Energy Northwest and Bonneville Power Administration Commercial Aggregator Demonstration

Final Report

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Contents

Executive Summary

From 2009 through 2012, Bonneville Power Administration (BPA) engaged in focused evaluation of demand response (DR) entailing field tests, demonstrations, modeling, and analysis. These efforts tested commercial and public building load control, residential and commercial space heating energy storage, water heater energy storage and load control, industrial process load control and energy storage, large farm water management system load control and storage, small scale battery energy storage, and load shifting utilizing aquifer recharge opportunities. From these efforts, BPA learned that DR is diverse, available in predicable and reliable quantities and time periods, available from many end users, and variable in cost.

Moving forward with these learnings, in March 2013, BPA solicited interest among its customer utilities for multiple new DR projects to “prove the availability and reliability of DR as a tool for addressing multiple needs in the region.” The 2-year (FYs 2014-2015) projects, expected to total greater than 50MW, were intended to “address multiple regional issues including utility peaks and distribution system constraints, whole system peaks, within-hour balancing, over-generation, and non-wires transmission and distribution investment deferral opportunities.”

Energy Northwest (EN), a Richland Washington, based joint operating agency providing cost-based generation and services to regional public power, assembled a team of public power utilities, technology providers, and other technical resources and advisors and responded with a conceptual-level proposal to the BPA solicitation. Upon review and consideration of the proposal, in May 2013, BPA invited the EN Team to prepare a more complete proposal which was submitted in July 2013. The proposal included 46 MW “INC” (load reduction) and 30 MW “DEC” (load increase) DR resources in the “fast” (<10 minute), hour-ahead, and day-ahead response regimes. In August 2013, BPA notified EN its proposal had been accepted and invited EN to engage in contract negotiations.

Subsequent to its invitation, BPA refined its goals for the project and provided EN a term sheet in December 2013 contemplating a much smaller resource, a shorter project period, and the use of fast INC resources only. Negotiations ensued and an agreement for the “Aggregated Demand Response Demonstration Project” (Demonstration Agreement) was executed between BPA and EN in September 2014.

On February 4, 2015, BPA formally accepted EN’s Demand Response Aggregated Control System (DRACS) as functional. On February 9, 2015, EN’s DR Demonstration resource, 17.88 MW under Dispatch Group A (DG-A), entered service. The resource size was increased over the course of the Demonstration to 35 MW in Dispatch Groups A & B. On January 13, 2016, Demonstration operations terminated under project agreement.

A total of 85 events were called over the course of the Demonstration with successful response being achieved 94.1% of the time.

Introduction

Project Team - Bonneville Power Administration
This demonstration required team members from across the organization. The BPA core team included:

Name	Role
John Wellschlager	Account Executive (Contract Signer)
Jason Weinstein	Account Specialist and Settlement Lead
Fran Halpin	Power Operations – Event Scheduling
Yvonne Johnson	Power Operations – Software & Event Process Oversight
Tony Koch	Metering and Settlement
Melanie Smith	Demand Response Operations
Frank Brown	Demand Response Advisor
Chris Sanford	Transmission - Dittmer Dispatch
Tom Brim (Contractor)	Project Manager
Cara Ford (Contractor)	Project Manager & Information Systems Lead
Eva Urbatsch (Contractor)	Data Analyst

Project Team – Energy Northwest
The primary project team from Energy Services and Development included the following:

Name	Role
John Steigers	Project Manager/Applied Technology & Innovation
Leo Quiachon	Technical Lead
Jim Gaston	Project Oversight
Jennifer Harper	Project Specialist

Load-Response Contributors to Energy Northwest Team

- City of Richland, a full requirements distribution utility customer of BPA, serves 25,300 customers in and near the community of Richland, Washington. It operates a total of 15 load tap changing (LTC) transformers in 10 substations.

- Public Utility District No. 1 of Cowlitz County, or Cowlitz PUD, is a “slice/block” customer of BPA serving 48,200 customers in Cowlitz County, Washington. It serves the Longview, Washington, Weyerhaeuser complex within which Northern Pacific Paper Company (NORPAC) operates.

- Public Utility District No. 1 of Pend Oreille County, or Pend Oreille PUD, a BPA “slice” customer that operates under the Avista Utilities balancing authority, serves 8,800 customers in NE Washington state. Its largest load is the Ponderay Newsprint Company (PNC) near the community of Usk.

- Powin Energy, headquartered in Tualatin, Oregon, is a developer and manufacturer of integrated lithium ion Battery Energy Storage Systems (BESS).

Other Contributors to Energy Northwest Team

Resource Associates International (RAI) of Spokane, Washington, offers integrated turn-key data collection and control solutions to energy utilities, industry, and others.

Pacific Northwest National Laboratory is one of ten federal Department of Energy managed national laboratories. A research institution contributing innovation and leadership to the fields of energy, national security, and others, it hosts and operates the Electric Industry Operations Center (EIOC) within its Richland, Washington, campus.

Others making significant contributions to the EN team but were not able to field load assets in the Demonstration as it was eventually configured included: City of Milton-Freewater, Franklin County PUD, Kootenai Electric Cooperative, and the Northwest Food Processors Association.

Background and Contracting

Requirements for Demonstration Events and Contract Performance – While not comprehensive, significant requirements of EN’s performance under the Demonstration Agreement included:

- Events may be called anytime, no restrictions on time of day or day of week.

- Starting from minute 00, event notification, EN reported aggregated net load response, by dispatch group, via its DRACS to BPA’s Demand Response Optimization Management System (DROMS).

- The contractual “required capacity” obligation, a combination of measured and verified load reduction and incremental discharge increases by the Powin BESS, must be accomplished by minute 10 following notification and sustained each minute through the event’s duration.

- Event duration, as measured from minute 10, may not exceed 90 minutes. BPA may signal for an early event termination.
- BPA may not call another event on that dispatch group until 24 hours after termination of the prior event.
- No more than 2 events may be called on a dispatch group within any calendar week.
- No more than 6 events may be called on a dispatch group in any calendar month.

The prime contract of the Demonstration was the agreement between BPA and EN which defined the specific products and performance criteria. The Demonstration Agreement contemplated:

- A nominal 12-month operating term with, at BPA's option, two 6-month term extensions; which, ultimately, BPA did not elect to exercise.
- A fixed capacity fee paid to EN by BPA on a per kilowatt-month (kW-month) basis for contracted load-response provided. No event-based or "energy" charge or compensation was made.
- EN assembled, managed, and prepared transaction settlement records and invoicing for the Demonstration.
- Contractually-prescribed penalties for failure to meet event load response performance criteria and provision for scheduled Demonstration resource outages.

EN, in turn, contracted individually with participant utilities and/or responding "assets" to acquire the cumulative load response they were contracted to provide. A fixed capacity "incentive" fee was paid by EN to the utilities or assets. Terms, penalties for non-performance, and outages largely mirrored the EN-BPA Demonstration Agreement. Each asset contract differed from one another but accomplished similar ends. Specifically:

- City of Richland, as the load-responding asset itself, accomplished its load response by directing its system LTCs to lower distribution voltage by a set increment thus reducing its served peak load.
- Cowlitz PUD, in turn, contracted with its served load Weyerhaeuser to shut down portions of NORPAC's cellulose fiber production facilities to effect load reduction.
- Pend Oreille PUD's load, PNC, very similar to NORPAC in many respects, reduced its fiber production. EN contracted directly with PNC as Pend Oreille PUD elected to not be a direct party to the asset contract, choosing instead to support and observe the Demonstration transaction within the scope of its existing contractual relationship with PNC. As Pend Oreille PUD is not in BPA's balancing authority, BPA, Avista Utilities, and Pend Oreille PUD agreed informally on system transmission management practices that allowed PNC's load response to effectively flow in real time between the two balancing

authorities and thus benefit BPA. This informal arrangement was not codified in a contract.

- Powin Energy was also contracted directly by EN. As it was deployed in Tualatin OR for the whole Demonstration outside the BPA balancing authority, its physical load response was not transferred to BPA. EN and BPA agreed, due to the relatively small load response and its potential learning value as the Demonstration's only BESS resource, that Powin's load response was deemed to have been delivered for purposes of the Demonstration.

EN separately contracted with RAI to provide both DRACS design/coding services and its deployment as well as operational and maintenance support of the DRACS through the course of the Demonstration. EN also contracted with PNNL to host the DRACS within its EIOC servers and communications infrastructure.

Over the course of the Demonstration, learnings prompted EN and BPA to make significant adjustments to their Demonstration Agreement:

- In March 2015 (1) the allowed Demonstration capacity was increased from 25 MW to 35 MW; (2) changes were made which allowed EN to better manage required capacity from month to month by means of notifications of capacity changes to and acceptance by BPA; and (3) changes provided for EN to propose and BPA to accept additional assets to the Demonstration before April 2015.
- In May 2015, based on learnings realized during the Demonstration, BPA and EN agreed to (1) revise Exhibit B, Measurement and Verification; and (2) to reduce the period prior to event notification from 30 to 5 minutes used to establish a Direct Load Control – Metered (PNC and NORPAC) baseline load.
- In August 2015, based on learnings realized during the Demonstration, BPA and EN agreed to revise Exhibit B to increase the deemed response of demand voltage reduction (City of Richland) by 50% from 0.50 to 0.75, (the percentage of kW change as a percent of voltage change).

Demonstration Objectives

BPA and Energy Northwest agreed to wide ranging agenda in this Demonstration, unique nationally in scope and aims. At the highest level, BPA sought to test a demand-side aggregation model for the purposes of acquiring third party balancing resources to support the integration of wind in the Pacific Northwest.   Energy Northwest sought to create a large scale DR resource by "public power for public power" serving as a not-for-profit Aggregator.

To support these goals, the following objectives were laid out:

- Use of an aggregator to recruit loads. Test a model of an aggregator working with utilities to recruit end-customers to participate. The Pacific Northwest is one of the few places in the nation where demand-side resources are acquired through a multi-level recruitment approach.   Further, the demonstration sought to aggregate smaller regional assets normally too constrained to serve in any grid balancing role within an effective DR Resource.

- Asset diversity. Test a variety of distributed energy resources including but not limited to traditional load reduction in the commercial, industrial, and residential sectors. As such, the demonstration also included Dispatchable Voltage Regulation (DVR) and a Battery Energy Storage System.
- Meter Strategy. Test strategies for baselining and measuring the kW delivered via direct load control, battery storage (discharge during events), DVR and electric water heaters (later removed from scope).
- Systems. Design and develop an integrated system to send dispatch events from BPA to Energy Northwest to end-loads, and receive back real-time data of event performance in the BPA Power Operations room.
- Integration into BPA Operations. Train and build comfort with BPA staff in Power and Transmission Operations in using, monitoring and triggering events for a non-federal, non-hydro resource.
- Settlement. Build an efficient process to settle monthly payments to Energy Northwest based on participating MW capacity, penalties for non-performance, and reductions for outages.
- Reliability. Demonstrate the performance rate (# of successful events / # of total events called) of the aggregated assets in meeting events calls that simulate system balancing needs.
- Transition Plan. Define the conditions under which BPA and Energy Northwest could transition to an on-going commercial DR relationship after the conclusion of this proposed Project.
- Coordination across balancing areas. In the spring of 2015, Energy Northwest approached BPA with adding an asset (Ponderay Newsprint) served by a BPA preference customer but outside of the BPA Balancing Authority. Ponderay was added to the demonstration, and this allowed BPA and Energy Northwest to test how to coordinate across balancing authorities and to test tagging procedures to ensure reductions appear on the BPA system.

Project Design and Implementation

Load Response Asset Overview

The City of Richland installed an RAI SCADA Nexus gateway at each of its 10 substations. The substation-installed hardware consisted of a weatherproof enclosure which was mounted on the side of the LTC which included: SCADA Nexus Gateway, DL05 Power Line Carrier (PLC), Cell Modem, Interposing control relays, power supply to accept 120 VAC and fused DC power distribution board, AC breaker, terminal blocks and wiring diagram to connection to up to three LTCs in the substation. The PLC output used a dry contact signal through the interposing relays to each LTC to run in Voltage Reduction Mode. There were ten enclosures, one for each City of Richland substation.

