4.0 Transactive System Test Cases

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The Pacific Northwest Smart Grid Demonstration (PNWSGD) transactive system described in Chapter 2 interacted with 30 asset systems at 10 of the 11 participating utilities. Chapter 2 described the functionality and general performance of the transactive system itself. This chapter summarizes the transactive system's requests for asset responses and the assets' actual responses. The project had requested that these assets be made responsive the PNWSGD transactive system, but the asset systems' responses were analyzed regardless whether they had been initiated by the transactive system or by alternative utility objectives and processes.

4.1 Asset System Summary

All of the utilities except the City of Ellensburg integrated one or more of their asset systems with the dynamic PNWSGD transactive system. Each utility established one or more transactive sites that received transactive incentive signals that had been calculated specifically for that site. The incentive signal was interpreted by one or more transactive toolkit functions at the utility site, and an asset control signal (ACS) output was provided from the site to the asset system's controller. The ACS was designed to request demand-response event periods from the asset system.

There are several important points to note about the interface between the transactive site and the asset system. First, just because the transactive site requested an event does not mean an event happened. In some cases the asset system had a human operator, and that person made the final decision whether to respond or not. A special case of this was output of requests to in-home-displays, in which case the energy customer made the final decision whether to respond or not.

Even when the responses were automated, utilities placed limits on the number of allowed responses. Customer agreements often specified a maximum number of allowed events in a month. Conventional demand-response programs, either direct load control or otherwise, are generally event-driven and are targeted toward managing few, short-lived incidents like critical peaks. Several well-placed asset responses may be adequate for conventional demand-response programs. Transactive systems, on the other hand, reveal a continuum of incentives to the utilities and asset system controllers and could engage assets much more dynamically according the each asset's capabilities and the flexibility of the asset's owner. This granularity of responses by many customers enables those customers who are both willing and able to respond (via automated systems) to participate according to their preferences rather than having their participation limited according to pre-determined agreements.

The responsive asset systems are summarized in Table 4.1. The primary assets were residential systems including water heaters with demand-response units, programmable thermostats, and smart appliances. In-home displays were also used by a small number of the utilities. Other assets included utility-scale battery storage, several types of distributed generators, building or commercial systems, and dynamic voltage control.

Table 4.1. Responsive Asset System Implementations at Transactive System Sites

	Residential	In-Home Displays	Battery Storage	Distributed Generation	Building / Commercial	Voltage Control
Avista Utilities	X	X		X	X	
Benton PUD			~~X~~[(a)]			
Flathead Electric Coop.	X	X				
Idaho Falls Power	X[(b)]		~~X~~[(a)]			X
Lower Valley Energy	X		X			
City of Milton-Freewater	X					X
NorthWestern Energy	X	X				
Peninsula Light Company	X					X
Portland General Electric	~~X~~[(b)]		X	X	X	
University of Washington				X	X	

(a) This asset system was eliminated due to the vendor going out of business.

(b) This residential water heater demand-response component was cancelled due to safety concerns.

4.2 Transactive System Costs

The project's transactive system may be coarsely divided into distributed and centralized infrastructure.[1] The costs of distributed infrastructure are allocated to the individual asset systems and their test cases in the project's model for tracking costs. The infrastructure required for a responsive asset system to participate in the transactive system might include

- system software
- computers, servers, or other computational infrastructure that can host system software
- network connectivity (almost exclusively internet for the PNWSGD participants)
- licenses, if required for access to needed software, hardware, or intellectual property
- backroom expenses (e.g., server and data management)
- security costs, including the costs to design and manage performance dashboards or otherwise monitor the system
- design labor
- installation labor expended for this infrastructure.

[1] The conceptual system model does not require centralized infrastructure. The objectives of transmission zones, which represent large bulk parts of transmission and generation in the Pacific Northwest, are represented centrally with Alstom Grid acting as surrogate owner of bulk generation resources and transmission. If the system were more distributed, as allowed in the conceptual model, one might instead discuss costs of participation in a transactive system at nodes that represent utilities, premises, or devices, but there would unlikely be a centralized part of the system to address.

Table 4.2 shows the annualized costs of transactive systems that were installed and implemented by the respective utilities at their sites.

