REPORT

Nexant



Puget Sound Energy Energize Eastside Outage Cost Study

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Prepared for Puget Sound Energy

Prepared by Josh Schellenberg Principal Consultant

Barney Speckman Senior Vice President

Le Xu Managing Consultant

Adriana Ciccone Senior Analyst

Nexant, Inc.

Table of Contents

1	E>	cecutive Summary	1
2	In	troduction	3
2	2.1	Map of Eastside Area	4
2	2.2	Report Organization	5
3	Μ	ethodology	6
З	3.1	Estimating Customer Outage Costs	6
З	3.2	Framework for Energize Eastside Outage Cost Study	7
Э	3.3	Rotating Outage Simulation	8
З	3.4	Incorporating Customer Data1	5
4	St	udy Results1	7
Ap	per	ndix A Qualifications for Outage Cost Studies2	20
Ap	per	ndix B Effectiveness Factors2	23

1 Executive Summary

Puget Sound Energy (PSE) is considering a transmission upgrade for service to the Eastside area. PSE's most recent planning studies indicate that several contingency scenarios could result in significant customer outages as early as 2018 in the Eastside area if no action is taken to upgrade the system, as described in the 2015 Supplemental Eastside Needs Assessment Report.¹ To assess the economic impacts of taking no action to upgrade the system, PSE retained Nexant to perform the independent analysis that is described in this report. The objectives of this study are to:

- Determine the extent of customer outages under several worst case equipment outage scenarios;
- Simulate the rotating customer outages (rolling blackouts) that would be needed under these scenarios if no action is taken to upgrade the system; and
- Estimate the customer outage costs that result from the rotating outage scenarios.

The three rotating outage scenarios chosen for this analysis were based on a series of load flow studies conducted for summer 2018 and 2024, and winter 2023-2024. These load flow studies were based on the updated Western Electric Coordinating Council (WECC) planning base cases for 2015, which are outlined in the Supplemental Needs Assessment. The chosen scenarios represent the three worst case scenarios that result in rotating outages. There are other scenarios that result in loss of service to customers due to operating the CAPs. The scenarios chosen for this study are:

- Scenario 1: An outage of two transmission substation transformers in the summer of 2018;
- Scenario 2: An outage of two transmission substation transformers in the summer of 2024; and
- **Scenario 3:** An outage of two transmission substation transformers in the winter of 2023-2024.

Figure 1-1 provides a summary of the key results from this study. The total customer outage cost resulting from the summer 2018 scenario is \$92 million, with nearly 131,000 customers experiencing rotating outages on up to 6 days over a period of 9 days. In the summer 2024 and winter 2023-2024 scenarios, the total customer outage cost increases to around \$275 million. The increase between the 2018 and 2024 scenarios is primarily attributed to the necessity for more rotating outages as a result of load growth. In the summer 2024 scenario, over 211,000 customers experience rotating outages on up to 9 days over a period of 16 days. In the winter 2023-2024 scenario, around 175,000 customers experience rotating outages on up to 13 days over a period of 29 days.



¹ Supplemental Eastside Needs Assessment Report. April 2015. Available here:

http://www.energizeeastside.com/Media/Default/Library/Reports/SupplementalNeedsAssessme ntReport_Redacted_April2015.pdf



Figure 1-1: Eastside Outage Cost Study Key Results by Rotating Outage Scenario

2 Introduction

PSE's most recent planning studies indicate that several contingency scenarios could result in significant customer outages in the Eastside area if no action is taken to upgrade the system, as described in the 2015 Supplemental Eastside Needs Assessment Report.² Based upon the Supplemental Needs Assessment, the Eastside area could have significant rotating outages (rolling blackouts) as early as the summer of 2018. Certain equipment outages could result in overloads of transmission power transformers. To prevent the overloads, Corrective Action Plans (CAPs) could be implemented, as described in the Supplemental Needs Assessment. The CAPs would be used to open transmission circuits that are normally closed in order to limit the impact of the initial outage. The CAPs, however, would place many customers at risk of rotating outages due to those customers being served by radially operated transmission lines. For some equipment outage combinations, the CAPs would not be sufficient and electric service to customers would have to be interrupted to reduce loading on overloaded transformers. PSE would most likely limit rotating outages to two hours at a time for each substation to mitigate the impact on customers who lose service. The potential for customer outages also increases over time, given that load is expected to grow at a rate of 2.4% per year in the Eastside area over the next 10 years, as indicated in the Supplemental Needs Assessment.

To assess the economic impacts of taking no action to upgrade the system, PSE retained Nexant to perform the independent analysis that is described in this report. The objectives of this study are to:

- Determine the extent of customer outages under several worst case equipment outage scenarios;
- Simulate the rotating customer outages (rolling blackouts) that would be needed under these scenarios if no action is taken to upgrade the system; and
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- Scenario 1: An outage of two transmission substation transformers in the summer of 2018;
- Scenario 2: An outage of two transmission substation transformers in the summer of 2024; and
- Scenario 3: An outage of two transmission substation transformers in the winter of 2023-2024.