The DataCatcher (SCADA Nexus Cloud Server Application) was installed on a cloud-based server and configured to communicate with the following: (1) Energy Northwest DRACS server: for communicating the Demand Response status and control and reporting the real-time and/or historical data for real-time feedback and auditing purposes of the Demand Response Events. (2) City of Richland Metering System FTP Server: for communicating the current and near past metering values on a one-minute basis for voltage and power values to provide feedback that the system is operational when called upon. (3) SCADA Nexus Gateway devices transmitted current/changed values back to the Central Data server using “push” or “pitch” technology over an SSL secured connection. (4) City of Richland users and system administrators had a web interface based upon the user’s credentials and role. Each user that was authorized for any given task was able to view dashboards which consisted of single line diagrams or other views to show the current system status including Demand Response status, historical charts, alarm limit checking and notifications via email and text messaging.

NORPAC installed both a secure hosted firmware-based gateway to replace the functionality of an old style masters and secure hardware-based energy management system for installation in the field near the ION meters in the motor control center. Both gateways had functionality for interfacing to the various meters within the plant operations using both industry standard and custom protocols. The hardware gateway pitched data from the data site to RAI’s SCADA Nexus Cloud Server using industry-standards-based, NERC secure, and NIST interoperability compliant Web-based Client/Server communication methods. The gateway polled for load data from a remote location next to the meter. NORPAC personnel had access rights to the SCADA using login and password security.

PNC installed a single gateway which replaced the functionality of a previous style, using a TCP/IP Modbus. The hardware gateway pitched data from the data site to RAI’s SCADA Nexus Cloud Server using IEEE Standards-based, NERC secure, and NIST interoperability compliant Web-based Clint/Server communication methods. The gateway polled for PNC PLC data from a remote location next to the IED/PLS/Meter. The gateway also wrote to the specified PLC memory to command the DRACS initiated DR event. All metering and IED SCADA status and analog data was available as web pages served from a cloud-based SCADA Nexus Cloud Server. PNC personnel had accessed the SCADA using login and password security.

A gateway and DataCatcher were installed on Powin’s SCADA Nexus site. The MODBUS “poller” defined messages and tags were configured. All required users and logins for the SCADA nexus Cloud Server were installed. Dashboards on the SCADA nexus Cloud Server were built based upon available data from the MODBUS map. The DRACS Dispatchable resource was developed. A “State Machine” was developed for Powin within the SCADA Nexus DataCatcher to allow dispatch during the Demand Response events. This application was controlled by the DRACS server hosted at PNNL.

BPA Systems

BPA System Description: BPA partnered with AutoGrid to utilize their Demand Response Optimization Management System (DROMS) for management of their demand response programs and products.

- Communications: DROMS communicates with EN's DRAC's via OpenADR2.0b. The integration allows for event signaling, 1 minute interval reporting, and outage scheduling. DROMS manages product availability and shows available products to BPA operators on a dashboard. Operators can dispatch or modify already scheduled events directly from the dashboard.

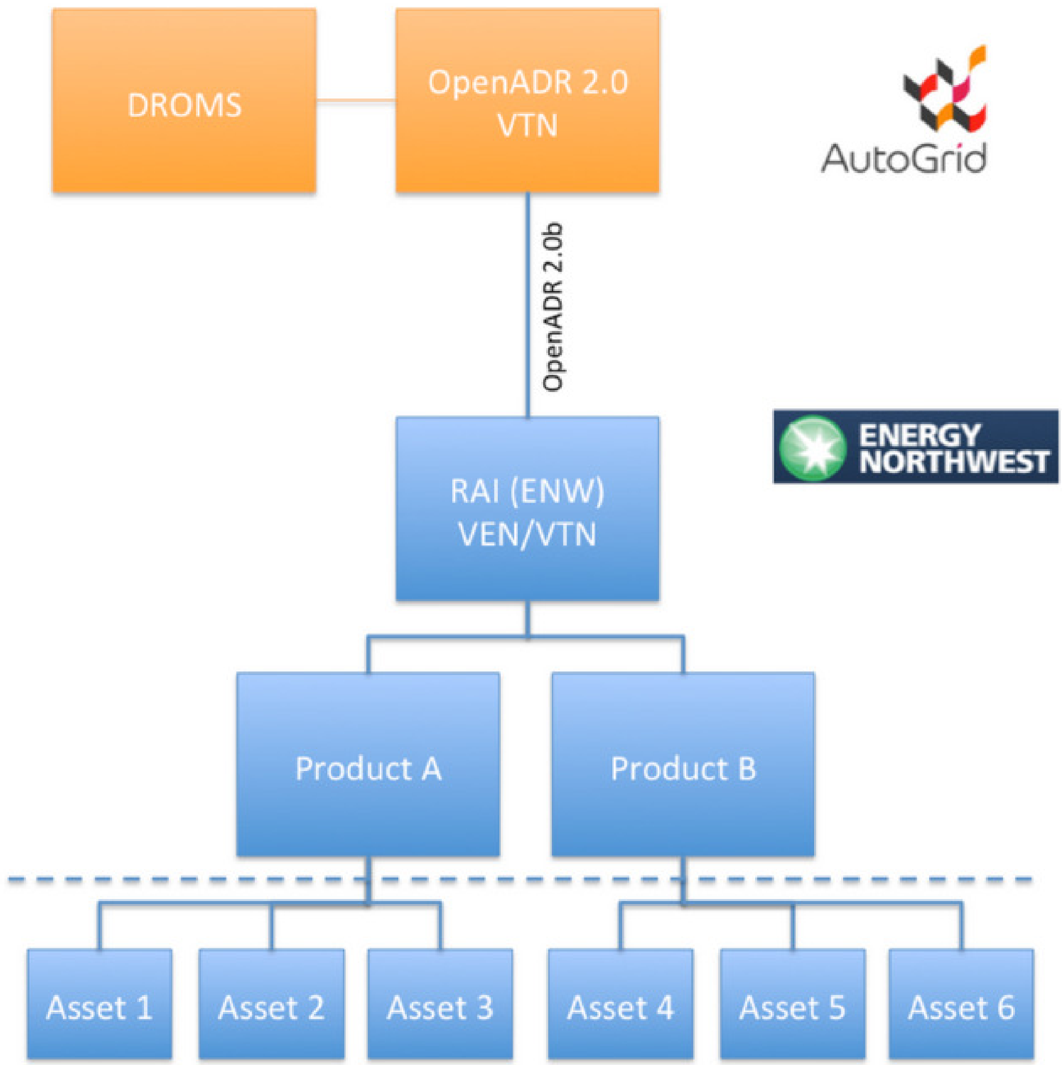
- Reporting: During an event, operators are able to view performance in near real time. DRACS's sends load shed totals using OpenADR's EiReport payload. These intervals are then displayed on the AutoGrid dashboard.

- Product Management: DROMS allows for creation of products and manages availability of the product based on constraints such as number of events allowed per week, and days of the week.

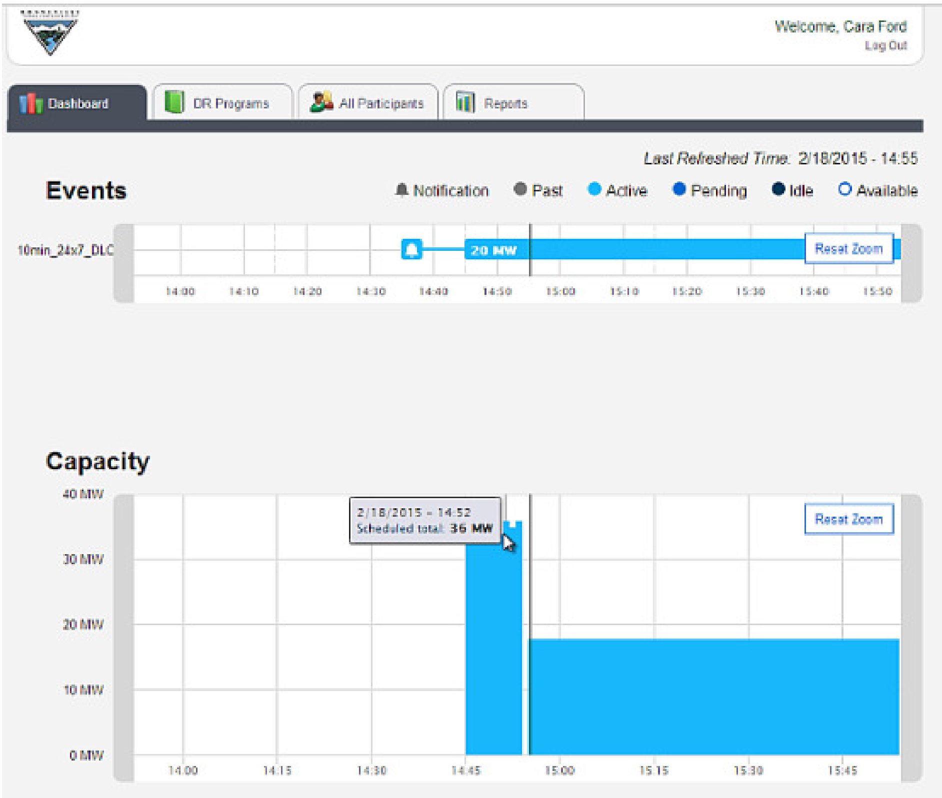
- Product Outages: EN DRACS was able to send maintenance and outage windows to DROMS via OpenADR. During those windows the product was unavailable to operators for dispatch.

- Event Scheduling: DROMS enabled BPA operations the flexibility to schedule events ahead of time or enter them in real time.

System Architecture Diagram:



AutoGrid Operator Dashboard:



Demand Response Aggregated Control System (DRACS)

Energy Northwest contracted with Resource Associates International (RAI) to develop the Demand Response Aggregated Control System (DRACS) which is a comprehensive data gathering, monitoring, control and communications infrastructure. Communication devices are installed by participating utilities to report to and receive direction from the DRACS via secure cloud-based data paths. DRACS is hosted within Pacific Northwest National Laboratory's Electricity Infrastructure Operations Center, a DOE-funded incubator facility built and operated for such roles.

Event Signaling

Event initiation by BPA operations action: Energy Northwest receives signals from BPA's DROMS system via OpenADR2.0b. Upon receipt of the signal, DRACS acknowledges and forwards the signal to multiple demand response assets. Upon receipt of the forwarded signal, each asset begins to reduce its loads. The load changes must be complete within 10 minutes and sustained through the event, up to 90 minutes in duration.

Reporting

During events, DRACS collects detailed metering information from each of the assets and reports total capacity response to BPA. Once an event ends, DRACS sends terminating signals to the Assets which can then resume normal operations.

Upon event termination, DRACS made available CSV files for each asset's performance. The data was collected as average one minute load reductions, measured in kilowatts. Each asset's performance was recorded in a time frame beginning 30 minutes prior to event through 30 minutes after event termination, regardless of event duration. For each event, a data file was produced for each asset in addition to a data file produced for each dispatch group. A log file was also produced, which recorded the date and time of each log event which occurred during the time of the event.

DRACS allowed access for each registered user to not only download settlement data, which was applied to templates to measure asset performance during each event, but also allowed users to download "raw data" for each event. The raw data report would be produced in CSV format, and would allow a 3 hour maximum of the "raw" data. The raw data file contains every read for every device that makes up each asset. The included raw data file has the following columns:

- Gateway Timestamp – this is the actual time when the data was captured in the field.
- Client DC Timestamp – This is the time when the data arrived at the client DataCatcher.
- DRACS Timestamp – This is the time when the data arrived at the DRACS
- Measurable – This is the description or label of the data point being measure. For example, kW_tot, or Vin_avg
- Value – Actual data point value.

The assets (end loads) have access in DRACS to the same settlement interface that Energy Northwest and BPA use, but it is filtered to only allow the asset to see data for their specific assets. They are also able to see a summary of the events and assets for their dispatch group.

Measurement & Verification Approach

Baseline Methodology by Asset Type

Direct Load Control – The original contract language for the baseline for Direct Load Control loads was calculated as the metered power (kW) averaged over the 30 minutes prior to the time of Event notification. Capacity delivered on a minute by minute basis was calculated as the difference between the Event Baseline and each one minute average power (kW) measured during the Event. This "meter before/meter after" baseline method can be challenging to apply (in order to produce an equitable delivered capacity) when a participant is in the process of ramping demand up or down just prior to the demand response Event dispatch. BPA and EN explored using a different baseline. Effective April 2015, BPA and EN agreed to use a 5 minute average kW prior to Event notification.

