flow through the NP and cause the device to open unnecessarily. In addition, since the network protector is also deigned to reclose for a pre-specified forward flow condition and does not have synchronizing capabilities it is possible to have a scenario where the NP might try to reclose out of synch on an islanded DG. It is because of these unique properties that many utilities that have networks do not allow their customers to interconnect a PV system (or any generating system) to the utility networks. However, there are utilities that have successfully allowed limited PV system interconnections.

Utilities that allow interconnection of PV systems on their secondary networks usually ensure that the energy produced is not fed back toward their system by requiring a minimum threshold power flow toward the customer. In the six cases studied in this report, four methods are employed as means to minimize, reduce, or eliminate the possibility of backfeed from the PV system through to the network protectors. These methods are as follows:

- *Keep the PV system sized lower than the minimum daytime load at the customer meter.* In doing so, the system is designed to ensure that the site load is always drawing some power from the utility grid with essentially no chance of exporting energy from the PV system to the network. This technique has been used in all four cities in at least a partial approach to minimizing backfeed.
- *Install a minimum import relay (MIR) or a reverse power relay (RPR).* The MIR will disconnect the PV system if the power flow from the utility drops below a preset threshold value, while the RPR will disconnect the PV system if the power flow from the utility drops to zero or if it reverses direction.
- *Install a dynamically controlled inverter (DCI).* This inverter controls the output of the PV system inverter(s). This type of system monitors the level of energy coming in to the customer location and will ramp down the PV energy production if the load drops below a specific threshold. This system would be a more desirable alternative than a minimum import relay as the amount of energy being generated can be governed rather than the PV system being disconnected.
- *Allow smaller PV systems to connect to a network*. Most small PV systems, of 30 kilowatts (kW) or less, on secondary networks will have limited opportunity to feed back toward the utility, and such small amounts of energy may be acceptable to the local utility.

In what may portend to be a future trend, Consolidated Edison of New York, Inc. (Con Edison), in an effort to reduce barriers to interconnection of customer-owned DG, has announced that while it will still perform a detailed, site-specific study when it receives a request for interconnection to its distribution network systems (secondary and spot networks), inverter-based solar generators up to 200 kW may interconnect to the company's distribution network system without such a study. It is expected that such inverter-based systems may export electricity into the secondary network without reverse-power protection or a dynamically controlled inverter, provided it is shown that the interconnection does not allow those systems to result in back feed through the NP and transformer.[1] Con Edison reserves the right to decline requests from inverter-based solar generators greater than 200 kW and requests from other generators to interconnect to distribution network systems when they deem it necessary to protect its system, facilities, or other customers.

1 Con Edison letter to Honorable Jaclyn A. Brilling, November 4, 2008, RE: Net Metering

Table of Contents

Executive Summary iii
List of Figures vi
1.0 Introduction 1
2.0 Understanding Electrical Distribution Systems 2
3.0 Radial Distribution Systems 4
4.0 Network Distribution Systems 4
4.1 Spot Networks 5
4.2 Area Networks 7
4.3 Network Protectors 8
4.4 Standards of Interconnection for Secondary Networks 9
4.5 Interconnecting Photovoltaic (PV) Systems with Secondary Networks 9
5.0 Case Studies 9
5.1 Purpose and Objectives 9
Case Study: Moscone Center – San Francisco, California 10
Case Study: James Forestall Building – Washington, D.C. 14
Case Study: Big Sue – Brooklyn, New York 18
Case Study: Kinnloch Black Bear – Brooklyn, New York 21
Case Study: GMDC – Brooklyn, New York 24
Case Study: Colorado Convention Center – Denver, Colorado 27
6.0 Methodologies Employed for Interconnection to Networks 31
7.0 Conclusions 32
Annex 33

List of Figures

Figure 1. Radial Distribution System Diagram 3
Figure 2. Typical Spot Network System Diagram 6
Figure 3. Example Area Network System Diagram 7
Figure 4. A Moscone Center Rooftop Loaded with PV Panels 10
Figure 5. Simplified Electrical One-line Diagram for the Moscone Center PV System . 11
Figure 6. PV Array on Forrestal Building 14
Figure 7. Four Technology Showcase 1 kWp PV Arrays 15
Figure 8. Simplified Electrical One-line Diagram for the Forrestal Building 16
Figure 9. The Main PV Array on Big Sue 18
Figure 10. Big Sue One-Line Diagram 20
Figure 11. View of the Rooftop PV System (Black Bear Co.) 21
Figure 12. Simplified Electrical One-Line Diagram for Black Bear Company, Inc. 22
Figure 13. Rooftop PV Systems at GMDC 24
Figure 14. Simplified Electrical One-Line Diagram for GMDC 25
Figure 15. Colorado Convention Center PV System 27
Figure 16. Colorado Convention Center 28
Figure 17. Simplified Electrical One-Line Diagram for the Colorado Convention Center 29

1.0 Introduction

Most electric utilities in the United States have adopted standard criteria and guidelines for interconnection of distributed generation (DG) to their electric distribution systems. Photovoltaic (PV) system installations effectively reduce the customer load and during minimum loading conditions may export energy back to the utility in a transaction known as “net energy metering” (NEM). These guidelines are used by PV system integrators to help them design PV systems that operate in parallel with the utility systems. The majority of PV systems in the United States are connected to systems known as “radial” electric distribution systems. In a radial system (the most common type of distribution system) electric energy is supplied from a single source and the system contains no closed “loops.” Nearly 94% of the distribution systems in North America are comprised of radial distribution systems. A less common type of electric distribution system, known as a secondary network distribution system (or simply a “network”), serves central business districts in many cities, and typically does not have any parallel generation. Over the past few years, however, several utilities and PV developers have successfully deployed PV systems onto secondary networks.

Networks differ from radial distribution systems because multiple feeders supply a number of transformers that are all banked together on the secondary side to serve customer load. Networks are designed to provide excellent service reliability and a capacity to serve large loads, such as for high-rise buildings, usually within a central business district, but incur premium design, construction, and maintenance costs.

Networks incorporate special protective devices, known as a “network protector” (NP), which is installed on the low-voltage side of each network transformer. NPs are designed to detect current flow toward the utility system. The normal direction of the current flow on network feeders is unidirectional from the utility toward customer loads. However, during a short circuit condition (known as a fault) on the high-voltage side of one of the network transformers, the direction of the current flow will reverse. NP relays are designed to detect this reversal and initiate the opening of the NP to eliminate the fault current contributions from the “healthy” feeders to the faulted feeder. This design prevents undesired current flow in the event of a faulted or de-energized circuit, and allows the network to maintain uninterrupted service to utility customers—even if one of the network feeders fails or is out of service for maintenance. When designing PV systems on spot networks, it is important to ensure that the PV system does not cause the network protectors to open. Some utilities require a minimum import relay (MIR) that is used to prevent the load from falling below a minimum level. Other utilities require the use of a reverse power relay (RPR), which is used to prevent any reverse power flow. If the load were to fall below a minimum level, one or more of the network protectors may open and therefore reduce the reliability of the spot network, or in the limit cause an outage to the spot network.

PV systems utilize electronic inverters, which convert DC power to AC power. Inverters are designed to commutate on AC voltage, therefore ceasing power production in the event of an outage. Inverters also produce low-levels of potentially harmful fault current in the event of a fault on the utility system. This is a beneficial characteristic when connecting to a network, as networks are inherently high in available fault current and utilities desire to keep this level as low as possible.

A recommended practice for interconnection of DG to secondary networks is being developed by the Institute of Electrical and Electronic Engineers (IEEE). The project is known as IEEE P1547.6, and when published will be a recommended practice for interconnecting distributed resources with electric power systems distribution secondary networks. Although this standard has not been completed at the time this paper is published, there are utilities that are successfully implementing PV systems on their secondary networks.

While the interconnection of PV systems onto networks may present challenges, there are U.S. utilities that know various ways to implement it. This report documents six examples of PV systems interconnected onto networks. In each of these examples, the systems are operating without impairing the reliability of the networks in which they are interconnected.

The PV systems we studied and documented in this report are in Denver; San Francisco; Washington, D.C.; and New York City. While some had concerns regarding the operation of the network components because of the presence of PV systems, there appear to have been no significant problems at any of these locations. The majority of these PV systems generate a relatively small amount of power compared to the power that is consumed on the customers' sites. Therefore, selection of appropriately sized PV systems for network applications inherently prevents power from flowing back toward the networks and places these systems in the non-exporting category.

2.0 Understanding Electrical Distribution Systems

Most electricity consumers in the United States are served by an electric utility (aka electric service provider), and are supplied at a voltage level of 480 volts or lower. Most utility customers are connected to a "radial" electric distribution system that feeds from a substation, through distribution feeders, through transformers and to their home or business (see Figure 1).

Most utilities design their radial systems in an open-loop design, which affords greater flexibility to serve changing loads or to switch around failed equipment. This design, while radial in nature, allows the utility to adjust its electric distribution system by opening and closing a series of medium-voltage switches in the loop.

There are a small percentage of customers in the United States that are fed by primary or secondary selective systems, in which there are two or more sources available from the utility[2]. These systems are designed for reduced outage time compared to radial systems.

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2 See http://www.nrel.gov/docs/fy05osti/38079.pdf (581 KB) for detailed schematics of these systems.

Primary or secondary selective systems are designed to keep power continually available to critical loads, such as hospitals, data centers, emergency service providers, or government facilities.

In many large metropolitan areas, electric service providers use another electric distribution system called a "network." Networks use multiple feeders and multiple transformers to serve each customer. These networks are further characterized as either "spot" networks or "grid" networks (grid networks may also be called "street" or "area" networks).

The term "grid" is often used in general when discussing electrical transmission and distribution systems. While secondary networks are arranged in a grid configuration, other types of distribution systems are not arranged in a grid configuration.

