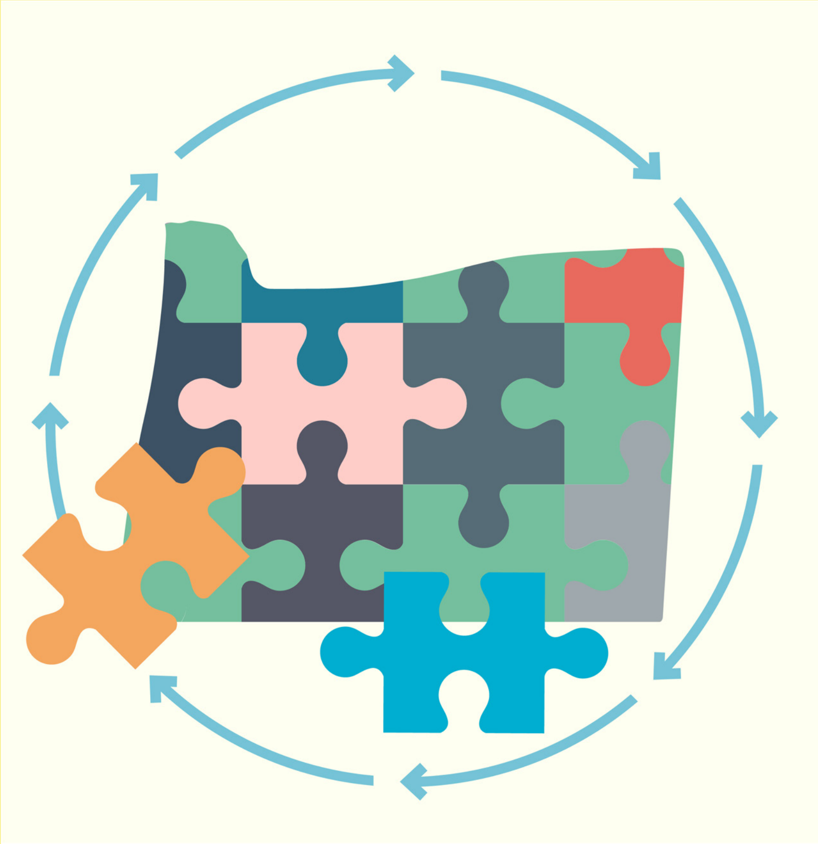
Chapter 5

Solution identification



Chapter 5. Solution identification

"We cannot ask others to do what we have not done ourselves."

– **Christiana Figueres**, diplomat and climate change leader

5.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice communities.[46] It's designed to improve safety, reliability, resilience and security, and apply an equity lens when considering fair and reasonable costs.

WHAT WE WILL COVER IN THIS CHAPTER

The system studies that are performed to further understand and characterize the prioritized grid needs

The benefit-cost analysis framework for evaluating proposed solutions

Scoring and ranking of recommended solutions

This chapter provides an overview of our solution identification for the prioritized grid needs. We describe how we develop solutions that respond to varying grid needs and how we rank these solutions. We also describe programs that are developed to address asset risks that are not addressed by other solutions.

Table 24 illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485.[47]

Table 24. Distribution system overview: Guideline mapping

DSP guidelines	Chapter section
5.3.a	**Section 5.3, 5.3.2**
5.3.b	**Section 5.3**
5.3.c	**Section 5.4, Appendix J**

46. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021
47. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf

5.2 Introduction

PGE's Solution identification chapter describes the process by which our planning engineers identify potential solutions that are needed to provide necessary additional capacity and address any identified system deficiencies. The solution identification process is directly fed from the output of our grid needs identification process. We perform a system study to develop and support potential project options. The study will include a problem statement, study methodology and analysis, project benefits, cost estimates and a recommended solution option. We utilize our distribution load flow software, CYME, to analyze distribution system options by modeling scenarios and running load flow simulations which will assist in determining a preferred solution option for a project.

