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Evaluation

Portland General Electric Dispatchable Standby Generation (DSG) Program

Puget Sound Energy, Inc

December 01, 2014

Summary:

The following evaluation report performed by Puget Sound Energy, Inc. (PSE) examines Portland General Electric's (PGE's) dispatchable standby generation (DSG) program as a potential capacity resource in the future. The evaluation looks into the financial and technical feasibility of PSE implementing a similar program in its service territory. This evaluation was stipulated in Washington Utilities and Transportation Commission (WUTC) Order 06 in docket UE-130617, in which both parties agreed that PSE should perform an evaluation. Specifically, the Settlement agreement states: *PSE agrees to evaluate the PGE Dispatchable Standby Generation (DSG) program, described in the testimony of staff witness Juliana Williams, and either provide a report to the Commission of PSE's conclusions and recommendations by December 1, 2014, regarding the financial and technical feasibility of PSE implementing a similar DSG program in its territory, or file a tariff implementing DSG service by December 1, 2014.*

This evaluation report begins with a summary of the PGE and PSE systems and capacity needs in each company's Integrated Resource Plan (IRP). Next, the evaluation explores the background, history, benefits, customer requirements, costs, operations, compliance, and other areas of the PGE DSG program. Understanding these components of the PGE program allows for context and comparison to PSE's current capacity needs, along with the constraints and opportunities PSE would encounter implementing a similar program. The evaluation concludes that while PGE has received benefits from its DSG program, PSE lacks a need for the primary benefits that a DSG program has provided PGE. In addition, uncertainty around costs, technical capability,

customer participation and federal emissions regulations make investment by PSE in a DSG program less prudent compared to current alternatives.

Key Findings:

- The primary benefit of the PGE DSG program has been the ability to use the standby generators as a cost-effective resource to meet non-spin operating reserve obligations
- PSE does not have a near-term need for non-spin operating reserves and has maintained more than adequate operating reserves during peak events
- While originally established as peaking resource, PGE’s use of its distributed standby generator fleet as a peaking resource has been *de minimis* during the life of the program
- New Environmental Protection Agency (EPA) emissions requirements that limit operation and testing on diesel-fired emergency standby generators create uncertainty and potential operational constraints during times of peak need
- Under normal conditions, PGE’s standby generator fleet is not economic compared to other alternatives during dispatch decisions
- PSE lacks sufficient market research of its customers that would justify investment in a DSG program including potential participation rates and standby generator inventory
- It is unlikely PSE would be able to implement a DSG program to meet any near-term capacity needs given time, resources, and current systems capability

EVALUATION

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1.0 GENERAL INFORMATION

1.1 Purpose

The purpose of this evaluation is to provide a preliminary examination of Portland General Electric's (PGE) Dispatchable Standby Generation (DSG) Program to determine the applicability of Puget Sound Energy, Inc. (PSE) implementing a similar program in its service territory. This evaluation is being performed in response to the Settlement Agreement between PSE and the Washington Utilities and Transportation Commission (WUTC) under Order 06 in WUTC docket UE-130617 et al. filed on October 23, 2013. Under the terms of the agreement, both parties agreed that PSE would file an evaluation of PGE's DSG program at the WUTC by December 01, 2014 that explores the financial and technical feasibility of PSE implementing a similar DSG program or file a tariff implementing DSG service. This evaluation is being conducted outside of PSE's regular Integrated Resource Planning ("IRP") process, which was agreed to by both parties. At this time, PSE is prepared to provide this preliminary evaluation only. More time and resources will be necessary to conduct further, in-depth studies to determine the feasibility of filing a tariff to implement a DSG program.

1.2 Scope

The scope of this evaluation will focus solely on the feasibility of implementing a PGE-like DSG program at PSE. Other potential least-cost options for capacity resources or distributed energy programs are outside the scope of this evaluation and will continue to be evaluated through the PSE IRP process. This evaluation will examine several components of PGE's DSG program including background, history, benefits, customer requirements, costs, operations, compliance and others. Further, this evaluation will explore the opportunities and constraints of developing a similar DSG system in the PSE service territory. This study is being conducted outside PSE's regular IRP process, which is the typical avenue for more in-depth evaluation of new supply or demand side resources.

1.3 Methodology

This evaluation was conducted using publically available data about PGE and its DSG program including the PGE IRP, public filings, promotion materials, PGE websites, and tariffs. In addition, first-person interviews were conducted with PGE staff, primarily the manager of the DSG Program.

1.4 Limitations

Before proceeding into a systems overview, this evaluation acknowledges several limitations. A major limitation to this evaluation was establishing accurate resource and cost estimates given the proprietary nature of several elements of PGE's DSG program including its service agreement, program and capital budgets, customer funding formulas, and interconnection standards. A second limitation is that PSE currently lacks a complete understanding of the potential software products, vendors, and costs that would be required to integrate into the PSE system including monitoring, operation, and maintenance of an emergency standby generator fleet with push-button remote dispatch capability. A third limitation is a legal opinion on the impact of EPA regulations on the operational capability of a DSG program. Finally, PSE currently lacks sufficient market research in its service territory to make a reasoned determination that customer demand exists to justify investment in a larger-scale dispatchable standby generator program.

2.0 SYSTEMS OVERVIEW

The purpose of this section is to provide a brief overview and background on the current electric transmission and distribution systems at PGE and PSE, and both utility's future estimated resource needs to meet physical and capacity needs. Further, this section will provide a general overview and relevant background on PGE's DSG program. This section provides context for further examination of the DSG program later in the evaluation.

2.1 Puget Sound Energy Electric System

PSE serves approximately 1.08 million electric customers located within 6,000 square miles of service territory in western Washington State. PSE's electric system consists of approximately 2,671 miles of transmission lines (55-kV and above, including 495-miles of jointly owned 500 kV line). The system includes approximately 20,479 miles of distribution lines and 428 substations.

2.2 Portland General Electric System

PGE serves approximately 836,070 retail customers located within 4,000 square miles of service territory in the State of Oregon. PGE's electric system consists of approximately 1,141 miles of transmission lines. PGE also has 26,867 circuit miles of primary and secondary distribution lines that deliver electricity to its customers.

