PACIFIC POWER
A DIVISION OF PACIFICORP

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July 12, 2021

VIA ELECTRONIC FILING

Edward Randolph, Director
Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102-3298
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RE: PacifiCorp's (U 901 E) Final Distribution Security Plan Pursuant to Decision 19-01-018

PacifiCorp d/b/a Pacific Power hereby submits its Final Distribution Security Plan which implements the requirements of Senate Bill 699 and Decision 19-01-018 in Rulemaking 15-06-009.

Please direct any questions regarding this filing to Pooja Kishore, Regulatory Affairs Manager, at (503) 813-7314.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

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Final Distribution Security Plan

PacifiCorp

Implementing Requirements of Senate Bill 699 and California Public Utilities Commission Rulemaking 15-06-009

7/12/2021

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Plan Revision Log

Date of Changes	Section(s) with changes	Summary of Changes	Changes Made by
7/12/2021	All	Initial Release	Sheila Andreatta, Asset Management

Plan Review Log

Date of Review	Name of Reviewer	Summary of Findings

Executive Summary

PacifiCorp d/b/a Pacific Power (PacifiCorp or company) hereby submits its Final Distribution Security Plan which implements the requirements of Senate Bill (SB) 699 and Decision (D.) 19-01-018 in Rulemaking (R.) 15-06-099.

In response to physical security breaches of electric supply substations[1] experienced in the state of California, the California Public Utility Commission (Commission) issued an Order Instituting Rulemaking (OIR) on June 11, 2015 to establish policies, procedures, and rules for the regulation of physical security risks to the electric supply facilities of electrical corporations. Following a multi-year collaborative effort between Staff, stakeholders, and utilities in this rulemaking, on January 10, 2019, the Commission adopted D.19-01-018, which required electric utilities to identify electric distribution assets that may merit special protection and measures to lessen identified risks and threats and mitigate the risk of long-term outages to distribution facilities serving a specific subset of critical loads.

Per D.19-01-018, Ordering Paragraph 2, the Commission directed Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco to prepare and submit to the Commission a Final Security Plan Report within 30 months of decision adoption.[2]

To meet this requirement, PacifiCorp first applied the methodology outlined in D.19-01-018 and the Joint Utility Proposal to identify critical loads and designate each corresponding substation as a Covered Facility.[3] As a result, PacifiCorp identified 22 critical loads served by 13 substations considered to be either loads critical for regional drinking and wastewater services or regional public safety establishments such as state level penitentiaries, state level emergency response offices, and multi-county level fire protection offices/facilities. The 13 substations serving these 22 loads were then designated as Covered Facilities and considered in scope for additional assessments and potential mitigation measures. All other distribution facilities were determined to be low or negligible risk and, consistent with the Joint Utility Proposal described in D.19-01-018, were not further evaluated.

Next, PacifiCorp applied a general risk assessment methodology including the assessment of both the likelihood and consequences of a top event occurring and evaluated whether or not existing mitigation measures in place at each location properly prevented or controlled the event to a LOW effective level of risk.

Consistent with D.19-01-018 and the Joint Utility Proposal, PacifiCorp's final assessment recognizes that distribution systems are not subject to the same physical security risks and associated consequences, including threats of physical attack by terrorists, as the transmission system. Therefore, only theft, vandalism, and ballistics attacks resulting in a successful physical security breach of the Covered Facilities and prolonged outage to critical loads were considered.

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[1] Specific events are described in D. 19.01.018 beginning at 3.
[2] D.19-01-018 became effective January 10, 2019.
[3] Per D.19-01-018 at 26, "Covered" is the utility working group term employed to describe those assets that are applicable, or that should be subject to physical security. Covered Facilities are also considered assets that require a subsequent assessment.

To perform the assessment, PacifiCorp grouped each criterion included in the Joint Utility Proposal[4] into either being indicative of a prevention or a control mitigation measure and then evaluated the effectiveness of each measure at the 13 Covered Facilities. The combination of these measures and an on-site physical security assessment performed in conjunction with an independent assessor were then leveraged to determine the effective risk level, as depicted visually in Figure 1 below.

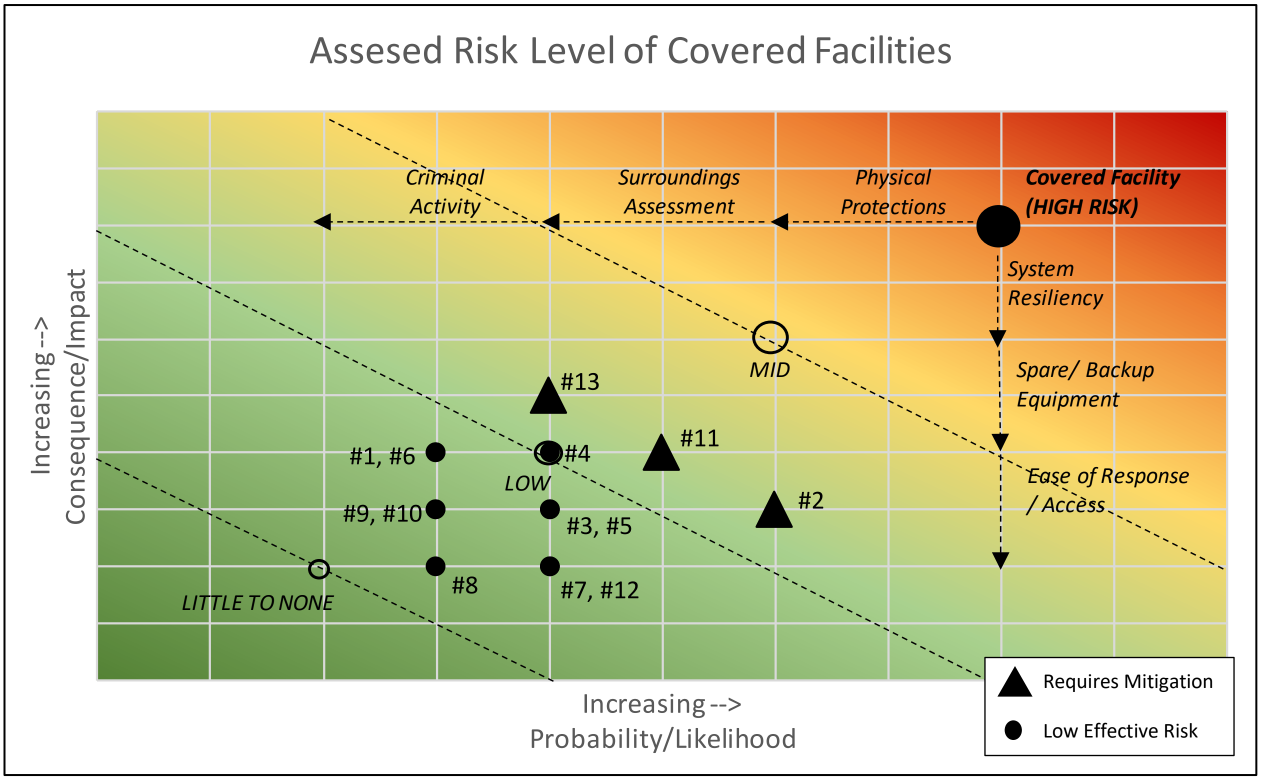

Figure 1: Assessed Risk Level of Covered Facilities

As a result, 10 of the 13 Covered Facilities were assessed to have a LOW effective risk level. As it is PacifiCorp's goal to operate the grid at a risk level as low as practical, the risk of a successful physical security breach on these Covered Facilities was determined to be properly mitigated at these 10 locations. However, as indicated in Table 1 below, three Covered Facilities were assessed to be a MID level of risk, indicative that additional mitigation measures may be needed to properly reduce the effective risk level to LOW.

[4] *See* D. 19-01-018 at 26-27.

Table 1: Assessment Summary of Covered Facilities that Require Mitigation Measures

Substation Name	Number of Critical Loads	PREVENTION MEASURES			CONTROL MEASURES				ASSESSED RISK LEVEL
		Criteria #3: Existing Physical Protections	Criteria #5: Physical Surrounding Assessment	Criteria #6: Criminal History	Criteria #1: Existing Resiliency / Redundancy	Criteria #2: Spares and Mobile Assessment	Criteria #4: Ease of Assess / Response Capability	*Criteria #7 - #9 (Already incorporated or not specifically considered)*	
Substation 2	**1**	**In Place / Partly Effective**	**In Place / Partly Effective**	**Not in Place / Not Effective**	**In Place / Partly Effective**	**Fully Effective**	**Fully Effective**		**MID**
Substation 11	**2**	**In Place / Partly Effective**	**Fully Effective**	**Not in Place / Not Effective**	**Not in Place / Not Effective**	**Fully Effective**	**Fully Effective**		**MID**
Substation 13	**1**	**In Place / Partly Effective**	**In Place / Partly Effective**	**Fully Effective**	**Not in Place / Not Effective**	**Fully Effective**	**In Place / Partly Effective**		**MID**

After completing the assessment, PacifiCorp worked alongside a third-party assessor to develop a list of mitigation projects at Substations 2, 11, and 13 to address existing vulnerabilities and reduce the effective risk level from MID to LOW. These projects, key target areas for improvement, high level cost estimates, and anticipated completion dates are included in Table 2 below.

Table 2: Summary of Final Mitigation Projects, Cost, and Timeline

Substation	Key Target Areas for Improvement	Description of Mitigation Projects / Measures	Estimated Incremental Spend ($)	Estimated Timeline
Substation 2	**Existing Physical Protections:** Given the high crime rate and prevalence for trespassers, the physical protections in place may not be sufficient. **History of Criminal Activity / Trespassers**: Substation 2 is located in a higher crime rate area with *observed presence of trespassers on site* identified during the physical site assessment	**Improvements to physical security above and beyond standard protocols:** Installation of additional fencing and gates alongside and behind substation in addition to existing barriers to prevent unauthorized vehicle traffic and trespassing behind the substation **Relocation of Active Trespassers:** PacifiCorp worked with local city officials to relocate existing trespassers to a safer location away from the substation	$15, 000	EOY 2021
Substation 11	**Existing Physical Protections:** Given the high crime rate and prevalence for trespassers, the physical protections in place may not be sufficient.	**Improvements to physical security above and beyond standard protocols:** Installation of additional fencing fabric with slats to enhance existing perimeter fencing to elevate level of deterrent.	$35,000	EOY 2022

Substation	Key Target Areas for Improvement	Description of Mitigation Projects / Measures	Estimated Incremental Spend ($)	Estimated Timeline
	Note: Substation 11 is located in a higher crime rate area but no specific observation of trespassers (Criminal History – Criteria #6)			
Substation 13	**Existing Physical Protections:** Given the vulnerability of the physical location and remote nature, existing physical protections in place may not be sufficient **Access Constraints:** Seasonal flooding could limit the ability for expedited restoration following an event.	**Improvements to physical security above and beyond standard protocols:** Installation of additional lights and fencing fabric with slats to enhance existing perimeter and elevate level of deterrent due to remote nature of the substation. **Removal of Seasonal Access Constraints:** Existing substation improvement project kicked off in 2020 at PacifiCorp to remove the seasonal access constraint (not incremental to this proposal).	$55,000	EOY 2023

The following depicts the future impact of executing the projects identified above to reduce the effective risk level from Mid to Low for Substation 2, 11, and 13.

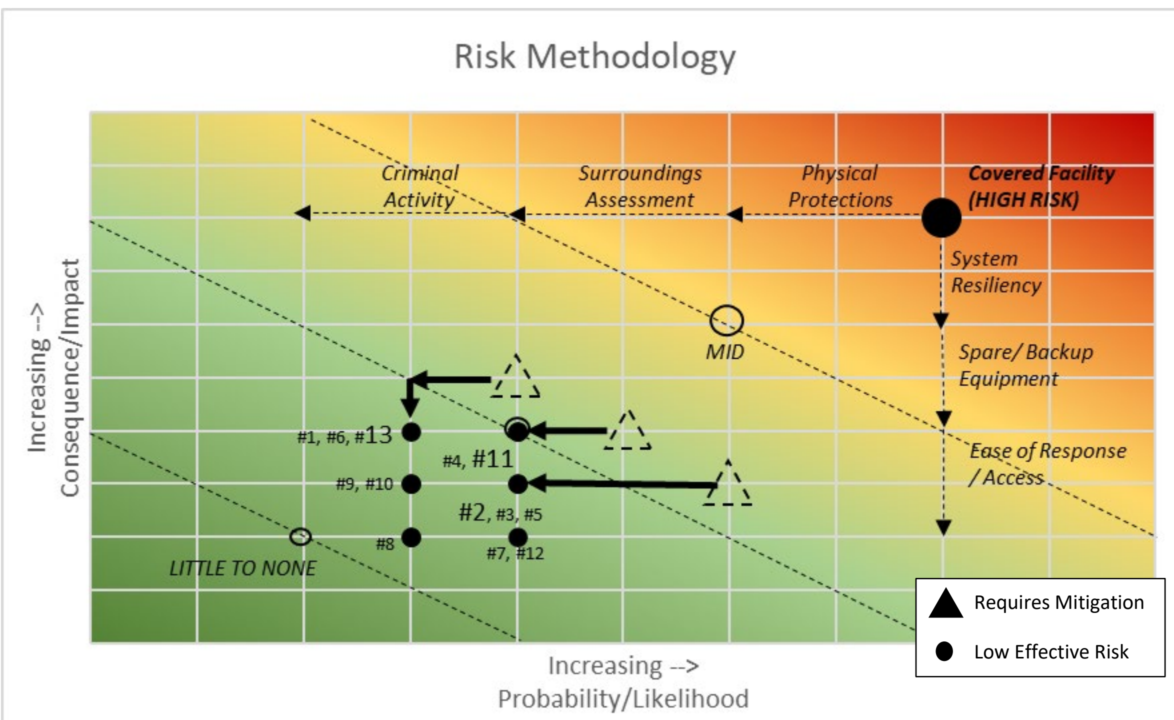

Figure 2: Impact of Mitigation Projects on Future Risk Assessed Levels

The following document, PacifiCorp's Final Distribution Security Plan, developed to meet the requirements in D.19-01-018, reflects the result of this effort to identify new mitigation measures as well as to document existing asset management, construction, and emergency response programs and protocols that support distribution physical security. Additional key plan elements, which can be found in the body of the document include plan management, ownership, and revision protocols, as well as record keeping and reporting requirements.

1. Introduction & Background

In response to the physical security breaches of electric supply substations in the state of California documented in D.19-01-018, the Commission issued an OIR (R.15-06-099) on June 11, 2015 to establish policies, procedures, and rules for the regulation of physical security risks to the electric supply facilities of electrical corporations consistent with Public Utilities (Pub. Util.) Code §364[5] (Phase I) and to establish standards for disaster and emergency preparedness plans for electrical corporations and regulated water companies consistent with Pub. Util. Code § 768.6 (Phase II).