- "Transactive Node": This column includes the equivalent annualized cost for installing, implementing, and testing the transactive nodes, and addressing cyber security at the respective utility sites. The annualized costs were calculated using the reported (and assumed when missing) lifetimes of the constituent system components. This column does not include the costs asset systems that were to be integrated with the transactive system.
- "Transactive Node and Equipment": This column includes both the equivalent annualized cost of transactive nodes, as listed in the column to the left, plus the annualized costs of asset system equipment, such as advanced metering infrastructure (AMI), responsive devices (e.g., water heater controllers), in-home displays, battery systems, voltage control devices, etc., that were procured by the utilities. The costs associated with the network infrastructure required for communications between the utility transactive site and the meters/devices are included in this column, too. Costs associated with licensing, customer participation incentives, etc., are also included. The costs of those components that were shared by more than one of a utility's asset systems were pro-rated across the asset systems. That is, the costs were allocated to the cost of the asset systems based on the reported proportional usage of that component by the various asset systems. For instance, if AMI was used by two asset systems, then 50% of the AMI's cost was likely allocated to the cost of each asset system.

Table 4.2. Transactive Asset System Costs Deployed by the Utilities

	Transactive Node (Annualized $K)	Transactive Node and Equipment (Annualized $K)	Affected Electricity Consumers (Thousands)	Number of Deployed Asset Systems
Avista Utilities	343	3,479	314	7
Benton PUD	26	84	39	1
City of Ellensburg	-	-	9	-
Flathead Electric Cooperative	377	788	48	6
Idaho Falls Power[a]	451	614	22	3
Lower Valley Energy[b]	8	209	29	2
City of Milton-Freewater	10	230	5	3
Northwestern Energy[c]	-	668	335	4
Peninsula Light Company	9	558	26	2
Portland General Electric[d]	109	2,485	714	4
University of Washington	156	1,100	355	3

(a) Includes PHEV (655K, 158K) and automated voltage regulation (557K, 117K) asset system costs that were not implemented
(b) Transactive node cost is only the cost of transactive signal integration. There may be other transactive node related costs that are not explicitly reported.
(c) Cost of transactive node system is not explicitly reported
(d) Includes cost of battery system

There is no obvious correlation between the service territory population and the costs of deploying the transactive asset systems. The project expected to observe a weak correlation between the costs of establishing a transactive site and the complexity of the sites, but the costs also do not show any discernible pattern with the number of asset systems. A deeper study is required to discern any relationship of deployment costs with the complexity/sophistication of the backend systems (energy management system, distribution management system, etc.), number of responsive assets, types of communications infrastructure, etc.

In the PNWSGD cost model, we must also sum the cost of the centralized infrastructure and fairly allocate these centralized expenses among the transactive asset systems. The following Table 4.3 shows the cost of centralized parts of the project's transactive system, i.e., the equipment needed to enable interaction of the utilities' transactive node sites with the project's central operations center.

Table 4.3. Costs of the Centralized Parts of the Project's Transactive System

Equipment Type	Description	Cost ($K)
Computer	Computer Servers	59
Data Storage	Data Servers	46
Appliance	Firewall Network Security Equipment	316
Switch	Network Switches	2
Total		**$423K**

The project elected to track costs primarily from a utility's perspective, and the above-listed costs of centralized infrastructure become calculated and allocated quite naturally to the utilities, which often assumed the role of an aggregator in the PNWSGD. The participating utilities worked closely with the project to state the costs of their asset systems. These costs are archived in sets of spreadsheets that the project refers to as "subproject workbooks" and are summarized in cost tables where the utilities' asset systems are discussed in Chapters 7–17.

A lesson learned was that vendors in the smart grid arena often prevent their utility customer from revealing specific cost information. This environment of secrecy sometimes forced the project to only report highly aggregated cost information, from which the costs of individual components could not be accurately inferred.

As a demonstration effort, the PNWSGD certainly incurred research and development costs that might not apply to the next system implementation. The project's cost model strives to estimate the costs of a second implementation of the project's transactive system. In summary, the centralized cost of the transactive system that must be allocated among all the transactive asset systems, including installation and design labor is about $850,000, which was estimated by doubling the equipment costs that were listed in Table 4.3.

Note that many of the centralized and the distributed asset system expenses of a transactive system would almost certainly have been expended similarly if one were to implement a more traditional demand-response program instead of a transactive system.

4.3 Addressing Impacts of Demand Charges

Explicit functions were applied at project sites Flathead Electric Cooperative, Lower Valley Energy, and the City of Milton-Freewater (see Table 4.4) to help them reduce their demand charges. These are among the project's utility participants that are Bonneville Power Administration (BPA) Preference customers and are therefore subject to BPA demand charges. The purpose of these functions was to predict and observe utility demand and to estimate the demand charges that are accruing as new monthly peak demands are becoming established. The calculated demand charges are then added to the sites' incentive signal and may thereby induce the sites' asset systems to respond. The resulting disincentive should encourage loads to curtail and generators to engage. The demand charges are real, and utilities are economically rewarded if they can avoid them.