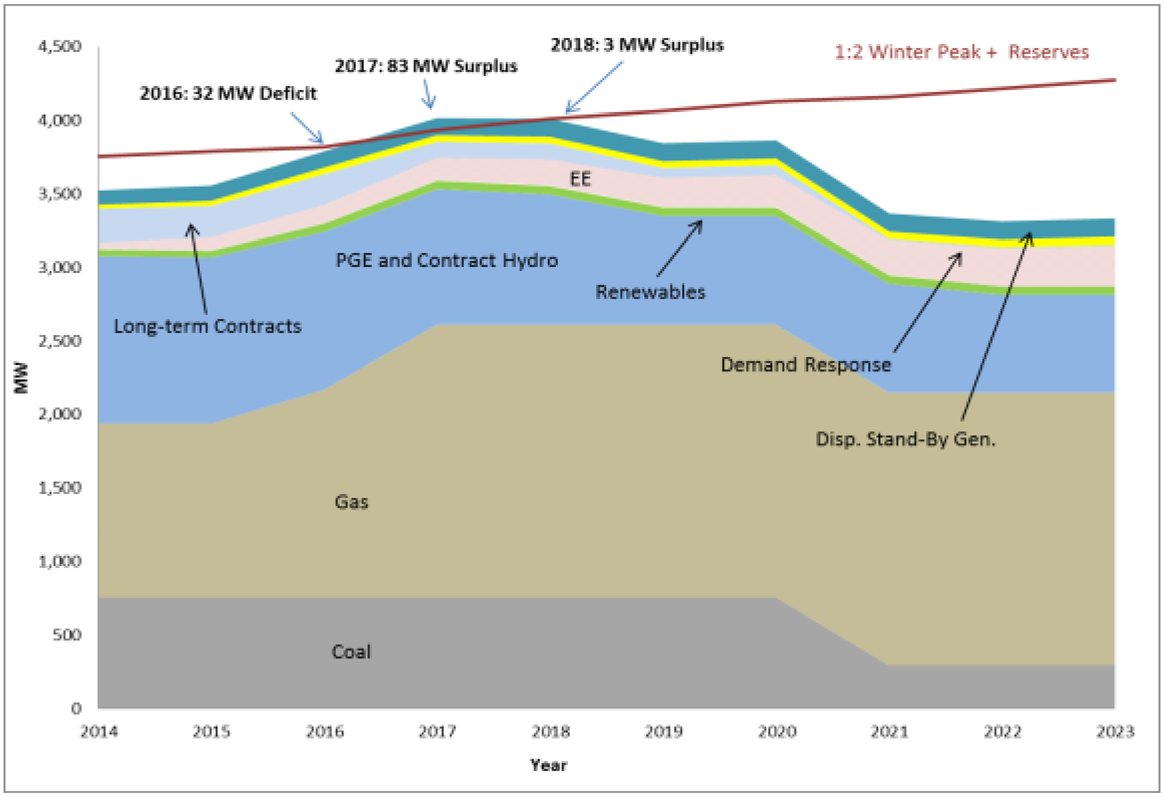
2.3 Electric Resource Need

Utilities such as PSE and PGE must plan for and meet the physical needs of their customers reliably and affordably. For resource planning purposes, those physical needs are simplified and expressed in terms of peak hour capacity and energy. Operating reserves are included in physical needs and are required by contract with the Northwest Power Pool and by the North American Electric Reliability Corporation (NERC), to ensure total system reliability.

Portland General Electric

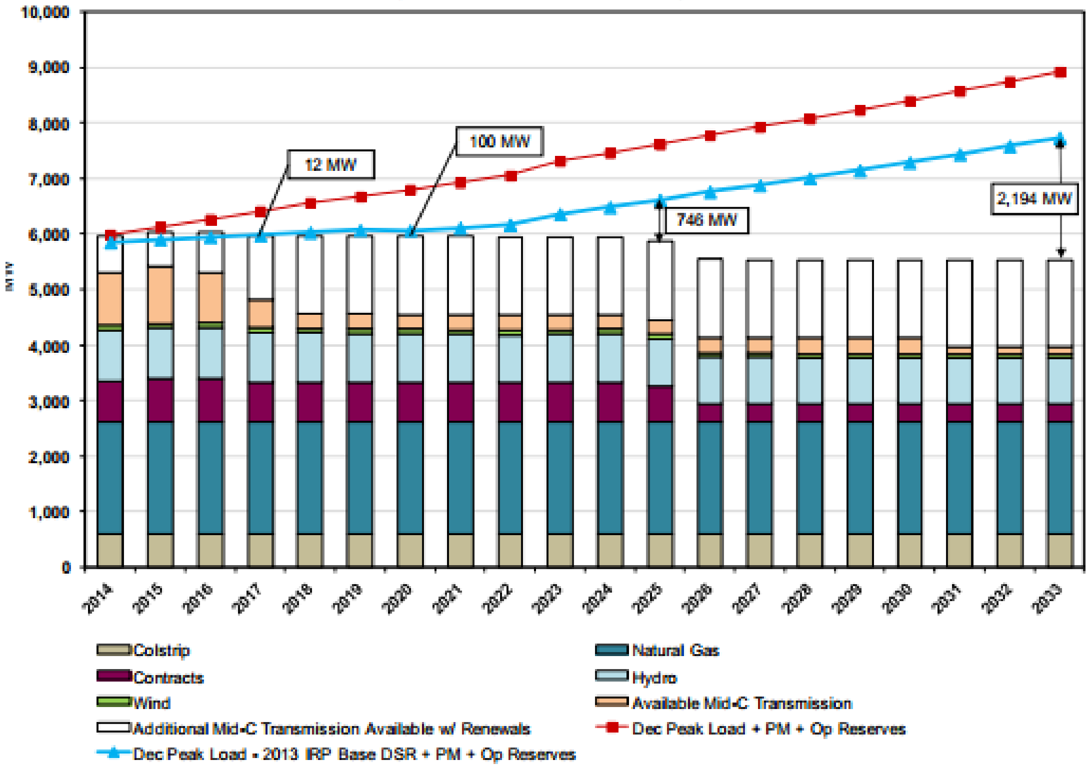
According to the latest version of the IRP, PGE is largely balanced through 2018 with respect to projected 1-in-2 winter peak demand (see chart below). Growing deficits emerge post-2018 due to contract expirations and load growth. Given these projections, no major new resource actions are warranted in the current IRP. The DSG program is considered a peaking resource in the forecast. In the intermediate-term (five to eight years hence) PGE will need to implement resource actions to meet the growing 2020 RPS requirements and to replace energy from the Boardman coal plant, which is scheduled to cease coal-fired operations in 2020. Additional energy and capacity actions may also be required to offset expiring contracts, potentially decreasing availability of market supply, and to integrate higher levels of variable energy resources (e.g., wind). These actions will be identified in a future IRP.