To address Phase I referenced above, SB 699 amended Pub. Util. Code § 364 and required that the Commission develop rules for addressing physical security risks to the distribution systems of electrical corporations. During Phase I of R.15-06-099, multiple pre-hearing conferences were conducted in 2015 and 2017 and, as a result, a Scoping Memo and Ruling was issued on March 10, 2017 requiring that 14 specific issues be addressed in the proceeding. In a Ruling dated July 12, 2017, the assigned Administrative Law Judge asked that parties file a consensus straw proposal or alternatives. On August 31, 2017, the joint utilities filed a Straw Proposal for Physical Security Regulations (Joint Utility Proposal) to begin addressing the issues raised in the Scoping Memo. [6]

A technical working group was then formed consisting of subject matter experts at the various utilities involved in the proceeding. The Joint Utility Proposal was subsequently developed through a series of four Safety & Enforcement Division's Risk Assessment & Safety Advisory (RASA)-led workshops and collaboration between RASA and the technical working group from May to September 2017. The Joint Utility Proposal was amended through workshops and adopted by the Commission in D.19.01.018 on January 10, 2019. As included in D.19-01-018, this Proposal describes how a utility should establish a Distribution Security Program[7] consisting of the following: (1) Identification of distribution facilities, 2) Assessment of physical security risk on distribution facilities, 3) Development and implementation of security plans, 4) Verification, 5) Record keeping, 6) Timelines, and 7) Cost recovery.

Per D.19-01-018, Ordering Paragraph 1, "Within 18 months of this decision being adopted, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall prepare and submit to the Commission a preliminary assessment of priority facilities for their distribution assets and control centers." Additionally, through subsequent communications, Staff requested that utilities include pertinent methodologies used to complete the identification and preliminary assessment along with this submission.

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[5] Pub. Util. Code §364 was subsequently amended by SB 697, effective January 1, 2016 as described in D.19-01-018 at 4.

[6] The parties to the Joint Utility Proposal are: Bear Valley Electric Service, California Municipal Utilities Association, Los Angeles Department of Water & Power, Liberty CalPeco, National Rural Electric Cooperative Association, PacifiCorp, Pacific Gas & Electric Company, Sacramento Municipal Utility District, San Diego Gas & Electric Company, and Southern California Edison Company.

[7] The Joint Utility Proposal defines Distribution Substation as an electric power substation associated with the distribution system and the primary feeders for supply to residential, commercial and/or industrial loads. A Distribution Control Center is defined as a facility that has responsibility for monitoring and directing operational activity on distribution power lines and Distribution substations. *See* D.19-01-018 at 23.

Consistent with D.19-01-018, Ordering Paragraph 1, additional requirements in D. 19.01.018, subsequent communications with Staff, and the overall guiding principles of the Joint Utility Proposal, the PacifiCorp 2020 Preliminary Assessment Report was submitted on July 10, 2020 and included PacifiCorp's identification and preliminary assessment of Covered Facilities including pertinent methodologies leveraged, and draft mitigation measures recommended.

The PacifiCorp 2020 Preliminary Assessment Report and PacifiCorp's overall progress were reviewed with Commission Staff during an interactive workshop on July 22, 2020 along with supporting sensitive and confidential documents. As a result, PacifiCorp was able to incorporate valuable comments and constructive feedback into the company's identification and preliminary assessment and move toward procuring third party services to complement this review and assist with a physical site assessment of the company's Covered Facilities.

After completing a competitive bidding process, a contract was awarded on October 1, 2020 to perform an unaffiliated third-party review of the company's methodology and plan within 27 months of January 10, 2019 consistent with the Joint Utility Proposal. The third-party reviewer (Reviewer) provided PacifiCorp with valuable feedback during a series of workshops conducted in the fourth quarter of 2020 culminating in physical site assessments in early 2021. As a result, PacifiCorp was able to incorporate recommendations from the Reviewer to refine the company's assessment criteria and methodology as well as mitigation project identification and scope to develop a Final Security Plan.

This document, PacifiCorp's Final Distribution Security Plan, developed to meet the requirements in D.19-01-018, is the result of these efforts.

2. PacifiCorp's California Assets

PacifiCorp is a multi-jurisdictional utility that operates in California, Idaho, Oregon, Utah, Washington, and Wyoming.[8] In Northern California, PacifiCorp serves approximately 45,000 retail customers in a large, rural area via 63 transmission and distribution substations and 3,300 miles of transmission and distribution lines across nearly 11,000 square miles. 44 of these substations meet the definition of Distribution Substation[9] as each is considered an electrical power substation associated with the distribution system and the primary feeders for supply to residential, commercial and/or industrial loads over approximately 2,500 circuit miles of distribution level voltage feeders.

Figure 3 below includes a high-level snapshot of PacifiCorp's distribution substations and circuits within PacifiCorp's northern California service territory.

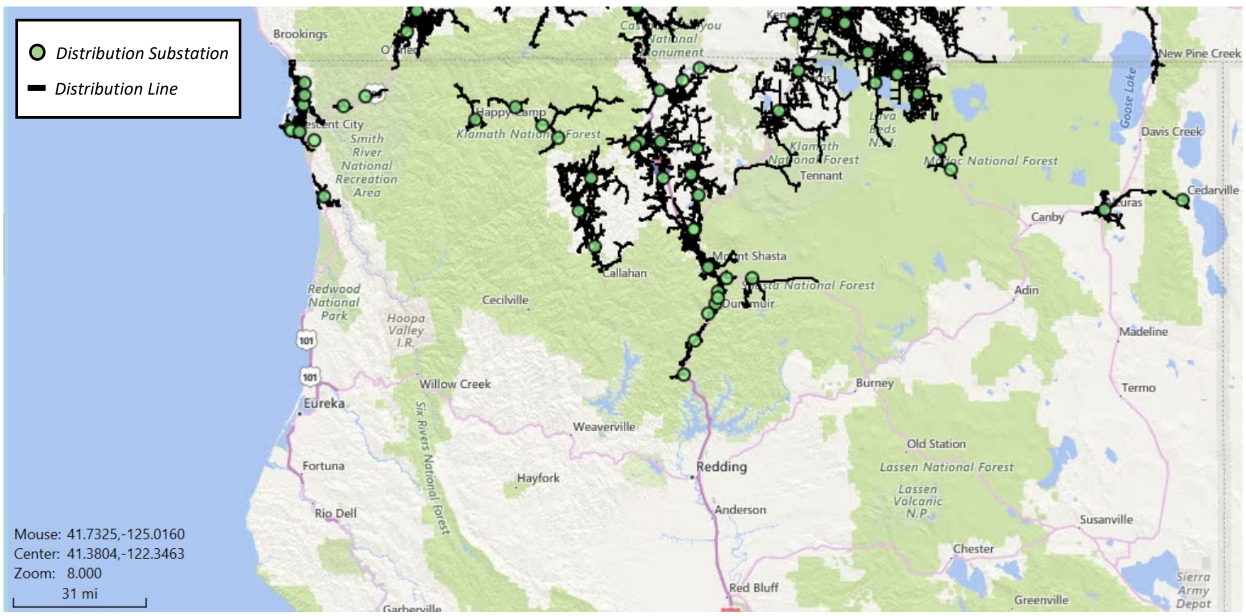

Figure 3: PacifiCorp's California Distribution Assets

At this time, PacifiCorp does not currently have any facilities located within the company's service territory in California meeting the definition of Distribution Control Center.[10] Therefore, only Distribution Substations were considered and evaluated in the company's Distribution Security Program.

[8] In California, Oregon and Washington, PacifiCorp provides service as Pacific Power. In Utah, Idaho, and Wyoming, PacifiCorp provides service as Rocky Mountain Power.

[9] D.19-01-018 at 23.

[10] Per D.19-01-018 at 23, "A Distribution Control Center is defined as a facility that has responsibility for monitoring and directing operational activity on distribution power lines and Distribution substations."

3. Distribution Security Plan Contents and Management

The following subsections describe PacifiCorp's overall plan contents and how these plan contents meet the pertinent requirements of D.19-01-018, as well as PacifiCorp's overall plan management, reporting, and record keeping requirements.

3.1 Requirements and Structure

Ordering Paragraph 8: Subsequent changes to the security plan requirements deemed beneficial and necessary, shall be enabled by one of the following: 1) Commission Resolution or Decision; 2) Ministerially, by Safety and Enforcement Division (or successor entity) director letter.

Ordering Paragraph 9: In carrying out any future changes to the security plan requirements, Safety and Enforcement Division shall confer with utilities about any recommended modifications to the plan requirements.

The components of PacifiCorp's Final Security Plan align with and meet the requirements set forth in D.19-01-018. Any subsequent changes to the security plan requirements deemed beneficial and necessary, shall be enabled by one of the following:

1) Commission Resolution or Decision; or

2) Ministerially, by Safety and Enforcement Division (or successor entity) director letter.

To the extent possible, PacifiCorp will confer, as requested, with the Safety and Enforcement Division regarding any recommended modifications to the plan requirements.

The following table describes the current requirements of the Final Security Plan as documented in D.19-01-018 and where detail can be found in this document to meet the specific requirement outlined.

Table 3: Decision Requirements and Corresponding Plan References

#	Ordering Paragraph	Corresponding Section in Plan
1	Within 18 months of this decision being adopted, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall prepare and submit to the Commission a preliminary assessment of priority facilities for their distribution assets and control centers.	*PacifiCorp's Identification and Preliminary Assessment of Covered Distribution Facilities was submitted on July 10, 2020*
2	Within 30 months of this decision being adopted, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall submit each utility's Final Security Plan Report.	*See current document*
3	Within 30 months of this decision being adopted, the Publicly Owned Utilities shall provide the Commission with notice of final plan adoption.	*N/A as PacifiCorp is an investor-owned utility*
4	The Publicly Owned Utilities' notice of final plan adoption may consist of a copy of a signed resolution, ordinance or	*N/A as PacifiCorp is an investor-owned utility*

#	Ordering Paragraph	Corresponding Section in Plan
	letter by a responsible elected- or appointed official, or utility director.	
5	All California Electric Utility Distribution Asset Physical Security Plans shall conform to the requirements outlined within the Joint Utility Proposal, as modified by this decision (rules and requirements collectively known as "security plan requirements").	*See Section 7 at page 28*
6	The Investor Owned Utilities and Publicly Owned Utilities shall adhere to the Safety and Enforcement Division's Six-step Security Plan Process.	*See Section 7 at page 28*
7	The Six-step Plan Process consists of the following: Assessment; Independent Review and Utility Response to Recommendations; Safety and Enforcement Division Review (for Investor Owned Utilities s); Local Plan Review (for Publicly Owned Utilities); Maintenance and Plan overhaul/new review.	*See Section 7 at page 28*
8	Subsequent changes to the security plan requirements deemed beneficial and necessary, shall be enabled by one of the following: 1) Commission Resolution or Decision; 2) Ministerially, by Safety and Enforcement Division (or successor entity) director letter.	*See Section 3.1 at page 14*
9	In carrying out any future changes to the security plan requirements, Safety and Enforcement Division shall confer with utilities about any recommended modifications to the plan requirements.	*See Section 3.1 at page 14*
10	Prior to the submittal of the Security Plan, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall each have their respective plan reviewed by an unaffiliated third-party entity.	*See Section 8 at page 51*
11	The unaffiliated third-party reviewer shall have demonstrated appropriate physical security expertise.	*See Section 8 at page 51*
12	California electric utilities shall, within any new or renovated distribution substation, design their facilities to incorporate reasonable security features.	*See Section 4 at page 22*
13	Utility security plans shall include a detailed narrative explaining how the utility is taking steps to implement an asset management program to promote optimization, and quality assurance for tracking and locating spare parts stock, ensuring availability, and the rapid dispatch of available spare parts.	*See Section 5.2 at page 24*
14	Utility security plans shall include a detailed narrative explaining how the utility is taking steps to implement a robust workforce training and retention program to employ a full roster of highly-qualified service technicians able to	*See Section 5.3 at page 25*

#	Ordering Paragraph	Corresponding Section in Plan
	respond to make repairs in short order throughout a utility's service territory using spare parts stockpiles and inventory.	
15	Utility security plans shall include a detailed narrative explaining how the utility is taking steps to implement a preventative maintenance plan for security equipment to ensure that mitigation measures are functional and performing adequately.	*See Section 5.1 at page 23*
16	Utility security plans shall include a detailed narrative explaining how the utility is taking steps to implement a description of Distribution Control Center and Security Control Center roles and actions related to distribution system physical security.	*See Section 0 at page 27*
17	Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall each document all third-party reviewer recommendations and specify recommendations that were accepted or declined by the utility.	*See Section 8 at page 51*
18	Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall each provide justification supporting its decision to accept or decline any third-party recommendations.	*See Section 8 at page 51*
19	Physical Security-related information is bifurcated into two categories. Recurring and routine utility compliance work products and ongoing utility updates required by this decision are not subject to the Reading Room approach but shall be transmitted to the Commission. All other physical security data requested by Commission Staff on an ad hoc basis shall be made available to the Commission on utility property in a manner agreed to by the Safety and Enforcement Division, or its successor, until such time that the Commission finalizes its rules for the handling, sharing, and inspection of confidential information.	*See current filing.*
20	If a Publicly Owned Utility has an existing blanket Security Plan that has been adopted by its Board of Directors or City Council within three years prior to the date of this decision, the requirement to have a plan adopted may be waived by the Commission.	*N/A for PacifiCorp*
21	In the event that a Publicly Owned Utility's (POU) Security Plan has not been adopted in time as required by this decision, the POU shall provide the Director of the Commission's Safety and Enforcement Division with a notice [30] days prior to the deadline with information on the nature of the delay and an estimated date for adoption.	*N/A for PacifiCorp*

#	Ordering Paragraph	Corresponding Section in Plan
22	Prior to Security Plan adoption, Publicly Owned Utilities in California shall have their plan reviewed by a third party.	*N/A for PacifiCorp*
23	Such third-party reviewer may be another governmental entity within the same political subdivision, so long as the entity can demonstrate appropriate expertise, and is not a division of the publicly owned utility that operates as a functional unit (*i.e.,* a municipality could use its police department if it has the appropriate expertise).	*N/A for PacifiCorp*
24	Publicly Owned Utilities shall conduct a program review of their Security Plan and associated physical security program every five years after initial approval of the Security Plan by their Board of Directors or City Council. Notice of such approval action shall be provided to the Commission's Safety and Enforcement Division within 30 days of Plan adoption by way of copy of signed resolution or letter by a responsible elected- or appointed official, or utility director.	*N/A for PacifiCorp*
25	Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall conduct a program review of their Security Plan and associated physical security program every five years after Commission review of the first iteration of the Security Plan.	*See Section 3.2 at page 19*
26	A summary of the program review shall be submitted to the Safety and Enforcement Division within 30 days of review completion.	*See Section 3.3 at page20*
27	In the event of a major physical security event that impacts public safety or results in major sustained outages, all utilities shall preserve records and evidence associated with such event and shall provide the Commission full unfettered access to information associated with its physical security program and the circumstances surrounding such event.	*See Section 3.3 at page 20*
28	An Exemption Request Process shall be available to utilities whose compliance would be clearly inappropriate or inapplicable or whose participation would result in an undue burden and hardship.	*N/A for PacifiCorp*
29	Utilities shall provide to the Director of the Safety and Enforcement Division and Energy Division copies of OE-417 reports submitted to the United States Department of Energy (U.S. DOE) within two weeks of filing with U.S. DOE.	*See Section 3.3 at page 20*
30	Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco (collectively, IOUs) shall seek recovery of costs associated with their respective Distribution Security Programs in each IOU's general rate case.	*See Section 7.3.3 at page 50*