5.3 Solution identification process

To accommodate load growth, such as the load growth identified in the grid needs analysis, PGE commonly implements new infrastructure, such as new transformers and/or distribution feeders. For substation transformers, our planners will determine the necessary transformer capacity based on standardized transformer sizes so we can accommodate the loading needs identified in the study. We have standardized transformers sizes (28 MVA and 50 MVA), however non-standard sizes may be required based on specific needs of a customer and/or a location. Our planners will then work to determine:

- If upgrading existing infrastructure will adequately alleviate loading concerns (such as upgrade an existing 28 MVA transformer to a 50 MVA transformer).
- If expanding an existing site will be enough (such as expanding an existing substation to have three transformers instead of two).
- If a new substation and associated equipment are necessary.

For distribution feeders, PGE's planners determine if reconductoring (upgrading existing conductor to a larger size) of an existing conductor will meet the loading needs and will develop a feeder reconductor project. Or, if there are reliability or jurisdictional requirements, our planners will develop an underground conversion or rebuild project. When existing feeders are heavily loaded, a new feeder may be necessary. The planner will determine the size of the new conductor and the best route.

Once PGE's planners have narrowed down options in a study, there will be discussions with internal stakeholders regarding feasibility, constructibility and any challenges. Some of the internal stakeholders our planners will work with are:

- **Substation Engineering team** — Help determine if an existing substation can accommodate upgrades to existing equipment or expansion of the site.
- **Property Services team** — Help identify and acquire real estate if a new substation site is required or if existing property expansion is possible.
- **Distribution Operations Engineering team** — Help determine if spacing will be an issue for new feeder getaways, if expanding an existing substation, and will provide feedback for new feeder routes and emergency switching sheets for transferring load off transformers and feeders.[48]

Next, PGE's planners work with our estimators to obtain substation and/or distribution system estimates for the proposed solutions options. Once estimates are acquired, the Asset Management Planning (AMP) group will perform an economic/cost-benefit analysis (see **Section 5.3.1**). The outputs of this analysis will include benefit-cost ratio, reduction in risk value, avoided customer interruptions, and reduction in customer minutes interrupted, among others.

The information PGE needs to identify solutions is provided by multiple internal teams and sources:

- **Historical loading** — Metered data points sourced from our PI Historian data (real-time data historian program).
- **Load forecast** — The corporate load forecast (**Section 3.3**).

48. Emergency switching sheets outline the necessary steps to transfer load from a feeder or transformer to neighboring feeders and transformers when we need to perform equipment maintenance or construction-related activities (such as rebuilding a substation), or when there is an outage.

- **Known block loads** — Information regarding projects coming online from our Economic Development, Key Customer Management, Distribution Operations Engineering, Design Project Management and Local Government Affairs teams.
- **New or upgraded substation** — Layout design from our Substation Engineering team.
- **New or expanded property** — Information from our Property Services team.
- **Distribution feeder layout and switching sheet feedback** — Information from our Distribution Operations Engineering.
- **Economic analysis** — Information from our AMP team.
- **Transmission analysis** — Information from our Transmission Planning team.
- **Estimates for substation, transmission, and distribution system work** — From our Estimators in the Project Management Organization (PMO) team.

PGE's distribution planning manager reviews our system studies to confirm that all important information has been included and will consider constructibility, cost and timelines. The study shows a recommended solution option, why it's being recommended and how much it will cost. Ideally, the recommended solution option would last for at least 10 years before requiring additional investment in new technologies and/or equipment. The study is used to formulate the design and construction scope of a project.

5.3.1 BENEFIT-COST ANALYSIS

A benefit-cost analysis (BCA) of options is performed by PGE's AMP team with the Integrated Planning Tool (IPT). Budgetary estimates for options are calculated by our Estimators in the PMO team and supplied to our Distribution Planning team.