² Supplemental Eastside Needs Assessment Report. April 2015. Available here: http://www.energizeeastside.com/Media/Default/Library/Reports/SupplementalNeedsAssessme ntReport_Redacted_April2015.pdf

This report summarizes the methodology and results of the assessment that evaluates the economic impacts of taking no action. This study first simulates the pattern and magnitude of rotating outages for the three scenarios above, based on an expectation of what PSE's likely response to the outage of two transmission substation transformers would be under each of the three scenarios. Then, the economic impacts are assessed by estimating the interruption costs that customers would experience under each of the three rotating outage scenarios.

2.1 Map of Eastside Area

For a geographic perspective of the area that is studied in these scenarios, Figure 2-1 provides a map of the Eastside, including the specific area affected by rotating outages.



Figure 2-1: Map of Eastside Area

2.2 Report Organization

The remainder of this report proceeds as follows. Section 3 summarizes the methodology for this outage cost study. Section 4 provides the study results. Finally, the appendices provide more methodological details and summarize Nexant's qualifications for conducting customer outage cost studies and applying these measurements to reliability planning.

3 Methodology

This section first provides background on the prior studies that are used to estimate customer outage costs for the Eastside area. Then, an overall framework of the outage cost study is provided, followed by further methodological details on simulating rotating outages and incorporating PSE customer data.

3.1 Estimating Customer Outage Costs

The preferred method for estimating customer outage costs is a survey that describes several hypothetical outage scenarios and asks customers to detail the costs that they would experience under those conditions, as described in the Electric Power Research Institute's Outage Cost Estimation Guidebook.³ Various parties have proposed many other approaches for estimating customer outage costs. The strengths and weaknesses of each approach are described in a literature review for the National Association of Regulatory Utility Commissioners.⁴ As discussed in this literature review, the customer survey is the preferred method for estimating customer outage costs because it directly measures the costs that customers experience under a variety of outage scenarios without relying on the relatively weak assumptions that alternative methods use.

The primary drawback of the survey-based outage cost estimation is that it requires collecting detailed information from large, representative samples of residential, commercial and industrial (C&I) customers. Therefore, only a few of the largest utilities in the U.S. have conducted customer outage cost surveys. To address this barrier to estimating customer outage costs, the Department of Energy (DOE), Lawrence Berkeley National Laboratory (LBNL) and Nexant have been working together for over a decade to make reasonable outage cost estimates readily available for utilities that have not conducted their own surveys. The first step in developing a national estimate of outage costs was to combine results from all of the outage cost surveys that were carried out using the methods outlined in the Outage Cost Estimation Guidebook. This aggregated statistical study, called a *meta-analysis*, was first done in 2003⁵ (with results from 24 surveys) and then updated in 2009⁶ and 2015⁷ (with results from 34 surveys, including the original 24). Based on this meta-analysis, DOE, LBNL and Nexant developed the Interruption Cost Estimate (ICE) Calculator⁸ in 2011 and then updated the tool in 2015. The ICE Calculator is a publicly-available online tool that uses the results of the meta-analysis to estimate customer



³ Electric Power Research Institute. 1996. "Outage Cost Estimation Guidebook." Available here: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=TR-106082

⁴ The literature review is in Section 2 of this report: National Association of Regulatory Utility Commissioners. 2011. "How to Assess the Economic Consequences of Smart Grid Reliability Investments." Available here: http://www.naruc.org/Publications/SERCAT_Illinois_2010.pdf

⁵ LBNL and Nexant. 2003. "A Framework and Review of Customer Outage Costs." Available here: http://eetd.lbl.gov/sites/all/files/publications/lbnl-54365.pdf

⁶ LBNL and Nexant. 2009. "Estimated Value of Service Reliability for Electric Utility Customers in the United States." Available here: https://emp.lbl.gov/sites/all/files/REPORT lbnl-2132e.pdf

⁷ LBNL and Nexant. 2015. "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States." Available here: http://eetd.lbl.gov/sites/all/files/lbnl-6941e_0.pdf

⁸ Available here: http://www.icecalculator.com

outage costs. The ICE Calculator also estimates the customer reliability benefits that are associated with user-specified reliability improvements that arise from smart grid and other types of investments.

3.2 Framework for Energize Eastside Outage Cost Study

Figure 3-1 summarizes the methodological framework for this study, including the development of the customer survey meta-database and the econometric meta-analysis described in Section 3.1. Due to the complexity of the rotating outage scenarios, this study does not directly apply the ICE Calculator. Instead, the econometric models that resulted from the 2015 meta-analysis are applied in this case. These ICE models are the same equations that were programmed into the ICE Calculator. Using the simulated rotating outage scenarios and PSE customer data as inputs, the ICE models produce outage cost estimates specifically for each scenario in the PSE Eastside area. Key inputs include the substations affected and duration for each outage event, customer class (residential, small C&I and medium and large C&I), usage (annual kWh) and industry type (for C&I customers only). After incorporating these inputs, the ICE models estimate customer outage costs for each rotating outage scenario, including an adjustment for load growth (2.4% per year) and inflation (2.0% per year). The next section provides the methodological details for the rotating outage simulation.