#	Ordering Paragraph	Corresponding Section in Plan
31	The utilities shall submit an annual report by March 31 each year beginning 2020, reporting physical incidents that result in any utility insurance claims, providing information on incident, location, impact on infrastructure and amount of claim. The insurance claim disclosure reporting, as described in this decision, should be included within a utility's broader annual Physical Security Report to the Commission due every March 31, beginning in 2020.	*See Section 3.3 at page 20*
32	As appropriate, the requirements set forth in Phase I of this proceeding shall apply to Alameda Municipal Power, City of Anaheim Public Utilities Department, Azusa Light and Water, City of Banning Electric Department, Biggs Municipal Utilities, Burbank Water and Power, Cerritos Electric Utility, City and County of San Francisco, City of Industry, Colton Public Utilities, City of Corona, Eastside Power Authority, Glendale Water and Power, Gridley Electric Utility, City of Healdsburg Electric Department, Imperial Irrigation District, Kirkwood Meadows Public Utility District, Lathrop Irrigation District, Lassen Municipal Utility District, Lodi Electric Utility, City of Lompoc, Los Angeles Department of Water & Power, Merced Irrigation District, Modesto Irrigation District, Moreno Valley Electric Utility, City of Needles, City of Palo Alto, Pasadena Water and Power, City of Pittsburg, Port of Oakland, Port of Stockton, Power and Water Resources Pooling Authority, Rancho Cucamonga Municipal Utility, Redding Electric Utility, City of Riverside, Roseville Electric, Sacramento Municipal Utility District, City of Shasta Lake, Shelter Cove Resort Improvement District, Silicon Valley Power, Trinity Public Utility District, Truckee Donner Public Utilities District, Turlock Irrigation District, City of Ukiah, City of Vernon, Victorville Municipal Utilities Services, Anza Electric Cooperative, Plumas-Sierra Rural Electric Cooperative, Surprise Valley Electrification Corporation, and Valley Electric Association.	*See current document*
33	This proceeding shall remain open so that the Commission may address the issues presented in Phase II of this proceeding.	*PacifiCorp is actively participating in the proceeding which remains open*

3.2 Plan Management and Ownership

Ordering Paragraph 25. "Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall conduct a program review of their Security Plan and associated physical security program every five years after Commission review of the first iteration of the Security Plan. "

While the plan contains elements executed by various departments, PacifiCorp's Final Distribution Security Plan is owned and maintained by the Asset Management Department within the Transmission and Distribution (T&D) Operations Organization. Asset management is responsible for the plan content and accuracy as well as the coordination of a review every 5 years with pertinent Subject Matter Experts as described below. The plan review and any subsequent modifications will be documented in the Document Control section on page 6.

Initial Plan Adoption Date:	July 12, 2021
Plan Owner:	Asset Management, T&D Operations
SME Reviewing Departments:	Substation Operations, T&D Operations Field Engineering, T&D Operations Security & Information Protection
Review Cycle:	5 years
Next Review Date:	Estimated Third Quarter of 2026[11]

[11] Pending Commission review and adoption of initial Security Plan.

3.3 Reporting

Ordering Paragraph 26: A summary of the program review shall be submitted to the Safety and Enforcement Division within 30 days of review completion.

Ordering Paragraph 27: In the event of a major physical security event that impacts public safety or results in major sustained outages, all utilities shall preserve records and evidence associated with such event and shall provide the Commission full unfettered access to information associated with its physical security program and the circumstances surrounding such event.

Ordering Paragraph 29. Utilities shall provide to the Director of the Safety and Enforcement Division and Energy Division copies of OE-417 reports submitted to the United States Department of Energy (U.S. DOE) within two weeks of filing with U.S. DOE.

Ordering Paragraph 31: The utilities shall submit an annual report by March 31 each year beginning 2020, reporting physical incidents that result in any utility insurance claims, providing information on incident, location, impact on infrastructure and amount of claim. The insurance claim disclosure reporting, as described in this decision, should be included within a utility's broader annual Physical Security Report to the Commission due every March 31, beginning in 2020.

PacifiCorp's Final Distribution Security Plan includes four main elements to ensure all reporting requirements are met.

1. First, to meet the requirement described in Ordering Paragraph 29 of Decision 19-01-018, PacifiCorp provides to the Director of the Safety Enforcement Division and Energy Division copies of OE-417 reports submitted to the United States Department of Energy (U.S. DOE) within two weeks of filing with the U.S. DOE.

2. Second, as described in Ordering Paragraph 31, PacifiCorp submits annually by March 31 each year beginning in 2020, a report of physical incidents that resulted in any utility insurance claims, providing information on incident, location, and impact of infrastructure and amount of claim. Claim notifications to insurers are made in compliance with internal policy notification obligations. PacifiCorp notifies insurers of claims when property damage at insured sites is likely to exceed half of the retention. This annual report also includes a summary of any ODOE 417 reports submitted during the reporting time period as described above. A summary of these reports filed since 2020 is included below.

Reporting Time Period	Report Date	Summary of OE 417 Reports	Summary of Insurance Claims
April 1, 2019 – March 31, 2020	March 31, 2020	No OE-417 reports	No claims
April 1, 2020 – March 31, 2021	March 31, 2021	No OE-417 reports	No claims

3. Third, as described in Ordering Paragraph 27, PacifiCorp shall, in the event of a major physical security event that impacts public safety or results in a major sustained outage, preserve records and evidence associated with such event and shall provide the Commission full unfettered access to information associated with its physical security program and the circumstances surrounding such event.

4. And finally, consistent with Ordering Paragraph 26, upon completion of the five-year plan review as described in Section 3.2 on page 19, PacifiCorp will submit a summary of the program review to the Safety Enforcement Division within 30 days and document the review in the Document Control Section on page 5.

3.4 Record Keeping

Consistent with the Joint Utility Proposal (JUP), electronic copies of this Distribution Security Program Implementation will be retained for not less than five (5) years. As such records are extremely confidential, these records will be maintained in a secure manner at the Operator's headquarters. The records maintained by an Operator will be available for inspection at its headquarters or San Francisco offices by Commission Staff upon request.

These records will include, at a minimum:

1) The Operator's Identification of Distribution Facilities requiring further assessment;

2) Each Operator's Assessment of the potential threats and vulnerabilities of a physical attack and whether existing grid resiliency, customer-owned back-up generation and/or physical security measures appropriately mitigate the risks on each of its identified Distribution Facilities;

3) Each Operator's Mitigation Plans covering each of its Covered Distribution Facilities under Section 4;

4) The unaffiliated third-party evaluation of the Operator's Identification and Assessment evaluations and Mitigation Plans performed and developed by the Operator; and

5) If applicable, the Operator's documented reasons for not modifying its Mitigation Plans consistent with the unaffiliated third-party's evaluation.

4. New Substation Construction

Ordering Paragraph 12: "California electric utilities shall, within any new or renovated distribution substation, design their facilities to incorporate reasonable security features. "

PacifiCorp relies on the application of baseline substation security standards for all new and/or renovated distribution substations to ensure consistent security posture across all of PacifiCorp's distribution facilities. The baseline identifies the minimum physical security requirements for new substation construction and consist of Preventive, Access, and Detective Controls which are inspected and maintained as part of PacifiCorp's Substation Security and Inspection Program further described in Section 5.1 on page 23.

While the specific control measures can vary from site to site depending on voltage class, location, and application, each substation typically includes at least one of each type of the controls listed below.

Table 4: PacifiCorp's Baseline Substation Security Controls

Control Type	Implemented Controls
Preventive Controls	Fence and Gates
	Security Signage
	Security Lighting
Access Controls	Locks/Keys
	Key Management System
Detective Controls	Door Position Remote Switch

Substation physical security design and application for construction of new build specifications is outlined in internal company engineering handbooks and standards. These handbooks and standards, which include specifications for fencing and gates, support National Electrical Safety Code or state specific compliance are leveraged for design and construction activities.

5. Substation Asset Management & Emergency Response Programs

As it pertains to substation physical security and PacifiCorp's Final Security Plan, PacifiCorp has three key asset management and emergency response /restoration programs and approaches: (1) Substation security inspection, (2) Critical Spare Inventory Management, and (3) Workforce Adequacy. PacifiCorp's substation security inspection program is critical to ensure that substation security preventions and controls are in place and maintained in good, working condition. Additionally, PacifiCorp's spare inventory management strategy and workforce adequacy are critical to ensure quick recovery to mitigate the longer-term impacts to customers and communities should a potential physical security breach or incident occur. These programs are described below in future details.

5.1 Substation Security Inspection Program

Ordering Paragraph 15: "Utility security plans shall include a detailed narrative explaining how the utility is taking steps to implement a preventative maintenance plan for security equipment to ensure that mitigation measures are functional and performing adequately."

PacifiCorp's preventative maintenance program includes the performance of substation inspections on a routine basis consistent with California General Order 174 requirements. As part of this program, qualified personnel inspect PacifiCorp substations in California which includes the assessment of physical safety, overall security of the substation, identify safety hazards, including fencing, grounding, and major equipment, as well as the performance of minor housekeeping tasks to ensure safe and reliable service. These inspections are considered standard operations that provide incremental reduction of risk due to defects in equipment or breakdowns in substation security mitigation measures. Table 5 describes the types of inspections performed as a part of this program and planned frequency for each.

Table 5: PacifiCorp's Programmatic Distribution Substation Inspection Cycles

Type of Inspection	Voltage Class	Frequency
Substation Inspection (including IR)	Distribution	Bi-Annual (24 months)
Substation & Security Inspection[12]	Distribution	At least 8 times per year (4 major, 4 minor)

A total of eight substation and security inspections are performed per year at each distribution substation.

Minor Substation & Security Inspection: At least four minor inspections are performed per year which generally include a visual inspection of key substation security features and the functional test of the control house remote alarm. For example, the doors and windows are visually inspected, and any spare equipment and PT fuses are verified to be in good, working condition. Additionally, the remote alarm on the Control House is functionally tested and verified with dispatch.

Major Substation & Security Inspection: Four major inspections are completed per year. In addition to the general visual inspection components included in the minor inspection, major inspections also include more detailed measurements and assessments such as fencing height, fencing climb ability, clearance of

[12] On average, substation and security inspections are typically performed on all substations on a monthly basis. However, internal policies require that inspections be performed at least 8 times per year.

climbable vegetation to fencing, existing gap between gate and finished grade, and general condition of masonry walls, other barrier conditions, tension and barbed wire condition. Additionally, major inspections include functional testing of entry lock, substation lighting, and remote alarms. Finally, major substation inspections include verification that only substation or critical equipment is stored within the fence at required distanced to deter attacks of "opportunity" for theft of material items.

5.2 Critical Spare Inventory Management

Ordering Paragraph 13: "Utility security plans shall include a detailed narrative explaining how the utility is taking steps to implement an asset management program to promote optimization, and quality assurance for tracking and locating spare parts stock, ensuring availability, and the rapid dispatch of available spare parts."

Asset management is responsible for the implementation of the broader strategy as well as purchasing and records management of key spare equipment throughout the company's service territory. Electronically, key spares are noted and tracked in SAP, PacifiCorp's System of Record for larger capital assets. Asset management takes a wholistic view to ensure spares are located throughout the company's service territory at a combination of local Service Centers and designated storage hubs. PacifiCorp maintains the capability to purchase or move spare inventory as needed to support operations. While asset management maintains responsibility for the overall strategy, local operations is responsible for assessing and mobilizing key spares in the event of an emergency or unplanned outage, which would include an outage as a result of a physical security breach.

Figure 4 depicts this general critical spare inventory management process.

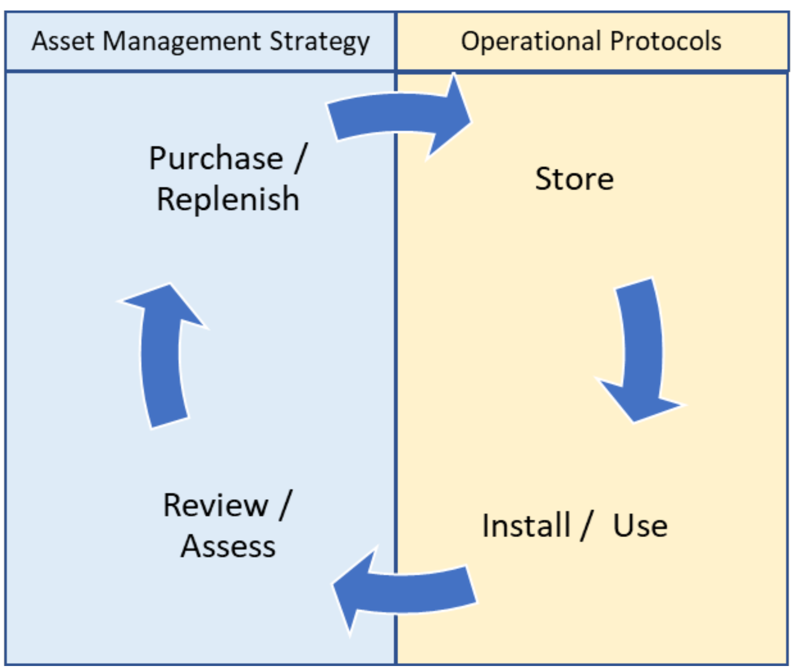

Figure 4: Critical Spare Inventory Management High Level Process

Purchase: As a part of routine evaluation or the result of an unplanned outage, asset management reviews existing inventory levels to identify gaps and recommend the purchase of new strategic spares. Where needed, asset management initiates this process to purchase spare equipment.

Storage: Spare equipment is stored at a combination of local Service Centers and designated storage hubs to ensure dispersion through the company's service territory and support rapid response and recovery. PacifiCorp visually inspects stored spare equipment at these facilities to correct identified deficiencies. Additionally, all new equipment is tested or inspected upon delivery consistent with manufacturer recommendations or warranty requirements.

Use: Local operations oversee the day-to-day usage and near-term decision making during an outage restoration effort and/or equipment failure. When an outage occurs, the initial outage restoration process utilizes alternate feeds and/or spare mobile substation installation to address the near-term need and restore service. Asset Management is contacted during an outage to determine which inventory spare to deploy and transport for installation and service restoration longer term. Transportation contracts are in place to quickly and safely transport mobile substations and spare equipment for customer restoration at the direction of either local operations or asset management.