The asset models described in **Section 4.4** give PGE information that we use to analyze risk and economic costs associated with specific assets. These asset-related risks and economic costs are aggregated to provide a project-level assessment of risk, benefits and costs. Some key metrics are:

- **Lifecycle cost of ownership (LCOO)** — The cost to own, operate and maintain asset(s) over time and is the net-present value (NPV) of an annual cost stream which includes maintenance, risk, and capital investment.
- **Near-term asset risk (NTR)** — The annual probability of failure multiplied by consequence of failure. This is simply the annual risk value for this year, as described in the asset models.
- **Near-term customers interrupted (CI) and customer minutes interrupted (CMI)** — Near-term customers interrupted is annual probability of failure multiplied by consequence of failure, but instead of consequence being measured in dollars, it is measured in customer interruptions. CMI is similar, but instead of interruptions, consequence is measured in total minutes interrupted.
- **Benefit cost ratio (BC ratio)** — Compares the reduction in lifecycle cost of ownership divided by capital investment required to determine whether risk and reliability benefits exceed investment.
- **Geographic risk (geo risk)** — The annual probability of an asset failing as a result of geographic conditions multiplied by the consequence of asset failure. Example sources of geo risk are vegetation, weather, lightning, animal and other risks, like a car hitting a pole.

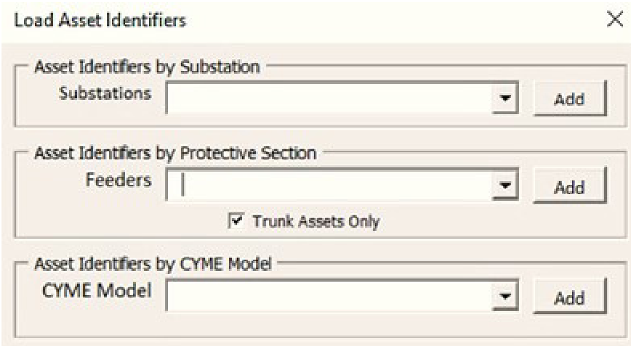
Each of these values is calculated at the individual asset level and rolled up to calculate total values across all the assets for each alternative considered for a project. **Section 5.3.1.1** discusses analyzing projects consisting of more than a single asset using the AMP team's IPT.

5.3.1.1 Integrated planning tool (IPT)

PGE utilizes an option analysis and cost benefit evaluation tool, IPT, to evaluate projects. The IPT evaluates projects consisting of many assets by combining the inputs and outputs of multiple asset models. PGE's AMP team uses the IPT to help analyze multiple project options, all measured against a current state or "base case."

When performing an analysis, PGE first creates a base case by pulling in all the assets related to the project in question. This can be done by substation, by feeder, by CYME Model (**Figure 33**), or one asset at a time.

Figure 33. IPT asset loading by substation, feeder, or CYME model



The tool loads the respective data for each asset from the individual models, such as asset age, failure likelihoods, load, consequence scenarios and replacement assumptions. At this step, these values can be adjusted from their modeled baseline values to account for any additional project-specific information.

Once assets and asset data are all loaded, the IPT calculates metrics for each asset, such as LCOO, NTR, near-term CI and CMI, BC ratio, geo risk, and years to replacement. The tool also performs a crucial function, aggregating these across all assets to provide project-level values for these metrics (**Figure 34** and **Table 25**).