Figure 2: PGE's projected winter (January) capacity needs



Puget Sound Energy

The latest version of PSE's IRP indicates the need for an additional 12 MW of peak hour capacity by 2017, assuming approximately 1,600 MW of PSE's capacity need is met by short-term purchases over firm transmission. The need grows to 100 MW by 2020 after acquisition of all cost-effective demand side resources. This need includes the resources necessary to meet reliability and operating reserve obligations.



2.4 Portland General Electric DSG Program

PGE's DSG program provides the utility with additional generation capacity by contracting with large nonresidential customers for the right to operate their standby or backup generator(s) to avert situations that could lead to power quality problems for the power supply in the local region. The program is voluntary and available to all large nonresidential customers with 250 kW or greater of permanently installed standby or backup generation capacity in place or planned for installation within 24 months in PGE's service territory. The Customer will grant PGE access to its generation such that the Company can operate the generator(s) at the site or remotely operate the generator(s) in parallel with the Company's distribution system. The

Customer may operate the generator(s) at the site as needed for a limited number of hours per year, as specified in the service agreement.

2.5 PGE DSG Program History

PGE began its DSG program as a pilot project in 1999 with the MacLaren Youth Correctional Facility in Woodburn, Oregon. PGE approached MacLaren after it purchased a 500 kilowatt (kW) generator, an automatic transfer switch and a transformer to step up the generator to 12 kilo volt (kV) distribution service feeder line serving MacLaren's facility. The PGE DSG program provided MacLaren with generator controls upgrade equipment and a paralleling system. The equipment provided by PGE included a digital control panel for the generator, interior lighting and soundproofing for the generator enclosure, an upgrade from a 300 to 1000 gallon diesel storage tank, upgraded auto-transfer switch with meter monitoring control, and a parallel switch with communication’s equipment to communicate with PGE’s dispatch center. The first dispatching test of a paralleled distributed generation system at the site PGE's system occurred in roughly June 2000.

2.6 PGE DSG Program Today

After almost 14 years in operation, PGE says the DSG program has approximately 30-35 customers under contract with 40-45 customer-owned standby generation sites. Those customer sites include 72 generators that contribute up to 99 MW of generation capacity onto the PGE system. PGE is able to control that generation from its central dispatch center located at PGE headquarters in downtown Portland, Oregon. PGE estimates that those 72 standby generators are available to provide 99 MW of usable capacity on the PGE system. The PGE 2013 annual report to shareholders states the expectation is that PGE will be able to add 30-40 MW of new standby generation under the DSG program in the 5-year period from 2014-2018 with the current project management staffing level. Examples of large nonresidential customers participating in the program include but are not limited to hospitals, wastewater treatment plants, and data centers

2.7 DSG Program Tariff

PGE customers participate in the DSG program under PGE tariff schedule 200, which was first issued by the Oregon Public Utility Commission on January 16, 2007 and became effective on January 17, 2007. An updated tariff was issued on October 25, 2013 and became effective November 27, 2013. The tariff has only been amended one time since initially approved. Per the tariff, participants pay standard rates for power used, regardless of where it’s being generated. However, PGE typically meters at both the generator and utility levels which allows the DSG program to net out any excess energy produced by the standby generator from the customer bill. For example, if the customer load was 1000 kilowatts (kW) during a time period and the standby generator produced 200 kW of excess electricity during that same period, the DSG program staff would net the amounts from both the utility and generator meters. The customer bill would reflect 800 kW of usage.

The tariff states that generators must be 250 kW or larger to participate in the DSG program, however PGE states that cost benefit analysis typically drives customers to choose 500 kW systems or larger. In terms of upfront capital and ongoing maintenance costs, PGE has a proprietary formula that calculates the company and customer costs of interconnecting a generator for each site. Typically, PGE invests enough to recover its fixed costs based on engineering estimates and the customer is responsible for the difference. In general, PGE gets greater benefit from larger systems which allow the company to invest greater amounts of capital in a customer's standby generator system.

3.0 BENEFITS & REQUIREMENTS

3.1 Stated Program Benefits to PGE Customer

This section summarizes the potential benefits to a customer that enrolls its standby generation system into PGE's DSG program. For the option to call upon a customer's generator, PGE states the DSG program includes some or all of the following benefits: provides funding to upgrade switchgear and install control and communications hardware; assumes most routine maintenance and operation costs for a customer's system; typically pays for fuel consumed by the standby generator; provides funding for additional fuel storage, provides monthly testing of the customer's generation system under high load and regular high-load to ensure the generator will operate successfully during an outage. This additional and routine testing often extends the life of the generators. In addition, PGE provides funding to equip a customer's standby generation system with paralleling switchgear, which allows the generator(s) to be operated by PGE in synchronization with the electric distribution system. The paralleling switchgear provides redundancy that minimizes outages at the site. Most often customers keep the upgraded communications and controls installed by PGE if they elect to terminate or not sign another contract after it expires. Finally, DSG program participants have systems in place that can provide a partial hedge against changing future power costs.

3.2 Stated Program Benefits to PGE

This section describes the benefits of a DSG program from conversations with PGE staff. The primary benefit has been the use of the standby generator fleet to help meet PGE's operating reserve requirements for non-spin resources (i.e. 10-minute ready resources). The other major benefit cited by PGE has been the customer satisfaction and positive response to the program as evidenced by the growing customer participation. Additional benefits of the DSG program to PGE include having a potential peaking resource during times of high power prices, increase reliability of substation feeders through peak shaving, other enhanced localized reliability, and improved efficiency due to avoided transmission losses. However, many of these additional benefits are limited by Environmental Protection Agency ("EPA") requirements on standby generators discussed further below. The primary benefits of the program remain the use of the standby generators to meet non-spin reserve requirements and increasing customer satisfaction with the Company thanks to positive experiences with the DSG program.