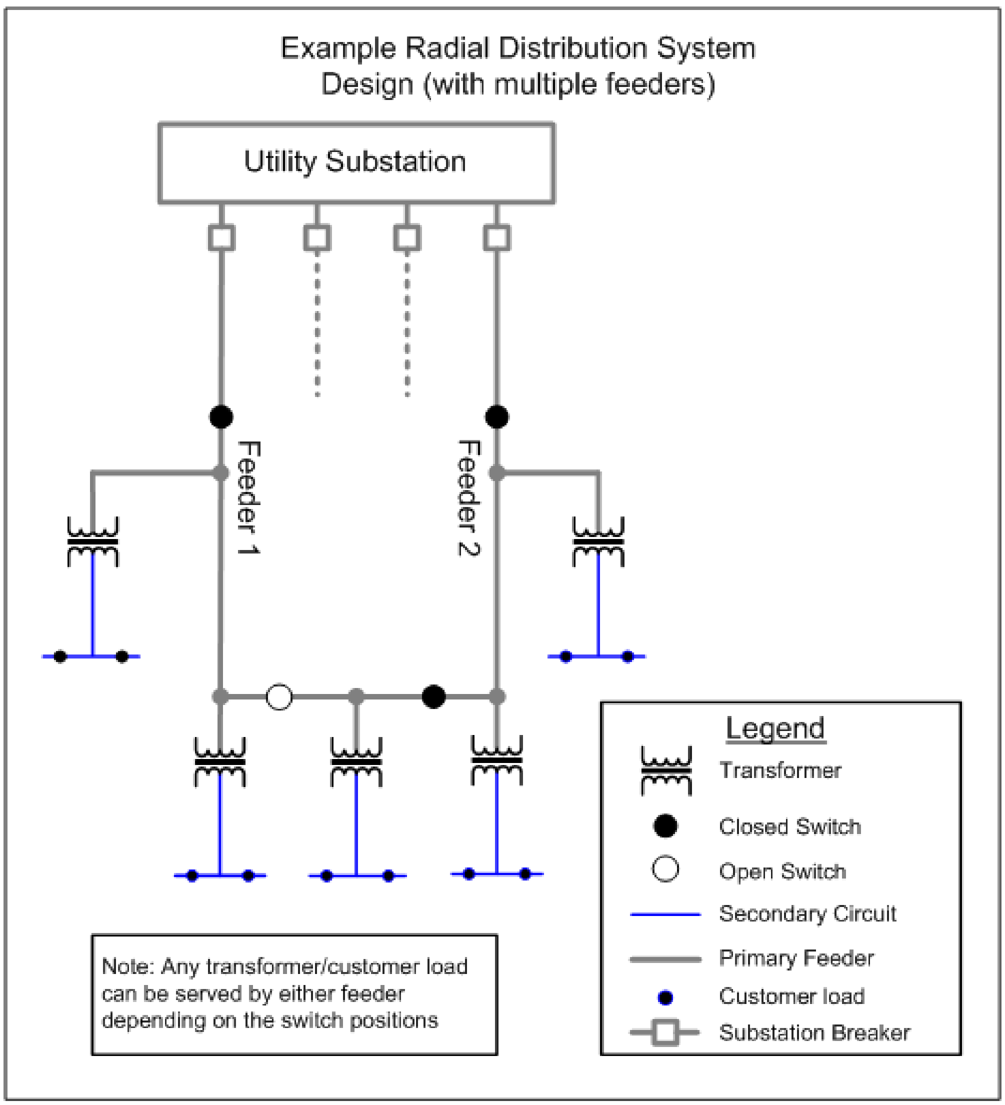

Figure 1. Radial Distribution System Diagram

3.0 Radial Distribution Systems

Radial distribution systems (RDS) are the most common design used by electric utilities, and are the least expensive to plan, construct, and maintain. They generally consist of an electrical substation (typically at medium voltage in the 15 kV class), radial feeders for energy delivery (which may be a few miles to a few dozen miles in length), and eventually tie to transformer(s) that convert the 15 kV voltage to a utilization level (120/240, 120/208 or 277/480). There are typically several hundred to several thousand electric utility customers on a feeder, and anywhere from one to twenty customers who may be served by selective transformers. Depending on the type of service agreements, these customers may be metered at either the primary voltage level (e.g. 15 kV class) or the utilization level.

Radial distribution systems are the simplest systems to plan, construct, and maintain, but are also the least reliable because of the radial nature of the design being served from a single source at a time. If any part of the system experiences a failure, some or all of the customers served by the radial feeder will be without power until a repair is completed. Straightforward design, lower cost, and decent reliability are the distinguishing characteristics of the RDS.

An auto-loop distribution system is a special type of radial distribution system and is differentiated by having two feeders that tie to a customer load. The auto-loop system automatically senses the loss of one source of voltage and quickly and automatically switches the load to the second feeder. This type of system adds reliability benefits by keeping outages to a few seconds (or less) but the added cost of having two sets of utility equipment at one location, could be as high as hundreds of thousands of dollars for each installation.

4.0 Network Distribution Systems

Networks are among the most sophisticated type of distribution system used by larger electric utility companies. A network is designed so that each load receives its power and energy from several transformers that are simultaneously supplied from different primary feeders. This is usually achieved by interconnection of the secondary windings of this transformer in a parallel configuration to form what is known as a “secondary grid system.” The loads are then served from this grid. If a secondary system is comprised of only a few network transformers at a particular location in order to serve a unit building, it is known as a “spot network.” Alternatively, if the secondary windings of many transformers in a wide area (up to several blocks) are connected together, the configuration is called an “area” or “street” grid system.

Engineers design spot networks and grid networks to provide power to their customers through redundant transformers and redundant feeders. This is a distinguishing characteristic of a network, as redundant feeders and transformers can be taken out of service without an electric consumer being affected. Network feeders, transformers, and NPs can be taken out of service for maintenance, adding new equipment, or when there is an equipment failure that causes a feeder or transformer outage, and when there is a significant drop in load on the network. Assuming “n” separate sources of power for a network, the engineers often design the network to operate at “n-1” or “n-2” outage contingency. The designation n-1 indicates that the network will be fully functional with one less feeder in service, where n-2 indicates that the network will be fully functional with two less feeders in service.

By design, network protectors are to remain closed unless there is a power outage on the primary side of the NP. If an NP opens because the load drops to a low level on a network, there is a minimized level of reliability because of the absence of part of the network. If multiple NP open because of low load levels, there is a risk of a complete outage, and therefore must be avoided.

Networks have been in operation in the United States for roughly 90 years, and are typically found in larger metropolitan areas such as New York City; Chicago; Seattle; Baltimore; Kansas City, Missouri; Boston; San Francisco; Washington, D.C.; Denver; Portland, Oregon; and even some smaller metropolitan areas such as Knoxville, Tennessee, and Syracuse, New York. Some large cities, such as San Diego, have significant loads in a dense area, but do not employ networks. Because of the high level of adaptability and reliability of networks, they are expected to be employed for many decades to come.

4.1 Spot Networks

A spot network is a type of secondary network distribution system that is frequently used to serve a single customer or multiple customers in a single building. Spot networks will have two or more feeders and two or more transformers networked together at an electric consumer’s site. Electric consumers who are served by spot networks are typically located in very large buildings with major electric loads. Three of the case study locations are served by spot networks, including systems in Colorado, California, and Washington, D.C. Figure 2 illustrates a schematic diagram of a typical spot network.