Figure 3-1: Framework for Energize Eastside Outage Cost Study

3.3 Rotating Outage Simulation

The 2015 Supplemental Eastside Needs Assessment Report summarizes various contingencies that have the potential to result in customer outages if the Energize Eastside Project is not completed. The report indicates that there will be a transmission deficiency by the winter of 2017-2018, and the potential for customer impacts will continue to increase as load grows in the Eastside area over time. The customer outage analysis looked at a number of the contingencies studied in the 2015 Supplemental Eastside Needs Assessment Report that could occur and have the potential to lead to customer outages as early as the summer of 2018. The transmission deficiencies identified in winter 2017-2018 would result in the use of CAPs, putting customers at risk, but would not require load shedding for the cases studied. This economic assessment examined three of several scenarios identified in the needs assessment that could lead to customer outages and are expected to have some of the largest potential customer outage/cost impacts. The three contingency scenarios studied were:

- Scenario 1 The simultaneous loss of two transmission level transformers during the summer⁹ of 2018. This is the first summer in which the needs assessment suggests that there is a transmission deficiency;
- Scenario 2 The same simultaneous loss of two transformers as in Scenario 1, but in the summer of 2024; and
- Scenario 3 The simultaneous loss of two transmission level transformers during the winter of 2023-2024.¹⁰

For both Scenarios 1 and 2, the contingency results in overloading the Sammamish Transformer #2. For Scenario 3, the contingency results in overloading the Talbot Hill Transformer #2. As described in the needs assessment, all three scenarios are classified as an N-1-1 contingency, in that the first contingency (failure of the first transformer) occurs and the second contingency occurs at later time. It is further assumed that there is sufficient time in between the two contingencies to allow for a Corrective Action Plan (CAP) to be implemented that will allow the system to be operated without violating North American Electric Reliability Corporation (NERC) Standards following the first contingency. The CAP consists of opening electrical switches on the transmission system in order to configure the system into a state that meets the NERC Reliability Standards for transmission system operations. Implementing the CAP also results in putting customers at risk if certain second contingencies occur, as described in the Supplemental Needs Assessment. The failure of the second transformer in the three scenarios is one such contingency. If the second transformer were to fail at the time of the summer peak (Scenarios 1 and 2), it would result in a Sammamish transformer loading to increase to a level that exceeds either the Operating Limit¹¹ for more than 8 hours or that exceeds the Emergency Limit¹², requiring immediate action to reduce the loading below the



⁹ The summer period is defined by PSE as the period from June 15 through September 15, roughly 90 days.

¹⁰ The winter period is defined by PSE as the period from November 1 to the end of February, roughly 120 days.

¹¹ The Operating Limit is a specific level of electrical loading that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

¹² The Emergency Limit is a specific level of electrical loading that a system, facility, or element can support or withstand for a finite period. The Emergency Limit assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Emergency Limit. At this point, the only option to reduce loading is to reduce customer loading on distribution substations that are served by this transformer. For Scenario 3, the failure of the second transformer during the winter period will result in a similar loading increase to a level that exceeds the emergency loading limit for the Talbot Hill #2 transformer, requiring immediate action to reduce the loading below the Emergency Limit.

The key parameters for Scenarios 1 and 2 are as follows:

- Sammamish #2 Transformer summer Emergency Limit: 410 MW;
- Sammamish #2 Transformer summer Operating Limit: 352 MW; and
- Sammamish #2 Transformer Loading as a result of the N-1-1 scenario and after the CAP implementation (453 MW for 2018 summer and 493 MW for 2024 summer).

The key parameters for Scenario 3 are as follows:

- Talbot Hill #2 Transformer winter Emergency limit: 484 MW;
- Talbot Hill #2 Transformer winter Operating limit: 398 MW; and
- Talbot Hill #2 Transformer Loading as a result of the N-1-1 scenario and after the CAP implementation (531 MW for 2023-2024 winter).

The methodology used to analyze the transmission system in the 2015 Supplemental Eastside Needs Assessment report was to examine the transmission system at the peak hour of the summer period, and at the peak hour of the winter period for each year studied.

Since the simultaneous loss of two transformers has the potential to result in the need to relieve the load on the overloaded transformer for multiple hours over multiple days, a method is needed to estimate the loading on the transmission system at hours other than those that were studied. The following methodology was used:

- For Scenarios 1 and 2, the loading on Sammamish Transformers #1 and #2 for the summer season of 2014 was summed to represent the aggregate loading pattern of the overloaded element and on the various substations that would be included in any simulated load shedding (rotating outage) program;
- This aggregate loading for each hour of the summer season was converted to a percentage value (by dividing by the 2014 peak loading value for the summer period), resulting in the percent loading at the peak hour equaling 100% and the percent value for all other hours being less than 100%;
- The amount of loading on the overloaded element (Sammamish Transformer #2) was determined for each hour of the summer season by scaling the value at the peak hour to all other hours, using the percent scaling values developed in the previous step and the loading in MW at the peak hour; and
- The hourly summer season loading for each of the substations that PSE identified to be included in load shedding was determined by scaling the value at the peak hour to all other hours, using the percent scaling values developed in the previous step and the loading in MW at the peak hour that was used in the study.