3.3 Customer Requirements

This section describes the requirements for customers that voluntary enroll in PGE's DSG program. Prior to receiving service under PGE Schedule 200, the customer and PGE must enter into a written service agreement, signed by the customer. The service agreement typically stipulates an initial 10-year term, with options to renew. Contracts are written to renew automatically unless the customer notifies the utility of termination. If the customer elects to terminate before the initial 10-year term, they are required to repay PGE on a pro-rated basis for the capital costs invested by the utility. The service agreement is a proprietary document owned by PGE. According to PGE, the document has been amended several times over the life of the

DSG program to address issues and concerns from customers. Further, customers are required to grant PGE access to generation sites such that the Company can operate the generator(s) at the site or remotely operate the generator(s) in parallel with PGE's distribution system. Customers will ensure that the generator(s), communications equipment, switchgear and metering equipment are accessible to PGE at all times. Most generators are connected to PGE's SCADA system and respond to dispatch signals from a control center and PGE headquarters. Typically, parties have an agreement that PGE may operate the generator(s) at any time. PGE sends an email to the customer each month asking the customer to certify that the standby generation system is ready and available to run, thus fulfilling the notification requirement. In some cases, PGE may also notify the Customer by telephone, fax or e-mail a minimum of 24 hours before starting the generators, as stated in the tariff, but this is rare. Finally, Customers are responsible for regulatory compliance of the standby generation system such as obtaining environmental permits, which is described further below in the "compliance" section. However, PGE often reimburses for permitting costs.

4.0 COSTS, OPERATIONS & COMPLIANCE

4.1 DSG Program Administration

This section provides an overview of types of costs and experience required by PGE to administer the DSG program. Currently, the PGE DSG program is administered by a manager with a staff of six full-time employees ("FTEs"). Note that number of FTEs has grown to six over the life of the program. The DSG program manager describes the program as self-contained and a full service shop with some dependence on the Major Customer Accounts group for some customer interactions. Generally, the DSG program is staffed by two FTEs in each of the following areas: maintenance, software, and program management. Maintenance staff are responsible for program administration and interface with the DSG program participants and third-party vendors. Software staff typically have a background in electrical engineering, software design or related fields and are responsible for software implementation, monitoring, analysis, upgrades, etc. Project managers typically have an electrical engineering background and are responsible for system monitoring, analysis, and design, along with marketing and others duties. PGE did not provide a hard cost or yearly budget for administration of this program.

4.2 Operations

This section describes the types of costs incurred by PGE to provide 24/7 operations of the DSG program. PGE is typically responsible for most or all of the costs to integrate the customer's generator into its distribution system. The generators contracted under the DSG program at PGE are primarily connected to the PGE distribution system. As outlined above in the Customer Benefits section, PGE typically assumes costs for upgrading switchgear, installing control and communications hardware, most routine maintenance and operation, generator fuel, regular system testing, etc. The standby generators enrolled in the program are monitored from a central control center using software and hardware purchased by PGE and integrated into its headquarters in Portland, Oregon. The DSG control center resides on a separate floor within the same building as the balancing area authority (BAA) operations center. Both the DSG program office and PGE BAA control centers have operational and dispatch control of the standby generator fleet as described further below. All six FTEs in the PGE DSG program have access to the dispatch and monitoring systems. The six DSG program employees work regular office hours, Monday-Friday. After hours monitoring, communication, dispatch, and other duties is a shared responsibility by the DSG program employees. Typically, alarms within the software system are linked to pagers and an Ultrabook that can remotely monitor the system. At all times, one of DSG employees will carry the Ultrabook and pager and be responsible for responding to events with the generators outside of normal business hours.

4.3 Software

This section describes the software systems used by PGE to carry out all the functions of the DSG program. The monitoring, dispatch, system analysis and other operational items require an advanced software system, which PGE purchased from a company called Invensys. The DSG project managers and software engineers first began with a supervisory technology software system platform called "WonderWare." As the program matured, PGE upgraded to a program called "Archestra." The software system provides several capabilities to operate, monitor, and analyze the fleet of generators. This software system provides real-time monitoring of the generators on the system, live video cameras, alarm systems, etc. The software also provides historical analysis services on each generator enrolled in the program. PGE states that over time the system has grown to collect over 200-300 points of data per generator. PGE pays for a license with Wonderware that allows 50,000 data point monitoring over its entire system. PGE collects approximately one terabyte of data per year and pays to store the data. According to PGE, the benefits of a software system with greater data capability are maintaining system integrity, accuracy and better customer service. The system can aggregate data or disaggregate data points such as voltage, amperage, breaker status, fuel level and several other points. This allows PGE to troubleshoot problems with a customer's standby generator system, provide trending analysis and share with the customer (i.e. generator owner). PGE did not provide any upfront or ongoing costs for the WonderWare or Archestra software systems. PGE stated that the more data points and granularity added to the system increases the costs. PSE has not yet reached out to Invensys to acquire cost estimates for similar systems.

4.4 BAA Integration

This section describes the system integration between the PGE Balance Area Authority (BAA) and the DSP program systems. The DSG system is integrated into the PGE Energy Management supervisory (EMS) control and data acquisition (SCADA) system at the BAA operations center. This integration allows PGE’s BAA operators to call upon the customer’s emergency standby generators as part of the PGE reserve capacity system. The PGE BAA office can dispatch the generators in aggregate (global dispatch) or in 25 MW blocks, but not individually. The full nameplate capacity of generators is not available for BAA dispatch because each generator is de-rated to 90 percent of its nameplate capacity to reduce wear and tear on the machines. In addition, the aggregate generators available are de-rated another 10 percent to account for a failure rate. Even though the DSG program states 99 MW of nameplate capacity, de-rating measures typically mean 50-70 MW are available in most hours.

The Schedule 200 tariff states that PGE may contact customers at a minimum of 24 hours before expected use. However, the PGE service agreement allows for real-time dispatch. In practice, the PGE DSG program will email customers each month asking if the generation system is ready for use anytime during that 30-day window. Operationally, this allows for PGE BAA to use the DSG standby generators to be included in their calculations as a capacity resource to meet operating reserve non-spin requirements. In terms of performance, PGE states most generators can be operational in sixty seconds, with some requiring five to six minutes. The aggregate available capacity amount to be called upon depends upon the number of customer confirmations and agreements in place before the operating hour. During the 14-year program, the generator fleet has been used an average of three to four hours per year.

It is important to note that the generators are not used for economic dispatch mainly because they are uneconomic compared to alternatives (estimates range from $250-$300 per megawatt hour). Therefore, the PGE Power Supply group (i.e. Marketing Function) does not have dispatch capability at this time.

4.5 Safety & Reliability

This section highlights some of the safety mechanisms and reliability schemes that PGE uses to integrate the standby generators into the distribution system. Each standby generator system is different and requires an engineering assessment to determine the appropriate level of protection, safety and metering. As noted above, PGE provides funding to equip each participating standby generator with paralleling switchgear that allows the unit to be operated by PGE in sync with the electric distribution system. The paralleling switchgear allows the customer's facility to always be connected to both the PGE distribution system and its own standby generator. In the event of a PGE outage, the PGE breaker opens and the onsite generation system continues to provide power to its facility.