Demand Voltage Reduction - Capacity delivered on a minute by minute basis from demand voltage reduction is the product of measured load (kW), the % change in voltage for that minute (expressed as a fractional change), and a deemed demand voltage reduction (DVR) load response factor of 0.5 (%kW /% voltage change). The % voltage change for each minute of an Event was calculated as the difference between the voltage set point one minute prior to the start of the DR event and the voltage set point for the particular minute within an Event. It is anticipated that the voltage set point may change within an Event. During the initial months of the demonstration a DVR load response factor of 0.5 was used. Data from the initial months was analyzed and BPA determined than the DVR load response factor should be increased to 0.75 to more accurately reflect the actual load reduction provided by DVR. The change in DVR factor was effective April 2015.

Battery Energy Storage System (BESS) - The battery energy storage system from Powin provides a unique set of conditions because a BESS is capable of consuming kW from the grid like a traditional load, operating at a neutral state without net in/out flow of kW to the grid, and delivering kW to the grid like a generator. If the BESS is receiving power from the grid when the Event notification occurs, the actual load reduction is the difference between the metered demand during charging and the metered output to the grid. If the BESS is in a neutral state the actual load reduction is measured as the kW discharged back to the grid. If the BESS is discharging kW to the grid when the Event is dispatched the load reduction is the difference between the incremental kW discharged back to the grid during the demand response Event and the kW discharged to the grid prior to the demand response Event.

Outages, Timelines, and Outage Penalties

The EN-BPA Demonstration Agreement included an outage notification requirement. EN outage notifications delivered 48 hours in advance of the outage reduced EN's exposure to unsuccessful event penalties. The Outage penalty was 1/31 of the monthly capacity payment for each 24 hour period of the outage. The Unsuccessful event penalty was 1/6 of the monthly capacity payment. The structure encouraged EN to accurately report outages instead of taking a chance that an event would be dispatched when the participating facility was unable to respond. This provision has some challenges as EN often does not receive 48 hours advance notice of the outage from the participating facility. During some time periods when outages occurred in the project there was an unexpected malfunction in the production equipment at the participating facility. This provision did not provide any incentive or relief for EN when the outage notice was provided with less than 48-hours advance notice. An alternative to this provision may be to use two different time horizons and penalty rates, for example an outage with 25 hours advance notice would result in a penalty of 1/31 of the monthly capacity payment and an outage with less than 24 hours' notice results in a penalty of 1/15 of the monthly capacity payment. Unsuccessful event penalties for future agreements will be tied to the number of load drops allowed per month and other deployment limitations.

Settlement Process

The settlement process and reporting and invoicing document templates were developed over the course of November 2014 through January 2015 in collaboration with, and ultimately accepted by, BPA.

As events occurred over a month, EN staff prepared an event-specific document set consisting of: (1) graphical & numeric summaries for the Dispatch Group and each contributing load asset and (2) the 1-minute data tables generated by DRACS supporting those summaries. EN elected to provide those summaries to BPA and load assets within, generally, 1-2 working days after the event. The summary documents for all contract events are provided as Appendix A.

At the end of each month, EN assembled the event summaries and data tables for the month's events, documentation detailing outages, prepared a combined invoice summary, and provided to BPA by the 5th working day of the subsequent month.

BPA staff reviewed the invoice package, worked collaboratively with EN staff to resolve questions and needed clarifications, and approved the invoice generally by about the 12th day of the subsequent month. Payment was made by BPA to EN by the 20th day.

Once BPA had indicated its acceptance of a month's invoice, EN staff prepared a similar document set for each of its participant assets and paid out incentives by the 28th day.

Performance Results

Background - When first placed in service mid-January 2015, the DRACS documented all events it had initiated. The Demonstration was placed into service at 00:00am February 9, 2015, with 48 events having been "called" in the course of DRACS and DROMS system development and functional demonstrations. The first event called under the contract was 1502-049 on February 10th. Note event numbering convention follows: "1502" indicating year 2015 and February, the 2nd month. Through the project's termination, 85 events were called on the Demonstration for contractual purposes ending with event 1601-141 on January 31, 2016. The 7 "missing" events (056, 060-064, & 118) were expended in testing and other non-contract performance activity.

Successful Events - 80 Demonstration events were contractually successful, yielding an overall success performance rate of 94.1%.

Unsuccessful Events - Five Demonstration events were unsuccessful for contract performance purposes:

- June 28, 2015 – DG-A event 1506-083 failed due to contingency shutdown conditions of an industrial load asset (NORPAC).
- June 29, 2015 – DG-A event 1506-084 failed due to DRACS not fully resetting after a canceled June 28th outage.
- July 17, 2015 – DG-B event 1507-089 failed due to contingency shutdown conditions of an industrial load asset (PNC).
- December 9, 2015 – DG-A event 1512-131 failed due to an operator error in applying established operating practices at an industrial load asset. (NORPAC)
- December 17, 2015 – DG-A event 1507-133 failed due to contingency shutdown conditions of an industrial load asset. (NORPAC)

Event 1502-053 on February 26, 2015, was initially measured as unsuccessful but EN and BPA subsequently agreed the event was successful. This event demonstrated a learning (discussed in more detail Paragraph 3.4 of this report) regarding use of baselines for industrial loads prone to rapid ramping.

Load Change Response Performance

- The Demonstration assets achieved sustained required capacity response typically in less than 5 minutes from minute 00 notification. Table 1 summarizes response by minutes taken to achieve sustained required load reduction:

	Response Time (Minutes)									
Dispatch Group	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**>10**
A	2	12	26	12	5	4	2	0	1	4
B	0	0	0	4	10	2	0	0	0	0

Table 1, Event Response Times

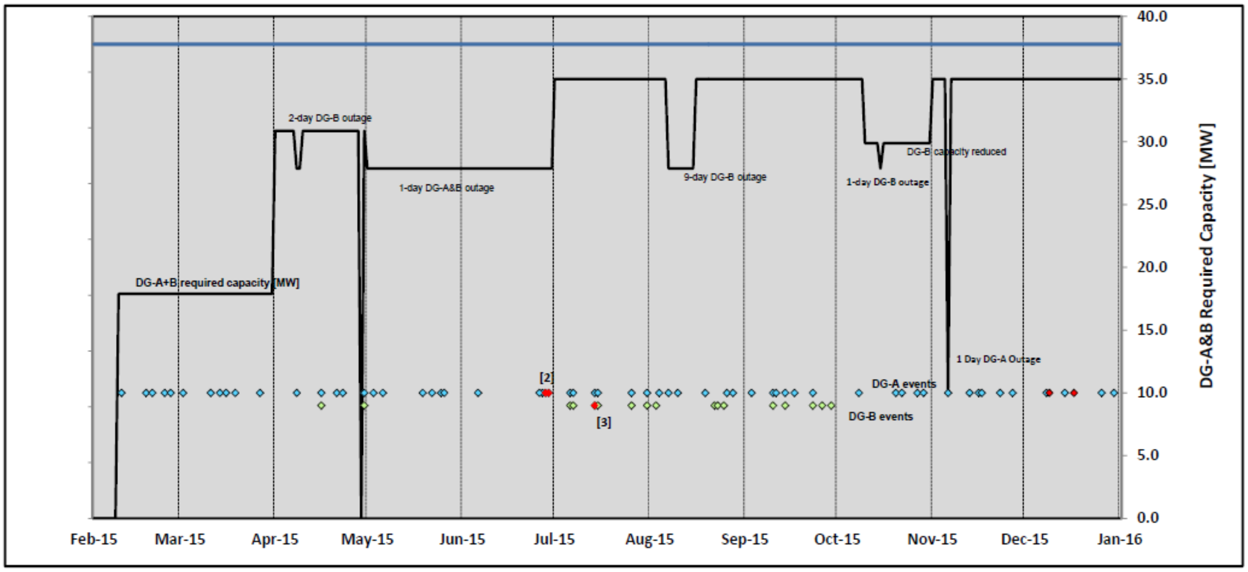
- The 85 contractual events are listed in Figure 1. The 5 unsuccessful events are highlighted in bold red font.

Figure 1 – Demonstration Event List

DG	event		notification	duration
			[mm/dd hh:mm]	[minutes]
A	1502	049	02/10 10:04	90
A	1502	050	02/18 14:34	90
A	1502	051	02/20 11:16	33
A	1502	052	02/24 07:10	85
A	1502	053	02/26 19:04	26
A	1503	054	03/02 02:13	47
A	1503	055	03/11 15:32	73
A	1503	057	03/14 10:07	90
A	1503	058	03/16 17:22	50
A	1503	059	03/19 10:26	83
A	1503	065	03/27 06:14	65
A	1504	067	04/08 09:23	86
B	1504	068	04/16 09:04	45
A	1504	069	04/16 09:04	55
A	1504	070	04/21 12:04	75
A	1504	071	04/23 12:19	90
A	1504	072	04/30 11:34	90
B	1504	073	04/30 11:34	90
A	1505	074	05/03 07:10	39
A	1505	075	05/06 03:38	71
A	1505	076	05/19 00:28	82
A	1505	077	05/22 17:07	80
A	1505	078	05/25 05:09	90
A	1505	079	05/26 09:45	33
A	1506	080	06/06 17:09	52
A	1506	081	06/26 02:10	60
A	1506	082	06/27 03:24	50
A	**1506**	**083**	**06/28 04:29**	**45**
A	**1506**	**084**	**06/29 16:41**	**0**
A	1507	085	07/06 15:49	90
B	1507	086	07/06 15:49	90
A	1507	087	07/07 17:34	90
B	1507	088	07/07 17:34	90
B	**1507**	**089**	**07/14 12:59**	**90**
A	1507	090	07/14 12:59	90
A	1507	091	07/15 02:44	90
B	1507	092	07/15 02:44	90
B	1507	093	07/26 16:49	90
A	1507	094	07/26 16:49	90
B	1507	095	07/31 03:49	90
A	1507	096	07/31 03:49	90
B	1508	097	08/03 16:49	90
A	1508	098	08/04 13:09	90

DG	event		notification	duration
			[mm/dd hh:mm]	[minutes]
A	1508	099	08/07 10:59	90
A	1508	100	08/10 12:09	90
A	1508	101	08/19 13:09	90
B	1508	102	08/22 16:19	90
B	1508	103	08/23 17:49	90
B	1508	104	08/25 15:49	90
A	1508	105	08/26 15:09	90
A	1508	106	08/28 11:19	90
A	1509	107	09/03 10:19	90
B	1509	108	09/10 21:19	90
A	1509	109	09/10 13:19	90
A	1509	110	09/11 15:19	90
B	1509	111	09/14 07:49	4
A	1509	112	09/14 07:49	90
A	1509	113	09/17 17:11	90
B	1509	114	09/23 08:19	90
A	1509	115	09/23 08:19	90
B	1509	116	09/26 07:19	90
B	1509	117	09/29 09:34	90
A	1510	119	10/08 15:00	90
A	1510	120	10/20 13:59	90
A	1510	121	10/22 10:04	90
A	1510	122	10/27 08:04	90
A	1510	123	10/29 15:49	90
A	1511	124	11/06 06:20	90
A	1511	125	11/13 21:24	90
A	1511	126	11/16 11:19	90
A	1511	127	11/17 15:49	90
A	1511	128	11/23 14:49	90
A	1511	129	11/27 07:49	90
A	1512	130	12/08 06:49	90
A	**1512**	**131**	**12/09 16:49**	**90**
A	1512	132	12/14 23:49	90
A	**1512**	**133**	**12/17 11:49**	**90**
A	1512	134	12/26 16:49	90
A	1512	135	12/30 15:49	90
A	1601	136	01/06 16:49	90
A	1601	137	01/12 16:49	90
A	1601	138	01/18 01:49	90
A	1601	139	01/22 07:49	90
A	1601	140	01/25 20:49	90
A	1601	141	01/29 17:49	90

Another graphical presentation of the Demonstration events and required capacity is provided as Figure 2.