For Scenario 3, the same approach was used, except that the loading on Talbot Hill Transformers #1 and #2 for the winter season of 2014 was summed to represent the aggregate



loading pattern of the overloaded transformer and on the various substations that could be used in any simulated load shedding program. The remaining steps were the same as used for Scenarios 1 and 2.

At this point in the process, there is sufficient information to estimate whether there is the potential to experience overloads of the:

- Sammamish Transformer #2 in all hours other than the summer season peak hour for Scenarios 1 and 2; and
- Talbot Hill Transformer #2 in all hours other than the winter season peak hour for Scenario 3.

For this analysis, two limits were used in each of the three scenarios. The two limits and the actions taken when these limits are exceeded, per PSE's standard operating procedures, are:

- The Emergency Limit, which if exceeded in operations requires that action must be taken immediately to bring the loading below 99% of this value; and
- The Operating Limit, which if exceeded in operations more than 8 hours in any day must result in action to limit the loading to 99% of this value for the remainder of the day.

Analysis was conducted to simulate the application of the two actions listed above for each hour of the day and for each day of the 2018 and 2024 summer seasons, and for each winter day of 2023-2024. At this point in the analysis, an estimate of the amount of transformer overloading that must be eliminated has been developed for every hour of the three study scenarios.

To simulate how these overloads could be relieved with rotating customer outages, PSE used the following three steps:

- 1) Substations that could contribute to mitigate the overloading scenario were identified;
- 2) PSE determined how much relief (in MW) would be experienced at the overloaded substation transformer for each MW of customer load shed; and
- 3) A substation set was developed for each scenario that could relieve the overload on the Sammamish Transformer #2 in Scenarios 1 and 2, and relieve the overload on the Talbot Hill Transformer #2 in Scenario 3.

Because of multiple transmission level transformers feeding substations in the Eastside area, a reduction of 1 MW of load does not reduce the transmission level transformer load by 1 MW. The ratio of the load shed to the loading relief is called the *effectiveness factor* for the substation. The substation sets were sequenced into multiple load shedding phases. The average load shedding effectiveness factor for each substation set were as follows:

- For summer 2018, the defined substations in each phase of load shedding have effectiveness factors that range from 1.76 to 4.54;
- For summer 2024, the defined substations in each phase of load shedding have effectiveness factors that range from 1.76 to 3.38; and
- For winter 2023-2024, the defined substations in each phase of load shedding have effectiveness factors that range from 3.51 to 6.30.



Using these effectiveness factors and the required amount of relief for each hour for each scenario, load shedding was simulated as follows:

- Load shedding was implemented in a rotating manner, starting at the first substation in the list and proceeding through the list of the substations until reaching the last substation in the list and then proceeding back to the first substation.
- Load shedding was implemented in the simulation until the total required load relief was achieved in each hour. This may have required load shedding at only one substation or up to 36 substation transformers.¹³
- The duration of load shedding (rotating customer outages) on any substation transformer was limited to a maximum continuous time of two hours, after which the next substation or substations on the list would be taken off line. The outage was limited to two hours to prevent impacting any set of customers for an excessive time and to give customers a planned restoration time. Two hours would enable PSE operators to prepare for the next switching sequence, while preventing cold-load pick-up problems during winter outages.
- The load shedding simulation continued until loading relief was no longer required.

In the event that shedding the entire load of the last substation needed in any given hour of the simulation would result in more loading relief than required, the following steps were taken:

- If the amount of excess loading relief is less than or equal to 5%, it is assumed that it is
 within the ability of the operators to manage loading shedding and is not modified; and
- If the excess load shedding amount exceeds 5%, it is flagged and will result in prorating the outage cost of that substation in the next step of the process (the outage cost estimation step described in Section 3.2).

For each season, the potential repair time following a transformer failure was analyzed. From historical PSE data, the time required to repair a transmission level substation transformer could take up to 5 weeks in the summer and up to 6 weeks in winter. Therefore, under a scenario that reflects two completely simultaneous transformer failures, it would result in 5 weeks with both transformers out of service (the N-1-1 contingency studied in the Supplemental Needs Assessment report) in order to repair both transformers in the summer, and 6 weeks in the winter.

Results from a few steps of the rotating outage load shedding simulation analysis are shown graphically in the following four figures. The data presented is from Scenario 2 in summer 2024.

In Figure 3-2, the hourly load on Sammamish Bank #2 is shown. As described above, the hourly load is calculated based on the estimated peak load on the transformer and the percent load profile developed from 2014 historical loading for Sammamish Bank No.1 and No. 2 during the substation peak day. The forecast data used is from July 9, 2024 (example event day), which is in the same week as the summer season peak day. In the figure, the blue color is used to indicate the hours when the loading is below the Operating Limit of Sammamish Bank No.2 (i.e., 352 MW); the green color is used to indicate the hours when the loading on the transformer is



¹³ Note some substations have two transformers whose load can be shed independently. Thus the reference to transformers refers to the level at which customer groupings are portrayed, down to the substation transformer level for those substations with two transformers.

above the Operating Limit but still below the Emergency Limit of Sammamish Bank #2 (i.e., 410 MW); and the orange color is used to indicate the hours when the loading is above the Emergency Limit. As shown in the figure, there are 15 hours during which loading is above the Operating Limit and 11 hours during which loading is above the Emergency Limit.