To provide a high level of reliability and safety, PGE protection systems use a variety of protection systems and schemes. PGE standards for interconnection at the points of common coupling are based on the Institute of Electrical and Electronic Engineers (IEEE) standard 1547.

The IEEE standard 1547 provides a common standard set of criteria and requirements for interconnecting distributed resources with electric power systems. While not exhaustive, below are a few examples of different levels of protection schemes for different varieties and sizes of emergency standby generation systems.

Protection One: A multi-function relay is used as the primary protection device. This relay provides over and under voltage protection, over and under frequency protection and over-current protection. Under most circumstances, this device should provide sufficient protection for the generator and the utility.

Protection Two: For larger generators or lightly-loaded utility distribution feeders, a communication system is installed for transfer-trip from substation to generator site. This is used when there is an "islanding" concern. Islanding occurs when a fault causes the breaker on the feeder serving the standby generator to trip at the substation. A large standby generator on a lightly-loaded feeder may continue to serve the loads on that feeder for more than a hundred milliseconds. The chances for problems are increased when the feeder serving the generator site is an overhead line. Automatic reclosers on the feeder may try to close the utility grid back in. The standby generator serving the load on that feeder is now likely to be out-of-phase with the grid. A catastrophic failure may occur, such as complete shearing of the generator shaft if the recloser operation energizes the feeder with the generator significantly out-of-phase with the grid. The transfer-trip system will sense when the feeder breaker is open, and, within 20 milliseconds, open the utility breaker at the generator site, eliminating the dangerous condition. To ensure solid communications between the substation and the generator, two primary communication methods are used. The Mirrored-Bits signals are transported on a direct fiberoptic line from the substation to the standby generator or on a licensed microwave radio signal. Both these methods are used for PGE's program.

Protection Three: As a last resort, a synch-check relay is installed on the feeder breaker in the substation. Before a recloser action, the synch-check relay checks to see if there is an out-of-phase condition on the feeder. If so, the recloser action will not occur. This method of protection is not ideal without the other methods because it may delay getting power back to other customers on the feeder. Many of PGE's feeders have fast recloser operations. This allows a fault to be cleared quickly to get customers back on line with a short flicker of the lights. If the synch-check relay will not let the recloser close the breaker to serve the loads on the feeder, those customers will lose power for more than a brief light flicker.

4.6 Compliance

This section describes the types of compliance requirements that customers are responsible for maintaining while participating in the PGE DSG program. As noted above in “customer requirements,” the customers enrolled in the PGE DSG program are responsible for obtaining and maintaining permits associated with operating the backup generator systems. This includes local, state and federal permits in areas such as siting, construction, air quality, emissions and others. The PGE Schedule 200 tariff states that customers “must obtain all required permits prior to service initiation to allow all planned operations as specified in the service agreement.”

PGE notes that recent changes by the Federal Environmental Protection Agency (“EPA”) to air quality permitting for standby generation systems have raised concerns. In 2013, the EPA finalized new rules and standards for Reciprocating Internal Combustion Engines (RICE) obtaining air quality permits related to meeting the National Emission Standard for Hazardous Air Pollutants (NESHAP), New Source Performance Standards and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. EPA informally calls this the "RICE rule" and the newest version requires lower operational requirements on existing emergency engines located at residential, institutional, or commercial area sources. Under the previous version of the RICE rule, emergency engines could run for up to 500 hours per year. For this reason, PGE typically contracted with standby generation systems to run for up to 400 hours per year. Under the new RICE rule updated most recently in August 2014, emergency engines may operate for 100 hours per year for any combination of the following:

- maintenance/testing;
- emergency demand response (in situations when a blackout is imminent – either the reliability coordinator has declared an Energy Emergency Alert Level 2 as defined in the North American Reliability Corporation (NERC) Reliability Standard; or there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency);
- 50 hr/yr of the 100 hr/yr allocation can be used for:
    1. non-emergency situations if no financial arrangement
    2. local reliability as part of a financial arrangement with another entity if specific criteria met (existing RICE at area sources of HAP only)
    3. peak shaving until May 3, 2014 (existing RICE at area sources of HAP only) if part of a peak shaving (load management) program

with the local distribution system operator and the power is provided only to the facility or to support the local distribution system

The third bullet above, in particular, creates a risk that each generator could only operate for 50 hours per year for the current uses in the DSG program. This rule creates a potential loss of 350 operating hours per year which has the potential to reduce the capability of the DSG program. However, the extent is not yet known. Judicial challenges to the rule are still pending and some generators may be grandfathered. Further analysis of the rule and its impacts are ongoing by PGE's legal staff and the DSG program staff. PGE did not disclose what percentage of generators would be grandfathered under the old requirements versus subject to new operational limits. All new generators signed into the program would likely be subject to the more limited operating requirements creating risk around their use for meeting peak load, peak shaving, non-spin, etc.

5.0 PSE POTENTIAL FOR DSG PROGRAM

The purpose of this section is to compare the current state of the PGE's DSG program with PSE's potential for integrating a similar program into its operations. The comparison will assess the current state of PSE's systems, constraints and potential opportunities for integrating a DSG program. This section will only use the PGE DSG program as a point of comparison to PSE.

5.1 Current systems

The IRP is PSE's primary system for assessing combinations of least-cost supply and demand side resources to plan for and meet peak electric needs. As noted above, the most recent IRP shows a need for 12MW of peak hour capacity by 2017. It is unclear whether this assessment will change during the next PSE IRP planning process. PSE has never formally assessed a dispatchable standby generator program as a least-cost resource in the IRP planning process to meet peaking needs. The PSE IRP planning process is capable of assessing a DSG program, however many variables and assumptions would have to be made and it is unclear whether such a program would prove to be cost effective compared to other alternatives.

PGE's DSG program began as a demand response pilot for meeting peak loads. While PSE has not conducted a similar pilot, it is important to highlight a few of PSE's efforts to implement energy efficiency and demand response programs that compliment a diversified portfolio of supply side resources and market purchases to meet peaks. For example, PSE implemented and the Commission approved a few voluntary tariffs to create interruptible rate schedules including electric schedules 043, 046 and 093.

Schedule 43 is an interruptible schedule available only to permanently located schools whose total water heating and space conditioning requirements are supplied by electricity. Generally, Schedule 43 pays the school for PSE's ability to interrupt electric loads to a level not to exceed 0.6 watts per square foot of structure between 5-8 p.m. on any day PSE requests interruption. PSE currently has 43 schools or districts voluntarily participating under Schedule 43 and pays those entities for the ability to interrupt their loads.