Figure 34. Example of economic outputs from the IPT

DEMOGRAPHICS		ECONOMIC OUTPUTS							
ASSET IDENTIFIER	ASSET CLASS	B/C RATIO	YTR	PROGRAM YTR	LIFECYCLE COST OF OWNERSH	NON-ASSET RISK, NPV	NEAR-TERM FAILURES	NEAR-TERM RISK	AGGREGATE RISK (5
ASSET 1	Substation Circuit Breaker	0.17	34		$57,800	$0	0.000	$443	
ASSET 2	Substation Relay System	0.14	45		$58,688	$0	0.001	$1,043	
ASSET 3	Substation Switch	0.36	34		$10,089	$0	0.001	$122	
ASSET 4	Substation Circuit Breaker	0.95	4		$104,419	$1,261,461	0.006	$3,874	
ASSET 5	Substation Switch	0.44	28		$11,974	$0	0.001	$167	
ASSET 6	Substation Switch	0.20	189		$2,043	$0	0.000	$80	
ASSET 7	Substation Switch	0.00	189		$400	$0	0.000	$0	
ASSET 8	Substation Switch	0.22	35		$5,347	$0	0.000	$32	
ASSET 9	Substation Switch	0.00	189		$400	$0	0.000	$0	
ASSET 10	Substation Relay System	0.06	145		$5,567	$0	0.008	$146	
ASSET 11	Substation Switch	0.16	70		$4,576	$0	0.001	$41	
ASSET 12	Substation Relay System	0.26	28		$41,831	$0	0.001	$791	
ASSET 13	Substation Circuit Breaker	0.95	4		$104,006	$1,508,553	0.006	$3,833	
ASSET 14	Substation Relay System	0.71	9		$58,147	$0	0.003	$955	
ASSET 15	Substation Circuit Breaker	0.47	23		$78,436	$0	0.002	$1,283	
ASSET 16	Substation Circuit Breaker	0.28	29		$64,547	$0	0.001	$743	
ASSET 17	Substation Relay System	0.00	190		$11,281	$0	0.001	$491	
ASSET 18	Substation Switch	0.22	35		$5,347	$0	0.000	$32	
ASSET 19	Substation Switch	0.00	189		$400	$0	0.000	$0	
ASSET 20	Substation Relay System	0.08	60		$69,629	$0	0.001	$2,309	
ASSET 21	Substation Transformer	1.53	0		$837,369	$0	0.029	$53,364	
ASSET 22	Substation SCADA System	0.29	18		$201,641	$0	0.018	$1,097	
ASSET 23	Substation Relay System	0.14	45		$58,688	$0	0.001	$1,043	
ASSET 24	Substation Switch	0.00	189		$400	$0	0.000	$0	
ASSET 25	Substation Switch	0.20	36		$5,136	$0	0.000	$26	
ASSET 26	Substation Switch	0.42	29		$11,598	$0	0.001	$159	
ASSET 27	Substation Switch	0.30	42		$8,197	$0	0.001	$93	
ASSET 28	Substation Relay System	0.24	30		$56,967	$0	0.001	$1,552	
ASSET 29	Substation Relay System	0.71	9		$58,147	$0	0.003	$955	

Table 25. Example economic outputs aggregated across assets in the IPT

Economic outputs	Option 1
Lifecycle cost of ownership, assets ($)	$735,258
Non-asset risk, NVP ($)	$10,224,462
Total cost ($)	$11,885,030
Benefit cost ratio (#)	1.46
Reduction in near-term total risk ($)	$554,948
Reduction in customer interruptions (#)	710.7
Reduction in minutes interrupted (#)	206,358

The same process is repeated for different proposed solution options for a project, with a key variation. When building out a proposed project solution option, all assets from the base case would typically be pulled into the tool, but now, certain input parameters can be adjusted. For example, PGE can mark equipment as "replaced" in the tool, which brings its age back to zero, resulting in adjusted risk calculations. Proposed project solutions may also reduce or eliminate geographic risk, and this can be accounted for as well.

The IPT allows for comparing multiple different solution options against a base case to see which option provides the greatest reduction in risk, or the greatest reduction in lifecycle cost of ownership. The tool does not compare completely different projects against one another. These types of comparisons are done at the transmission and distribution portfolio level and use several of the key outputs from the IPT.

5.3.2 PLANNING PROJECT PRIORITIZATION

The distribution planning projects shown in Table 25 are prioritized using the same Distribution Planning Ranking Matrix as the grid needs prioritization (**Figure 32**). This prioritized list is used to inform the portfolio planning stage. These projects were analyzed for solutions as part of the 2023 capital cycle, which began in 2021 and are based on equipment loading information from 2020. PGE will continue to work with communities and partners to identify improvements to our project prioritization process.