PacifiCorp's robust equipment inventory and replacement program provides system spare availabilities for each district specific to equipment and voltage needs. To ensure additional availability, equipment purchased for specific projects is also placed in reserved status and can be used if needed during an outage or other unplanned emergency.

Review / Replenish: As spare equipment is installed to restore customer power as a part of this overall process, a subsequent process is initiated to evaluate and assess the need to purchase or replenish any spare inventory installed. Major equipment removed from service is evaluated for repair and, where appropriate, are refurbished and returned to spare inventory by PacifiCorp's Technical Support Department. Where not possible, the equipment is scrapped, and a replacement is purchased.

5.3 Workforce Adequacy and Capability

Ordering Paragraph 14: "Utility security plans shall include a detailed narrative explaining how the utility is taking steps to implement a robust workforce training and retention program to employ a full roster of highly-qualified service technicians able to respond to make repairs in short order throughout a utility's service territory using spare parts stockpiles and inventory."

Should a physical security breach occur that results in physical asset damage and a prolonged outage, PacifiCorp's emergency planning and preparedness capabilities support rapid response and recovery from the incident. An adequate and capable workforce is a component of this overall preparedness.

Key personnel responsible for emergency restoration, including substation restoration are typically journeyman/lineman or meter relay technicians.

> **Substation Journeyman Wireman** are qualified electrical workers and must have: (1) working experience as a Journeyman Wireman or (2) and graduated from a sanctioned apprenticeship program and must also have successfully passed a pre-hire physical assessment. Skills and abilities required by this job are of a level normally acquired by completion of job-related high school courses and the apprenticeship program for Journeyman Wireman.
>
> **Meter Relay Technicians** have a working knowledge of Company substation protection and control schemes. As assigned, they install, maintain, adjust, test, troubleshoot and repair substation protection and control equipment which includes but is not limited to apparatus, meters, relays, controls and remote-control equipment.

External Journeyman new hires with limited substation experience take part in a two-year substation specific Core Module program. Meter/Relay apprentice must meet required criteria and pass an administered test prior to an interview invite, and train in a three-year program to qualify for a Technician position. A Federal Communications Commission license is required for Communication Technicians and Assistant positions.

In addition to these inherent qualifications, PacifiCorp implements training, tools, work processes, and procedures to support maintaining a workforce capable of installing/repairing equipment during an unplanned outage to restore service, which includes outages caused by potential physical security breaches. Initial Safe Entry Training is required for all workforce personnel. Safety and environmental training is also required and refreshed annually alongside a review of mobile substation and emergency generator installation procedures. Furthermore, PacifiCorp's Technical Support and Relay Support Departments host annual craft seminar training for Substation Journeyman and Meter/Relay Technicians covering topics such as equipment maintenance procedures and operating practice, includes hands on training and use of test equipment for maintenance and repair of major equipment such as circuit breakers, transformers, and batteries.

Workforce levels are routinely reviewed by the director of Substation Operations for available and necessary support within each operating district, which includes PacifiCorp's service territory. Additionally, PacifiCorp's California assets and workforce represent a small percentage of the company's overall resources. Should the need present itself, PacifiCorp has access to additional resources located in Southern Oregon and throughout the company's entire service territory which can be deployed to California should the need arise. Furthermore, PacifiCorp is a member of mutual assistance agreements with partnering utilities that provide access to resources if required when responding to an event.

6. PacifiCorp's Distribution Control Center

Ordering Paragraph 16. "Utility security plans shall include a detailed narrative explaining how the utility is taking steps to implement a description of Distribution Control Center and Security Control Center roles and actions related to distribution system physical security."

PacifiCorp's central security control center is responsible for immediate triage of physical security incidents impacting PacifiCorp transmission and distribution assets. Operators monitor alarms where security technology and controls are deployed. Upon notification of an alarm or incident, operators will notify local law enforcement for immediate response. PacifiCorp's corporate security department provides post incident investigation support, security coordination and ensures all appropriate internal and external offices are notified based on the impact to the site and security threat identified. Operations personnel routinely perform substation inspections and identify security impact and concerns. All findings are reported to security for additional coordination and remediation. Reporting procedures are provided as part of new hire and annual security training requirements referenced in Section 5.3 of this Plan. Key security contact numbers and other security notification tools are provided to all employees.

Operation of PacifiCorp's assets are monitored remotely from a central Distribution Control Center. This center provides a full accompaniment of security protections and controls to ensure the safe monitoring and operation of the 44 identified Distribution Facilities within the company's California service territory. These include preventive controls such as barriers, climb-resistant fencing, visible security presence, and security signage. Detective capabilities incorporate a state-of-the-art intrusion detection system, video monitoring, 24x7 onsite security presence plus 24x7 remote security monitoring and alarms. Additionally, the center includes 24x7 on-site security and active engagement with law enforcement.

7. PacifiCorp's Distribution Security Program

Ordering Paragraph 5: All California Electric Utility Distribution Asset Physical Security Plans shall conform to the requirements outlined within the Joint Utility Proposal, as modified by this decision (rules and requirements collectively known as "security plan requirements").

Ordering Paragraph 6: The Investor Owned Utilities and Publicly Owned Utilities shall adhere to the Safety and Enforcement Division's Six-step Security Plan Process.

Ordering Paragraph 7: The Six-step Plan Process consists of the following: Assessment; Independent Review and Utility Response to Recommendations; Safety and Enforcement Division Review (for Investor Owned Utilities s); Local Plan Review (for Publicly Owned Utilities); Maintenance and Plan overhaul/new review.

As described in the introduction, the Joint Utility Proposal was developed through a series of four RASA-led workshops and collaboration between RASA and a technical working group from May to September 2017. The Joint Utility Proposal was initially filed on August 31, 2017, amended through workshops and adopted by the Commission in D.19-01-018.

As described in D.19-01-018, the intent of the Joint Utility Proposal is to implement a risk management approach toward distribution system physical security, with appropriate considerations of resiliency, impact, and cost.[13] In order to accomplish this risk-based approach, general principles were derived from information described and evaluated during the workshops to guide the utility's overall evaluation of Distribution Facilities. These principles note the following:

1. Distribution systems are not subject to the same physical security risks and associated consequences, including threats of physical attack by terrorists, as the transmission system.
2. Distribution utilities will not be able to eliminate the risk of a physical attack occurring, but certain actions can be taken to reduce the risk or consequences, or both, of a significant attack.
3. A one-size-fits-all standard or rule will not work. Distribution utilities should have the flexibility to address physical security risks in a manner that works best for their systems and unique situations, consistent with a risk management approach.
4. Protecting the distribution system should consider both physical security protection and operational resiliency or redundancy.
5. The focus should not be on all Distribution Facilities, but only those that risk dictates would require additional measures.
6. Planning and coordination with the appropriate federal and state regulatory and law enforcement authorities will help prepare for attacks on the electrical distribution system and thereby help reduce or mitigate the potential consequences of such attacks. [14]

The Joint Utility Proposal also describes how a utility should establish a Distribution Security Program consisting of the following key elements: 1) Identification of distribution facilities, 2) Assessment of

[13] D.19-01-018 at 24.
[14] *Id.*

physical security risk on distribution facilities, 3) Development and implementation of security plans, 4) Verification, 5) Record keeping, 6) Timelines, and 7) Cost recovery.[15]

Figure 5 below depicts PacifiCorp's general approach to develop a Final Utility Security Plan consistent with the guiding principles above, the Joint Utility Proposal, and required key elements, and other requirements set forth in D.19-01-018.

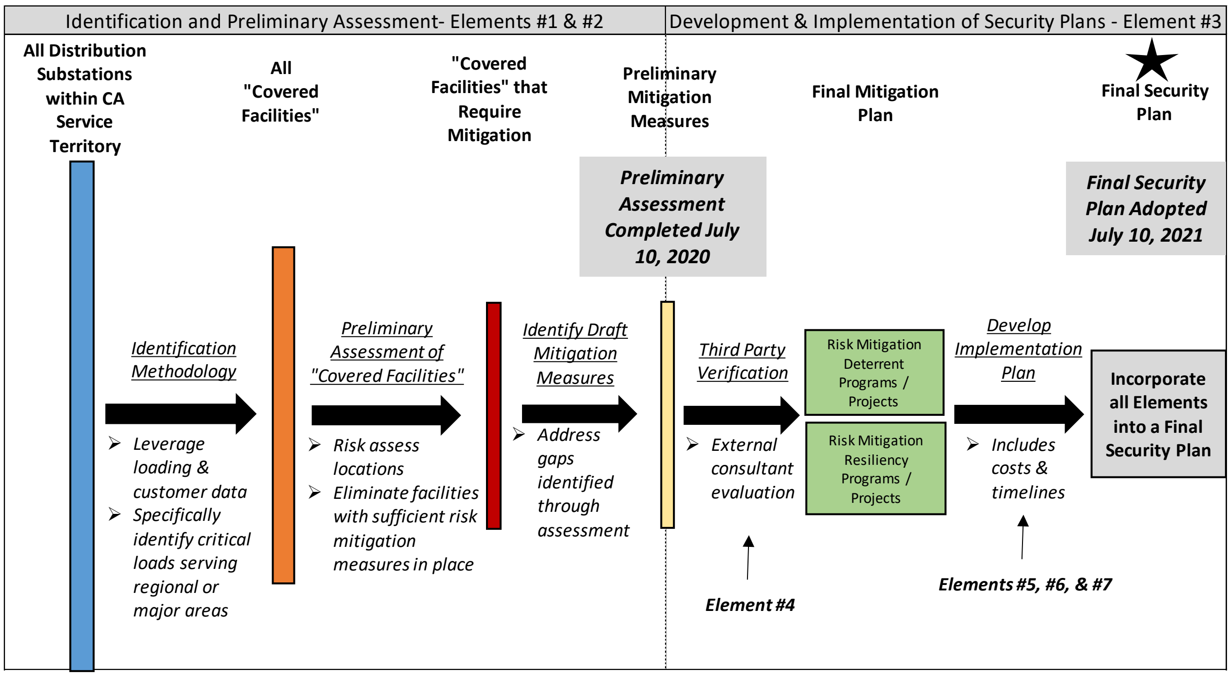

Figure 5: PacifiCorp's General Approach to Develop a Final Utility Security Plan

As identified above, PacifiCorp's general approach to address the six key elements includes five important steps or phases: (1) Identification of Covered Facilities, (2) Assessment of Covered Facilities, (3) Identification of Preliminary Mitigation Measures, (4) Third Party Verification, and (5) Development/Implementation of a Final Security Plan. These pertinent steps align with the key elements in D.19-01-018 and are further described in Table 6 below.

Table 6: High Level Description of Steps Pertinent to PacifiCorp's General Methodology

#	Process Step	PacifiCorp's Approach/General Description
1	Identification of Covered Facilities	The evaluation of electrical system and customer information to identify distribution facilities, defined as Covered Facilities, serving high risk critical loads (as defined by the criteria included in the Joint Utility Proposal and D.19-01-018) that require further risk assessment and, potentially, implementation of risk

[15] *Id.* at 23.

#	Process Step	PacifiCorp's Approach/General Description
		mitigating measures due to the potential impacts of a successful physical attack on the facility.
2	Assessment of Covered Facilities	A risk assessment associated with a probable and successful physical attack of Covered Facilities, including an evaluation of existing prevention and control mitigating measures in place (such as spare equipment, alternate feeds, and physical deterrents) and gap identification.
3	Identification of Preliminary Mitigation Measures	The preliminary identification of the prevention and/or control risk mitigating measures needed to address any gaps identified in Step #2 and reduce the risk of a potential and successful physical attack on a Covered Facility to a reasonable level.
4	Third Party Verification	The procurement of third-party expertise to review the company's preliminary assessment and draft mitigation measures, including an on-site assessment of security risks.
5	Development of Implementation Plan	Incorporation of third-party review and recommendations and refinement of mitigation project scope, budget, and timeline.

Consistent with Ordering Paragraph 1 of D.19-01-018, PacifiCorp filed a 2020 Preliminary Assessment Report on July 10, 2020, which included a discussion of company's general approach and methodology reflected in this section, as well as draft content to meet steps 1 through 3 above. The following subsections revisit these topics, include any modifications or enhancements made as a result of Commission Staff feedback and the external third-party review, and provide new information regarding the final mitigation plan including costs and an implementation timeline.

7.1 Identification

As described in the Joint Utility Proposal memorialized in D.19-01-018 and the general methodology described in the previous section, the identification of Distribution Facilities represents PacifiCorp's first step toward the establishment of a Distribution Security Program to meet the requirements of SB 699. This section includes PacifiCorp's general approach and methodology as well as the results of applying this methodology to its California Distribution Facilities to determine a list of facilities considered to be Covered Distribution Facilities[16] and, therefore, included in scope of subsequent steps and the assessment.

[16] Per D.19-01-018 at 26, "covered is the utility working group term employed to describe those assets that are applicable, or that should be subject to physical security."

7.1.1 Identification Methodology

Consistent with the general principles outlined in the section above and D.19-01-018, the Joint Utility Proposal suggested that not all Distribution Facilities require a full assessment and set forth the following as facilities that do require a subsequent assessment:

1. Distribution Facility necessary for crank path, black start or capability essential to the restoration of regional electricity service that are not subject to the California Independent System Operator's (CAISO) operational control and/or subject to North American Electric Reliability Corporation (NERC) Reliability Standard CIP-014-2 or its successors;
2. Distribution Facility that is the primary source of electrical service to a military installation essential to national security and/or emergency response services (may include certain air fields, command centers, weapons stations, emergency supply depots);
3. Distribution Facility that serves installations necessary for the provision of regional drinking water supplies and wastewater services (may include certain aqueducts, well fields, groundwater pumps, and treatment plants);
4. Distribution Facility that serves a regional public safety establishment (may include County Emergency Operations Centers; county sheriff's department and major city police department headquarters; major state and county fire service headquarters; county jails and state and federal prisons; and 911 dispatch centers);
5. Distribution Facility that serves a major transportation facility (may include International Airport, Mega Seaport, other air traffic control center, and international border crossing);
6. Distribution Facility that serves as a Level 1 Trauma Center as designated by the Office of Statewide Health Planning and Development; and
7. Distribution Facility that serves over 60,000 meters.[17]

In order to identify which of the 44 Distribution Facilities within PacifiCorp's California service territory provide electricity to critical loads meeting one or more of these definitions, PacifiCorp pulled all of the company's loading and customer information in California, mapped this data back to the electric supply source facility (Distribution Facility), and then categorized the customer information according to the seven definitions above. Consistent with the guiding principles and the criteria above, any customers with full back up generation at their site, operational fail-over capability, or alternate feeds were excluded from the list as any physical security incident at the substation would not have a significant impact to reliability for that customer.

Table 7 below includes PacifiCorp's specific approach to applying the six screening criteria defined in D.19-01-018 to company-specific critical loads/customers.