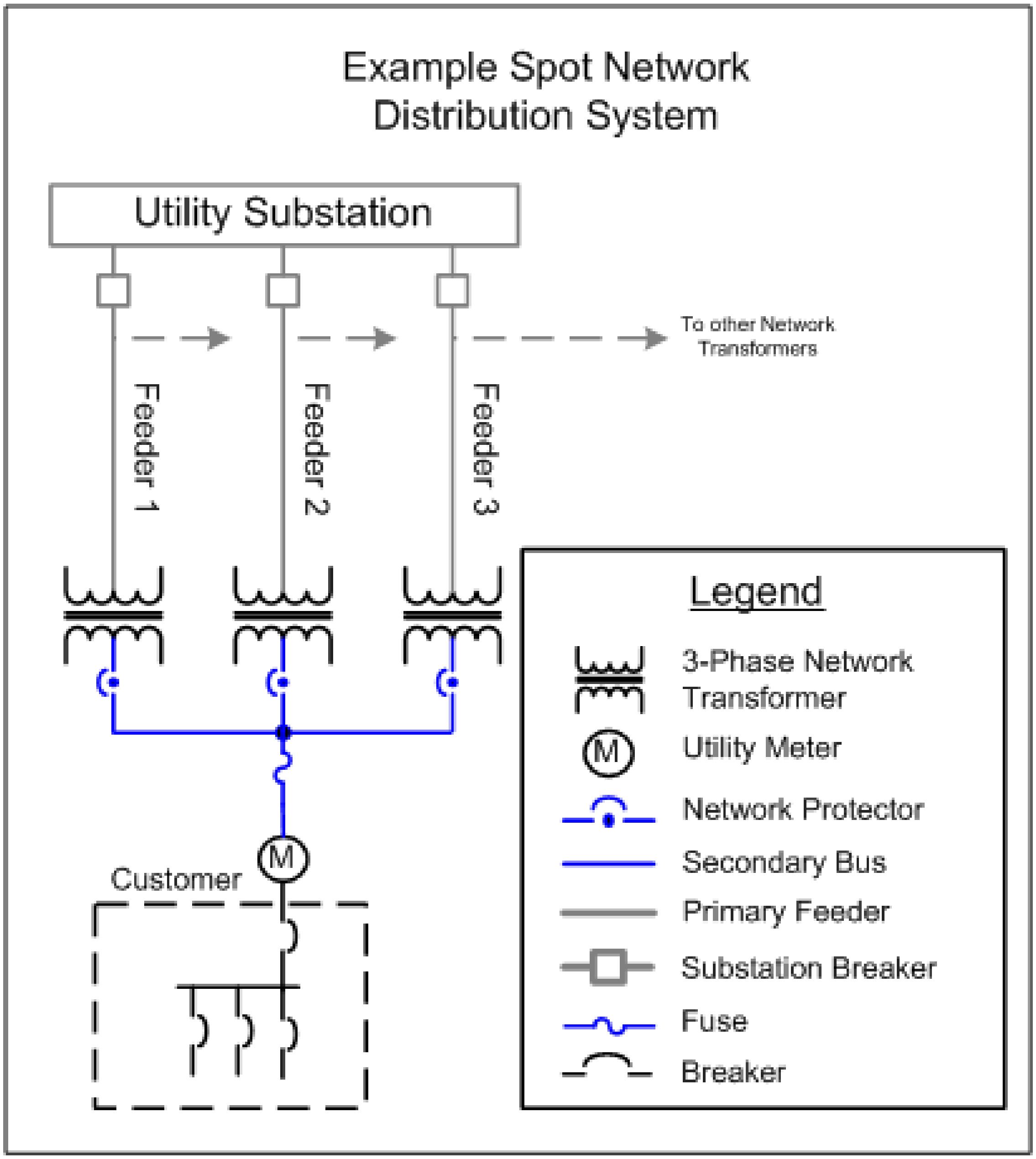

Figure 2. Typical Spot Network System Diagram

4.2 Area Networks

Area networks are a type of secondary network distribution system that are typically used in larger metropolitan areas, and may serve all sizes of electric customers (residential, commercial, and industrial). Area networks are also known as “street networks” or “grid networks.” Similar to the spot network, the area network has redundant feeders and transformers, and may serve hundreds to thousands of customers. The area network may include as many as ten transformers to more than a thousand transformers, and be served by three to thirty five distinct electric distribution feeders. The typical area network voltage is 120/208 and is always three-phase, although there are typically many single-phase loads served by the network. Some area networks can serve up to several square miles. Area networks are designed to serve all network customer loads, during a peak-demand day, with one to two feeders out of service depending on the design criteria used. Many networks could operate with additional feeders out of service during nonpeak loading conditions. See Figure 3 for a one-line diagram representing an area network.

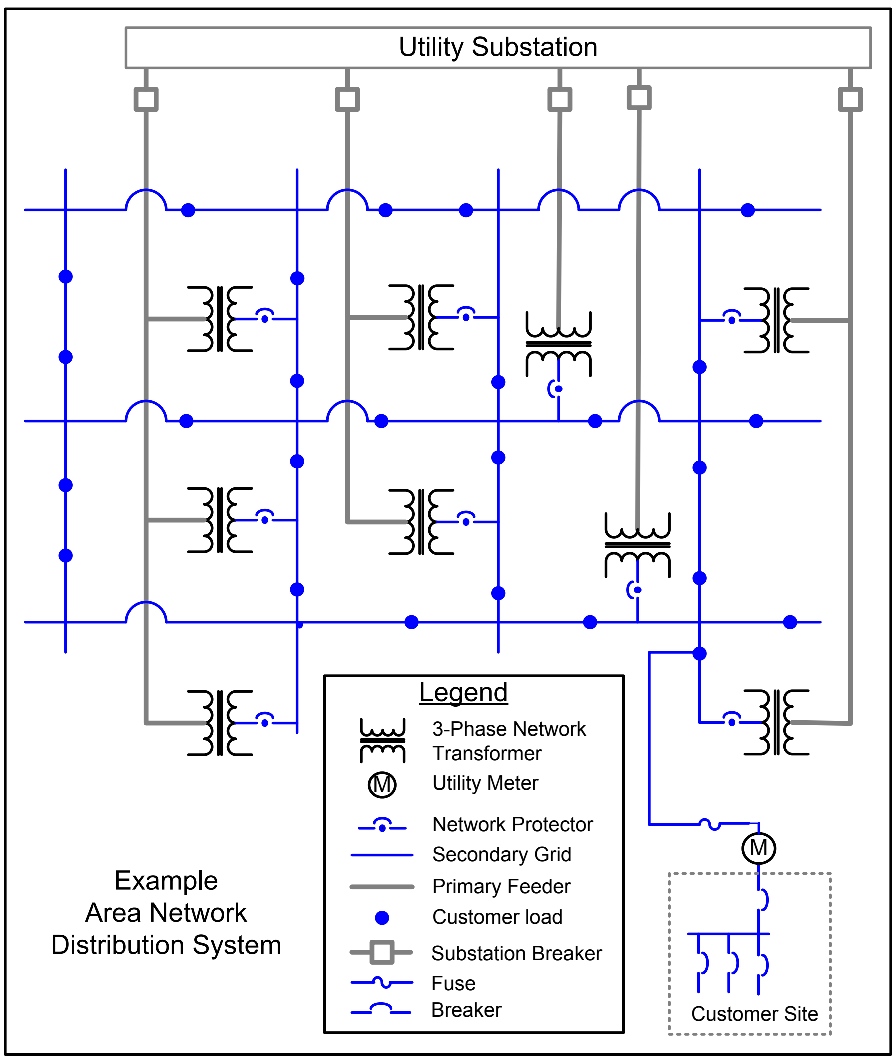

Figure 3. Example Area Network System Diagram

4.3 Network Protectors

A unique feature of any secondary network distribution system, compared to a radial distribution system, is the addition of the NP. The NP is a relay and breaker pair that senses reverse-power flow toward the utility (from either a faulted component or a planned outage) and is designed to interrupt the power from flowing back toward the utility system by opening its contacts for this condition. Usually, the power reversal is either planned by the utility, such as during a feeder clearance, or it occurs during a fault on a primary feeder or during a primary feeder fault. Therefore this NP opening ensures isolation of the faulted or cleared feeder from other energized feeders. This is an important design feature that ensures reliability and continuous operation if one or more feeders are lost due to a device failure or if the utility must conduct maintenance activities (planned outages on a feeder). Network protectors are normally closed devices, but may open during light-loading conditions, often during early-morning hours or weekends when loads are at a minimum. Such light-loading operation is considered normal and expected from time to time.

Network protectors consist of a low-voltage circuit breakers with relays, backup fuses, and auxiliary devices, all enclosed within a metal case mounted on the secondary side of the transformer (submersible type) or separately mounted (frame type). The function of the relay is to open the breaker on power flow reversal (as low as that caused by reverse magnetization of its associated transformer or as high as that caused by a fault in the primary feeder or the transformer itself). The relay will also reclose the breaker when the voltage and phase of the primary feeder are such that power will flow into the network, when the breaker is reclosed. It is also designed to recognize a cross-phase condition (caused by improper feeder re-splicing**),** which prevents the breaker from closing.

Networks were originally designed for one-way power flow from the electric utility to the consumer. The NP is designed to sense and open its contacts under reverse power flow conditions (among other functions). While The NP can be set to allow low levels of reverse power for a short period of time to accommodate power swings it is generally not acceptable in a network system, and net metering poses additional complications and is often difficult to implement.

It is important that a PV system disconnect from the network in the event of a power outage to avoid a situation known as "unintentional islanding." If an unintentional island were to occur, it is possible that some network protectors may experience cycling problems or could damage the utility or PV system as the systems move out of phase. IEEE Std 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, contains specific language to address this potential problem[3].

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3 IEEE std 1547-2003, Section 4.4.1 page 10 (ISBN 0-7381-3720-0)

4.4 Standards of Interconnection for Secondary Networks

The Institute of Electrical and Electronic Engineers (IEEE) Standards Coordinating Committee 21 currently sponsors a working group that is drafting recommended practice for interconnection of DG (which includes PV) onto distribution secondary networks (see P1547.6[4] – Draft Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks). The working group has been meeting for several years and the recommended practice is expected to be ready for ballot in 2010. This important recommended practice will complement IEEE 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, which is currently incorporated into most state rules in the United States and has been cited by the Federal Energy Regulatory Commission (FERC).

4.5 Interconnecting Photovoltaic (PV) Systems with Secondary Networks

There are several electric utilities in the United States that are working with PV system integrators and allowing interconnection and even net metering onto area networks. Four cities, and four electric utilities, are examined in the six case studies within this report in which there are PV systems interconnected to spot networks and area networks.

5.0 Case Studies

5.1 Purpose and Objectives

There are many electric utilities that operate secondary network distribution systems, but relatively few that have PV systems installed and interconnected to those secondary network distribution systems.

The main objectives of these case studies were to:

- Record all interconnection requirements that were implemented by each local utility to interconnect each PV system to the spot network or the area network
- Evaluate the performance of these systems to date with respect to their integration with the electric utility.

Our purpose was to illustrate successful installations of PV systems on secondary network distribution systems. The case studies show that it is not only possible to interconnect PV systems to secondary network distribution systems, but with implementation of proper modifications and requirements, PV systems can operate safely, efficiently, and reliably on secondary network systems.

4 http://grouper.ieee.org/groups/scc21/1547.6/1547.6_index.html

Case Study: Moscone Center – San Francisco, California

Key Highlights

System Owner:	San Francisco Public Utilities Commission (SFPUC)
Utility:	• Power Provider: San Francisco Public Utilities Commission • Distribution Company: Pacific Gas & Electric (PG&E)
System Integrator:	SunPower (formerly PowerLight)
System Size:	676 kWp DC
Network Type:	Spot Network
Special Interconnection Requirements:	• Customer must maintain a minimum of 450 kW daytime load • Minimum import relay installed

Figure 4. A Moscone Center Rooftop Loaded with PV Panels

Introduction

The Moscone Center, located at 747 Howard Street in San Francisco, is a large multi-functional facility that is primarily used as a convention center. The center is more than 2 million square feet in size. The facility is owned by the City and County of San Francisco.