Schedule 46 is available to PSE high voltage customers taking electric delivery at 50,000 volts or higher. Generally, PSE pays customers on schedule 46 for up to 210 hours of interruptible service annually. Service can be interrupted between the hours of 8 a.m. – noon and 5-8 p.m. Monday through Saturday and PSE must notify customers at least 14 hours in advance of the interruption. PSE currently has 5 customers voluntarily participating under Schedule 46 and pays those customers to be ready for load interruption at any time.

Schedule 93 is a voluntary load curtailment rider in which PSE and the customer share the difference of retail and hourly market rates. Generally, customers who volunteer to curtail during periods established by PSE will earn a credit for each kWh of energy curtailed during the period at a rate of 0.5 x ((offer price x loss factor) – Base Schedule Energy Charge x Curtailed Energy. Currently, PSE has zero customers on participating under Schedule 93. More information about each tariff can be found on the PSE website.

For the past decade PSE has had very limited need to use these programs, and therefore *de minimis* or non-existent activity has existed on each schedule. Finally, PSE has conducted or is currently managing various distributed demand response pilot programs in areas such as load control, dispatchable load, demand side management and battery storage. For example, the PSE Glacier Battery Storage Pilot Project entails instillation of a 2 MW (4.4 MWh) lithium-ion battery system at the existing substation near Glacier, Washington. The system will be tied into the PSE power grid and with dispatch control from the operations center. The pilot will test the battery's capability for backup during outages, dispatch during periods of high demand, and integration with variable resources.

5.2 Constraints & Opportunities

While not an exhaustive list, this section describes several known constraints and opportunities that PSE would face implementing a DSG program similar to PGE. The first major constraint is that PSE does not maintain a comprehensive or reliable inventory of customers who own and operate standby generation systems located within its 6,000 square mile service territory. The most recent attempt to create a comprehensive inventory occurred in 2011. PSE approached the commercial real-estate company CBRE Group, Inc with a proposed partnership to help PSE identify large nonresidential customers that own and operate standby generation systems. CBRE agreed to conduct initial outreach to its customers. The result of the outreach was that no customers expressed any interest in further engagement with PSE to interconnect a standby generation system to the grid. For confidentiality reasons, CBRE was unwilling to provide PSE the list of customers they developed that own standby generation systems. PSE's major accounts representatives have some knowledge of customers with standby generation systems, but it is by no means comprehensive. A key component to making the business case for a DSG program at PSE would be more in-depth market research of the fleet of standby generators located within the service territory. Such in-depth market research would likely require time, currently un-funded budgets and re-direction of personell resources. Several elements of the standby generator fleet in PSE's service territory would need to be considered including size, location, interconnection potential, security, communication, reliability, and others.

Further, PSE has not conducted any formal market research to determine the interest level of large nonresidential customers interconnecting their standby generator systems to the PSE grid. PSE is also not aware of any requests from its nonresidential customers to interconnect their standby generator to the PSE system for dispatch during peak times. Finally, PSE has never conducted a pilot program in partnership with a large nonresidental customer to interconnect the customer's standby generator to the PSE grid. For PSE to follow the PGE model of developing a DSG program, the first step would be to invest time and resources in more robust market research. That research would seek to determine the size of the standby generator fleet within the PSE service territory (described above), feasibility for interconnecting the generators, and customer interest in a program. A better understanding of the standby generator fleet and customer interest would be needed to make the business case for proceeding to a pilot program or tariff at PSE.

Monitoring and dispatch are two further constraints PSE would face in implementing a DSG program. PSE does not own software that allows for monitoring and push-button dispatch of standby generators from a central control center. PGE states this capability is necessary to gain the value of using the generators to meet the 10-minute ready requirements for non-spin reserves. Push-button dispatch software is less critical for only using standby generators to meet peaking needs. PSE could theoretically contact a standby generator via phone in advance of upcoming peaks. This would be similar to the method PSE has in place today to notify its existing fleet of simple cycle peaking units. However, internal systems and protocols would need to be developed by the PSE load office and trade floor. Further, a combination of tariff and service agreement would need to explicitly outline protocols for dispatch, monitoring, controls, liability and several other areas to ensure reliability. This systems integration would take significant time and PSE resources to develop.

PGE states another key benefit of advanced software is the ability to provide customers with historical data on their standby generators. PSE would need to purchase and integrate new software, such as Invensys, that is capable of more advanced monitoring and dispatch than PSE's existing systems. In addition, PSE would need to develop the operational and technical knowledge to operate and maintain the new software. PSE currently uses an Alstom Energy Management System (EMS) to monitor and control operations. Related data is stored and may be retrieved using the Historical Data Retrieval (HDR) function of EMS and OSIsoft's PI data historian. System Operators monitor loads and resources and together with other marketing and transmission personnel make dispatch decisions. PSE lacks push-button dispatch control from the central load office for most units. Typically, after the dispatch decision is made in real-time, the Generation desk telephones personnel at the generating plant(s) to start the unit(s). The Generation Dispatcher gives instructions to the plant personnel for run times, output, etc. Push button dispatch from central command would be much more sophisticated than the current system and need to be integrated carefully. Any new software purchase or integration would require various levels of installation, training, optimization, etc. PGE was not willing to share the price of its software costs and PSE has not reached out to vendors to develop an estimate.

Two more constraints to developing a similar DSG program relate to interconnection. First, PSE has not developed specific technical standards and specifications for interconnecting standby generators to the PSE distribution system for use as a dispatchable resource. PSE would need to assess its current Technical Specifications and Operating Protocols and Procedures for Large and Small Generator Interconnections Standards for Interconnection (PSE-ET-160.50) to determine whether more extensive standard development measures are necessary. Developing standards is a formal process at PSE undertaken by a team of engineers from areas such as substation design, corporate security, metering, controls, real estate, system protection, SCADA, project controls and others. A new standards drafting team would need to be formed to design and develop new standards and specs for interconnection standby generators. Generally, this process can take 12-18 months after the appropriate team is assembled.