Monthly		Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Totals to-date	Score [5] [6]
Tot. Avg. Required Capacity [MW]		17.88	17.88	29.65	27.88	27.88	35.00	32.93	35.00	32.43	34.17	35.00	35.00		
DG-A	No. Events	5	6	5	6	5	6	6	6	5	6	6	6	68	94.1%
	No. Event Fails					2						2		4	
	No. Outage Days			1							1			2	99.1%
DG-B	No. Events			2			6	4	5					17	94.1%
	No. Event Fails						1							1	
	No. Outage Days			3				9		1				13	89.3%

Notes

Note 1 - $243k actual margin at 1/31/2016

Note 2 - (2) DG-A fails: 6/28-norpac forced outage; 6/29-dracs failed to functionally reset

Note 3 - (1) DG-B fail: 7/14-pnc forced outage

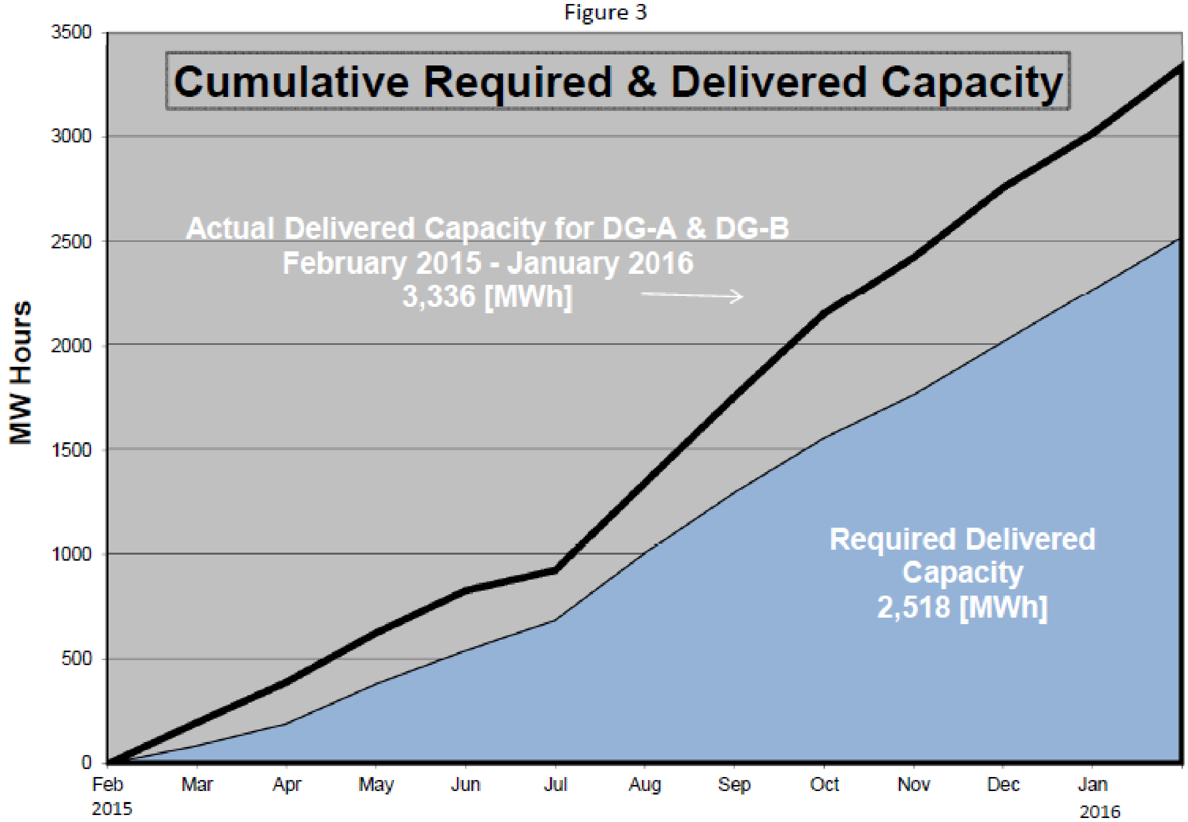
Note 4 - capacity limits: pnc:16MW (apr 3MW, may-jun 0MW, jul-aug 12MW, oct 10->2 MW); norpac 27MW; cor: 0.85MW; powin 0.03MW

Note 5 - Reliability=1-fails/all events, Availability=1-outage days/contracted days

Note 6 - norpac forced outage jun 27, notified but not counted as unable to meet notification timing requirements; norpac outage 12/22-23 exempt from outage deductions due to weather

A graphic showing cumulative energy contributed, contracted and actual is provided as Figure 3.

Figure 3



Scheduled Outages/Availability

The Demonstration Agreement provided for EN to call scheduled outages on a minimum 48 hours notice, delivered by OpenADR signal via DRACS and DROMS. A return to service from outage required minimum 24 hour notice, also by OpenADR signal.

For purposes of contractual performance, DG-A declared an outage on 1 day of the 356 in-service days for an availability of 99.7%. A number of additional forced outages occurred attributable to BPA regional system disruptions, forced outages at NORPAC that would have precluded DG-A performance but occurred within 24 hours of a prior event (contractual "recovery" period when further events may not be called), and in one case a NORPAC forced outage too short to have called for an outage but no event was called. Even if all the above exceptional circumstances were counted, DG-A availability exceeded 97%.

For contractual purposes, declared DG-B outages totaled 13 days of 163 in-service days for an availability of 92%.

With advance notice by EN to BPA, the Demonstration Agreement provided for a single 2-hour outage per calendar month to accommodate routine installation of security patches at the PNNL

EIOC servers hosting the DRACS. In practice, these patches never resulted in the DRACS unavailability but were provided for as a precaution.

Load Asset Performance

City of Richland DVR – City of Richland's performance rate was 97%, successfully responding to 66 out of 68 events.

Event 1502-059 was unsuccessful on March 19th due to three transformers in two substations having been taken off-line for troubleshooting. This resulted in 742 kW of 850 kW delivered.

Event 1512-135 was unsuccessful on 12/30. It was determined the regional transmission system, supplying City of Richland, likely experienced a short-duration voltage spike which in turn was interpreted by the DRACS as a reduction in load response. The spike appeared near simultaneously across all monitored voltage points (over 60) with no corresponding voltage control change signals, thus no reduction in response occurred. This incident resulted in a lesson learned for future implementation of DVR-based demand response assets.

Cowlitz PUD/NORPAC – Cowlitz PUD and NORPAC's performance rate was 95.59%, successfully responding to 65 out of 68 events.

Event 1506-083 was called on June 28th, and was unsuccessful. The waste water treatment facility that serves Weyerhaeuser's Longview WA complex, which hosts the NORPAC facility, incurred a contingency condition Saturday, 6/26, which limited its processing through put capacity. Initial assessments by Weyerhaeuser site staff determined NORPAC would not be impacted. As matters developed, however, NORPAC was asked to shut down just after midnight on Sunday morning in order to preclude Weyerhaeuser from exceeding its waste water discharge permit standards. As a result, when the event was called several hours later, NORPAC did not respond, not having any dispatchable load available, and thus the Demonstration failed the event.

Event 1512-131 failed due to NORPAC not achieving its obligated 27,880 kW capacity in the 10-minute ramp. Post-event findings indicated the crew was not clear of expected actions, and secured only 3 of the 9 operating refiner lines to respond to the event signal. Remarkably, this is arguably the only instance in the Demonstration where human actions or inactions, caused an unsuccessful event.

Event 1512-133 was called on 12/17, and failed due to NORPAC having shut down earlier in the morning to repair a steam leak that had developed overnight. The repair required all 9 refiner lines to temporarily shut down.

Pend Oreille PUD/PNC – Pend Oreille PUD and Ponderay Newsprint's performance rate was 94.12%, successfully responding to 16 out of 17 events.

Event 1507-089 was called on July 14 at 13:30. Ponderay happened to be engaged in operations recovery, ramping up, so its load increased rather than decreased from 13:10 – 13:14, which contributed to the combined loads of Dispatch Groups A and B to fall below 35,000 kW during these minutes.

Powin Energy – Powin Energy's performance rate was 70.59%, responding successfully to 48 out of 68 events.

Powin's unsuccessful events were caused primarily by communication challenges on Powin's side of the interface which were resolved as they were identified. None of its failed events contributed to any failures to Dispatch Group A.

Energy Northwest Lessons Learned

Utility Engagement

Responding, in part, to feedback from multiple public utilities' experience in demand side programs elsewhere, the EN Team committed to a firm policy of engaging a prospective load's hosting utility. This policy came to be very strongly recognized and supported by regional public utilities. Some further aspects:

- Recruiting of loads for demand side programs within a non-balancing authority host utility introduces potentially disruptive influences to that utility's system management. It can be particularly adverse when the utility is not a participant to the transaction.
- A further concern identified was the utilities' observation that the most cost-effective load prospects available among a host utility's customers were targeted for the demand side programs. Should a utility subsequently find itself in need of demand side resources those customers, having committed to other transactions or having made investment in communications/control infrastructure, are less available for the utility's own programs.
- Demand side programs are very much in use elsewhere in the US. Many regional commercial and industrial utility customers participate, at a corporate level, in other markets and thus can be very familiar with the practice. The incremental revenues earned as incentives can contribute favorably to the bottom line. Host utilities, having no need for demand side resources themselves, saw this Demonstration as an opportunity to meet their customers' interest while ensuring them a positive role in the transaction. Again, this was a source of strong interest in and support for the Demonstration.

DRACS Development & Deployment

The DRACS was absolutely key to the Demonstration's functionality and operability and performed very well throughout the course of the Demonstration. Some aspects might have been improved however if circumstances had allowed.

- A more timely articulation of BPA's requirements, specifications, and expectations for the Demonstration's communications, control, and reporting functionality, and particularly its security aspects, would have substantially facilitated the design and implementation effort.
- Alignment of EN and BPA expectations "on the fly", while more challenging than it might have been, was accomplished nonetheless on the strength of superb efforts by both BPA and EN's development teams.

- The one event fail, on June 29, 2015, attributable to mis-operation of the DRACS occurred after EN/ and RAI had undertaken to better align DRACS outage notification and management functionality with BPA's expectations. An unanticipated effect of the coding changes resulted in the DRACS indicating its readiness to respond to events when it remained in outage mode. Thus, when the subsequent event initiation signal was received from DROMS, DRACS did not timely initiate load assets' response and the event failed. The lesson learned was that any changes made to coding potentially affecting core functionality should be followed by a comprehensive full-spectrum system testing.

- Allen Bradley Device Accommodations – For both PNC and NORPAC, it was necessary to interface the on-site SCADA Nexus communications gateway to the respective facilities' Allen Bradley PLC based plant systems. Both sites required the use of a "Prosoft" card, a relatively uncommon device, to make the connection and resulted in a substantial effort to accommodate during deployment especially on the part of plant controls staff. Since then, RAI has incorporated the Allen Bradley communication protocols directly into its SCADA Nexus device, eliminating the need for the Prosoft card. Future installations should be greatly facilitated.

Outage Notification

The Demonstration Agreement provided for EN giving BPA a 48-hour minimum notification to put the Demonstration resource into outage and proved to be adequate for scheduled outages when they occurred. Forced outages though, when equipment casualties or failure of support infrastructure and services (not under direct control of the load assets) resulted in unexpected loss of the loads available for response, were not supported.

On numerous occasions through the Demonstration such forced outages occurred, were resolved, and operations restored in timeframes, and with a degree of uncertainty, that a Demonstration resource outage could not be timely implemented. EN timely communicated with BPA project and operating staffs as circumstances developed but neither could truly effectively manage the situations to either's needs.

Forced outages are an inevitable aspect of industrial loads yet the reliability requirements of meeting BPA's system operational needs must be met. Potential accommodations to address this challenge should be more completely explored for future demand side programs.

Performance Criteria & Data Retention Requirements

One-Minute Compliance – The Demonstration Agreement required that the load response required capacity be achieved each minute.

Industrial facilities are complex highly interdependent facilities. It was found by NORPAC and PNC particularly that loads could be reasonably managed against unexpected circumstances. An example of unexpected circumstances observed was a load starting up elsewhere in the facility, not directly under control of the facility process operators. The one minute compliance rule precluded a load increase from being identified and actions taken to compensate.