Figure 3-2: Total Load on Sammamish #2 on Example Event Day

Figure 3-3 shows the loading relief required for Sammamish Transformer #2 for July 9, 2024. According to the two limits used for this analysis, if the loading of Sammamish Transformer #2 exceeds the Emergency Limit, actions are required to immediately bring the loading below 99% of the limit value. In the figure, the orange color is used to indicate this scenario. For example, the transformer loading is 419.6 MW at hour 11, exceeding the Emergency Limit of 410 MW, requiring 13.7 MW of relief to bring the transformer loading below 99% of the Emergency Limit (405.9 MW). In addition, if the loading of Sammamish Transformer #2 (or any transformer) exceeds the Operating Limit for more than 8 hours in any day, action is required to bring the loading below 99% of the Operating Limit for the remainder of the day. In the figure, the green color is used to indicate this scenario. For example, the transformer loading starts to exceed the Operating Limit in hour 9, but no action is needed (to limit loading to be below the Operating Limit) until hour 17 when the transformer loading exceeds the Operating Limit for more than 8 hours, and based on load pattern, the relief action must be taken until hour 23.

When the transformer loading exceeds the Operating Limit for 8 hours, the second, lower limit overrides the first one such that actions are required to bring the transformer loading below 99%

of Operating Limit instead of below 99% of Emergency Limit. For example, the loading of Sammamish Transformer #2 at hour 17 is 489.8 MW, which is above the Emergency Limit. The Emergency Limit would require actions to bring loading below 99% of the Emergency Limit. However, since it is already the 9th hour that the transformer loading is above the Operating Limit, the Operating Limit rule requires action to bring the transformer load below 99% of the Operating Limit. This is the reason why there is a spike of loading relief required for Sammamish Transformer #2 in hour 17.



Figure 3-3: Loading Relief Required for Sammamish #2 on Example Event Day

In Figure 3-4, the rotating outage results are shown substation. In the first column, the substations that are included in the rotating outages are listed.¹⁴ If a substation is included in the load shedding at any given hour, the corresponding cell is blue. This data corresponds to the same day simulated in Figures 3-2 and 3-3. For the first hour that loading relief is required (hour 11) load shedding is required at the first three substations in order to bring the transformer load below 99% of the Emergency Limit. The three substations that are subjected to load shedding in hour 11 are Substations #1, #2 and #3. The duration of load shedding on any substation is limited by rule to a maximum of two continuous hours, which is shown in Figure 3-4.

¹⁴ To ensure that sensitive information is not made public, the names of the individual substations have not been included in this report.

Rotating Outages																								
Substation\Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Substation #1	1 Î	-	<u> </u>	<u> </u>				<u> </u>							10	10		10		20				
Substation #2	+													<u> </u>										
Substation #3	+											-												
Substation #4	+																							
Substation #5	+	-																						
Substation #6	+	-		-		-			-		-							-					\vdash	\vdash
Substation #7	+	-		-	-	-			-	-	-							<u> </u>					<u> </u>	\vdash
Substation #9	+	-	<u> </u>	<u> </u>	-	-			-	-	-	-			-	<u> </u>		<u> </u>						
Substation #0	+	-		<u> </u>	-	-			-	-	-							-						
Substation #10	+	<u> </u>	<u> </u>	<u> </u>	-	<u> </u>			-	-	-	<u> </u>	<u> </u>					<u> </u>					<u> </u>	
Substation #10	-	<u> </u>		<u> </u>	<u> </u>	<u> </u>			<u> </u>	<u> </u>	<u> </u>	<u> </u>						<u> </u>	<u> </u>				<u> </u>	
Substation #11	+	<u> </u>			<u> </u>					<u> </u>					├──									
Substation #12	-	<u> </u>	<u> </u>	<u> </u>	<u> </u>				<u> </u>	<u> </u>	<u> </u>	<u> </u>						<u> </u>					<u> </u>	
Substation #13	+	<u> </u>				<u> </u>			<u> </u>			<u> </u>	<u> </u>	<u> </u>				<u> </u>	—				_	<u> </u>
Substation #14	—	<u> </u>				<u> </u>						<u> </u>	<u> </u>	<u> </u>				<u> </u>	└──				└──	
Substation #15	_																		\vdash					
Substation #16	1																		\vdash					
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Substation #28																								
Substation #29																								
Substation #30	+																							
Substation #31	+																							
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Substation #34	+	-							\vdash	\vdash	\vdash			<u> </u>					<u> </u>					
Substation #35	+	-							\vdash			<u> </u>		<u> </u>					<u> </u>					
Substation #36	+	-							-			<u> </u>							<u> </u>					
Substation #37	+	<u> </u>				<u> </u>			-		-	<u> </u>	<u> </u>	<u> </u>	-				<u> </u>					
Substation #38	+	-	<u> </u>						-		-	-		-					<u> </u>					
Substation #20	-	-	<u> </u>	<u> </u>					-		-	-		-		<u> </u>			<u> </u>					
Substation #40	+	-	<u> </u>	<u> </u>	-				-	<u> </u>	-	-		-		<u> </u>			<u> </u>					
Substation #41	+	<u> </u>	<u> </u>	<u> </u>	-	<u> </u>		<u> </u>	-	-	-	<u> </u>	-		<u> </u>			<u> </u>	<u> </u>					
Substation #41	+		<u> </u>	<u> </u>	<u> </u>	<u> </u>			-	<u> </u>	-	<u> </u>			<u> </u>									
Substation #42	+	<u> </u>			<u> </u>	-	<u> </u>				<u> </u>													
Substation #43	+	<u> </u>		<u> </u>		<u> </u>	<u> </u>		<u> </u>	<u> </u>														
Substation #44	+	<u> </u>				<u> </u>			<u> </u>		<u> </u>	<u> </u>	<u> </u>	<u> </u>					<u> </u>					
Substation #45	-	<u> </u>			<u> </u>	<u> </u>			<u> </u>	<u> </u>	<u> </u>	<u> </u>		<u> </u>	<u> </u>				<u> </u>				<u> </u>	<u> </u>
Substation #46									<u> </u>			<u> </u>							\vdash				┝──	\vdash
Substation #47	1																						<u> </u>	
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Substation #54																								