Second, PSE does not have a formal interconnection agreement that specifically addresses interconnecting emergency standby generators over 250 kW to the PSE distribution system for dispatch purposes. PGE has indicated their interconnection agreement is proprietary and was developed over multiple iterations. PSE would need to dedicate time and resources, including legal resources, to draft and develop an appropriate interconnection agreement that specifically addresses all the issues with emergency standby generators at 250 kW and above. PSE does have interconnection agreements for large and small generators (LGIA and SGIA), as well as distrusted generators. Schedule 150 Attachment A includes an application and agreement for interconnection for distributed resources under 100 kW such as customer generator owned fuel cell, solar, wind, biogas, combined heat and power or hydropower. PSE could potentially use some of these agreements as a guide, but would need to devote a minimum of 6-12 months and several resources to develop a new interconnection agreement for emergency standby generators above 250 kW.

Another major constraint is that PSE currently has several low-cost resources to meet non-spin reserve obligations and lacks a need, at the current time, for additional non-spin resources. PSE does not have the same need for non-spin reserves that PGE states is a primary benefit of the DSG program. Exhibits A, B and C are examples demonstrating PSE’s lack of need for additional non-spin reserves. Exhibit A shows that PSE experienced peak events in December 2013 and February 2014. Exhibit B shows that during the December 2013 peak PSE was exceeding its operating reserve requirements by more than 200-400 MW in most hours. Exhibit C shows during the February 2014 peak PSE exceeded operating reserve requirements by more than 200-400 MW in most hours.

Another major constraint is uncertainty around EPA’s requirements that potentially limit run times for new standby diesel-fired generation systems. Limited generator run times to only 50 hours per year (including testing) could place operational constraints on the machines during times of peak need. PGE has not had to test this scenario during the life of their program. Further, limited run times could impact the ability to use the generators for operating reserves depending on the outcome of the final rules.

6.0 CONCLUSIONS

- PGE has deemed its DSG program a success evidenced by the growing participation over a 14 year time period.
- The primary benefit of the PGE DSG program has been the ability to use the standby generators as a cost-effective resource to meet non-spin operating reserve obligations.

- Another benefit has been the safe and reliable integration of a large number of standby generators into the PGE distribution system.
- Customer satisfaction with the PGE DSG program is considered high based on growing enrollment and informal conversation with customers. No formal customer satisfaction survey has been conducted.
- The program is generally supported by the Oregon Public Utility Commission evidenced by allowing the utility to continually recover costs and expand the DSG program over its lifetime.
- The program is generally supported by the Oregon Department of Environmental Quality evidenced by the permits issued to allow the program to continue expanding.
- The program has provided localized reliability in areas of PGE service territory.
- The standby generator fleet is not economic compared to other alternatives for use in normal dispatch decisions.
- Lack of peaking events during the life of the program creates limited evidence to determine the effectiveness of PGE DSG program generators as a peaking resource.
- EPA requirements that limit operation and testing on diesel-fired emergency standby generators create uncertainty and potential operational constraints during times of peak need.
- PSE does not have a near-term need for non-spin operating reserves and has maintained more than adequate operating reserves during peak events.
- PSE created interruptible schedules, energy efficiency programs and distributed energy pilot projects to address peak events.
- PSE does not maintain a comprehensive or reliable inventory of customers who own and operate emergency standby generation systems located within its 6,000 square mile service territory.
- PSE has not conducted any pilot programs regarding dispatchable standby generator programs.

- PSE lacks formal service and interconnection agreements for dispatchable standby generators (and a formal tariff for standby dispatchable standby generation).
- PSE lacks specific interconnection standards for emergency standby generators 250 kV and above to be used as a dispatch resource.
- Currently, PSE lacks the internal systems, software and training to implement a dispatchable standby generator program with remote, push-button dispatch.
- Uncertainties around internal systems, software, costs, customer participation and EPA regulations make a PSE-owned dispatchable standby generation program an unwise use of resources to meet near-term capacity needs identified in the IRP.

7.0 RECOMMENDATIONS

This evaluation shows that time, resource, and system constraints, coupled with cost and environmental regulatory uncertainty, severely limit the technical and financial feasibility of PSE implementing a DSG program similar to PGE in a time frame to meet capacity needs. At this point, any attempts to estimate financial feasibility would be questionable given current information. This evaluation also demonstrates that PSE currently lacks the need for additional resources to provide non-spin operating reserves, which PGE states is a primary benefit of a DSG program. In addition, EPA regulations on diesel-fired standby generators for utility use create uncertainty around investing in a new dispatchable DSG program for meeting capacity needs. Finally, PSE has limited understanding of its customers with standby generators in its service territory including their willingness to interconnect to the PSE grid. For these reasons, PSE does not recommend filing a tariff or implementing a dispatchable standby generator program at this time.

This evaluation acknowledges several limitations. A major limitation to this evaluation was establishing accurate resource and cost estimates given the proprietary nature of several elements of PGE's DSG program including its service agreement, program and capital budgets, customer funding formulas, and interconnection standards. A second limitation is that PSE currently lacks a complete understanding of the potential software products, vendors, and costs that would be required to integrate into the PSE system including monitoring, operation and maintenance of an emergency standby generator fleet with push-button remote dispatch capability. A third limitation is a legal opinion on the impact of EPA regulations on the operational capability of a DSG program. Finally, PSE currently lacks sufficient market research in its service territory to make a reasoned determination that customer demand exists to justify investment in a larger-scale dispatchable standby generator program.