[17] D.19-01-018 at 25-26.

Table 7: Identification Screening Criteria Detailed Approach

#	Screening Criteria	PacifiCorp's Specific Approach
1.	Distribution Facility necessary for crank path, black start or capability essential to the restoration of regional electricity service that are not subject to the California Independent System Operator's (CAISO) operational control and/or subject to North American Electric Reliability Corporation (NERC) Reliability Standard CIP-014-2 or its successors;	PacifiCorp reviewed system operations, grid operations, and area planning to identify any crank path or black start essential facilities within PacifiCorp's California service territory. As PacifiCorp does not currently have any black start facilities in the state of California, no loads or facilities were expected to meet this criteria.
2.	Distribution Facility that is the primary source of electrical service to a military installation essential to national security and/or emergency response services (may include certain air fields, command centers, weapons stations, emergency supply depots);	PacifiCorp reviewed customer and load attributes to identify those specifically critical to national security, excluding administrative or recruiting facilities. Upon review of PacifiCorp's critical load/customer load database, no pertinent facilities essential for national security were identified and, therefore, no facilities were selected based on this criteria.
3.	Distribution Facility that serves installations necessary for the provision of regional drinking water supplies and wastewater services (may include certain aqueducts, well fields, groundwater pumps, and treatment plants);	Through collaboration with other utilities, PacifiCorp reviewed critical customer/loading information to identify in scope locations serving regional drinking water supplies and wastewater supplies that has the potential for a major impact, scaled to fit PacifiCorp's unique service territory. In performing this evaluation, PacifiCorp eliminated localized facilities and individual pump locations which have the potential to impact small portions of small communities and, instead, focused on major hub facilities with the potential to impact wastewater treatment or water delivery to larger region or system of facilities. This "hub and spoke" approach allowed PacifiCorp to focus on the major and regional facilities consistent with the risk-based approach contemplated in the Joint Utility Proposal. As a result, PacifiCorp identified and included 11 points of delivery with the potential to impact a significant portion of communities.
4.	Distribution Facility that serves a regional public safety establishment (may include County Emergency Operations Centers; county sheriff's department and major city police department headquarters;	PacifiCorp reviewed critical customer/loading information to identify in scope locations such as major county fire service headquarters or state

#	Screening Criteria	PacifiCorp's Specific Approach
	major state and county fire service headquarters; county jails and state and federal prisons; and 911 dispatch centers);	and federal prisons meeting one of the following definitions: Given the rural and small footprint of PacifiCorp's service territory within northern California, it is reasonable and expected that no distribution facility is likely to provide electricity to a major state or city facility. However, similar to screening criteria #3, PacifiCorp scaled this approach to fit the company's unique service territory and included facilities critical to regional wildfire protection and restoration that may not have met the strict definition above. As a result, 11 critical points of delivery were identified, mostly consisting of state level penitentiaries, state level emergency response offices, and multi-county level fire protection offices/facilities.
5.	Distribution Facility that serves a major transportation facility (may include International Airport, Mega Seaport, other air traffic control center, and international border crossing);	PacifiCorp reviewed critical customer/loading information to identify major transportation facilities. Given the rural and small footprint of PacifiCorp's service territory within northern California, it is reasonable and expected that no distribution facility is likely to provide electricity to a major transportation facility in northern California.
6.	Distribution Facility that serves as a Level 1 Trauma Center as designated by the Office of Statewide Health Planning and Development;	PacifiCorp reviewed current listings of Level 1 Trauma Centers and cross referenced with the company's service territory and customer information. No Level 1 Trauma Centers were found to be located within PacifiCorp's California service territory.
7.	Distribution Facility that serves over 60,000 meters.	PacifiCorp identified distribution substations providing electrical service to more than 60,000 meters, equivalent to approximately 60,000 customers. PacifiCorp only serves 45,000 customers throughout the company's California service territory. Therefore, as expected, no substation was identified as providing service to more than 60,000 customers/meters.

7.1.2 Identification Results – List of Covered Facilities

As a result of applying the methodology and general approach set forth by the Joint Utility Proposal to the 44 identified Distribution Facilities within the company's California service territory, PacifiCorp identified 22 critical customers/services/loads served by 13 different substations to be included in the development of the company's Distribution Security Program and, therefore, assessed for physical security risk. See the high level summary in Table 8 below of the identified Distribution Facilities.

Table 8: Identification of Covered Distribution Facilities Summary

Substation Generic Name[18]	# of In Scope Critical Facilities[19]	*Distribution Substation Serves as the Primary Supply of Electricity For:*						
		Crank Path, Black Start	Military Installation Essential to National Security	Regional Drinking or Wastewater Services	Regional Public Safety Est.	Major Transp. Facility	Level 1 Trauma Center	Over 60,000 Meters
Substation 1	3	-	-	-	X	-	-	-
Substation 2	1	-	-	-	X	-	-	-
Substation 3	1	-	-	-	X	-	-	-
Substation 4	1	-	-	-	X	-	-	-
Substation 5	4	-	-	X	-	-	-	-
Substation 6	2	-	-	-	X	-	-	-
Substation 7	2	-	-	X	-	-	-	-
Substation 8	1	-	-	X	-	-	-	-
Substation 9	1	-	-	-	X	-	-	-
Substation 10	1	-	-	-	X	-	-	-
Substation 11	2	-	-	X	-	-	-	-
Substation 12	2	-	-	X	-	-	-	-
Substation 13	1	-	-	-	X	-	-	-

As indicated above, all 22 of the critical loads identified were considered regional public safety establishments such as state level penitentiaries, state level emergency response offices, and multi-county level fire protection offices/facilities or loads critical for regional drinking or wastewater services. These thirteen Covered Facilities were then considered in scope for additional assessments and potential mitigation measures. All other distribution facilities were determined to be low or negligible risk and, consistent with the Joint Utility Proposal described in D.19-01-018, were not further evaluated.

[18] To protect information that is critical to either maintaining the security of the electrical grid or confidentiality of the customer(s), the Covered Facilities have been assigned generic names which are used throughout this filing.
[19] Number of facilities used in this context refers to the number of points of delivery.

7.2 Assessment

Consistent with the Joint Utility Proposal and D.19-01-018, after PacifiCorp identified 13 Distribution Facilities requiring additional assessment, the company moved from the Identification of Covered Distribution Facilities to the company's Preliminary Assessment to determine whether or not existing risks are appropriately mitigated. This represents PacifiCorp's second step toward the development of a Final Security Plan. The following section includes PacifiCorp's general approach and methodology as well as the results of applying this methodology to its California Covered Distribution Facilities.

7.2.1 Assessment Methodology

PacifiCorp defines risk as a combination of probability (also referred to as likelihood) that an event or type of event might occur and the consequences (also referred to as impact) of that event occurring. The presence of risk relies on both probability and consequences and, therefore, the level of risk remains low if either probability or consequence is considered insignificant or negligible. Risk can also be categorical, such as the general risk associated with distribution substations as a category which could be located at multiple locations, or site specific, such as the risk associated with a specific distribution substation at a particular location. For the purposes of the assessment contemplated in this filing and methodology, PacifiCorp leveraged the general risk assessment approach depicted in Figure 6 below to perform site specific assessments of Covered Facilities.

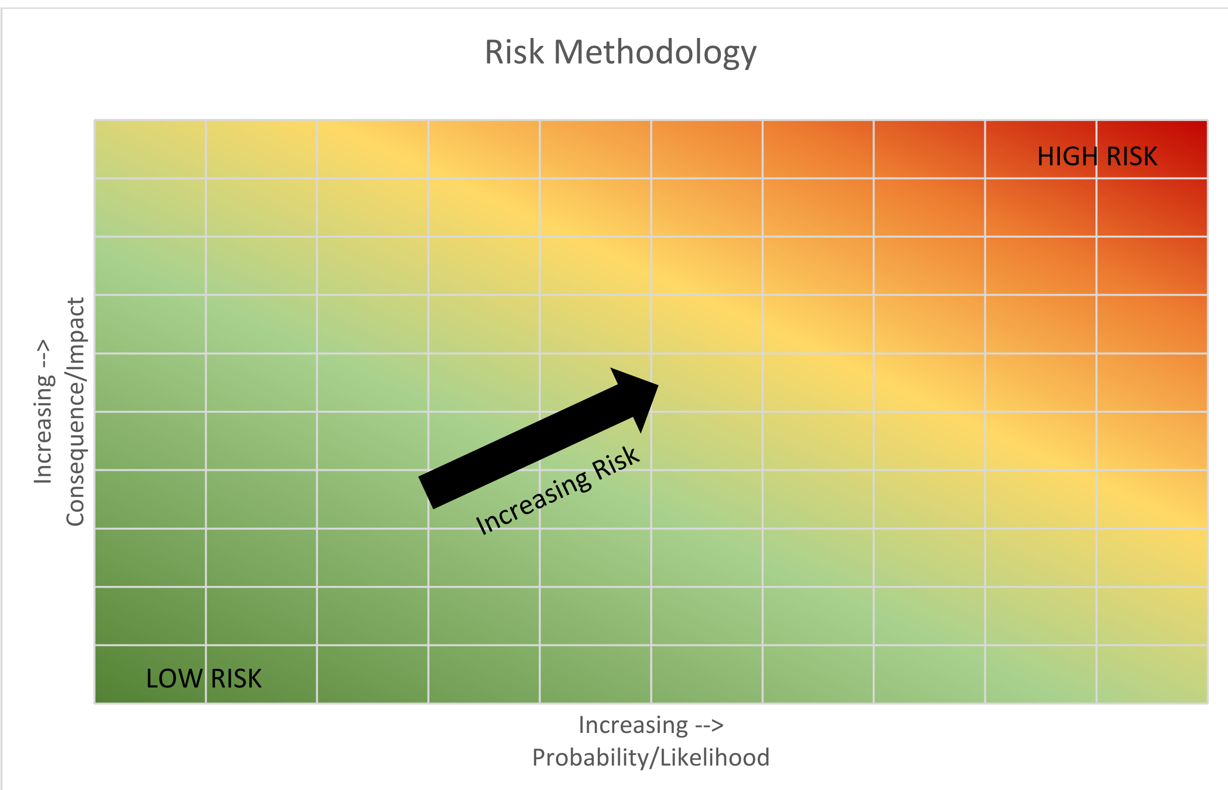

Figure 6: General Risk Methodology Visualization

As contemplated in this methodology, the level of risk assessed is qualitative and comparative in nature but is proportional to the order of magnitude of both probability and consequence. The level of risk both increases and decreases proportionally with an increase or decrease in probability and/or consequences and, therefore, the level of risk can be changed or altered through the implementation of mitigating measures. To further explore site-specific risk assessments and how a risk level can be changed or mitigated, PacifiCorp leveraged a standard bow-tie approach, which is depicted in Figure 7 below.

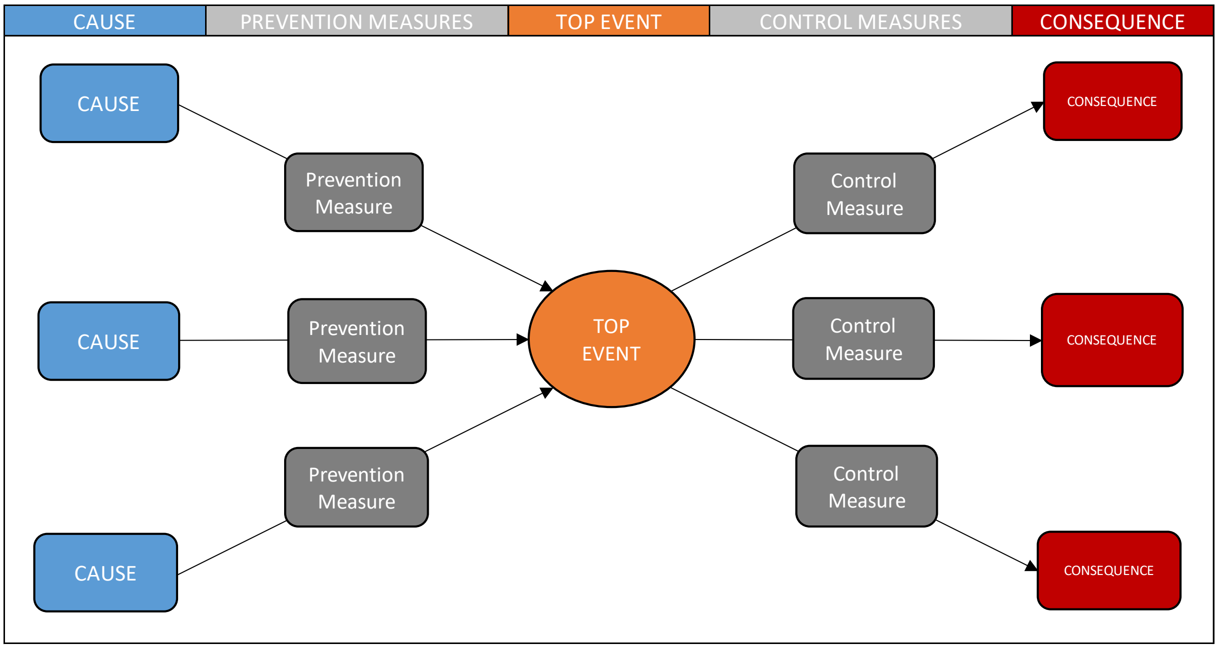

Figure 7: Risk Mitigation - Standard Bow-Tie Approach Visualization

This general bow-tie risk assessment methodology includes the identification of cause(s) for a defined top event or threat as well as the assessment of prevention measure(s) and control measure(s) in place to prevent these causes from resulting in a top event or prevent the top event from resulting in the identified negative consequence(s).

While the implementation of both prevention and control measures can effectively lower risk, each works in its own way or in combination. As indicated by the name, prevention measures prevent the top event from occurring altogether, effectively reducing the likelihood of an event, while control measures work to control the extent of an event and limit the negative impact, effectively reducing the consequences. Implementing either prevention or control measures can reduce risk. Additionally, both prevention and control measures can work together to effectively mitigate or lower the risk level.

Figure 8 below depicts the qualitative impact of prevention and control mitigation measures on risk level independently as well as how a combined program can effectively lower the level of risk.