Engineering staff from the National Renewable Energy Laboratory (NREL) examined the PV system on the rooftop, the inverters, and the (480/208) transformer.

System Overview

PV System Description: The PV arrays (676 kWp DC) are located on several different roof areas of the facility. The arrays are arranged as three PV systems connected to a 225 kW inverter located in electrical rooms near the roof in the center. The Moscone Center is served by a single spot network, with four feeders, each supplying one 2 MVA transformer capable of serving enough power for a large convention with an n-1 contingency.

The overall layout is shown in Figure 5.

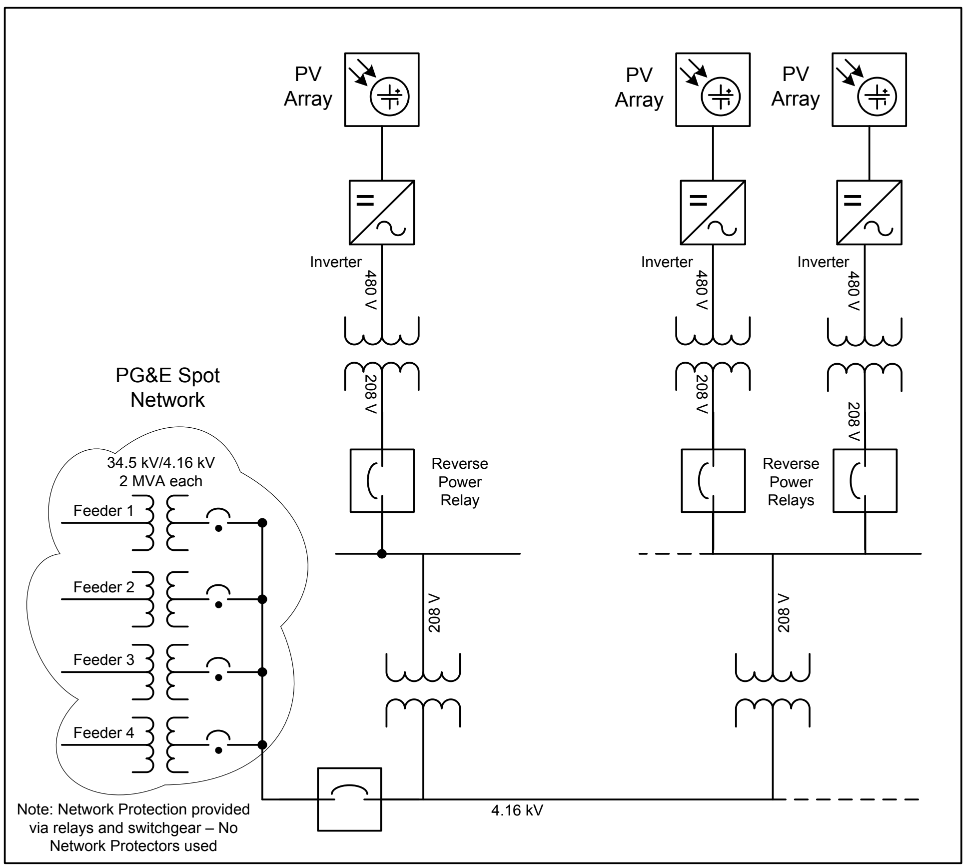

Figure 5. Simplified Electrical One-line Diagram for the Moscone Center PV System

Network Description: The PG&E spot network that serves the Moscone Center is operated under a special contract with the SFPUC (a municipal utility). The network that serves the Moscone Center has the following characteristics:

- A 4-transformer spot network with a separate feeder serving each transformer
- Transformers rated at 34.5 kV to 4.16 kV, 2 MVA
- Each transformer has equipment that emulates NPs (this is done because NPs are rated up to 600 volts and this system is 4,160 volts)
- Each network relay is monitored via fiber optic link to the PG&E Supervisory Control and Data Acquisition (SCADA) system.

Evaluation

This PV system is a relatively large commercial rooftop system. However, it only generates approximately 3.18% of the energy the Moscone Center uses in the course of a year. Because of this, and because the minimum daytime load is typically much greater than the PV system generation capability, there is no chance of any power flowing out toward the utility system. The utility requires that inverters for these systems be listed to UL 1741 and be certified to meet IEEE 1547 interconnection requirements. PG&E also requires totalized minimum import relays (set at a minimum power import level) to be used to trip the PV system offline when the load at the Moscone Center falls below the minimum load during normal operations. The totalized minimum import relays are set at 200 kW for one section of the PV system and 250 kW for the remaining section of the PV system.

According to SFPUC representatives, the system has operated as expected and has not caused any problems for the staff of the Moscone Center or the city of San Francisco.

Utility Perspective

The Moscone Center PV system has not caused any known equipment failures or system outages. There have been reports of protector operations for unknown reasons. However, PG&E continues monitoring and evaluating the PV system and the network components. According to a PG&E network engineer, there has been an increase in the number of relay operations since this system has come online (where the network transformer drops out of the circuit and reconnects at a later time). It is speculated that the increased number of operations is caused by the net decrease in demand load, especially during days when there is little activity at the center. One engineer suggested that some of the relays went from operating 10 times a year to 10 times a month; an increase of 110 operations per year (under no-load conditions). PG&E plans to replace the relays in the older electro-mechanical network protectors with microprocessor-based relays because the older relays are obsolete and no longer produced. PG&E also has plans to install a monitoring device to study the behavior of their network relays as a function of loading and generation profile.

Conclusion

At this writing, the Moscone Center PV installation is the largest known PV system interconnected on a distribution network in the United States, and is operating within expected parameters. The system was reviewed by PG&E and SFPUC to ensure there would be no export of power through any network transformer. Three minimum import relays, functioning in a minimum power import mode, were installed to ensure that a minimum load was drawn from the utility grid at all times. The totalized minimum import relaying system would otherwise trip the PV systems off-line if the power consumption drops below the minimum load threshold.

Case Study: James Forestall Building – Washington, D.C.

<u>Key Highlights</u>

System Owner:	U.S. Department Of Energy (DOE)
Utility:	Potomac Electric and Power Company (PEPCO)
System Integrator:	SunPower
System Size:	205 kWp DC and four 1 kWp DC systems
Network Type:	Spot Network – Primary-metered / Customer-owned network
Special Interconnection Requirements:	None

Figure 6. PV Array on Forrestal Building

Introduction

The James Forrestal Building, located at 1000 Independence Ave., SW, in Washington, D.C., is the headquarters of the U.S. Department of Energy. The building has more than 1.6 million square feet of combined office and parking space.

NREL engineering staff visited the site and examined the rooftop arrays, as well as the inverters, switchgear, and the secondary network.

System Overview

PV System Description: The PV arrays (205 kWp DC total) are located on several sections of the Forrestal Building rooftop (Figure 6). There are four 1 kWp "Technology Showcase" arrays with single-phase inverters on the roof (Figure 7), and a large 205 kWp system covering the majority of the remaining area. The 205 kWp array was installed using 230 Watt panels. The test arrays were manufactured using cadmium telluride, amorphous silicon, crystalline silicon and copper indium gallium diSelenide (CIGS).

The larger array feeds into a 250 Watt inverter. The inverter is then tied into the main switchgear via a circuit breaker. All of the electrical equipment (the inverter and switchgear) are located in the same vault as the network transformers and network protectors. The building is served by a spot network designed to be operated on three of its four network transformers and still meet demand load.