Alternative compliance criteria that might still meet BPA needs but provide a better opportunity to manage loads should be explored. An example might be to use a rolling 5-minute or longer load average compliance window, or to discard the highest and lowest 1-minute reads in a given period.

The one-minute criteria required the industrial load asset to be much more conservative in its load response offering in turn resulting in often significant over-response. More efficient utilization of the load asset's actual response could be beneficial to both the asset itself and the asset customer's (BPA) to rely on and thus benefit from the load response.

DVR Data Collection and Retention – The Demonstration performance criteria relied on 1-minute average load response reporting. Generating those 1-minute data points relied on data collected from field devices at 5 to 10-second intervals or less.

A Demonstration requirement was that all such "raw" data points be retained and archived. Over the course of the 12-month Demonstration over 2 billion lines of data were generated. By a substantial margin, most of that data was generated from the City of Richland's DVR installation.

Contemplating future programs, with likely multiple utility participants fielding DVR-based or other data-intensive assets, consideration should be given to keeping the raw data at the "data catcher" level, rather than at DRACS, such data can at need be retained and downloaded for verification or research purposes but would not create such a substantial data management and archiving burden.

Participant Lessons Learned

City of Richland - An often expressed concern of host utilities when contemplating demand side programs is the prospect of reducing energy sales due to the increased "downtime" of loads. For the Demonstration, it is the consensus of participating utilities that, in this case, the feared reductions did not occur. Arguably, energy sales may have increased at some nominal level. By load asset type:

- Demand Voltage Response (DVR) Load Loss – City of Richland observed indications that, subsequent to an event's 90-minute duration load reduction, a load recovery period occurred. While not confirmed, it seems reasonable that some resistive customer loads, such as space heating which voltage reduction most effectively impact, tend to shift in time rather than be displaced. This would not be true of, for example, lighting loads but overall, the observation is DVR seems to have minimal to no impact on overall energy sales for City of Richland.

- DVR Impacts on Service Quality – In implementing its DVR program, incremental voltage reductions were set at 2.5% for 13 of its 15 LTCs. On two LTCs which served loads potentially more sensitive to voltage fluctuations, the voltage change increment was set at 1.5%. During the Demonstration run City of Richland received no customer complaints regarding power quality that might be attributed to DVR operations.

Cowlitz PUD/NORPAC – They were verifiably one of the more successful load asset participants in the Demonstration, consistently performing at a high level in both reliability and in large scale response. NORPAC shut down two of its “TMP Mill” refining lines, each with four 5,000 to 6,000 hp electric motors, plus associated support system loads. NORPAC relies on close coordination of its nine refining lines to supply a steady supply of suitably graded cellulose fiber in support of its three on-site paper manufacturing machines. To fulfil its paper customers’ needs, the operation is intended to operate 24/7 year-round with minimal plant-wide outages for maintenance. Refiner lines are removed from and placed in service routinely as changes in feedstock wood species, fiber grade, and paper production schedules occur.

- Routine refiner shut downs and subsequent restarts are accomplished in as little as three to five minutes, with minimal operational impacts. A forced refiner shutdown, as occurred on December 23, 2015, precipitated by weather-related disruptions in BPA’s regional grid, require a much more convoluted refiner start up, under some conditions taking days to fully recover.

- NORPAC found itself initially able to readily accommodate the further disruption caused by the Demonstration’s 90-minute maximum duration events, relying on the 24-hour event recovery period and its normal practices to ensure continuity in its operations and product quality control. As the Demonstration progressed and NORPAC’s order book improved, operational margins narrowed and NORPAC found itself at times in circumstances that one additional disruption just before or after an event had potential to adversely impact its production. Detailed discussion with NORPAC management and operations staff indicated several encouraging means by which the concerns might be effectively addressed should NORPAC be afforded the opportunity to continue in future demand side programs.

BPA Lessons Learned

Contracting

As stated earlier, the contract between BPA and Energy Northwest was very specific as to the terms of the Demonstration. While it took a significant time investment to lay out each portion of the Demonstration, BPA and EN found that this process ensured strong design, including the metering plan by participants, clear performance criteria, system requirements, information security and event parameters. When the 12 month event phase started, BPA and EN found that the team was well prepared to execute.

Nonetheless, issues arose during event testing – e.g. how to measure accurately measure dispatchable voltage regulation, whether a thirty minutes prior baseline methodology was suitable for a ten minute notification product, how to add an asset that required a separate pre-scheduled process. EN and BPA took a flexible approach to making contract modifications, in the spirit of a learning demonstration, throughout the Demonstration to accommodate these issues. This proved effective for all parties.

Operations

1. DR Operations Lead designated: Designating and having a member of the operations team working closely with the project team through design, implementation, and testing was critical to BPA's operational engagement and success.

2. Processes: Clearly defining dispatch processes including all touch points and approvals with the operations and management teams was important as well as documenting the process and updating as needed.

3. Training: Operations staff work hours made a traditional group training approach ineffective. The DR Operations Lead coordinated individual trainings for staff, ensuring each dispatcher was trained before testing began. During early testing the DR Operations Lead was present during event scheduling and dispatch to support operators. As operators became more comfortable with the system and product they transitioned from pre-scheduled events to events triggered based on system conditions.

Systems

1. Vendor Collaboration: Having a project kickoff and in person testing systems with BPA, EN, EN's system technology partner RAI, and AutoGrid was a key element in system implementation and integration successes. They were able to build rapport that allowed them to tackle challenges as a team. During onsite testing vendors were able to fix bugs in real time and retest, saving repetitive testing cycles.

2. Virtual Private Network (VPN): Installation of the VPN and subsequent stability of the VPN was challenging and took some time to figure out across all involved including the Amazon cloud vendor, AutoGrid, EN, RAI, PNNL, and BPA IT resources. We learned that having a backup VPN enabled and a working IP Service Level Agreement monitor resulted in stability. We learned this by pushing the vendors and engaging the right networking resources at BPA. There are maintenance windows for all involved which impacted the ability to make rapid changes and they should be considered in the future.

3. User collaboration: The early involvement of schedulers and scheduling technical support led to great success in user interface requirements and the end product. Because of those efforts the system met users' expectations and has been well adopted.

4. Software Customizations: BPA limited customizations and AutoGrid was able to integrate a majority of our requirements that were new for them into their base product. No code is being maintained especially for BPA.

Go Live Process

The team was concerned about entering into the event demonstration phase with incentive payments and not having criteria defined. As such, a formal set of criteria was set (see below) and entrance into test events would not be contemplated until the conditions were satisfied and signed off by project leaders from BPA and Energy Northwest.

Go Live Entrance Criteria
1. Contracting: • EN and BPA contract is fully executed. Contracts are fully executed with utilities and/or end loads that will be participating in the EN Demonstration Phase I.
2. **EN Communication Event Ready**. • EN to confirm DRACS is enabled for two way communications. All OpenADR 2.0b services implemented are validated as passing using the QualityLogic testing harness.
3. **BPA Duty Scheduling personnel training.** • BPA has trained power schedulers in the Duty Scheduling Center (DSC) on the objectives of the Demonstration, the pre-event process, and how to execute events end-to-end.
4. **Successful Integration with BPA DRMS Test.** • BPA and EN will conduct two successful system integration tests. These tests will necessitate load movement of a non-deemed resource to verify the ability to send back meter data using EiReport. See Interop testing plan.
5. Settlement. • Measurement and settlement worksheets will be produced and reviewed (by each party) to agree on calculations and methodology. These will be the production templates to be used after the go live date. Will include an Event-by-Event summary details, and supporting graphs to show performance for each asset.
6. **Successful End-to-end Test Runs, including Communications, Load Movement and Measurement and Verification.** BPA and EN will conduct a dry run test (communications, load movement, and measurement and verification), tests to include all loads for Day One go-live. **a) Communications.** a. The BPA Demand Response Management System (DRMS) accurately communicates event requests to the Energy Northwest DRACS. b. EN DRACS accurately accepts and acts on DRMS-originated event request. The Energy Northwest DRACS provides two-way communication between the loads responding to Events under this contract and BPA's DRMS. c. The Energy Northwest DRACS is able to ingest BPA's event requests, communicate to end loads, and provide back to BPA the defined event data. **b) Load movement.** a. Loads move as requested from the BPA DRMS within the ramping period (10 minutes) for each of the three participating loads. b. Loads move to the degree (kW) agreed with Energy Northwest prior to the dry run. **c) Data and Settlement.** a. The DRACS provides a central repository for all data associated with response to events. Energy Northwest provide a CSV-formatted data file with complete and accurate raw data as defined above for the period 700am

Go Live Entrance Criteria
through 1250pm on February 3rd. b. Energy Northwest provides BPA with a settlement package (settlement and worksheet file) in the pre-agreed template with accurate data for the dry-run event.
7. **Final Go-Live Meeting.** • Final check-off from stakeholder list that we are ready to enter payment phase. • Formal sign-off authorized by project leads from BPA and Energy Northwest:

Communications

The team held regular project calls (weekly, then bi-weekly) throughout the design, implementation and event testing phases of the Demonstration. These calls were critical to work through issues quickly and included representatives of BPA, AutoGrid, Energy Northwest, and RAI.

Slice Customer Billing and Scheduling

As a BPA Slice customer, Cowlitz is required to submit both energy and transmission schedules to BPA no later than 30 minutes before the hour. Once those schedules are submitted they may not be changed. For each monthly bill, after-the-fact accounting is done to quantify just how accurate those schedules were. For actual loads that run higher than their scheduled load, Slice customers are charged an indexed rate for any additional energy taken for that hour. For actual loads that run lower than their scheduled load, Slice customers are credited an indexed rate for any energy that was scheduled but not taken. These charges/credits are subject to varying indexed rates depending upon how large the variance was from what was scheduled. Below is a summary of those "bands" used under their BPA contract.

Band 1 – the greater of 1.5% of load or 2 MW whichever is larger – this is settled using physical energy

Band 2 - between band 1 and 7.5% of load or 10 MW whichever is larger – this is settled as paying the Slicer 90% of index for any energy scheduled but NOT taken or charging the Slicer 110% of index for any energy taken which wasn't scheduled.

Band 3 – Greater than band 2 - this is settled as paying the Slicer 75% of index for any energy scheduled but NOT taken or charging the Slicer 125% of index for any energy taken which wasn't scheduled.

A review of the Energy Imbalance (EI) worksheets for Cowlitz show that they almost never go into Band 3 with their hourly scheduling variances.

The Issue

Under the Demonstration, Energy Northwest was asking Cowlitz to drop load within the hour after their schedules were submitted. This created a situation where energy imbalance credits resulted for Cowlitz as a result of BPAs request to drop load. This means that if BPA paid them for the energy not taken when they deployed, then BPA would in essence be paying them twice for responding to BPAs request to drop load.

Solution

Our solution was to simply leave the charges/credits as they occur including the load reductions that resulted from BPA deployment requests for the Demonstration. This approach resulted in Cowlitz getting a slightly higher energy credit during the periods in which they responded to load. Cowlitz's demand response, compared to their total load served by BPA, is on the order of 4.86% (roughly 29MW/597MW), so about half of their variance would be within Band 1, with the other half spilling over into Band 2. This means BPA would be paying them an energy credit at less than index for the Band 2 portion of the energy not taken (reduced). The only down side to this approach would be that BPA would in essence be paying Cowlitz for the energy not taken (either in energy credits or payment), unlike the other participants in the Demonstration who were not compensated at all. Given the relatively small amount of this credit compared to the capacity payment, it seemed reasonable for this demonstration and was by far the easiest approach to implement.

Conclusion

This demonstration provided tremendous learnings around developing, contracting, participating, utilizing and supporting a demand response aggregation model in the Pacific Northwest, and in this case, a model of how a public entity works with public power utilities to bring a wholesale service. As BPA continues to explore the use of demand response and distributed energy resources these learnings and the platforms built during this demonstration will be leveraged.