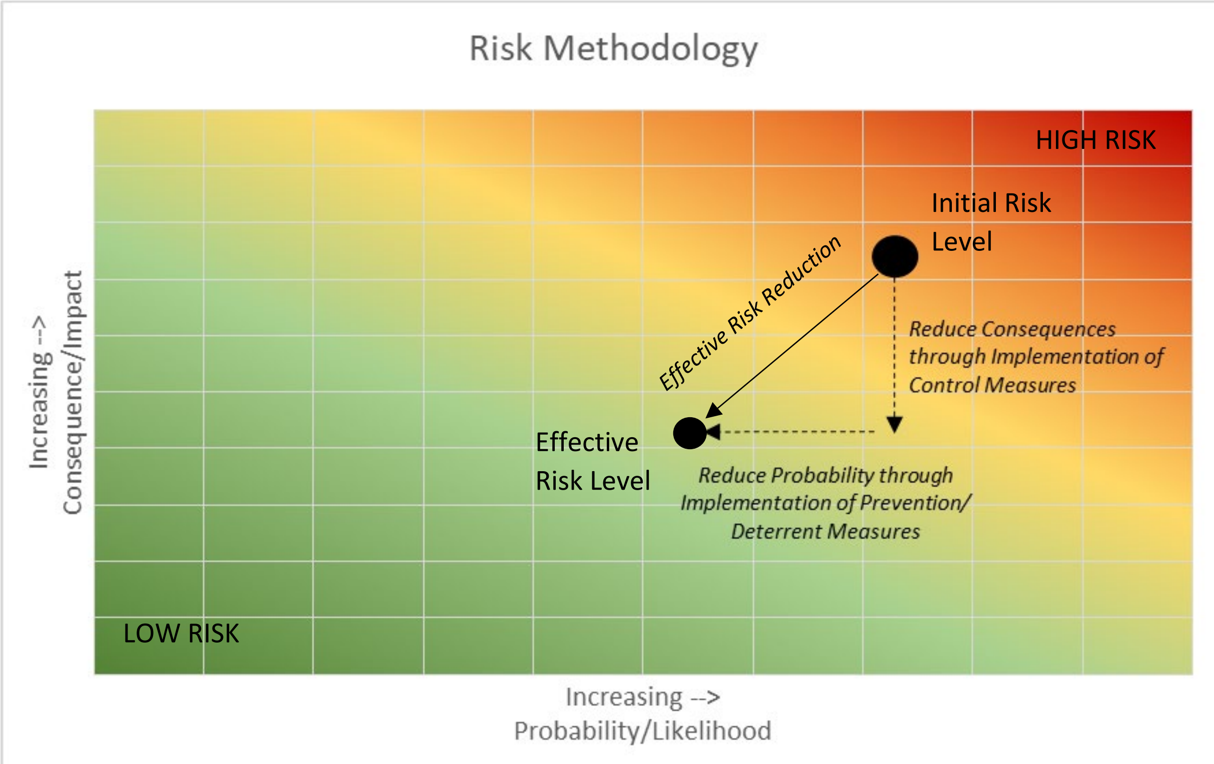

Figure 8: General Impact of Prevention and Control Measures on Risk Level

Based on this framework, PacifiCorp's assessment of Covered Facilities includes the following four main components:

1) Definition of the Top Event
2) Identification of Causes and Consequences
3) Evaluation of Prevention and Control Mitigation Measures
4) Assessing Risk Level of Locations

These components are further discussed in the following subsections.

7.2.1.1 Top Event /Threat

Consistent with D.19-01-018, SB 699, and the Joint Utility Proposal, PacifiCorp's Distribution Security Program only includes the risk assessment of a successful physical security attack on any of the company's Covered Facilities. PacifiCorp's program does not include an assessment of other Distribution Facilities or other types of top events or threats, such as a cyber security attack.

7.2.1.2 Threat Causes Considered

Consistent with D.19-01-018 and the Joint Utility Proposal, PacifiCorp's assessment recognizes that distribution systems are not subject to the same physical security risks and associated consequences, including threats of physical attack by terrorists, as the transmission system. Table 9 below summarizes all potential threat causes considered and whether or not these threat causes were considered in scope for distribution system assessments, not including those more applicable for a transmission level evaluation.

Table 9: Physical Security Breach Causes in Scope for Distribution Assets

Threat Cause	In Scope? [Yes/No]
Theft	Yes
Vandalism	Yes
Ballistic Attack – Small Arms	Yes
Improvised Explosive Device (IED)	No
Vehicle Borne Improvised Explosive Devices (VBIED)	No
Other major terrorist attacks	No

7.2.1.3 Impact/Consequences

Based on the threat causes identified, a successful physical security attack contemplated in this assessment is defined as a physical security breach due to theft, vandalism, or a small arms ballistic attack that results in damage or loss of control of up to a single transformer or other related equipment critical to provide uninterrupted service to up to one feeder or circuit from a Covered Facility and a prolonged outage to the critical loads on that circuit previously identified.

For example, this methodology considers a scenario where a physical security breach leads to significant vandalism and damage to a distribution substation transformer, rendering it inoperable and requiring that that transformer be removed and replaced prior to restoring service to the corresponding circuit or feeder. In this scenario, an unplanned prolonged outage may occur, negatively affecting the critical loads identified on that circuit.

Complete destruction or inoperability of a Covered Facility was not considered in this risk assessment due to the nature of the threat and causes contemplated and in recognition that distribution systems are not subject to the same physical security risks and associated consequences, including threats of physical attack by terrorists, as the transmission system.

7.2.1.4 Evaluation of Existing Prevention and Control Risk Mitigation Measures

As described in D.19-01-018, the following may be considered when conducting an evaluation of the potential risks associated with a successful physical attack on a Covered Distribution Facility.

1. The existing system resiliency and/or redundancy solutions (*e.g.,* switching the load to another substation or circuit capable of serving the load, temporary circuit ties, mobile generation and/or storage solutions);
2. The availability of spare assets to restore a particular load;
3. The existing physical security protections to reasonably address the risk;
4. The potential for emergency responders to identify and respond to an attack in a timely manner;
5. Location and physical surroundings, including proximity to gas pipelines and geographical challenges, and impacts of weather;
6. History of criminal activity at the Distribution Facility and in the area;

7. The availability of other sources of energy to serve the load (*e.g.*, customer owned back-up generation or storage solutions);

8. The availability of alternative ways to meet the health, safety, or security; and

9. Requirements served by the load (*e.g.*, back up command center or water storage facility). [20]

As shown in Table 10 below, consistent with the general methodology leveraged by PacifiCorp, the above assessment criteria were grouped into either being indicative of a prevention (or likelihood) or a control (consequence) mitigation measure.

Table 10: Categorization of Assessment Criteria – Prevention or Control Mitigation Measure

#	Mitigating Measure/Assessment Criteria	Prevention OR Indicative of Likelihood	Control OR Indicative of Consequences
1	The existing system resiliency and/or redundancy solutions (*e.g.,* switching the load to another substation or circuit capable of serving the load, temporary circuit ties, mobile generation and/or storage solutions);		X
2	The availability of spare assets to restore a particular load;		X
3	The existing physical security protections to reasonably address the risk;	X	
4	The potential for emergency responders to identify and respond to an attack in a timely manner;		X
5	Location and physical surroundings, including proximity to gas pipelines and geographical challenges, and impacts of weather;	X	
6	History of criminal activity at the Distribution Facility and in the area;	X	
7	The availability of other sources of energy to serve the load (*e.g.*, customer owned back-up generation or storage solutions);		X
8	The availability of alternative ways to meet the health, safety, or security; and		X
9	Requirements served by the load (*e.g.*, back up command center or water storage facility).		X

After categorizing the assessment criteria, as show in Table 11 below, PacifiCorp took the approach of assessing the presence and effectiveness of the existing prevention and control measures at each Covered Facility.

[20] D.19-01-018 at 26-27.

Table 11: PacifiCorp's Approach to Assessment of Existing Mitigating Measures

#	Mitigating Measure/Assessment Criteria	PacifiCorp's Approach to Assessment
1	The existing system resiliency and/or redundancy solutions (*e.g.,* switching the load to another substation or circuit capable of serving the load, temporary circuit ties, mobile generation and/or storage solutions);	PacifiCorp evaluated existing level or resilience and/or redundancy on the distribution system to provide an alternate source of electricity to critical loads previously identified, through either switching or alternate generation, should the primary source or electricity be compromised at the Covered Facility resulting in a prolonged outage. As a result, three Covered Facilities were found to already have the ability to switch/alternate feeds. Six Covered Facilities were found to have partial capability, with seasonal loading constraints. However, the remaining four Covered Facilities were determined to have no switching or alternate generation capabilities.
2	The availability of spare assets to restore a particular load;	PacifiCorp's existing dispatchable mobile and spare transformer inventory was evaluated (as this would be a long lead/prolonged outage) to identify the type and number of compatible spare units for each in service transformer within the Covered Facilities that functions as the primary source of electricity to the critical loads identified. As a result, all transformers at Covered Facilities serving critical loads were identified to have multiple compatible backups that could be dispatched to the Covered Facility to restore service and prevent an extended outage.
3	The existing physical security protections to reasonably address the risk;	PacifiCorp evaluated site specific physical security barriers and deterrents above and beyond standard physical security measures such as remotely monitored alarms or additional locks on equipment inside the substation fencing. While all Covered Facilities were found to have at least one or more enhanced security protections in place, only two facilities were determined to have all enhanced physical security protections in place to fully mitigate risk. All other Covered Facilities were determined to have partial mitigation measures in place.

#	Mitigating Measure/Assessment Criteria	PacifiCorp's Approach to Assessment
4	The potential for emergency responders to identify and respond to an attack in a timely manner;	Based on the recommendation from the third-party assessor, PacifiCorp mapped out the closest emergency responder to each Covered Facility which would be contacted in case of emergency to determine both distance and transport time. Each Covered Facility was then ranked based on the following criteria: Drive Time ≤ 15 mins = LOW Drive Time >15 mins & ≤ 30 mins = MID Drive Time > 30 mins = HIGH All substations were found to be within a 15-minute drive of the nearest emergency responder. This result was then layered with any known seasonal access constraints the could potential hinder assess and fast response. As a result, 2 substations were identified with seasonal access constraints and assessed as a MID level of risk.
5	Location and physical surroundings, including proximity to gas pipelines and geographical challenges, and impacts of weather;	PacifiCorp, in collaboration with the third-party assessor, performed physical site assessments of the Covered Facilities to evaluate whether or not the location and physical surrounding provided natural mitigation and deterrents that reduce risk or exposed the substation to vulnerabilities. As a result, 3 covered facilities were found to have a MID level of exposure and risk, while the remaining 10 substations were assessed as low risk.
6	History of criminal activity at the Distribution Facility and in the area;	Similar to screening criteria #5, the history of criminal activity in the area of a Covered Facility may be indicative of the probability that a physical security breach due to vandalism, theft, or ballistic attack will happen. PacifiCorp evaluated a history of criminal activity in the vicinity of each Covered Facility as compared to the national average crime rates. Covered Facilities with crime rates lower than the national average were deemed to be low likelihood, those with crime rates higher than 50 percent above the national average were considered to be high likelihood, and facilities with crime rates in between were identified as having a medium level of likelihood.

#	Mitigating Measure/Assessment Criteria	PacifiCorp's Approach to Assessment
		This data driven analysis was also layered with the results of the physical site assessment to include any observed trespassing, damage, or vandalism. As a result, 4 Covered Facilities were assessed HIGH, 2 MID, and the remaining 7 as LOW.
7	The availability of other sources of energy to serve the load (*e.g.*, customer owned back-up generation or storage solutions);	At this time, PacifiCorp has not evaluated the potential for customer owned generation at each critical load as a part of this assessment.
8	The availability of alternative ways to meet the health, safety, or security; and	At this time, PacifiCorp is not formally considering providing alternate ways to meet the needs served by the critical loads and therefore, has not considered this aspect as part of this assessment.
9	Requirements served by the load (*e.g.*, back up command center or water storage facility).	Inhered to the identification methodology considered, the critical loads and corresponding Covered Facilities were selected based on the necessity of the load and corresponding community service provided and lack of alternatives available to provide that service. Therefore, the requirements served by the load were already considered in the identification and not further contemplated as part of this assessment.

Figure 9 below depicts the culmination of this effort to define the top event and identify causes, consequences, and existing mitigation measures to perform a assessment of Covered Facilities.

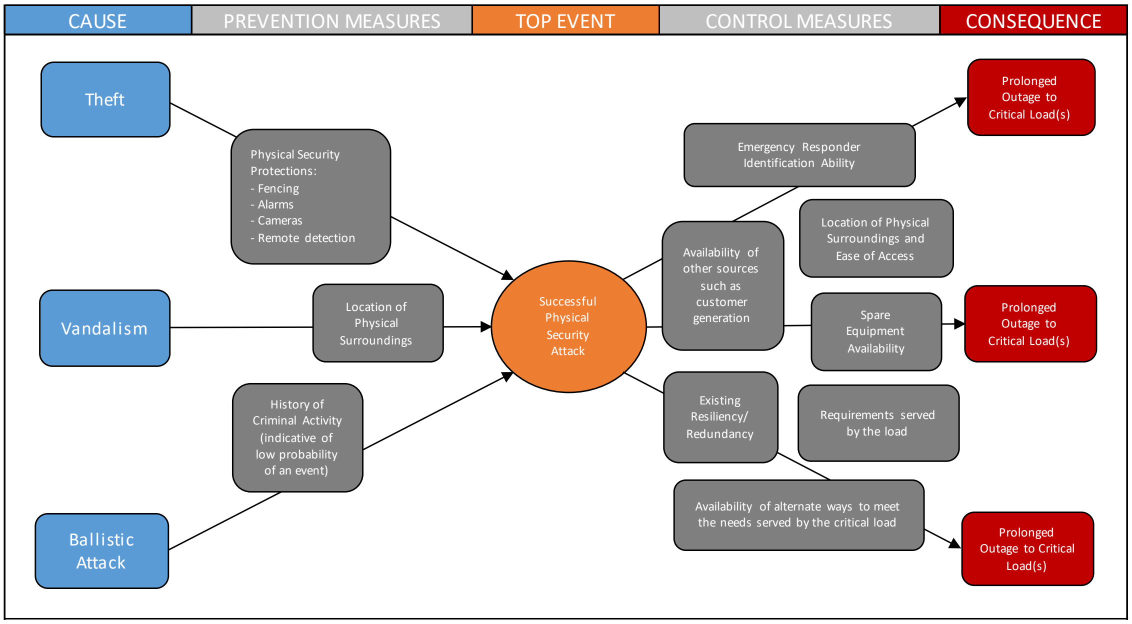

Figure 9: Preliminary Assessment of Covered Facilities Bow-Tie

Furthermore, Figure 10 below depicts how the existing prevention and control mitigation measures assessed by PacifiCorp on all Covered Facilities were used to determine an effective risk level.