Figure 3-4: Rotating Outages on Example Event Day



Figure 3-5 shows the load shedding or customer load drop required (customer load not served) for the same day in July. The total customer load dropped is calculated from the substation load in the rotating outage scheme shown in Figure 3-4.



Figure 3-5: Customer Load Dropped on Example Event Day

The amount of load shed is larger than the amount of load relief achieved. For example, the relief required for Sammamish Transformer #2 at hour 20 in this example is 105.3 MW (Figure 3-3); with 12 substation transformers included in the load shedding (Figure 3-4). However, the total customer load dropped is 196.7 MW. The equivalent effectiveness factor for hour 20 is 1.87, indicating that it requires dropping 1.87 MW of customer load in order to achieve 1 MW of loading relief on the Sammamish Transformer #2 with the particular group of substation transformers that were included in the load shedding. Appendix B provides more details on the effectiveness factors for each grouping of substations in the rotating outage scenarios.

3.4 Incorporating Customer Data

As described in Section 3.2, key customer data inputs for the ICE models include the customer class (residential, small C&I and medium and large C&I), usage (annual kWh) and industry type (for C&I customers only). This study incorporates all of the customer data inputs at the individual customer level for each individual outage event. Each outage event is defined as a substation (or set of substations) that loses power for a specific duration on a specific day and time. For example, as shown in Figure 3-4, Substation #1 experiences a 1-hour outage during hour 11 on July 9, 2024 (example event day). To estimate the cost for this individual outage event, data for



customers served by Substation #1 are identified, and then the cost of a 1-hour summer outage during hour 11 for those specific customers is estimated, based on the customer class, usage and industry type of each customer. These disaggregated outage cost estimates at the individual customer level for each individual outage event are then summed up for each of the three rotating outage scenarios.

In some cases, the last substation dropped for a given day and hour would provide much more load relief than what was necessary and an adjustment to the outage cost for that substation would be required in the analysis. If the last substation dropped for a given day and hour provided more than 105% of the required load relief, the outage cost for that substation would be scaled down in proportion to the amount that is required to meet 105% of the load relief required. For example, consider a situation in which 5 MW of additional load relief is required in a given day and hour, but the last substation dropped in that hour provides 10 MW of load relief. In that situation, it is assumed that PSE operators would be able to shed a partial amount of the last substation dropped. In this case, only around 50% of the 10 MW of load relief would be required. Therefore, the outage cost for that substation would be scaled down by 50% for that outage event.

4 Study Results

The analysis shows that the outage of two transmission level transformers whose outages overlap for about a week or two would result in a significant number of customer outages during the period of overlap. The customer outages would result from the need to use rotating outages to avoid overloading another transmission level transformer, which would result in even more customer outages. The rotating outages that were simulated in this analysis using anticipated rotating outage schemes were limited to no longer than two hours. After a two hour outage period to any set of customers, the outage would be rotated to a different set of customers so the first set can have their power restored.

Table 4-1 provides the results of the rotating customer outage analysis. For Scenario 1 (summer 2018), customers would experience rotating outages on 6 days over a period of 9 days. For Scenario 2 (summer 2024), customers would experience rotating outages on 9 days over a period of 16 days, and customers would experience rotating outages on 13 days over a period of 29 days for Scenario 3 (winter 2023-2024). In these scenarios, the maximum number of substation transformers shedding load in any given hour ranges from 25 to 36 transformers. The total amount of transformer loading relief required was approximately 1,500 MWh in the summer of 2018 and around 3,800 MWh in the summer of 2024 and winter of 2023-2024.