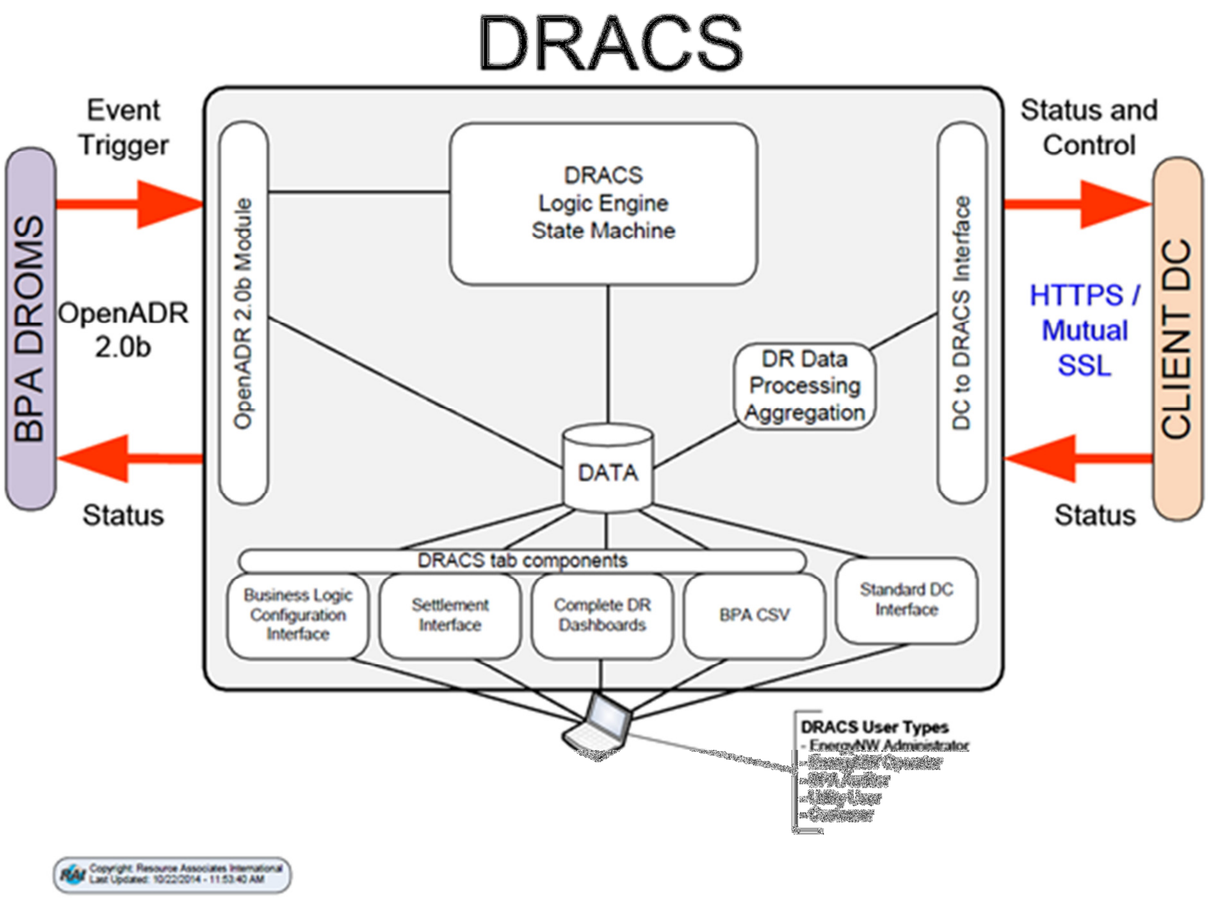
From the beginning, BPA recognized that demand response must meet several objectives to succeed at BPA: it has to be highly reliable, it has to be cost-effective, and it has to be easy to use and deploy. In each of these areas, the demonstration built a track record that shows promise for the future. Energy Northwest built a comprehensive program working with BPA to meet those objectives, as they were able to prove their ability to act as an aggregator, delivering an automated, highly reliable, fast DR product. Both BPA and Energy Northwest were nationally recognized for their efforts around this very successful ground breaking DR project. The team was recognized nationally with the Peak Load Management Alliance Pacesetter award. Additionally, this project received great interest from across the US from various publications and news organizations. Details of the Pacesetter Award and the numerous interviews done on this project can be found in Appendix E.

BPA will continue exploring what types of DR are going to best meet current and future needs, whether it's for supplementing the federal hydro system in the supply of balancing capacity, reducing temporary transmission constraints or deferring transmission investments, meeting winter or summer peak load events, or potentially increasing consumption when wind and hydro power is generating more than the system needs.

Appendix A – Event Summaries

Appendix A-Event Summaries.pdf

Appendix B – DRACS Functional Schematic



Appendix C: Project Recognition and News

- PLMA PaceSetter Award
  - BPA - EnergyNorthwest Demand Response Projects Wins National Award
- Forbes:
  - 'Demand Response' Is How The Smart Grid Will Save Us Billions
- Greentech Media:
  - How Bonneville is Tapping Demand Response to Balance Power from Dams, Wind and Sun
- Utility Dive:
  - Why BPA sees aggregation as the future of demand response
- Yahoo Finance, Power Engineering, Street Insider, Market Wired:
  - Bonneville Power Implements Fast and Intelligent Demand Response Demonstrations With AutoGrid
- Clearing Up:
  - Demand Response Gathering Momentum (3/6/2015)
  - Council Find EE DR Best Short Term Options for Regional Capacity (6/12/15)
  - DR Deployed in Phase 3 of BPA-ENW Aggregation Pilot (11/6/15)

Appendix D – Deep Dive Data Analysis: City of Richland DVR

Introduction

Demand voltage reduction (DVR) is a demand response (DR) measure which involves reducing the substation bus voltage in order to achieve a reduction in power load (kW) for some period of time. In this project, the maximum event window was 90 minutes. Although DVR is believed to be an effective capacity reduction measure it is challenging to measure the actual kW reduction. This is because the effective load reduction is about the same as the naturally occurring minute-by-minute change in load. That is, a 100 MW substation load may be changing by 1-2 MW from one minute to the next on its own accord, which is approximately the same capacity reduction expected from 2-3% change in voltage setting.

BPA-dispatched DVR is a new DR measure for BPA, (BPA had implemented several past utility-dispatched DVR pilots, field tests, and R&D projects, going back to 1984.). Part of the motivation to accept the measure into this project was to allow the opportunity to record data on the measure and study it further. Because of this challenge and lack of recent experience with DVR, the project contractually used a constant DVR factor method to calculate capacity reduction (kW). The DVR factor is a ratio of percent kW reduction per percent voltage change. Contractually, DVR factor was set to 0.5 until mid-June, then increased 0.75. Capacity reduction using DVR factor was calculated by multiplying the substation power by the DVR factor by the voltage change percent reduction, on a minute-by-minute basis, using one minute average load profiling substation data. In this project, the capacity delivered for the event was the minimum one minute number during the event, which is consistent with a balancing capacity product.

The study portion of the project deployed a strategy to attempt to measure DVR factor by assuming the capacity reduction in kW is the observed reduction in load in the first minute of voltage change. This load change is a mixture of the voltage change effect and the naturally occurring change in load for the substation. It was hoped that a statistically significance could be observed in this method. If the observed change in load in that first minute is assumed to the caused voltage reduction then a DVR factor can be calculated, and thus compared to the ones used contractually.

Calculation Methodology

Because DVR measurement and verification (M&V) is still in its infancy, and the subtleties are not widely understood even by practitioners, this simplified model was compared to a more traditionally calculated DVR factor. Minute-by-minute information about substation bus voltage, voltage regulator setting, and substation load for fifteen substations was provided for a window of time around each voltage control event. All voltage data was converted to 120V basis. For each event, a DVR factor was calculated for each substation using the equation:

$$\frac{(P_{t-1} - P_{t+1})/P_{t-1}}{(V_{t-1} - V_{t+1})/V_{t-1}}$$

Where:
P = Power

V = Voltage (120V basis)

t=0 Event start minute (minute during which voltage regulator setting was changed)

Or, to put that in words: (Power/Load (in kW) at t-1 minus Load (in kW) at t+1 divided by Load (in kW) at t-1) divided by (Voltage t-1 minute minus voltage t+1 min) divided by Voltage t-1). The first minute of voltage transition was omitted from the calculation. This is the minute when we first see a change in the voltage regulator setting. The reason for omitting this data point is to allow time for the regulator to establish a new steady-state voltage.

Although straightforward, this equation can run into trouble if the voltages happen to be equal before and after the event. While there are many solutions to this problem, for this analysis any substation where this happened in a given event was ignored for that event. This should only happen when the substation voltage setting didn't change, but it is possible this may throw out a viable substation and may lead to underreporting. This question was not reviewed.

The first methodological question to arise was how to derive an overall DVR factor for each event. Originally, the calculated DVR factors were simply averaged across all 15 substations, but because the substations did not have an evenly distributed load, it was decided a weighted average (based on substation load percentage of total city load the minute before the voltage setting change □P_{t-1} (time = t-1) would be used.

This led to some DVR factor numbers far outside of the expected values of 0.5-1.5. These events were reviewed, and in most cases a single substation was throwing the numbers off. In most of those cases, it was because some substations were not involved in some events. This highlights a problem with applying the calculated factor to load across substations; it is more logically sound to apply the factor only to participating substations. In most cases this does not change the results much, but it seems prudent to include this in any M&V strategy going forward. In this analysis, peak load reductions were reported based on participating substations only.

Appendix E contains a summary table of analysis results for the 62 events for which data was provided and analyzed.

Data Anomalies

Events that had data anomalies are highlighted in bold in Appendix E. Events highlighted in blue were removed from analysis.

The nature of each anomaly is summarized in Table 1, below.

Table 1: Anomalous Events

	Description	Count	Event #s	Used in Analysis
	Total events	**62**		
1	No voltage change occurred	2	84, 105	No
2	Event broke across minute	2	50, 107	No
3	Manual adjustment due to large load change on one substation (SH1)	2	120, 127	Yes
4	One minute voltage setting reversion in the middle of the event	2	130, 135	Yes
5	Event duration less than 15 minutes	8	106, 107, 110, 112, 132, 135, 136, 138	Yes

The first category of anomaly is fairly straightforward – voltage setting was not changed during that event. Category 2 anomalies occurred in instances when the voltage setting change for some substations occurred in one minute appeared during the next on other feeders. Presumably this is due to bad luck; communication is not quite instantaneous and signals may have arrived seconds apart, but our data granularity is insufficient for this to be visible. While it would be possible to calculate DVR factors based on the different minutes when the command was reached, this added analytical challenge was not tackled during this analysis.

Category 3 problems are ones where the DVR factor came up above 2 even when corrected for substation participation. In both cases, investigation revealed that one factor had a very large load drop over the 2 minute period (8.6% and 4.0%). In consultation with a demand response (DR) subject matter expert (Mr. Tony Koch), it was decided that this substation should be left out of the calculation. In both cases the same substation (SH1) was at issue, leading to the hypothesis that it feeds a large industrial load that is sensitive to voltage changes, or has naturally occurring large swings in load. It should be noted that in the statistical analysis, this substation was considered to be not-participating and the load drop on this substation was not included in the reported savings (to be consistent across events). This substation was heavily loaded, so this may skew the results slightly, implying that less load reduction was achieved.

Categories 4 & 5 represent issues that were discovered during the deep dive analysis that may or may not be issues in future DR projects. No explanation was developed for these issues; they may be artefacts of the data received, communication errors, or have other causes. They are reported here for awareness purposes. During two events, for one minute during the event, the reported voltage setting reverted to its pre-event setting, then went back the next minute

(Category 4). During several events in the latter half of the project, voltage settings were changed for less than 15 minutes (Category 5), rather than the called for event duration.

Statistical Analysis

After resolving the issues as described in the Calculation Methodology section, events with Category 1 & 2 errors were removed from the data set. This left 58 events for statistical analysis. Several factors that might affect DVR factor or load reduction were hypothesized. These included season, time of day (minutes past midnight), weekday vs weekend, and outdoor air temperature during event. Dummy variables were created for calendar seasons, where summer =the three hottest months of the Typical Meteorological Year (TMY3) (June, July, August) and winter = the three coldest (December through February); and two specific periods of interest for peak shaving, namely: Morning Peak (6-9 AM) and Afternoon Peak (15-19:00).

Table 2: Monthly Temperature by Month (TMY3 Data, Pasco, WA, Site: 727845)

	Average Monthly Temperature (deg F)	Season
Jan	35	Winter
Feb	38	Winter
Mar	46	
Apr	55	
May	62	
Jun	70	Summer
Jul	76	Summer
Aug	72	Summer
Sep	61	
Oct	50	
Nov	42	
Dec	37	Winter

It should be noted that events were not randomly distributed. The following histograms illustrate the distribution of events by month, time of day, and outdoor air temperature.