EXHIBITS

Exhibit A

Peak events over past 21 months

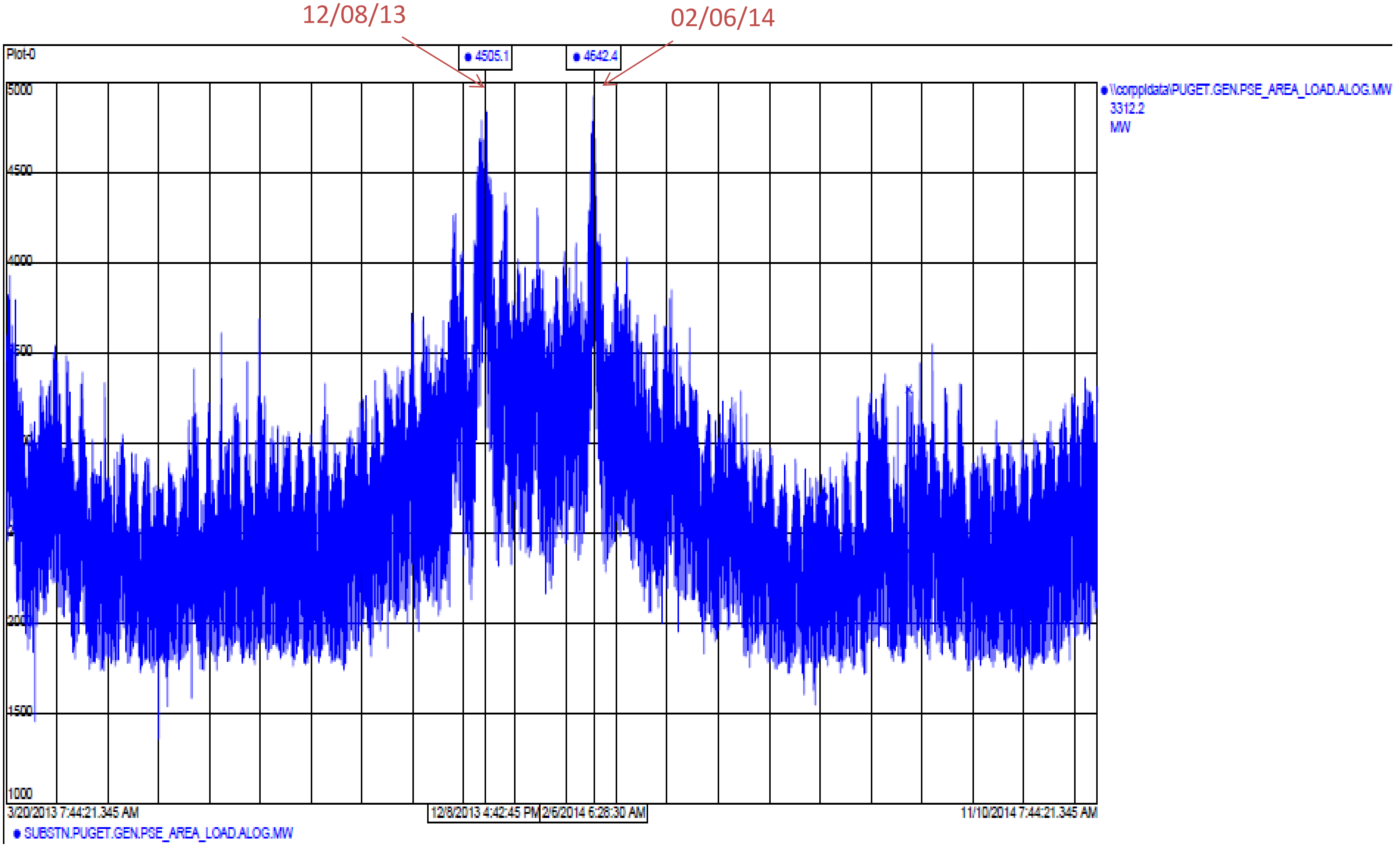


Exhibit B

December 7 – 9, 2013

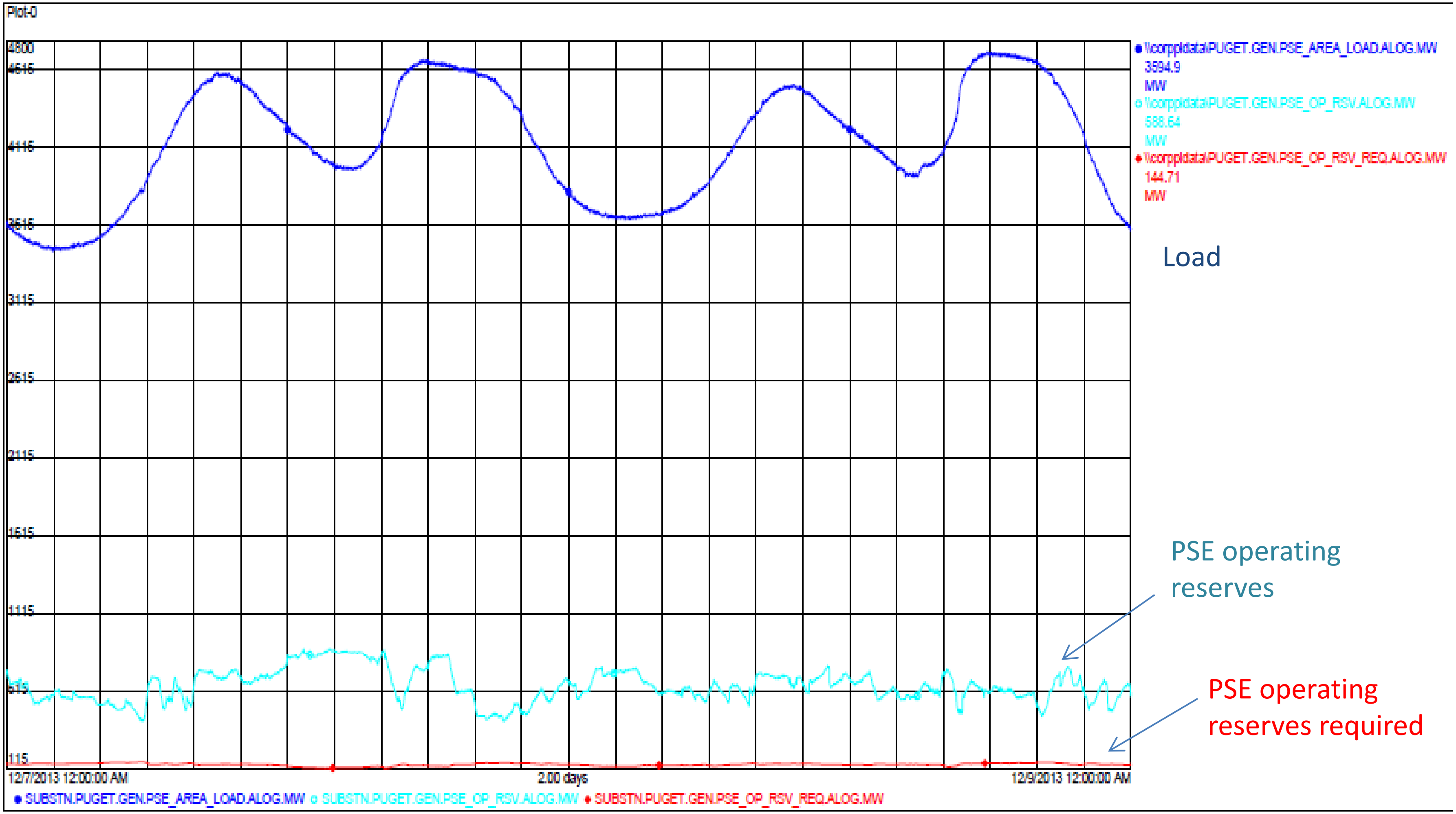


Exhibit C

February 5 – 7, 2014