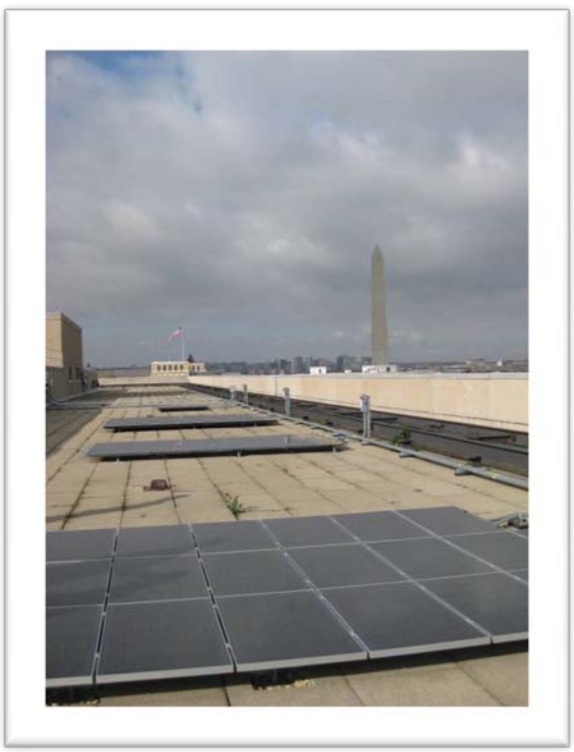

Figure 7. Four Technology Showcase 1 kWp PV Arrays

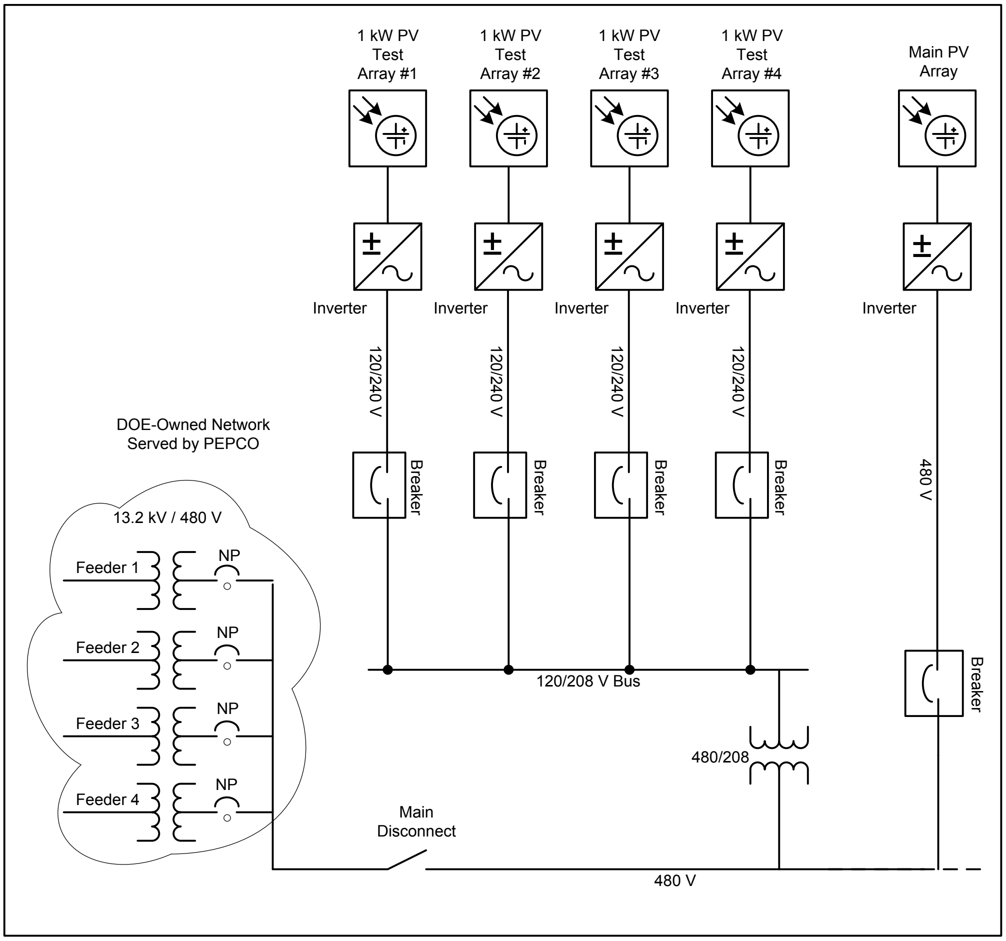

Figure 8. Simplified Electrical One-line Diagram for the Forrestal Building

Network Description: The spot network is served by four PEPCO feeders and is primary metered and owned by DOE. The network has the following characteristics:

- Four-transformer, four-feeder spot network
- Each transformer is rated at 13,200/480 volts, 1 MVA
- Each transformer has a relay network protector (not microprocessor-based)
- Networks are not monitored electronically.

Evaluation

The PV system is a relatively large rooftop system that generates up to 8 % of the buildings annual energy usage.[5] Because the minimum daytime load of the entire

5 See the DOE report http://www.energy.gov/news/6521.htm

building is significantly greater than the PV system peak output, there is no forecasted chance of exporting power toward the Potomac Electric and Power Company (PEPCO) grid. To reduce network protector operations, the PV system was connected at the switchgear panel that had the highest daytime load in the building. The interconnection guidelines for PEPCO require that the system meet IEEE 1547 standards and that the inverters are listed to meet UL1741 requirements. According to the system operators, there have been no problems associated with these PV systems or any equipment within the building.

Utility Perspective

PEPCO was easy to work with prior to and during the installation for both the client and the system integrator. While there have been no noticeable system problems, we assume that the PEPCO engineers are watching this system to see if there are any negative issues associated with the interconnection.

Conclusion

The Forrestal Building PV system is the largest PV system installed in Washington, D.C. The main PV system operates at 205 kWp (DC) and has not experienced any failures since the system was installed in 2008. In addition to the 205 kWp system, there are four "Technology Showcase" systems producing 1 kWp each. (The Technology Showcase systems are designed to showcase the various technologies in PV arrays.) PEPCO does not require any special minimum import relays or dynamically controlled inverters because the PV system peak output is well below the minimum building load.

Case Study: Big Sue – Brooklyn, New York

Key Highlights

System Owner:	Big Sue, LLC
Utility:	Consolidated Edison (Con Edison)
System Integrator:	Solar Energy Systems; Brooklyn, New York
System Size:	One 39.6 kWp DC and one 7 kWp DC
Network Type:	Area Network
Special Interconnection Requirements:	None (Reverse power relay installed initially, then removed)

Figure 9. The Main PV Array on Big Sue

Introduction

The Big Sue PV system, located at 925 Bergen Street, Brooklyn NY, is part of a redevelopment project that has been installed on a 130-year-old building (Figure 9). There are 25 commercial units in the building that are served by the same Con Edison electrical meter, as well as the PV system. The owners of Big Sue have also refurbished a building adjacent to the site, at 1024 Dean Street that has six residential apartments. The roof of the apartment building has a roof-integrated 7kWp PV system.

System Overview

PV System Description: The PV arrays on the Bergen Street site (40 kWp DC) are mounted on one integral structure (see Figure 10). The DC power then ties to a 50 kW inverter, which then feeds building loads. Originally a reverse power relay was installed, but removed when the facility was examined for net-metering operation. This became the first net metered system tied to an area network in the United States. The PV system on the residential apartment building on Dean Street (7 kWp DC) is a rooftop integrated system that feeds back into the meter serving the top-floor apartment. The simplified one-line diagram in this case study does not show the apartment PV system.

Network Description: Both the Bergen Street and Dean Street buildings are served by a Con Edison area network system. The area network details are confidential because of the large number of customers served, but the system has hundreds of network transformers and network protector combinations (known as network units). The network serves customers in this area at 120/208 VAC three-phase power. The network has the following characteristics:

- Multi-transformer, multi-feeder area network (hundreds of transformers)
- Each transformer is rated at 27 kV/208V
- Each transformer has a network protector (some NP have been converted to microprocessor based units)
- Network protectors are monitored via power line carrier (PLC) to the substation, then on fiber optic line to the SCADA host computer (all network protectors in Con Edison service territory are monitored via a SCADA system).

Evaluation

The Bergen Street PV system is considered a medium-sized PV system, and generates approximately 51 MWh of energy per year. The percentage of energy use for the building is unknown because the tenant mix changes from time to time. Con Edison had initially required a reverse power relay to prevent power from flowing back to its network, but has recently eliminated that requirement for this system.

According to the system owners (Big Sue, LLC) and the system integrator (Solar Energy Systems), the PV system has not experienced any operational problems since its installation.

Utility Perspective

The Big Sue PV system has not caused any known problems to Con Edison's area network system, but Con Edison believes that the PV system generates a small enough amount of energy that only rarely is it not entirely consumed in the building. However, it is possible that the PV system may export power to the network on weekends during the hours of 10 AM - 2 PM in the unusual instance when the building load is low and the PV system output is high. Other area loads would likely absorb this excess PV system power without adversely impacting the area network.

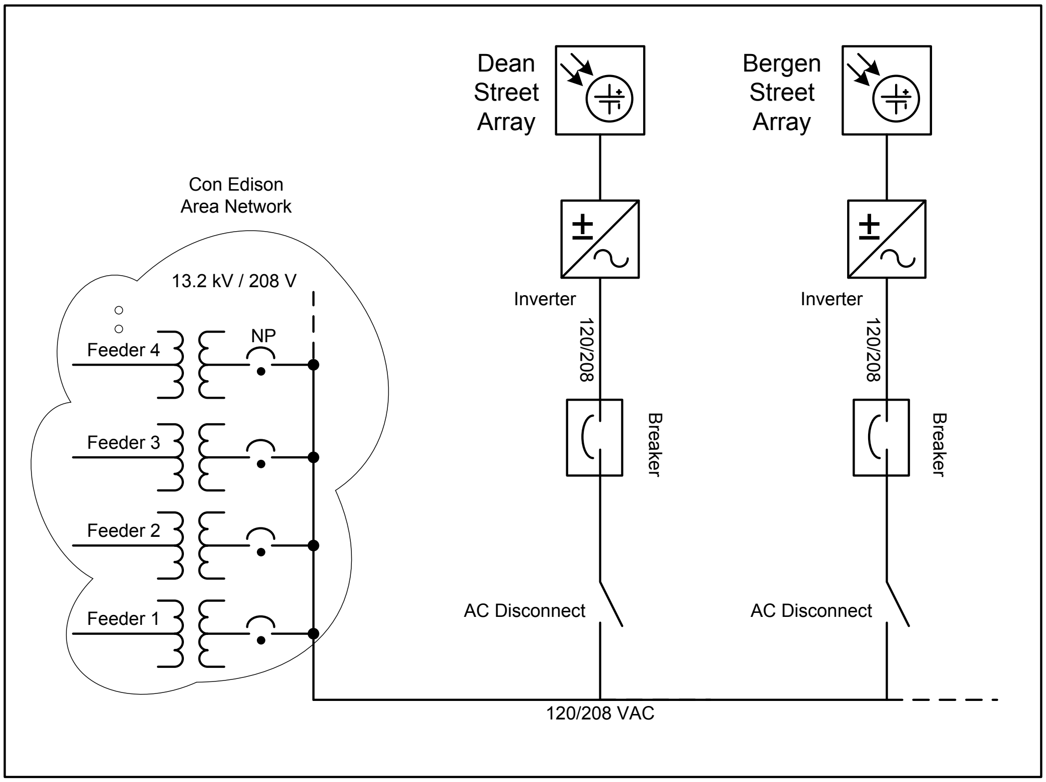

Figure 10. Big Sue One-Line Diagram

Conclusion

It is highly likely that the Big Sue PV system is the first PV system in the United States to actually net meter power back to a secondary network. The system, by all accounts, is operating within design parameters and has caused no adverse situation for the customer or the utility company. The system was initially designed with reverse power relays, which were installed, but that requirement was dropped by Con Edison in late 2008 and the relays were scheduled for removal in early 2009. Most of the generated energy is likely consumed on site, but there remains the possibility that energy might be exported onto the network during the daytime hours on weekends (because there are numerous tenants who, because of turnover, may change from time to time and affect the building load profile).