Table 26. Planning project prioritization list

Priority	PGE Location	Grid need	Project	Ranking total
1	Evergreen substation	Industrial load growth in North Hillsboro	Evergreen	149
2	St. Louis substation	Commercial load growth in Woodburn area and 57 kV system constraints	St Louis	102
3	Silverton substation	Existing loading issues and industrial load growth in Silverton	Silverton	96
4	Redland substation	Aging infrastructure, heavily loaded transformer and feeders, lack of telemetry east of Oregon City	Redland	84
5	Kaster substation	Substation with high arc flash concerns, commercial load growth in St Helens	Kaster	83
6	Glisan substation	Industrial load growth in Gresham	Glisan	81
7	Waconda substation	Commercial load growth south of Woodburn and 57 kV system constraints	Waconda	78
8	Harrison substation	Capacity addition to implement other grid need mitigations, temporary equipment being used for support in inner SE Portland	Harrison	73
9	Linneman substation	Residential load growth in the Happy Valley and Gresham areas, temporary equipment being used for support	Linneman	58
10	Boring substation	Transformer failure resulting in capacity constraints, aging infrastructure in the Boring area	Boring	55

Priority	PGE Location	Grid need	Project	Ranking total
11	Glencullen substation	Capacity addition to implement other grid need mitigations in SW Portland, lack of SCADA telemetry, feeder reliability improvements	Glencullen	54
12	Scholls Ferry substation	Existing loading issues and residential development in the Murrayhill/Scholls areas resulting in capacity constraints	Scholls Ferry	38

5.3.3 EMERGING PROGRAMS DRIVEN BY ASSET RISK

Risk driven asset investments are identified utilizing the economic life cycle models as described in **Section 4.4.1**. These models calculate the optimal time, based on cost and risk, to proactively replace an asset. Replacement is recommended when the risk of owning and operating the asset is greater than the annualized cost of replacing the asset.

The models have enabled PGE's AMP team to understand the various drivers, or combination of drivers, such as age, condition, poor make/model, reliability, safety, obsolete technology, among others, that accelerate assets to the end of their economic life. If the magnitude of the assets is due or coming due for replacement is greater than the forecasted rate of replacement from other existing projects or programs, then our AMP team undertakes steps to analyze the benefits of a proactive replacement program.

These proactive replacement programs are developed in collaboration with the subject matter experts to recommend a replacement cadence targeting the highest risk assets within a certain asset class or sub-class while also considering operational realities. To be part of the economic program, the asset needs to be identified as being economically due for replacement and will target assets that will not be addressed under other planned capital investments.