Results	Scenario 1, Summer 2018	Scenario 2, Summer 2024	Scenario 3, Winter 2023-2024
Number of Days of Load Shedding (Days)	6	9	13
Duration of Load Shedding Period In Days from Start to End (Days)	9	16	29
Maximum Number of Substation Transformers Shedding Load in Any Hour (Count)	25	32	36
Total Amount of Transformer Loading Relief Required (MWh)	1,506	3,864	3,764

Table 4-1: Summary of Rotating Outage Analysis

Table 4-2 provides a summary of the outage cost analysis. The total customer outage cost resulting from the summer 2018 scenario is \$92 million. In the summer 2024 and winter 2023-2024 scenarios, the total customer outage cost increases to around \$275 million. The increase between the 2018 and 2024 scenarios is primarily attributed to the necessity for more rotating outages as a result of load growth. Given the effectiveness factors, the total amount of customer load shed is higher than the total relief delivered to the transformer described in Table 4-1. In the winter 2023-2024 scenario, nearly 19,000 MWh of customer load is shed. As is typically found in customer outage cost surveys, the total cost is concentrated in the C&I sectors, given that these customers experience substantially higher direct (tangible) costs as compared to residential customers.

Scenario	Customer Class	Number of Customers Experiencing	Total Outage Cost	Customer Load Shed	Cost per Unserved kWh	
		Outages	\$ Millions	MWh	\$	
	Medium and Large C&I	2,799	\$65.1	2,419	\$26.9	
Scenario 1,	Small C&I	7,983	\$23.3	207	\$112.5	
2018	Residential	120,213	\$3.8	2,093	\$1.8	
	Scenario 1 Total	130,995	\$92.1	4,719	\$19.5	
	Medium and Large C&I	4,480	\$179.3	5,266	\$34.0	
Scenario 2,	Small C&I	14,086	\$84.5	577	\$146.4	
2024	Residential	192,674	\$10.8	4,751	\$2.3	
	Scenario 2 Total	211,240	\$274.6	10,594	\$25.9	
	Medium and Large C&I	3,142	\$153.1	8,897	\$17.2	
Scenario 3,	Small C&I	9,786	\$115.7	875	\$132.3	
2023-	Residential	161,890	\$8.1	8,914	\$0.9	
	Scenario 2 Total	174,818	\$276.9	18,686	\$14.8	

Table 4-2: Summary of Outage Cost Analysis

Figure 4-1 compares the cost per unserved kWh estimates to those of the most recent LBNL/Nexant meta-analysis. Even though the LBNL/Nexant meta-analysis results are not scaled up for future inflation, the cost per unserved kWh estimates are lower in this study for small C&I and residential customers. For medium and large C&I customers, this study produces higher cost per unserved kWh estimates in the summer scenarios, but slightly lower estimates in the winter scenario. In general, the orders of magnitude of the cost per unserved kWh estimates are similar within each customer class. The primary explanation for why the PSE estimates are lower in most cases is that the outages occur during peak periods when electricity usage (kWh) is relatively high, and therefore, the dominator of the cost per unserved kWh value is higher, leading to a lower estimate.



Figure 4-1: Comparison of Cost per Unserved kWh Estimates between PSE Eastside Study and Most Recent LBNL/Nexant Study

Appendix A Qualifications for Outage Cost Studies

Nexant has many qualifications for conducting customer outage cost surveys and applying these measurements to reliability planning. Over the past 25 years, Nexant has designed, managed and implemented over a dozen large customer outage cost studies. These studies have stood up to regulatory scrutiny and have factored into key planning decisions related to large reliability and resiliency investments. The remainder of this section provides a summary of each of the most relevant qualifications.

Interruption Cost Estimate (ICE) Calculator

Lawrence Berkeley National Laboratory (LNBL) and the U.S. Department of Energy (DOE), Berkeley, CA and Washington, DC

Nexant developed a DOE-funded customer outage cost calculator that estimates the value of reliability investment alternatives. This tool is called the ICE Calculator and is publicly available at www.icecalculator.com. This tool allows planners to assess the cost-effectiveness of service reliability improvements by determining how a change in SAIFI, SAIDI or CAIDI affects aggregate outage costs. Considering that reliability improvement is one of the most frequently cited justifications for utility investments, planners use this tool to objectively compare investments using a generally accepted methodology for estimating outage costs.

Nationwide Customer Outage Cost Study

LNBL and DOE, Berkeley, CA and Washington, DC

Nexant was retained by LBNL and DOE to provide valid and reliable estimates of customer outage costs for electricity customers in the United States. This aggregated statistical study, called a meta-analysis, was first conducted by Nexant in 2003 and then updated in 2009 and 2015. The 2015 customer outage cost estimates were obtained by analyzing the results from 34 customer outage cost studies conducted by 10 major U.S. electric utilities between 1989 and 2012. Because these studies used nearly identical outage cost estimation methods, it was possible to integrate their results into a single meta-database describing the outage costs observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer outage costs per event by season, time of day, day of week and geographical regions within the U.S. for industrial, commercial and residential customers. The regression model allows utilities to customize outage cost estimates and use them to assess the economic efficiency of investments in generation, transmission and distribution systems.