Case Study: Kinnloch Black Bear – Brooklyn, New York

<u>Key Highlights</u>

System Owner:	Black Bear Company, Inc., Long Island City, New York
Utility:	Con Edison
System Integrator:	Solar Energy Systems; Brooklyn, New York
System Size:	17 kWp (DC)
Network Type:	Area Network
Special Interconnection Requirements:	Minimum load is greater than maximum PV system production

Figure 11. View of the Rooftop PV System (Black Bear Co.)

<u>Introduction</u>

The Black Bear Company Inc. installed their 17 kWp PV system in 2007 with the help of Solar Energy Systems of Brooklyn, New York. The Black Bear building houses a limousine service dispatch center along with a specialized oil company.

System Overview

PV System Description. The PV panels (17 kWp DC) are located on the main section of the building rooftop (Figure 11). The DC system is connected to three inverters located 30 feet from the array, and three-phase AC power is then tied to the main electrical room on the first floor of the building. The AC power goes through a production meter, an AC disconnect switch, and then tie into the main panel. The system has no reverse power relay, nor any dynamically controlled inverters.

The simplified electrical one-line diagram is shown in Figure 12.

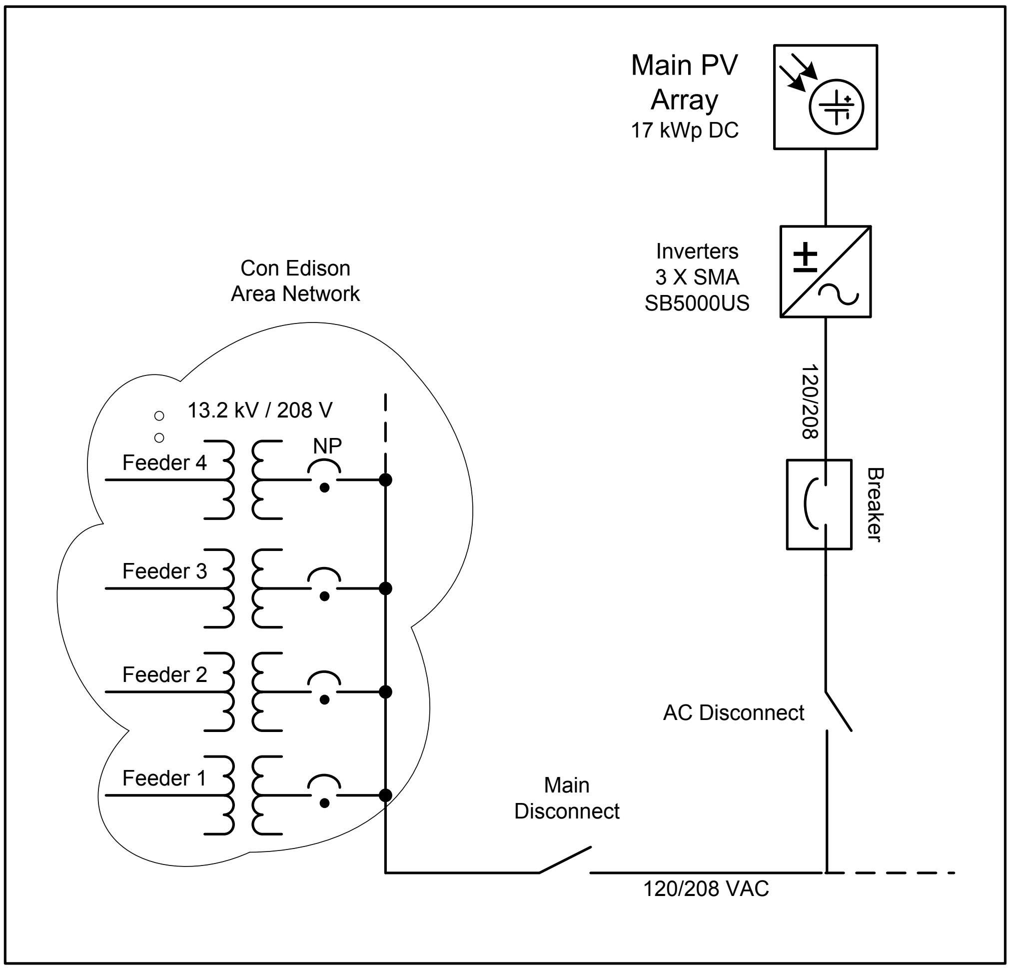

Figure 12. Simplified Electrical One-Line Diagram for Black Bear Company, Inc.

Network Description. The Black Bear Company building is served by a Con Edison area network system. The area network details are confidential because of the large number of customers served, but the system has hundreds of network transformers and network protector combinations (known as network units). The network serves customers in this area at 120/208 volt, three-phase power. Con Edison does not require reverse power relay protection for this PV system. The network has the following characteristics:

- A multi-transformer, multi-feeder area network (hundreds of transformers)
- Each transformer is rated at 34 kV/208 V
- Each transformer has a network protector (some network protectors have been converted to microprocessor based units)
- Network protectors are monitored via power line carrier to the substation, then on fiber optic line to the SCADA host computer.

Evaluation

The Black Bear PV system is considered by Con Edison to be a small-sized PV system, and generates approximately 21 MWh of energy per year. The minimum demand for the building, during daytime hours, is significantly higher than the AC power output of the PV system (approximately 13 kWp AC).

According to the system owners (Black Bear Company, Inc.) and the system integrator (Solar Energy Systems), the PV system has not experienced any operational problems since its installation.

The system has not been designed with any reverse power relay equipment nor any dynamic inverter controller. However, the energy produced by the PV system is considerably less than the daytime energy consumed at the building during the work week. The load during the weekend has the potential of dropping below the output of the PV system, and thus this system may export power through the utility meter back toward the area network.

Utility Perspective

The Black Bear Company PV system has not caused any known problems to Con Edison's network system, but it is believed that the system generates a small enough amount of energy that it is likely that all generated energy is consumed within the building. However, it is possible for the system to export surplus energy to the network on weekends during the hours of 10 AM - 2 PM.

Conclusion

The system has been operating within design parameters and has caused no known adverse situation for the customer or for Con Edison. Most of the generated energy is consumed on site, but it is possible that power is exported to the network during the daytime hours on weekends. This is an excellent example of a smaller commercial PV system that is tied to a network and requires no reverse power protection.

Case Study: Greenpoint Manufacturing and Design Center – Brooklyn, New York

Key Highlights

System Owner:	Greenpoint Manufacturing and Design Center (GMDC)
Utility:	Con Edison
System Integrator:	altPOWER; New York, New York
System Size:	55 kWp (DC)
Network Type:	Area Network
Special Interconnection Requirements:	Minimum load is greater than maximum PV system production

Figure 13. Rooftop PV Systems at GMDC

Introduction

The Greenpoint Manufacturing and Design Center (GMDC) is a nonprofit industrial developer in New York City, and has been in business since 1992. The building at 1155 Manhattan Avenue is one of five rehabilitated manufacturing buildings operated by

GMDC. There are more than 100 businesses with more than 500 people employed by those businesses. The 55 kWp (DC) PV system was installed in 2005.

System Overview

PV System Description. Because of several roof penetrations, the panel arrays are placed wherever there is space, with some room between arrays (Figure 13). The system was installed by altPOWER, and on a typical day most PV-generated energy produced is consumed on site. The array is tied to an inverter, located in the basement, and is fed into a breaker panel adjacent to the inverter. There is a production meter located next to the inverter, which is also very close to the utility revenue meter. The system feeds back to the electrical service at a 120/208 volt level. Figure 14 illustrates the simplified electrical one-line diagram of the PV system up to the utility network.