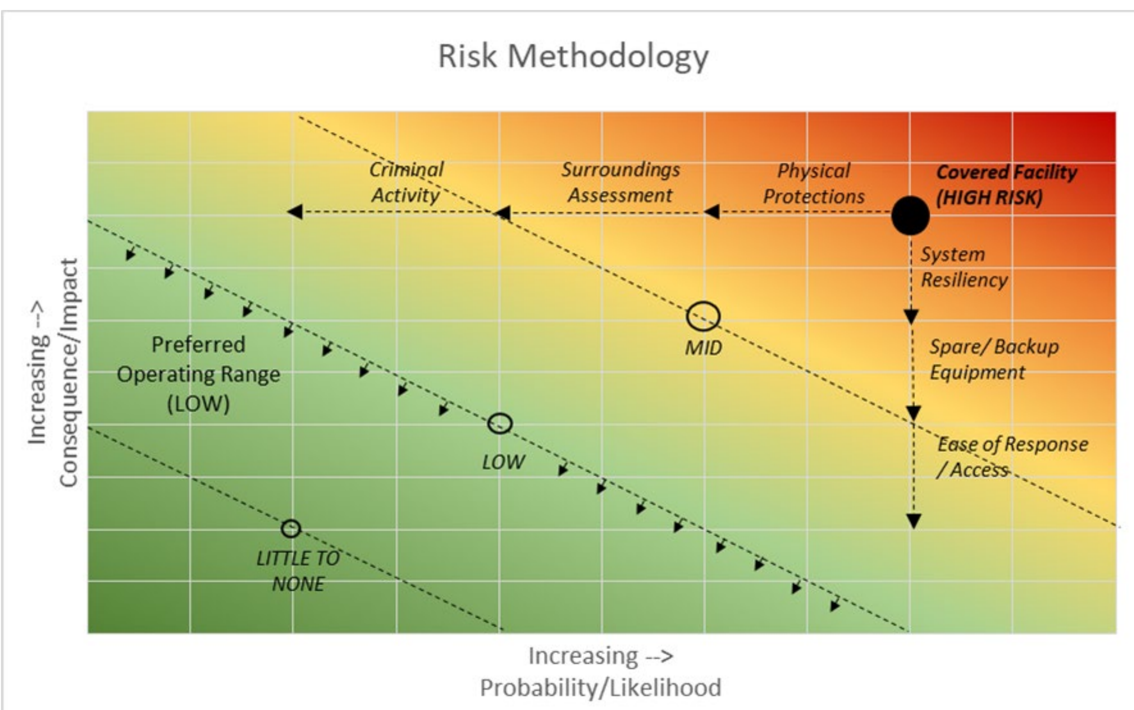

Figure 10: Preliminary Assessment of Covered Facilities Effective Risk Level Mapping

As described in the above figure above, all Covered Facilities are initially designated as high risk given the nature of the proceeding and the assessment of impact through the identification of critical loads. The assessed risk level of each Covered Facility is then a result of both the presence and the effectiveness of existing prevention and control mitigation measures in place. A greater number of or more effective measures, reduce the risk level at a greater rate than fewer or less effective measures.

The following section includes the results of applying this methodology to the 13 Covered Facilities along with the resulting assessed effective risk level.

7.2.2 Assessment Results

Table 12 below includes the results of applying the previously described methodology to the list of Covered Facilities to determine the Assessed Risk Level of each site.

Table 12: Risk Assessment of Covered Facilities Results

Substation "Name	Number of Critical Loads	PREVENTION MEASURES			CONTROL MEASURES				ASSESSED RISK LEVEL
		Criteria #3: Existing Physical Protections	Criteria #5: Physical Surrounding Assessment	Criteria #6: Criminal History	Criteria #1: Existing Resiliency / Redundancy	Criteria #2: Spares and Mobile Assessment	Criteria #4: Ease of Assess / Response Capability	*Criteria #7 - #9 (Already incorporated or not specifically considered)*	
Substation 1	3	In Place / Partly Effective	Fully Effective	Fully Effective	In Place / Partly Effective	Fully Effective	In Place / Partly Effective		LOW
Substation 2	**1**	**In Place / Partly Effective**	**In Place / Partly Effective**	**Not in Place / Not Effective**	**In Place / Partly Effective**	**Fully Effective**	**Fully Effective**		**MID**
Substation 3	1	Fully Effective	Fully Effective	Not in Place / Not Effective	In Place / Partly Effective	Fully Effective	Fully Effective		LOW
Substation 4	1	In Place / Partly Effective	In Place / Partly Effective	Fully Effective	Not in Place / Not Effective	Fully Effective	Fully Effective		LOW
Substation 5	4	In Place / Partly Effective	Fully Effective	In Place / Partly Effective	In Place / Partly Effective	Fully Effective	Fully Effective		LOW
Substation 6	2	In Place / Partly Effective	Fully Effective	Fully Effective	Not in Place / Not Effective	Fully Effective	Fully Effective		LOW
Substation 7	2	Fully Effective	Fully Effective	Not in Place / Not Effective	Fully Effective	Fully Effective	Fully Effective		LOW
Substation 8	1	In Place / Partly Effective	Fully Effective	Fully Effective	Fully Effective	Fully Effective	Fully Effective		LOW
Substation 9	1	In Place / Partly Effective	Fully Effective	Fully Effective	In Place / Partly Effective	Fully Effective	Fully Effective		LOW
Substation 10	1	In Place / Partly Effective	Fully Effective	Fully Effective	In Place / Partly Effective	Fully Effective	Fully Effective		LOW
Substation 11	**2**	**In Place / Partly Effective**	**Fully Effective**	**Not in Place / Not Effective**	**Not in Place / Not Effective**	**Fully Effective**	**Fully Effective**		**MID**
Substation 12	2	In Place / Partly Effective	Fully Effective	In Place / Partly Effective	Fully Effective	Fully Effective	Fully Effective		LOW
Substation 13	**1**	**In Place / Partly Effective**	**In Place / Partly Effective**	**Fully Effective**	**Not in Place / Not Effective**	**Fully Effective**	**In Place / Partly Effective**		**MID**

As included in Table 12 above, after evaluating the existing protection and control mitigation measures in place, 10 of the 13 Covered Facilities were assessed to have a LOW effective risk level. As it is PacifiCorp's goal to operate the grid at a risk level as low as practical, the risk of a successful physical security breach on these Covered Facilities was determined to be properly mitigated at these 10 locations. However, three Covered Facilities were assessed to be a MID level of risk, indicative that additional mitigation measures may be needed to properly reduce the effective risk level to LOW. See the final results plotted below in Figure 11.

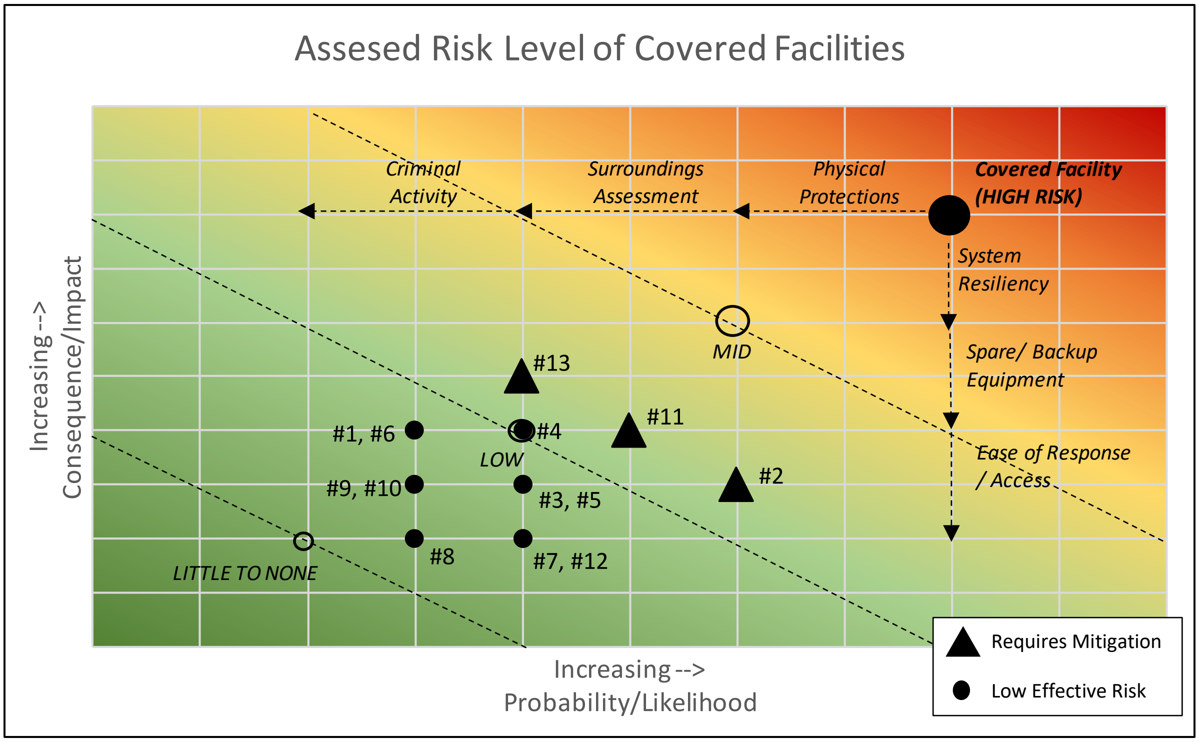

Figure 11: Final Assessment of Covered Facilities - Results

7.3 Mitigation Plan

PacifiCorp aims to operate the electrical grid with a risk level as low as practical. As a result of the Assessment, PacifiCorp identified three substations that may need additional mitigation measures to properly reduce the effective risk level to LOW. See Table 13 below and Figure 12 below.

Table 13: Risk Assessed Covered Facilities that Require Mitigation Measures

Substation Name	Number of Critical Loads	PREVENTION MEASURES			CONTROL MEASURES				ASSESSED RISK LEVEL
		Criteria #3: Existing Physical Protections	Criteria #5: Physical Surrounding Assessment	Criteria #6: Criminal History	Criteria #1: Existing Resiliency / Redundancy	Criteria #2: Spares and Mobile Assessment	Criteria #4: Ease of Assess / Response Capability	*Criteria #7 - #9 (Already incorporated or not specifically considered)*	
Substation 2	**1**	In Place / Partly Effective	In Place / Partly Effective	Not in Place / Not Effective	In Place / Partly Effective	Fully Effective	Fully Effective		MID
Substation 11	**2**	In Place / Partly Effective	Fully Effective	Not in Place / Not Effective	Not in Place / Not Effective	Fully Effective	Fully Effective		MID
Substation 13	**1**	In Place / Partly Effective	In Place / Partly Effective	Fully Effective	Not in Place / Not Effective	Fully Effective	In Place / Partly Effective		MID

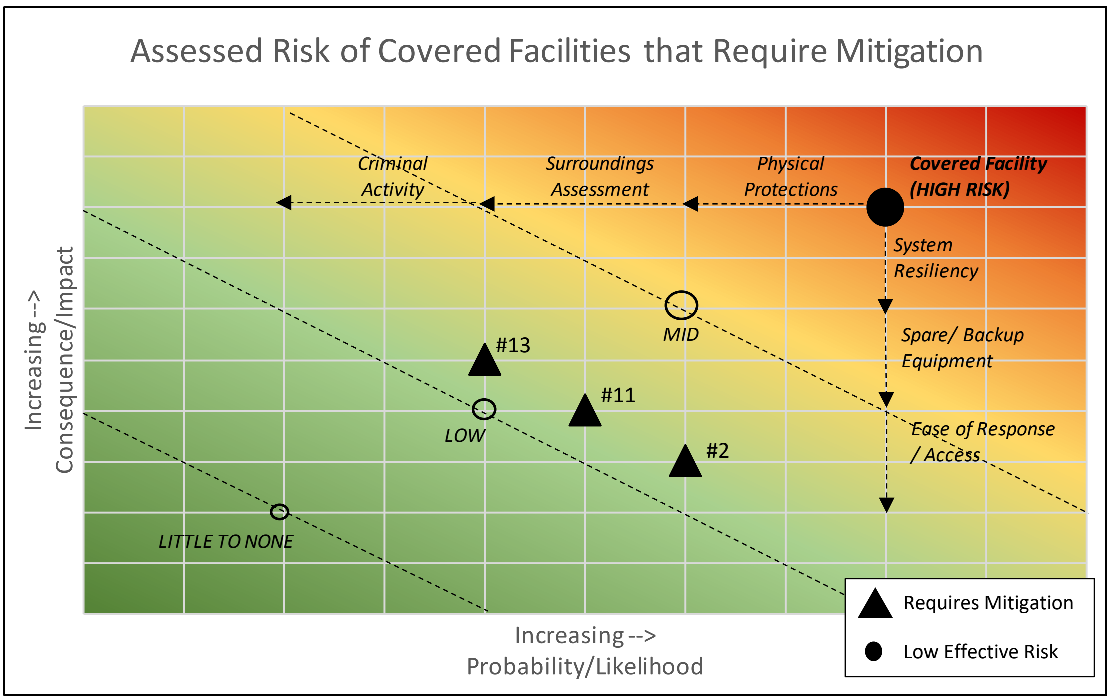

Figure 12: Assessed Risk Level of Covered Facilities that Require Mitigation

As PacifiCorp's goal is to operate the system and mitigate risk to the lowest level practical, PacifiCorp, in collaboration with the third-party assessor, developed a list of mitigation measures or projects targeted at the partly effective or not effective existing measures in order to reduce the Assessed Risk Level from MID to LOW. As a result, PacifiCorp's has preliminarily identified mitigation projects shown in Table 14.

Table 14: Mitigation Project Summary

Substation	Number of Critical Loads	Assessed Risk Level	Key Target Areas for Improvement	Description of Mitigation Projects / Measures
Substation 2	1	MID	**Existing Physical Protections:** Given the high crime rate and prevalence for trespassers, the physical protections in place may not be sufficient. **History of Criminal Activity**: Substation 2 is located in a higher crime rate area with *observed presence of trespassers on site* identified during the physical site assessment	**Improvements to physical security above and beyond standard protocols:** Installation of additional fencing and gates alongside and behind substation in addition to existing barriers to prevent unauthorized vehicle traffic and trespassing behind the substation **Relocation of Active Trespassers:** PacifiCorp worked with local city officials to relocate existing trespassers to a safer location away from the substation
Substation 11	2	MID	**Existing Physical Protections:** Given the high crime rate and prevalence for trespassers, the physical protections in place may not be sufficient. *Note: Substation 11 is located in a higher crime rate area but no specific observation of trespassers (Criminal History – Criteria #6)*	**Improvements to physical security above and beyond standard protocols:** Installation of additional fencing fabric with slats to enhance existing perimeter fencing to elevate level of deterrent.
Substation 13	1	MID	**Existing Physical Protections:** Given the vulnerability of the physical location and remote nature, existing physical protections in place may not be sufficient **Access Constraints:** Seasonal flooding could limit the ability for expedited restoration following an event.	**Improvements to physical security above and beyond standard protocols:** Installation of additional lights and fencing fabric with slats to enhance existing perimeter and elevate level of deterrent. **Removal of Seasonal Access Constraints:** Existing substation improvement project kicked off in 2020 at PacifiCorp to remove the seasonal access constraint (not incremental to this proposal).

Table 15 below depicts the risk assessed level at each substation following the implementation of these identified projects.