Table 3: Event Frequency by Month

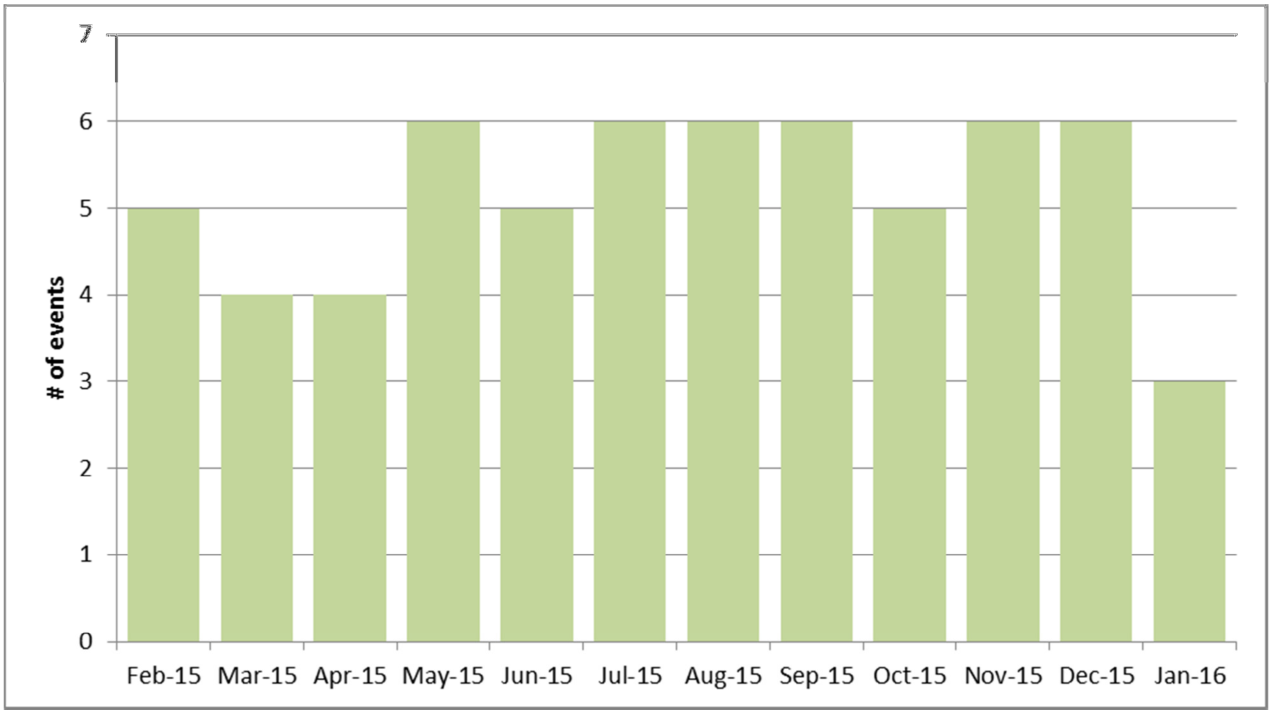


Table 4: Event Frequency by Time of Day

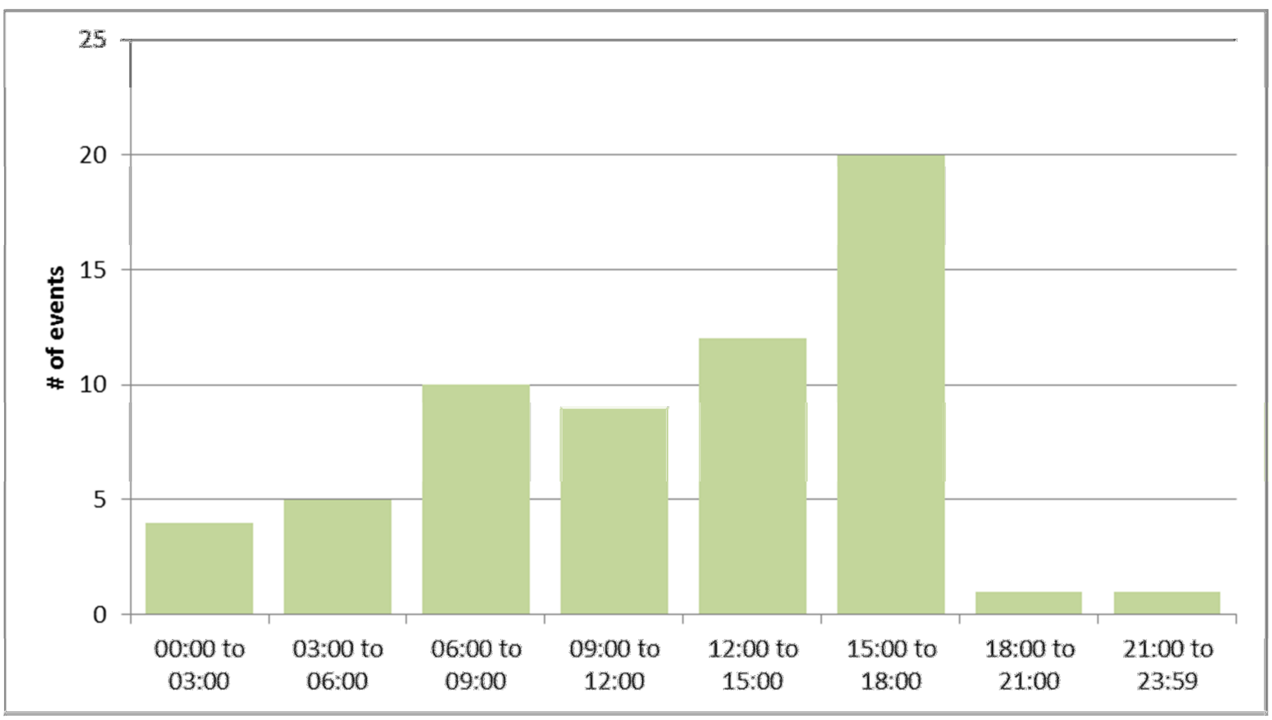


Table 5: Event Frequency by Outdoor Air Temperature

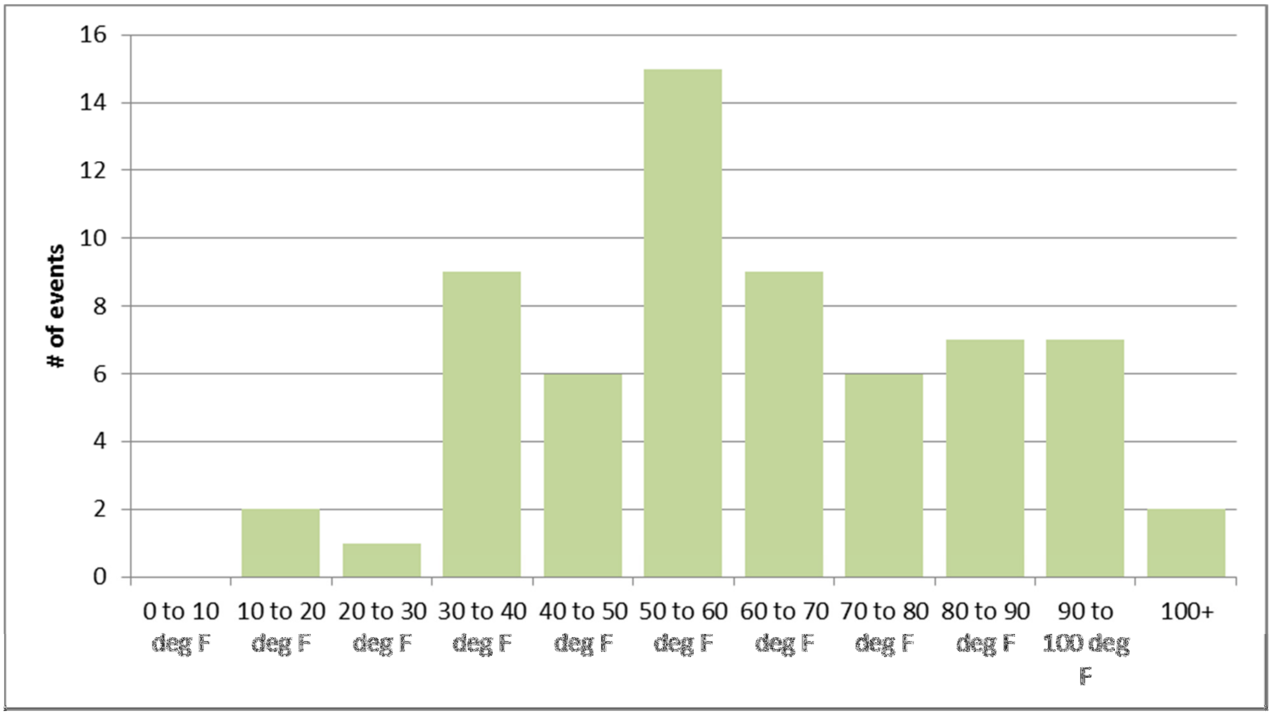


Table 6: Regression Results for DVR Factor

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	1.147	0.11	10.85	0.000	0.93	1.36
Morning Peak (6-9 AM)	0.031	0.07	0.46	0.651	-0.11	0.17
Afternoon Peak	-0.058	0.08	-0.75	0.457	-0.21	0.10
Season (Summer)	0.022	0.08	0.29	0.771	-0.13	0.17
Season (Winter)	0.115	0.07	1.76	0.084	-0.02	0.25
weekend	-0.083	0.08	-1.05	0.298	-0.24	0.08
Time of Day	0.179	0.15	1.22	0.228	-0.12	0.47
Temp during Event	-0.007	0.00	-3.48	0.001	-0.01	0.00

The classical way to determine whether a value is significant is to look at the p-value, where a variable with a p-value below 0.2 is significant (the null hypothesis is rejected). For this analysis, winter and temperature during event were the significant independent variables. The adjusted R squared for this table was 0.43.

The average DVR factor for all events was 0.897. The winter average DVR factor was 1.08 (compared to 0.675 for summer).

The temperature coefficient in this model supports this idea; the DVR factor drops 0.007 for every increased degree of temperature in these events (although the coefficient of the “winter” variable is positive; perhaps load factors are more significant here.)

Table 7: Regression Results for Delivered Capacity (kW)

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	1909	387.30	4.93	0.000	1131	2687
Season (Summer)	335	249.82	1.34	0.186	-167	837
Season (Winter)	-503	281.33	-1.79	0.080	-1068	62
Weekend	355	275.69	1.29	0.203	-198	909
Time of Day	292	240.24	1.22	0.229	-190	775
Morning Peak (6-9 AM)	-358	288.17	-1.24	0.220	-936	221
Afternoon Peak (15-19:00)	1536	538.80	2.85	0.006	454	2618
Temp during Event	-25	7.15	-3.45	0.001	-39	-10

When the regression was repeated for delivered kW, many more variables appeared significant. Winter and temperature were significant again, but also whether the event occurred in summer or during the afternoon peak. The information shown above confirms the intuitive predictions that less peak shaving is possible using this approach during the summer and more is possible during winter and when temperature is lower. The adjusted R squared for this table was 0.33.

The relatively low R-squared values for the regression tables imply that these factors do not fully explain the variation in either effect. As expected, not all salient contributors to delivery capacity or DVR factor are being captured in this analysis.

Limits of this Sample

This analysis was a post-hoc investigation on a limited set of events being done to fulfill other needs. As a result, some variables of interest did not have enough points for reliable analysis.

Thus, some factors could not be reliably investigated. Weekday summer afternoon peaks are of particular interest to utilities, but only two events with these characteristics occurred. The events for each variable are summarized in Table 8.