Economic Benefits of Increasing Electric Grid Resilience

U.S. President Barack Obama's Council of Economic Advisers, Washington, DC

Nexant advised the White House Council of Economic Advisers on how to incorporate the results of Nexant's nationwide customer outage cost study into an August 2013 White House report on the economic benefits of increasing grid resilience.¹⁵ Primarily relying on estimates

¹⁵ Executive Office of the President. "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages." August 2013. Available here:

http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf



from Nexant's study, the report called for continued nationwide investment in grid modernization and resilience, saving the economy billions of dollars.

Embarcadero-Potrero 230 kV Transmission Study

Pacific Gas & Electric Co. (PG&E), San Francisco, CA

Nexant conducted a localized survey and analysis that estimated the cost of unserved energy among businesses in a vital urban center (downtown San Francisco), for long duration power outages lasting one day to seven weeks. The estimated cost of unserved energy ranged from \$200 million to \$9 billion for these power outage scenarios. Nexant provided testimony to incorporate the estimated cost of unserved energy into decision making regarding a \$200 million transmission line reinforcement (referred to as the Embarcadero-Potrero 230 kV Transmission Project). This transmission project was approved by the California Public Utilities Commission (CPUC) on January 16, 2014 in CPUC Decision 14-01-007.

Outage Cost Surveys

Various Electric Utilities, United States

Nexant has been retained by a number of utilities to estimate the costs that their customers experience as a result of electric system unreliability and poor power quality. These studies consisted of three phases:

- Design the survey instrument and field the survey for a given rate class;
- Analyze the survey data and estimate customer damage functions that were used to calculate the cost of unserved energy under various conditions; and
- Report the results to utility staff and, for some projects, to regulators.

Table A-1 provides a list of 10 utilities for which the Nexant team has conducted an outage cost study. In all of these projects, the Nexant team designed, managed and implemented the study.

Utility	Year	Location
Southern Company	2011	Atlanta, GA
PG&E	2012, 2005, 1993	San Francisco, CA
MidAmerican Energy	2002	Des Moines, IA
Salt River Project	2000	Phoenix, AZ
Puget Sound Energy	1999	Bellevue, WA
Duke Energy	1997, 1993	Charlotte, NC
Alabama Power	1997	Birmingham, AL
Mississippi Power	1997	Gulfport, MS
SEMPRA Energy	1997	San Diego, CA
Cinergy Corp.	1996	Plainfield, IN

Table A-1: List of Outage Cost Studies Conducted by Nexant

Outage Cost Estimation Guidebook

Electric Power Research Institute (EPRI), Palo Alto, CA

Nexant was retained by EPRI to prepare a technical report summarizing the state of the art in engineering and economic thinking concerning the application of customer outage costs to generation, transmission and distribution planning. Nexant developed a detailed report describing state of the art procedures for identifying and analyzing customer outage costs using customer survey techniques. The report contained detailed descriptions of methods and procedures used to survey customers to estimate outage costs as well as examples of how the results of these studies are used to evaluate the cost-effectiveness of investments in generation, transmission and distribution systems. The results of the effort were published in an EPRI report.

Evaluating Reliability Benefits

National Association of Regulatory Utility Commissioners (NARUC) and the Illinois Commerce Commission, Washington, DC and Springfield, IL

In a report prepared for NARUC and the Illinois Commerce Commission, Nexant reviewed nearly 40 years of technical literature that addresses how to evaluate reliability benefits. Nexant summarized much of what has been learned in the industry and academic literature with respect to:

- Value-based reliability planning;
- Methods for estimating outage costs;
- Approaches to calculating reliability benefits; and
- Incorporating these benefits into reliability planning.

Nexant also provided a list of specific steps for the Illinois Commerce Commission to carry out in order to implement value-based reliability planning among utilities in its jurisdiction.

Appendix B Effectiveness Factors

The following three tables list the number of substations that were included in the each of the three scenarios and the effectiveness factors for those particular groupings used.

Phase	Number of Substations Dropped	Effectiveness Factor
Day 1 Phase 1	5	1.763
Day 1 Phase 2	6	1.760
Day 1 Phase 3	7	3.108
Day 1 Phase 4	11	4.541
Day 2 Phase 1	6	1.982
Day 2 Phase 2	7	3.113
Day 2 Phase 3	11	4.099
Day 2 Phase 4	11	4.073

Table 3-2: Scenario 1, Summer 2018 Substations

Table 3-3: Scenario 2, Summer 2024 Substations

Phase	Number of Substations Dropped	Effectiveness Factor
1	7	1.765
2	7	1.762
3	14	3.100
4	14	3.376
5	12	3.320

Table 3-4: Scenario 3, Winter 2023-2024 Substations

Phase	Number of Substations Dropped	Effectiveness Factor
1	8	3.510
2	6	3.742
3	7	5.132
4	11	5.666
5	10	6.301