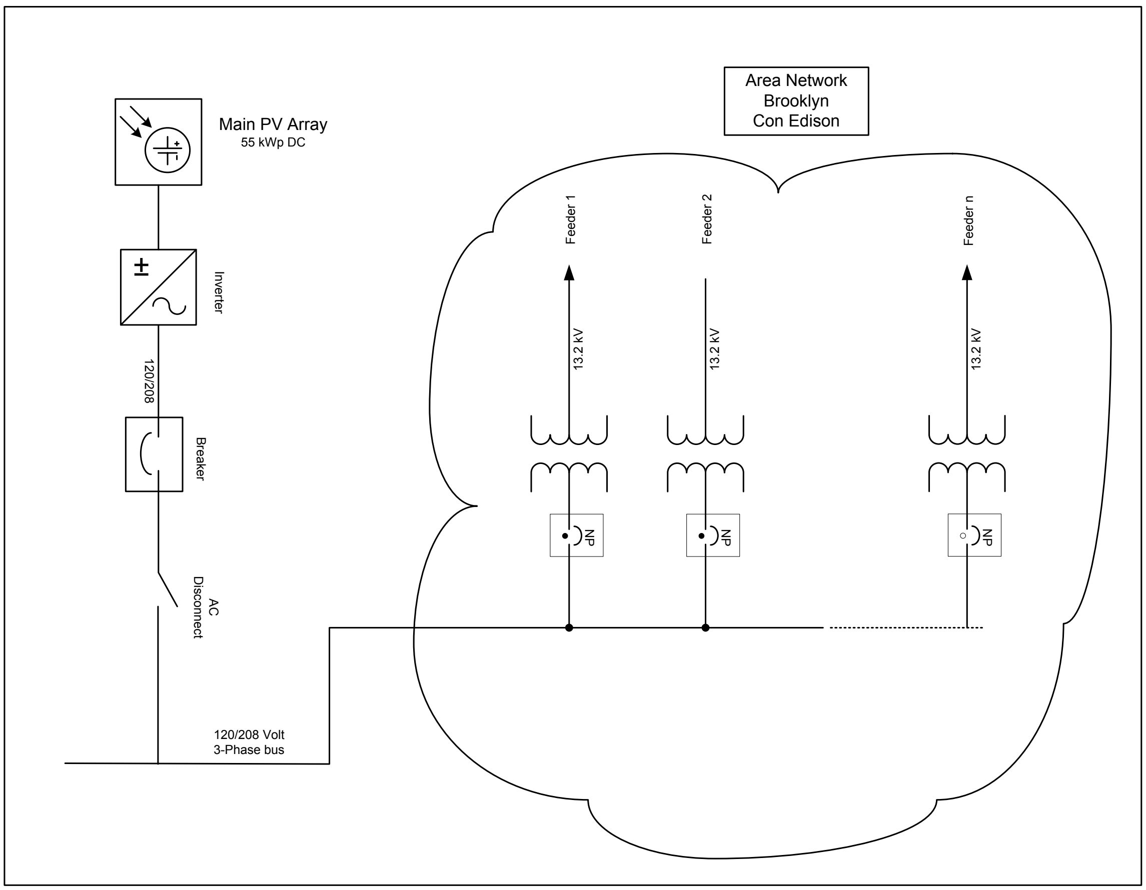

Figure 14. Simplified Electrical One-Line Diagram for GMDC

Network Description. The GMDC building is served by a Con Edison area network system. The area network details are confidential because of the large number of customers served, but the system has hundreds of network transformers and network protector combinations. The network serves customers in this area at 120/208 volt, three-phase power. Con Edison does not require reverse power relay protection for this system. The network has the following characteristics:

- A multi-transformer area network (hundreds of transformers)
- Each transformer is rated at 34 kV/208 volt
- Each transformer has a network protector (some network protectors have been converted to microprocessor based units)
- Network protectors are monitored via Power Line Carrier (PLC) to the substation, then on fiber optic line to the SCADA host computer.

Evaluation

The GMDC PV system is considered a medium-sized PV system by Con Edison, and generates approximately 68 MWh of energy per year. The minimum load demand for the building, during daytime hours, is significantly higher than the AC power output of the PV system.

According to the system owners (GMDC) and the system integrator (altPOWER), the PV system has not experienced any operational problems since its installation in 2005.

The system has not been designed with any reverse power relay equipment nor any dynamic inverter controller. However, the energy produced by the PV system is considerably less than the daytime energy consumed at the building during the work week. The load during the weekend has the potential of dropping below the output of the PV system, and thus this system may export.

Utility Perspective

The GMDC PV system has not caused any known problems to Con Edison's secondary network. It is believed that the system generates a small enough amount of energy that it is likely all consumed within the building.

Conclusion

The system has been operating within design parameters and has caused no known adverse situation for the customer or for Con Edison. Since this is a medium-sized PV system that is on a commercial building, and all of the energy is consumed on site, it is unlikely to produce enough excess power to upset any network protectors. This is an excellent example of a medium-size commercial PV system that is tied to a network and requires no reverse power protection.

Case Study: Colorado Convention Center – Denver, Colorado

Key Highlights

System Owner:	City and County of Denver
Utility:	Xcel Energy
System Integrator:	Namasté Solar; Boulder, Colorado
System Size:	300 kWp (DC)
Network Type:	Spot Network (Eight spot networks, PV system into one)
Special Interconnection Requirements:	Minimum import relay Dynamically Controlled Inverters (3) Minimum Load greater than PV generation

Figure 15. Colorado Convention Center PV System

Introduction

The Colorado Convention Center is located at 700 14th Street in Denver and has almost 600,000 square feet of meeting space. Namasté Solar, of Boulder, Colorado, was chosen to do the system layout and installation of the PV system. The three inverters were custom-designed for the center and have a dynamic control on each. The overall PV system design uses three different methods to ensure no backfeed occurs onto the network.

System Overview

PV System Description. The PV array is located on the southern side of the rather large Colorado Convention Center roof, and was installed in 2008 (Figure 15 and Figure 16). The layout and installation of the PV array was completed by Namasté Solar, and is mounted using a system that does not require roof penetrations. There are three SatCon inverters (each three-phase) that are connected to the AC disconnect switch adjacent to the service disconnect. The SatCon inverters are all controlled using an innovative "dynamic controlled inverter" system which reduces energy output from the inverters at times when the convention center may not be able to consume the energy. This dynamic control system is one of three methods used to eliminate power backfeed into the spot network. The Namaste engineer and utility representative verified that the load on this spot network was more than 350 kW during daytime hours using five years of recorded data. The PV system also employs a minimum import relay in the event the dynamic controlled inverters fail to function properly. The PV system is estimated to produce 479,000 kWh during the year.

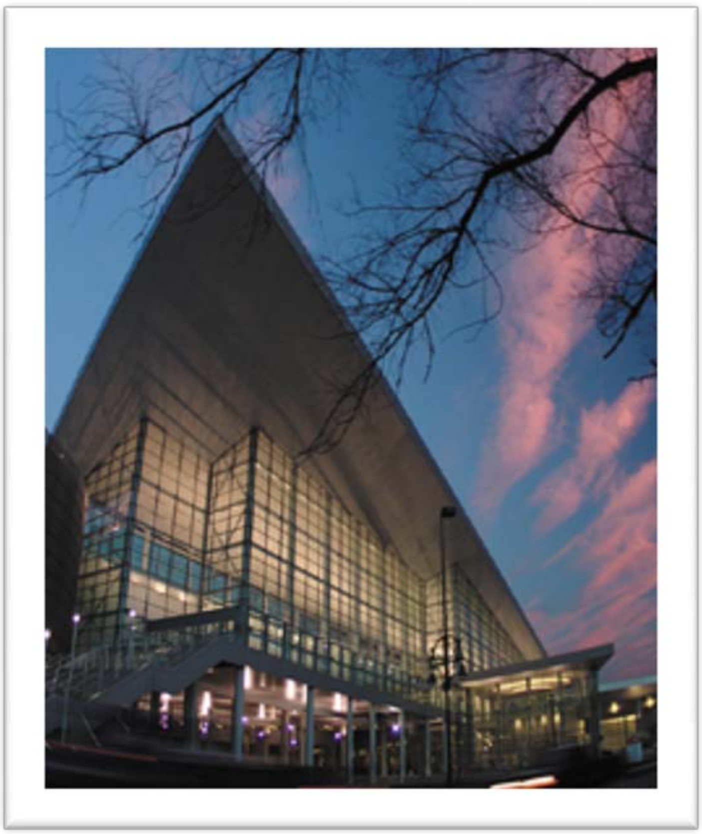

Figure 16. Colorado Convention Center

The convention center expanded over the last five years, and there are older sections of the roof that were designed only for snow load and for display load (hanging from the ceiling below the roof) and will not accommodate additional PV arrays. The system is rated at 300 kWp DC.[6] The load on the other spot networks is minimal when the facility is not in use.

Network Description. The Colorado Convention Center was built in two phases. Phase I required five spot networks located on the east side of the complex. Phase II consisted of a separate mirror image complex built later, which was independent of the Phase I complex. An additional five spot networks were required to serve the Phase II electrical forecasted peak load demands.

The spot network supplies all parking lighting, emergency circuits, and fire systems, as well as various other loads. That spot network was chosen because its minimum load exceeded the PV system maximum output, which makes it an ideal spot network for PV system interconnection. The network is a three-feeder, 13.2 kV to 480 volt, with three 750 kVA network transformers. The network protectors are not monitored electronically, but are checked periodically.

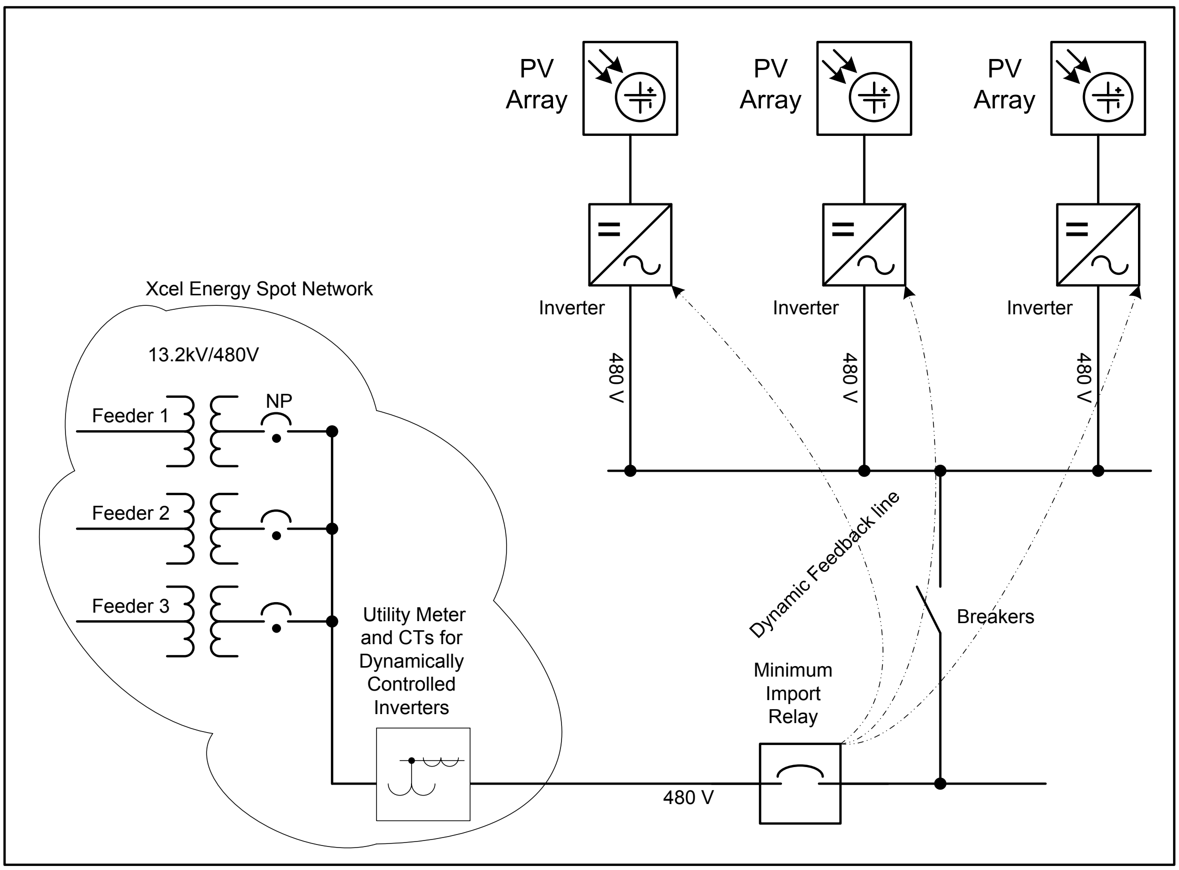

Figure 17. Simplified Electrical One-Line Diagram for the Colorado Convention Center