Another demand-charge function was applied at the University of Washington campus. However, this location addressed both peak demand charges and daily time-of-use charges that the campus pays to Seattle City Light, its electricity supplier.

Even if a peak magnitude is accurately predicted, minor differences in the prediction of the new peak event may cause the demand-charges disincentive to be entirely misplaced in time. If this approach is used again in the future, implementers are advised to spread the impact over time to address the uncertainty with which the peak can be predicted in time.

Finally, load predictions must be informed by recent measurements of the load that is being tracked. Our site implementers did not provide and use such measurements. Consequently, load predictions were too inaccurately modeled, and the component influences from demand charges were not predicted and applied by the project as well as should be possible.

Table 4.4. Summary of Demand-Charge Results

Utility	Estimated Demand-Charge Impact
Flathead Electric Cooperative	Reduction of ~$3,500 per year for in-home displays. The in-home display impact was based on extrapolation from data observed during March 2014
	Reduction of ~ $1,163 ± 11 per year for demand-response units
	Reduction of ~$190 ± 10 per year for smart appliances
Lower Valley Energy	Reduction of ~$120 ± 40 per year for battery system
City of Milton-Freewater	Reduction of ~$4,400 ± 1,300 per year for water heater demand response estimated
	Reduction of ~$1,620 ± 260 per year for voltage responsive water heater demand response
	Reduction of ~$4,400 ± 1,500 per year using conservation voltage reduction on feeders 1–4
University of Washington	Insufficient data to estimate

The results are not especially compelling, but do show promise for use of demand response to avoid demand charges. Whether automated or manual, the challenge is for the utility to accurately predict the peak heavy load hour (HLH) every month. The project tested algorithms to automate this with limited success. Increasing the number of asset systems' allowed events and their durations would increase the probability of reducing load during the HLH and thus the impact of the program. Another challenge is the ability to accurately predict load in a distribution system, a key input into an automated demand-charge-management algorithm. Based on the PNWSGD experience, the project believes that such algorithms can be improved with further research.

4.4 Summary Asset Responses

The following steps were to occur as an asset system responded to the project's transactive system:

First, presuming that the site node hosts a functional interface (i.e., a *toolkit load function*) between the transactive system and one of its asset systems, the functional interface reviews local conditions and the incentive signal and determines if and when the asset system should respond. Many, but not all, the asset systems respond in a discrete way with discrete events in time (usually *curtailment* events).

One output from the functional interfaces to the physical asset system advises it when and how much it should respond.[1] Another output from the functional interface predicts the change in energy consumption if the asset system responds as it has been advised, based on a dynamic model of the asset system that resides at the functional interface.

The next two paragraphs address data collection practices that the PNWSGD established to record and confirm asset's responses:

When the asset system, in fact, becomes engaged, regardless of the reason, a confirmation is submitted to the project in the form of a *test-case event* indicator.[2] Accompanying the test-case event indicator is the new status. For example, if an asset system becomes curtailed, the asset system might send the project a test-case event indicator titled "curtailment status has changed" along with the asset's new status "curtailed." Another test-case event should be sent to the project at the time the asset system returns to its normal status.

While not a feature included within the transactive system, the project asked asset system implementers to supply meter instrumentation with which the magnitudes and timing of asset system responses can be verified. Therefore, the project received two independent assessments of the change in energy that accompanies an asset's responses—the measured response and the change in energy that has been predicted for the asset system by the functional interface (i.e., by the *toolkit load function* and its *asset model*). The predicted change in energy for the asset systems was discussed in Chapter 2 "The

[1] A clever, normalized, *advisory control signal* was developed by and specified by the project. This byte signal ranges over [−127, 127] to represent an asset's entire normalized capacity to consume or generate, based on fractions of nameplate ratings.

[2] The test-case event indicator was implemented as part of the PNWSGD data collection system. Future implementers should consider integrating this validation signal into the transactive system. It is different from most transactive system data in that it does not include predictions.

Transactive System." In this chapter the analysis of the measured responses is summarized. The details of the analysis are found in Chapters 7–17 for the corresponding utilities.

Table 4.5 summarizes the responses of all asset systems.