Table 8: Distribution of Variables

	Observations	*Mean*	*Standard Deviation*	*Minimum*	*Maximum*
Weighted DVR Factor	58	0.85	0.23	0.41	1.34
Season (Summer)	58	0.26	0.44	0	1
Season (Winter)	58	0.22	0.42	0	1
Weekend	58	0.10	0.31	0	1
Time of Day	58	11:33:48 AM	306 minutes	12:39:00 AM	9:35:00 PM
Morning Peak (6-9 AM)	58	0.17	0.38	0	1
Afternoon Peak (15-19:00)	58	0.17	0.38	0	1
Temp during Event	58	59.8	20.7	18.5	100.0

Conclusions

Overall, this analysis seemed to validate a DVR factor of 0.5. It pointed to the idea that a simplified DVR factor might be raised in the winter (possibly 0.8) and lowered for the summer (possibly 0.6). It is important to note that DVR factor is reflective of the type of load being controlled, so this analysis may not be universally applicable. Constant impedance loads produce the highest DVR factors, whereas constant current loads produce lower DVR factors, and constant power loads produce DVR factors of zero[1].

It also showed a few areas where oversight might be warranted, in order to ensure reliable peak shaving, namely whether voltage setting remains constant during the entire event and whether the voltage setting is changed for the entire duration of event called.

It also points to a few areas that could use further discussion, namely the proper method for dealing with large load changes within a substation during an event and event persistence – the peak reduction was considered at a single point in time, and any decay effects during the event were not considered. Further analysis should include a comparison to DVR factors based on voltage setting rather than actual voltage to compare the results.

[1] Examples of constant impedance loads are electric resistance heating or regular AC motors. An example of a constant current load is LED lighting, and a variable frequency drive (VFD) is a constant power load.

Appendix E: Summary of Cleaned Data for All Events

#	Event date	Event Start (Time of Day)	OAT (deg F)	Start kW	Start kW Participating	Delta	End kW	End kW Participating	Weighted Avg DVR Factor Participating	Avg DVR Factor Participating	All Subs Reduction (kW)	Reduction Participating (kW)	Delta	Avg VS Change
49	Tue 2/10/2015	10:15 AM	56	98,500	98,500	-	93,400	93,400	0.86	0.91	2039	**2039**	-	2.30%
50	***Wed 2/18/2015***	***2:45 PM***	*54*	*97,700*	*97,700*	*-*	*98,700*	*98,700*	#N/A	*1.05*	*2180*	***2180***	*-*	*2.29%*
51	Fri 2/20/2015	11:27 AM	57	96,800	96,800	-	96,100	96,100	1.04	0.85	1526	**1526**	-	2.29%
52	Tue 2/24/2015	7:21 AM	31	142,100	142,100	-	128,600	128,600	0.97	1.21	3629	**3629**	-	2.29%
53	Thu 2/26/2015	7:20 PM	48	99,900	99,900	-	102,900	102,900	1.30	0.75	2001	**2001**	-	2.29%
54	Mon 3/2/2015	2:24 AM	31	86,900	71,300	15,600	90,300	74,500	0.76	0.98	872	**924**	(52)	2.35%
55	Wed 3/11/2015	3:43 PM	66	87,000	87,000	-	89,400	89,400	0.81	0.80	1380	**1380**	-	2.29%
58	Mon 3/16/2015	5:33 PM	60	91,500	91,500	-	93,300	93,300	0.75	0.93	1451	**1451**	-	2.29%
65	Fri 3/27/2015	6:25 AM	41	85,000	85,000	-	92,500	92,500	0.79	1.05	699	**699**	-	2.35%
67	Wed 4/8/2015	9:34 AM	56	94,800	94,800	-	92,200	92,200	0.73	0.87	1176	**1176**	-	2.35%
69	Thu 4/16/2015	9:15 AM	50	100,400	100,400	-	97,600	97,600	0.79	0.54	1721	**1721**	-	2.35%
70	Tue 4/21/2015	12:15 PM	76	97,100	97,100	-	100,300	100,300	0.49	1.03	40	**40**	-	2.35%
71	Thu 4/23/2015	12:30 PM	51	88,000	88,000	-	85,500	85,500	0.76	0.71	454	**454**	-	2.35%

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VS = Voltage Setting

#	Event date	Event Start (Time of Day)	OAT (deg F)	Start kW	Start kW Participating	Delta	End kW	End kW Participating	Weighted Avg DVR Factor Participating	Avg DVR Factor Participating	All Subs Reduction (kW)	Reduction Participating (kW)	Delta	Avg VS Change
74	Sun 5/3/2015	7:21 AM	50	74,100	72,700	1,400	79,000	77,500	0.78	0.84	-56	**-97**	41	2.33%
75	Wed 5/6/2015	3:49 AM	40	69,000	69,000	-	74,300	74,300	0.58	1.06	314	**314**	-	2.35%
76	Tue 5/19/2015	12:39 AM	59	73,800	68,300	5,500	71,200	65,600	0.92	0.77	1109	**1057**	52	2.36%
77	Fri 5/22/2015	5:18 PM	80	114,300	114,300	-	107,600	107,600	0.80	1.13	1992	**1992**	-	2.30%
78	Mon 5/25/2015	5:20 AM	59	68,300	68,300	-	71,700	71,700	0.88	0.76	1068	**1068**	-	2.30%
79	Tue 5/26/2015	7:27 AM	61	86,700	72,000	14,700	89,700	74,700	0.76	0.60	440	**426**	14	2.27%
80	Sat 6/6/2015	5:20 PM	93	139,000	139,000	-	134,900	134,900	0.55	0.71	904	**904**	-	2.29%
81	Fri 6/26/2015	2:21 AM	60	84,100	77,800	6,300	81,900	75,800	0.66	0.71	1079	**985**	94	2.35%
82	Sat 6/27/2015	3:35 AM	66	90,400	90,400	-	91,100	91,100	0.70	0.70	1422	**1422**	-	2.29%
83	Sun 6/28/2015	4:40 AM	72	100,400	100,400	-	92,200	92,200	0.66	0.49	928	**928**	-	2.29%
84	***Mon 6/29/2015***	***4:49 PM***	*99*	*171,300*	*-*	*-*	*170,600*	*-*	#N/A	*0.48*	*-739*	***0***	*(739)*	
85	Mon 7/6/2015	4:00 PM	100	169,100	169,100	-	173,300	173,300	0.47	0.50	627	**627**	-	2.29%
87	Tue 7/7/2015	5:45 PM	99	173,000	138,800	34,200	165,200	130,900	0.54	0.92	986	**1203**	(217)	2.25%
90	Tue 7/14/2015	1:10 PM	87	140,000	112,700	27,300	146,300	117,700	0.41	0.76	877	**929**	(52)	2.32%
91	Wed 7/15/2015	2:55 PM	90	150,200	128,700	21,500	148,100	126,400	0.91	0.82	1032	**1270**	(238)	2.25%

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#	Event date	Event Start (Time of Day)	OAT (deg F)	Start kW	Start kW Participating	Delta	End kW	End kW Participating	Weighted Avg DVR Factor Participating	Avg DVR Factor Participating	All Subs Reduction (kW)	Reduction Participating (kW)	Delta	Avg VS Change
94	Sun 7/26/2015	5:00 PM	79	104,000	78,300	25,700	106,700	81,500	0.67	0.76	363	**512**	(149)	2.30%
96	Fri 7/31/2015	4:00 AM	56	77,200	63,400	13,800	77,400	63,400	0.93	0.98	923	**894**	29	2.23%
98	Tue 8/4/2015	1:20 PM	91	130,800	114,800	16,000	138,100	121,200	0.67	0.85	937	**884**	53	2.32%
99	Fri 8/7/2015	11:10 AM	80	104,200	104,200	-	113,100	113,100	0.90	0.47	402	**402**	-	2.27%
100	Mon 8/10/2015	12:20 PM	86	116,000	70,500	45,500	126,100	75,900	0.82	1.01	773	**672**	101	2.25%
101	Wed 8/19/2015	1:20 PM	94	140,100	140,100	-	151,800	151,800	0.48	0.60	131	**131**	-	2.29%
105	***Wed 8/26/2015***	***3:20 PM***	*93*	*147,100*	*-*	*XXX*	*153,100*	*-*	#N/A	*0.57*	*-178*	***0***	*(178)*	
106	**Fri 8/28/2015**	**11:30 AM**	81	120,900	120,900	-	121,400	121,400	0.75	0.74	1406	**1406**	-	2.29%
107	***Thu 9/3/2015***	***10:30 AM***	*66*	*101,800*	*89,800*	*12,000*	*106,100*	*94,100*	#N/A	*0.63*	*630*	***563***	*67*	*2.33%*
109	Thu 9/10/2015	1:30 PM	84	117,400	117,400	-	128,300	128,300	0.57	1.10	513	**513**	-	2.29%
110	**Fri 9/11/2015**	**3:30 PM**	90	139,400	139,400	-	142,400	142,400	0.58	1.03	1209	**1209**	-	2.29%
112	**Mon 9/14/2015**	**8:00 AM**	60	93,400	68,300	25,100	97,300	71,200	0.83	1.13	669	**594**	75	2.23%
113	Thu 9/17/2015	5:22 PM	72	103,800	61,600	42,200	98,000	60,700	0.66	0.82	160	**947**	(787)	2.38%
115	Wed 9/23/2015	8:30 AM	59	95,400	95,400	-	96,000	96,000	0.95	0.85	1720	**1720**	-	2.29%
119	Thu 10/8/2015	3:11 PM	70	94,900	70,000	24,900	95,200	70,900	1.01	0.70	1282	**1122**	160	2.33%

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120	**Tue 10/20/2015**	**2:10 PM**	71	95,500	95,500	-	96,800	96,800	1.05	1.27	1929	**1349**	580	2.29%
121	Thu 10/22/2015	10:15 AM	58	81,500	81,500	-	86,100	86,100	0.72	1.07	1166	**1166**	-	2.35%
122	Tue 10/27/2015	8:15 AM	41	94,600	94,600	-	89,300	89,300	0.83	1.30	1618	**1618**	-	2.35%
123	Thu 10/29/2015	4:00 PM	67	85,400	85,400	-	88,200	88,200	0.73	1.16	745	**745**	-	2.35%
124	Fri 11/6/2015	6:30 AM	32	106,400	106,400	-	110,300	110,300	1.19	1.15	2184	**2184**	-	2.35%
125	Fri 11/13/2015	9:35 PM	60	84,100	84,100	-	74,300	74,300	0.94	1.09	1678	**1678**	-	2.35%
126	Mon 11/16/2015	11:30 AM	49	94,300	94,300	-	92,200	92,200	1.28	1.14	2457	**2457**	-	2.35%
127	**Tue 11/17/2015**	**4:00 PM**	61	88,000	62,600	25,400	97,100	69,600	0.93	0.77	2175	**811**	1,363	2.30%
128	Mon 11/23/2015	3:00 PM	30	121,000	121,000	-	129,300	129,300	1.12	1.03	2734	**2734**	-	2.35%
129	Fri 11/27/2015	8:00 AM	19	147,100	147,100	-	138,700	138,700	1.20	1.11	2628	**2628**	-	2.35%
130	**Tue 12/8/2015**	**7:00 AM**	52	113,100	113,100	-	101,600	101,600	1.24	0.99	2073	**2073**	-	2.35%
131	Wed 12/9/2015	5:00 PM	50	101,400	95,500	5,900	108,200	102,000	0.76	0.92	750	**725**	25	2.33%
132	**Mon 12/14/2015**	**12:00 PM**	48	97,500	97,500	-	96,300	96,300	1.01	1.34	1535	**1535**	-	2.35%
133	Thu 12/17/2015	12:00 PM	31	127,300	127,300	-	132,600	132,600	1.18	0.97	2934	**2934**	-	2.35%
134	Sat 12/26/2015	5:00 PM	31	124,700	109,400	15,300	128,800	113,200	1.05	1.24	1856	**1836**	20	2.42%

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135	**Wed 12/30/2015**	**4:00 PM**	27	115,700	115,700	-	140,600	140,600	0.84	0.00	736	**736**	-	2.42%
136	**Wed 1/6/2016**	**5:00 PM**	33	135,200	128,100	7,100	133,000	125,800	1.34	0.95	2848	**2747**	101	2.42%
137	Tue 1/12/2016	5:00 PM	34	131,600	131,600	-	132,000	132,000	0.95	0.00	1525	**1525**	-	2.42%
138	**Mon 1/18/2016**	**2:00 AM**	35	82,600	82,600	-	90,100	90,100	1.22	0.00	912	**912**	-	2.42%

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