6 This is based on NREL data using the IMBY simulation program found at http://www.nrel.gov/eis/imby/.

Evaluation

The Colorado Convention Center PV system is considered a large-size PV system by Xcel Energy, and generates approximately 480,000 kWh of energy per year. The minimum load demand for the building, during daytime hours, is significantly higher than the AC power output of the system. The system is very new, but has had no operational problems since installation in the second-half of 2008. The system was designed with dynamic-controlled inverters, which govern the energy produced by the PV system and will reduce output if the power coming through the meter drops below 50 kW. The 50 kW was chosen to ensure no additional network protector cycling would occur due to system unbalance and to accommodate the loss of any one branch load without tripping the PV system or risking network separation. To add another level of redundancy, the system employs a minimum import relay, which will open the service if any power flows back toward the network protectors.

Utility Perspective

Xcel Energy required multiple and independent methods to assure themselves that the Colorado Convention Center PV system would not export power into the spot network or jeopardize the reliability of the power delivered to this high profile load. The specific requirements were worked out between Xcel Energy, the customer, and the system integrator to ensure the operational, safety, and reliability needs of all parties were met. The Xcel network engineering team will monitor this PV system and spot network to validate there are no interconnection problems.

Conclusion

The system has been operating within design parameters and has caused no known adverse situation for the customer and Xcel Energy. All energy produced by the PV system is consumed on site.

6.0 Methodologies Employed for Interconnection to Networks

Based on the case studies evaluated in this report, there were four methodologies used to successfully integrate PV onto secondary networks. Some PV system installations in the six case studies were required to incorporate two or three of the methodologies. Those methodologies are:

1) Identify Minimum Load – Evaluate at least 12-24 months of daytime demand data for the site under consideration and size the PV system so that it will not produce more energy than the facility consumes at all times. The approach is simple, and that is to ensure the site consumes a minimum amount of utility power at any given moment, thus eliminating the possibility of network backfeed. This approach may not prevent some of the network protectors from opening during times the load is lower than previously measured or calculated. This approach can be made more robust if the load center's branch loads are quantified to determine the largest load that can trip off or be off for maintenance. The allowable minimum load limit that is chosen should have enough margin to cover this contingency.

2) Install Minimum Import Relay (MIR) or Reverse Power Relay (RPR) – A MIR can be preset to insure that a customer consumes a minimum power level, where an RPR is set to a power level closer to zero. If there is a possibility that the PV system might be exporting to the utility, and that is deemed unacceptable, then an MIR/ RPR may be installed to disable the PV system to eliminate the possibility of a backfeed situation. Some utilities require an MIR or RPR, along with other measures, to provide some redundancy and ensure proper operations in the event of relay failure. This system is a simple approach to ensuring no backfeed based on real-time monitoring. One downside to this approach is that the MIR/RPR breaker is often a manual-reset device that, when tripped, requires an electrician to reset the minimum import relay. If not diligently monitored, the PV system may be offline until the tripped MIR/RPR is found.

3) Install Dynamic Controlled Inverter System (DCI) – At least one inverter manufacturer is offering an option for a dynamic controlled inverter, which, unlike the MIR, ramps down the power level of the inverter if the energy being consumed at the site drops below a specific level. The energy flow is monitored at the main disconnect (or at the utility revenue meter) and a control signal is sent to the inverter(s) which initiates a reduction of output power if required. This type of inverter system may be the most cost-effective and logical approach of all options being considered at this time. This approach allows a larger PV array to be installed as it will ramp down for the rare cases when there is not enough load present to ensure a reliable interconnection. The disadvantage to this type of system is there may be lower power output and thus lower energy generated during the lifetime of the system, which reduces the economic value of the PV system.

4) Allow Net Metering – On selected area networks, some PV systems may be allowed net energy metering on secondary network distribution systems, although many of these PV systems appear to be producing less energy than the utility customer is consuming. Allowing net metering for PV systems would likely reduce installed costs for the PV system integrator. This option is limited to area networks and for a limited amount of total generation.

7.0 Conclusions

This report discussed four investor-owned utilities in the United States that operate secondary network distribution systems and that have allowed PV systems to be interconnected to those networks. Six PV systems in four cities were examined and these PV systems are operating normally with no known significant problems. While there are several approaches adopted by those utilities, it can be concluded that:

- Secondary network distribution systems and certain PV systems can be interconnected and operate in parallel.
- There are several methods that have been employed in interconnecting these PV systems to prevent or minimize the impact on the network.
- Engineering studies may conclude that a PV system may not be technically viable to interconnect at any specific location.
- These solutions might prove successful in addressing network PV system interconnections used in other U.S. cities even though the design and operation of the system may vary from city to city.

Annex

The following paragraphs were taken from NREL Technical Report NREL/TP-560-38079 (July 2005) titled "Secondary Network Distribution Systems Background and Issues Related to the Interconnection of Distributed Resources." The report offers more detailed definitions and presents additional illustrations of networks and other types of electric distribution systems. It is suggested reading for those individuals wanting to learn more of the technical concerns and details surrounding integrating distributed generation onto secondary networks. http://www.nrel.gov/docs/fy05osti/38079.pdf (581 KB).

Review of Secondary Network Distribution Systems

(Network) Protector ratings are given by IEEE Standard C57.12.44-2000 (see appendix). They can be in non-submersible housings, submersible housings, or housings suitable for mounting within a low-voltage switchgear assembly. The ratings of the protectors vary depending on the manufacturer, the type of the protector, and the secondary voltage. Continuous current ratings are 800–6,200 A, 216–600 V. The interrupting ratings are 30,000–85,000 A, and close and latch ratings are 25,000–65,000 A.

Network protectors are maximum current-rated devices and have no published overload rating. Installed NP are generally selected so their current ratings are generally 33%–67% higher than the continuous ratings of the transformers they protect to take advantage of short-term transformer overload capability.

Spot Networks

Spot network systems are designed to provide highly reliable 277/480-V or 120/208-V service to a single site. (In rare cases, 240-V delta ungrounded service may be provided.) These systems are commonly applied in high load-density areas such as metropolitan and suburban business districts.

Spot networks have the following characteristics:

1. Most utilities operate each network system isolated, but some utilities may provide alternative sources to the primary network feeders.

2. A spot network consists of two or more network transformers (a three-transformer spot network is common) that are paralleled at the secondary bus.

3. In some cases, fast-acting secondary bus tie breakers may be applied between bus sections to isolate faults in the secondary switchgear and limit loss of service to those loads connected to the faulted equipment.

In the spot networks of most utilities, a fault or failure of the paralleling bus (collector bus) will result in a service outage. This is one part of the system for which redundancy does not exist for most utilities, so its design and integrity is of great importance.

Also, for some utilities, a fault on the medium voltage bus in the substation that supplies the primary feeders will result in an outage to the network. This does not apply to those utilities that have ring bus designs, double synchronization bus designs, automatic bus transfer designs, etc., for their medium-voltage substations.

Grid Networks

The “grid” secondary network distribution system consists of an interconnected grid of circuits operating at utilization voltage and energized from a number of primary feeder circuits and network units. The number of cables that tie the secondary buses to one another can be anywhere from one to dozens. These cables are also referred to as secondary mains. The numerous cables allow for multiple current paths from every network unit to every load within the grid.

Cable limiters protect some of these cables (by “limiting” thermal damage to the cables under fault conditions). The grid or mesh is designed so adjacent network transformers are served by different primary feeders.

Grid networks have the following characteristics:

1. The secondary voltages are either 208 Y/120 V or, in rare cases, 480 vY/277 V.
2. The integrity of the grid network is based on multiple paths through individual cables. This integrity is maintained by individual cables, and, if used, cable limiters burning clear any faulted cable sections.
3. The conductors from which customer service is tapped generally follow the geographical pattern of the load area and are located under streets and alleys.

Load flow within the grid network will significantly change as a function of:

- Medium-voltage feeder outage conditions
- Changing customer load conditions
- Reduced current carrying capacity because of cleared cable limiters.

Primary feeder outages and burned-off cables or cleared limiters because of previous faults within the grid will cause changes in load flow that are not readily detected. The inherent system redundancy generally prevents any customer from experiencing poor power quality. Load flow analysis is necessary to understand the maximum current levels at any point and may be required to determine which network units are exposed to cycling under minimum load conditions.

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14. ABSTRACT *(Maximum 200 Words)*
This report examines six case studies of photovoltaic systems integrated into secondary network systems in four major U.S. Solar America cities.

15. SUBJECT TERMS
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