Table 4.5. Asset System Response Summaries

Site Owner	Site	Asset Description	Number of Events Observed	Number of Response Points	Average Observed Response
Peninsula Light Company	Fox Island, WA	Water Heater Control	217	500	NMI
		Dynamic Voltage Management	-	6 capacitor banks	NMI
University of Washington	UW Campus, Seattle, WA	Building HVAC Management	-	1	Insufficient data
		Two Diesel Generators	32	2	Insufficient dispatch and data
		Steam Turbine	136	1	+253 ± 29KW summer; +468 ± 91 kW winter
Portland General Electric	Oxford Rural Feeder, Salem, OR	Residential DR	-	20	No Data Received
		Commercial DR	-	8	NMI
		Distributed Generators	-	3	-
		Battery Storage	Indeterminate	1	No observable response relationship to incentive signal
City of Ellensburg	Renewable Energy Park, Ellensburg, WA	None	-	-	-
Benton PUD	Reata Feeder, Kennewick, WA	Energy Storage Modules	-	5	No useful data received
Avista Utilities	Pullman, WA	Residential DR	636	57	18 W reduction per premises
		Dynamic Voltage Control	-	13	Test Case Cancelled
		WSU Tier 1 HVAC Control	12	39	239 ± 41 kW reduction during events
		WSU Tier 2 Chiller Control	5	9	0.38 ± 0.07 MW reduction per event
		WSU Tier 3 Diesel Generator Control	2	1	Not dispatched
		WSU Tier 4 Gas Generator control	3	1	Not dispatched
		WSU Tier 5 Gas Generator Control	0	1	Not dispatched

Table 4.5. (cont.)

Site Owner	Site	Asset Description	Number of Events Observed	Number of Response Points	Average Observed Response
Flathead Electric Coop.	Libby, MT	Water Heater Control	19	85 to 92	239 ± 28 W reduction per premises
		Smart Appliances	19	67 to 101	140 ± 40W reduction per premises
		In-Home Displays	56	90	140 ± 80 W reduction per premises
	Marion/Kila, MT	Water Heater Control	20	15 to 21	142 ± 42 W reduction per premises
		Smart Appliances	19	12 to 17	215 ± 43W reduction per premises
		In-Home Displays	7	12	Insufficient data
City of Milton-Freewater	Milton-Freewater, OR	Water Heater (DRU) Control	200	800	100 ± 10W reduction per premises
		Voltage Responsive DRU	217	152	170 ± 40W reduction per premises
		Dynamic Voltage Control	217	5	100 ± 100 kW increase per event
Northwestern Energy	Helena, MT	Water Heater Control and Dynamic Voltage Control	397	0	- -
	Philipsburg, MT	Water Heater Control	-	-	-
		Dynamic Voltage Control	-	-	-
Lower Valley Energy	Teton-Palisades Interconnect, WY	Water Heater Control	306	104	370 ± 80 W reduction per premises
		Battery Energy Storage	3,236	1	$120 ± 40 per year reduction in demand charges
Idaho Falls Power	Idaho Falls, ID	Building DR Management	-	-	Test case cancelled
		Water Heater Control	288	213	Not observable
		Thermostat Control	410	42	0.052 ± 0.054 kW reduction per premises

"-" means that the asset system was never fully connected to the transactive system or data was never provided for the asset system from the site's transactive system implementation.

DR = demand response
DRU = demand-response unit
HVAC = heating, ventilation, and air conditioning
NMI = no measurable impact
WSU = Washington State University

The performance of transactive/demand responsive asset systems varied widely across the project participants. As shown in the table above, some utilities demonstrated very promising results—primarily through manual control of the asset systems rather than response to the project's transactive incentive signal.

In general, the signal-to-noise ratio was quite low. In some cases, the utilities were unable to report the necessarily time-aligned data to analyze the events. For example, voltage management assets permitted the project to independently confirm the event periods that were reported to the project, and the accuracy of the reported events was often found to be inadequate. In the case of Peninsula Light Company, only daily summaries were available at the premises level. Individual premises events were usually unobservable at the feeder level due to their small magnitude of the impacts compared to total feeder load.

The signal-to-noise ratio problem was further compounded by small numbers of response points relative to total feeder population. Several of the utilities were unable to achieve their target numbers of participants.

Overall, the results are encouraging enough that several of the utilities are continuing to use and even expand their demand-response systems. The detailed analysis for each of the utilities' asset systems is discussed in Chapters 7–17.