Table 15: Impact of Mitigation Projects on Future Assessed Risk Levels

Substation Name	Number of Critical Loads	PREVENTION MEASURES			CONTROL MEASURES				ASSESSED RISK LEVEL
		Criteria #3: Are existing physical protections in place above standard?	Criteria #5: Does the location and physical surroundings reduce risk?	Criteria #6: Is there documented history of criminal activity?	Criteria #1: Does sufficient resiliency/redundancy exist?	Criteria #2: Are spares or mobiles available to restore a load?	Criteria #4: Can the location be easily accessed?	*Criteria #7 - #9 (Already incorporated or not specifically considered)*	
Substation 2	1	**Fully Effective**	In Place / Partly Effective	In Place / Partly Effective	In Place / Partly Effective	Fully Effective	Fully Effective		**LOW**
Substation 11	2	**Fully Effective**	Fully Effective	Not in Place / Not Effective	Not in Place / Not Effective	Fully Effective	Fully Effective		**LOW**
Substation 13	1	**Fully Effective**	In Place / Partly Effective	Fully Effective	Not in Place / Not Effective	Fully Effective	**Fully Effective**		**LOW**

The impact of the mitigation projects on future assessed risk levels is plotted below in **Figure 13**.

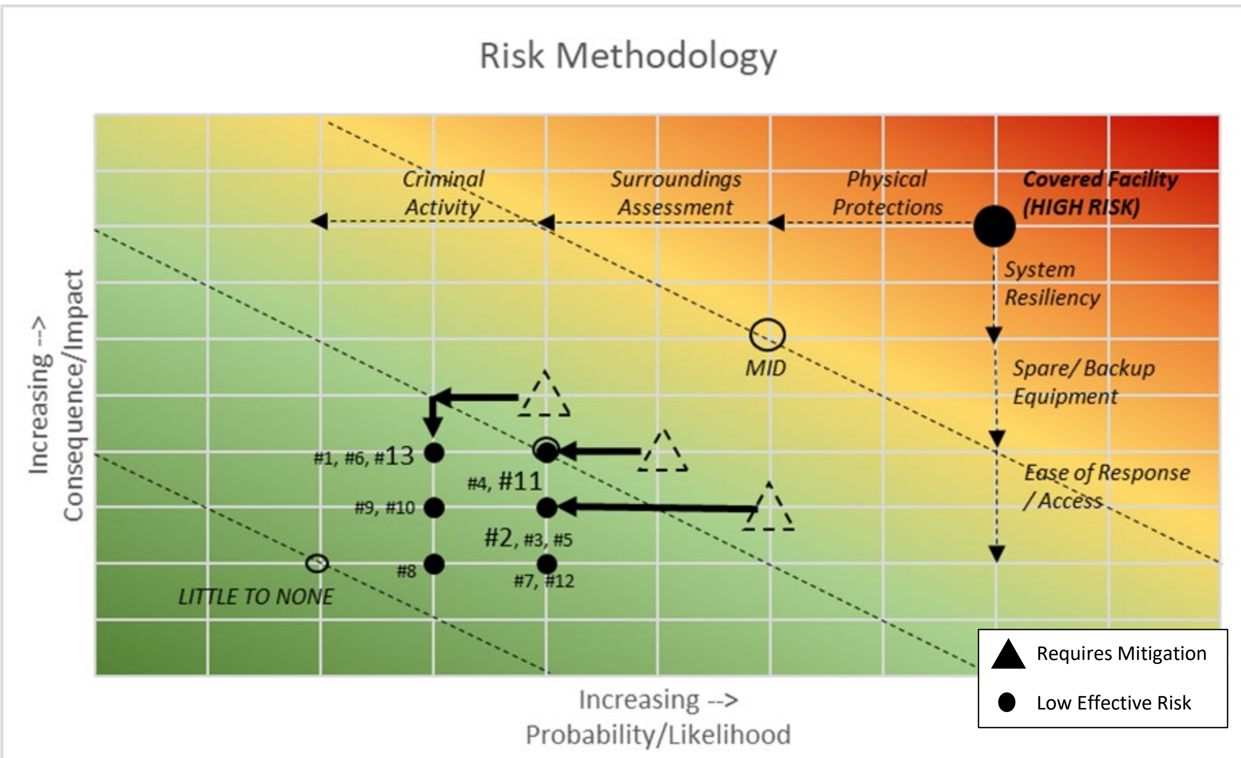

Figure 13: Impact of Mitigation Projects on Future Risk Assessment Levels

7.3.1 Mitigation Plan Implementation

PacifiCorp intends to follow a standard project pipeline process to implement these mitigation measures as described below. Currently, PacifiCorp has complete project definition, scoping, a high-level cost estimate, and project plan approval as indicated by the orange box in the diagram.

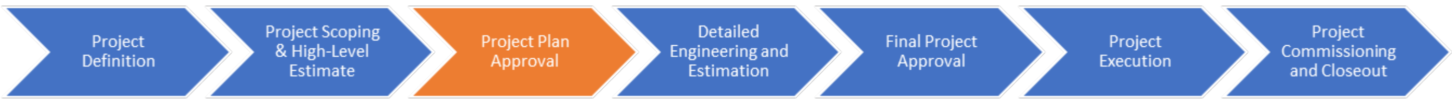

Figure 14: PacifiCorp's Planned Project Pipeline

As indicated in Figure 14 above, next steps include performing detailed engineering and estimation into order to seek final project approval and execute per plan. The high-level cost estimates and project plan timelines have been included in the following subsections.

7.3.2 Timeline

PacifiCorp's current estimated completion date of proposed projects is included in Table 16 below.

Table 16: Estimated Completion Date of Mitigation Projects

Substation	Project Name	Estimated Completion
Substation 2	Physical Security Improvements – Additional Fencing and Gates	EOY 2021
Substation 11	Physical Security Improvements – Install Fencing Fabric with Slats	EOY 2022
Substation 13	Access Improvement to Eliminate Seasonal Flooding	EOY 2023 *(Critical path constraint – Permitting)*
	Physical Security Improvements – Enhanced Lighting and Fencing Fabric with Slats	EOY 2023 *(Critical path constraint – Permitting)*

7.3.3 Costs

PacifiCorp's current estimated costs of planned projects is included in Table 17 below. PacifiCorp intends to seek recovery of these costs consistent with Ordering Paragraph 30 of D.19-01-018.[21]

Table 17: PacifiCorp's Estimated Project Costs

Substation	Project Name	Total Incremental	2021	2022	2023
Substation 2	Physical Security Improvements	$15,000	$15,000	-	-
Substation 11	Physical Security Improvements	$35,000	-	$35,000	-
Substation 13	Access Improvement to Eliminate Seasonal Flooding	Not Incremental			
	Physical Security Improvements	$55,000	-	-	$55,000

[21] Per Ordering Paragraph 30, "Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco (collectively, IOUs) shall seek recovery of costs associated with their respective Distribution Security Programs in each IOU's general rate case."

8. Third Party Verification

Ordering Paragraph 10: Prior to the submittal of the Security Plan, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall each have their respective plan reviewed by an unaffiliated third-party entity.

Ordering Paragraph 11: The unaffiliated third-party reviewer shall have demonstrated appropriate physical security expertise.

Ordering Paragraph 17: "Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall each document all third-party reviewer recommendations, and specify recommendations that were accepted or declined by the utility."

Ordering Paragraph 18: "Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison, PacifiCorp, Bear Valley Electric Service, and Liberty CalPeco shall each provide justification supporting its decision to accept or decline any third-party recommendations."

As described in Section 1, PacifiCorp submitted the 2020 Preliminary Assessment Report on July 10, 2020, which included the company's identification and preliminary assessment of Covered Facilities including pertinent methodologies leveraged, and draft mitigation measures recommended. PacifiCorp's 2020 Preliminary Assessment Report and PacifiCorp's overall progress were reviewed with Commission Staff during an interactive workshop on July 22, 2020. As a result, PacifiCorp was able to incorporate valuable comments and constructive feedback into the company's identification and preliminary assessment and move toward procuring third party services to complement this review and assist with a physical site assessment of the company's Covered Facilities.

In order to procure services to perform an unaffiliated third-party review of the company's methodology and plan within 27 months of January 10, 2019 consistent with the Joint Utility Proposal, PacifiCorp conducted a competitive bidding process from August 2020 to September 2020. As a result, PacifiCorp awarded a contract on October 1, 2020 to the third-party reviewer (Reviewer) with an active ISO9001 Certification and both military and nuclear physical security expertise, consistent with the requirements in D.19-01-018.

An initial kick-off meeting was held on October 21, 2021 and, through a series of workshops conducted from November 1, 2021 and December 15, 2021, the Reviewer was able to review and conclude that PacifiCorp's general framework and methodology fully attempted to meet the regulatory intent outlined in California R.15-06-009. Specifically, the Reviewer concluded that the existing framework and preliminary assessment revealed a thorough and detailed effort to analyze and appropriately classify each of the Covered Facilities. The Reviewer was also able to recommend a few modifications to further refine the framework. PacifiCorp was able to incorporate these recommendations as further detailed in Table 18 on page 52. The Reviewer also identified areas for further evaluation to be incorporated into the physical site assessments.

Following the initial evaluation of PacifiCorp's framework, the Reviewer, escorted by representatives from PacifiCorp's Asset Management, Field Operations, and Corporate Security departments, performed on-site physical security assessments of the 13 facilities during the week of January 11, 2021.

Following the site assessments, the Reviewer submitted a site report to PacifiCorp in February of 2020 detailing the observations and assessments of the 13 covered facilities identified in PacifiCorp's preliminary assessment to determine whether existing security measures were adequate to meet the requirements detailed in D.19-01-018. As documented in this report, the Reviewer determined that meeting the general objective of D.19-01-018 could be accomplished through risk mitigation, consequence mitigation, or a combination of the two, siting the fiscally impractical nature of relying completely on risk mitigation, particularly when attempting to defend from an attack by a determined hostile action. The Reviewer took the position that a combined methodology is the correct balanced approach achieved by employing a reasonable risk mitigation strategy enhanced with a robust consequence mitigation plan, consistent with PacifiCorp's general framework.

The Reviewer's findings reported that PacifiCorp has met this goal by employing a risk-appropriate level of industry standard physical security measures at each facility providing a reasonable level of deterrence to criminal activities and backed with an in-depth post-incident response and recovery plan that provides rapid restoration of services to PacifiCorp customers.

However, the Reviewer did note a few areas of potential enhancement for PacifiCorp to consider. These enhancements, identified in Table 18 below, were critical to informing the list of final mitigation projects and mitigation plan described in Section 7.3. In general, PacifiCorp was able to incorporate all recommendations, except the recommendations to procure additional portable generators to support restoration at Substations #11 and #13.[22]

A deeper analysis of circuit loading and the potential for generator compatibility for Substation #11 backup yielded that a portable generator large enough to support customer load is not readily available on the market. Additionally, existing mobile substations, available spare equipment, and close proximity to town provided the most viable and practical solution of restoration in the event of an outage.

Regarding Substation #13, upon review of the existing planned projects in place and existing mobile substation and spare inventory, the purchase of an additional generator did not seem necessary in order to mitigate the risk level. While a generator could be purchased, it did not seem to fit the overall balanced approach once other projects are completed.

Table 18 below further outlines the Reviewer's recommendations and how PacifiCorp incorporated these recommendations into the company's Final Security Plan.

Table 18: Summary of Reviewer's Recommendations, Incorporation, and Impact

#	Reference Document	Third Party Reviewer Recommendation	Incorporated by PacifiCorp (Yes/No)	Impact / Rationale
1	Module 1: Review Item 1	Change the assessment methodology to delineate the difference between 2 physical security enhancements from just 1 physical security enhancement.	Yes	Changed equation to incorporate additional difference as identified. Initial impacts to risk assessment as indicated in Module 1.
2	Module 1: Review Item 2	Identify the distance and/or travel time of emergency responders to better assess Criteria #4.	Yes	Removed use of populated place data and incorporated travel time as recommended, specifically focusing on 15-30 minute travel time for emergency responders.

[22] See Items 10, 13, and 16 in Table *18*.

#	Reference Document	Third Party Reviewer Recommendation	Incorporated by PacifiCorp (Yes/No)	Impact / Rationale
3	Module 1: Review Item 3	Recommend referencing a different source or methodology for Criteria #4.	Yes	See Review Item #2. Revised methodology and eliminated use of populated place data
4	Module 1: Review Item 4	Change the risk level logic tab in cells F9, F33, and E8 to LOW	Yes	Addressed calculation error to ensure that the results of the equation consistently follow the Assessed Risk threshold line
5	Module 2	General Observation: Substations could benefit from enhancements to perimeter security	Yes	Incorporated in Mitigation Plans where appropriate for MID level substations
6	Module 2: Substation 2	The use of barriers would seal off rear section and surrounding area of substation	Yes	Incorporated into Mitigation Plan to prevent unauthorized vehicle traffic
7	Module 2: Substation 13	Noted flooding concern and fence degradation at Substation #13	Yes	Mitigation Plan includes new fence structure along with access improvement project that addresses flooding
8	Module 3: Item 1	Revise Criteria #5 evaluation rating and overall score methodology	Yes	Revised Criteria #5 to move from a desktop exercise to a physical site assessment, incorporating the recommended rating factors and physical surrounding factors. This resulted in significant assessed levels at each substation for Criteria #5 which should be more representative of physical risks.
9	Module 3: Item 1	Suggested moving unauthorized traffic criterion from Criteria #5 to Criteria #6	Yes	Incorporated into Final Assessment as recommended – changed the risk ranking of Substation 2 from Mid to High for criteria #6.
10	Module 3: Item 2	Address criteria with most severe level for each substation of concern	Partially	Mitigation Plans identified for Substations #2, 11, and 13. Substation #11 – no compatible generator could be identified to support increased resiliency Substation 13 – Purchasing an additional generator did not seem balanced given other projects in place will reduced the effective risk level of the substation to Low.

#	Reference Document	Third Party Reviewer Recommendation	Incorporated by PacifiCorp (Yes/No)	Impact / Rationale
11	Module 3: Site #2	Propose installing additional fencing and gates to prevent unauthorized vehicles behind the substation	Yes	Incorporated into Mitigation Plan which includes enhancing physical security around substation addressing Criteria #3 and #5
12	Module 3: Site #11	Propose enhanced fencing, installing additional lights or cameras	Yes	Incorporated into Mitigation Plan to install additional fencing reducing potential for criminal activity.
13	Module 3: Site #11	Address resiliency/redundancy to restore power to critical loads	No	See Review Item 10. Substation #11 – no compatible generator could be identified to support increased resiliency
14	Module 3: Site #13-a	Propose addressing seasonal flooding constraint	Yes	Project underway to eliminate flooding and reduce Criteria #4 from MID to LOW
15	Module 3: Site #13-b	Propose enhanced fencing, installing additional lights or cameras	Yes	Incorporated into Mitigation plan to enhance physical security protections through the installation of new fencing and lighting
16	Module 3: Site #13-c	Consider addressing sufficient redundancy Criteria	No	See Review Item 10. Substation 13 – Purchasing an additional generator did not seem balanced given other projects in place will reduced the effective risk level of the substation to Low.