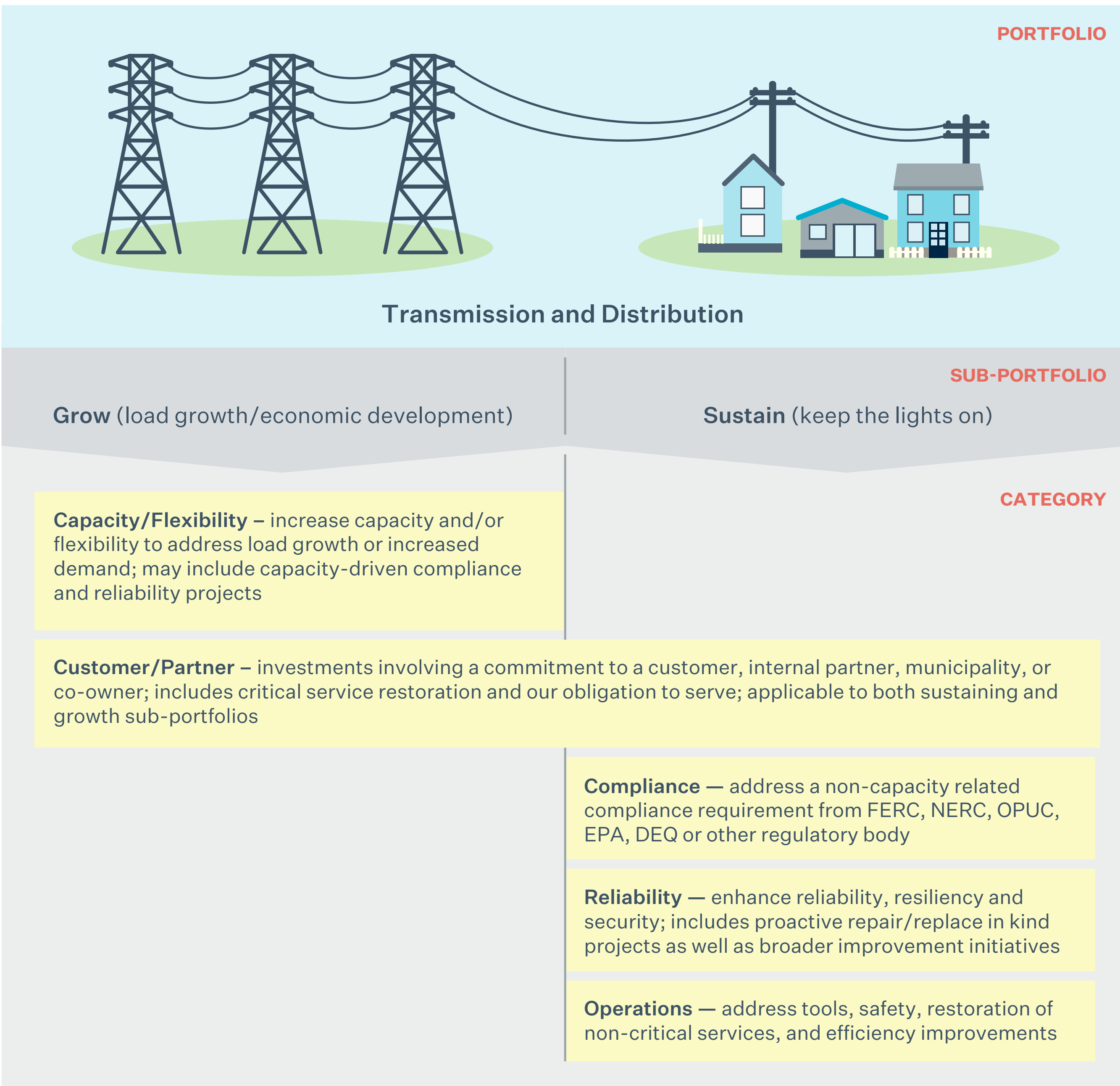
PGE is in the process of developing proactive replacement programs for each of the following asset classes. These emerging programs will propose projects for future planning cycles.

- **Substation transformers** — Developing a proactive replacement program to address the subset of the substation transformer fleet that are at a higher risk of failure due to age and condition.
- **SCADA** — Developing a proactive program to replace antiquated MV90 technology with current standard SCADA technology. MV90 collects and records meter data but does not support real-time data for operations. Upgrading to the current standard SCADA monitoring technology will enable real time operator visibility, support switching tasks, enable improved voltage monitoring and control, capacity, safety and further support integration of DERs into the grid.
- **Substation circuit breakers** — Developing a proactive replacement program to address the population of oil circuit breakers that are at high risk of failure due to age and condition coupled with environmental concerns. Replacing the assets with new gas breakers will address the above concerns, but also result in operational efficiencies.
- **Distribution switches** — Developing a proactive replacement program to address the population of live-front pad mount switches that present safety concerns and reliability risks due to their design. Replacing these assets with the dead-front switches, will address the above concerns, but also result in operational efficiencies.

5.3.4 PORTFOLIO PLANNING

PGE utilizes a portfolio planning process that is managed by our Generation, Transmission & Distribution (T&D) Portfolio team. This portfolio is split along two axes: Sustain the business and Grow the Business, and Discretionary and Non-discretionary. Along one axis, the portfolio is split between Sustain the Business (STB) and Grow the Business (GTB) (**Figure 35**). Projects in the GTB portfolio are non-discretionary due to their focus on serving new customer load growth. For that reason, those projects are not subject to the scoring and ranking process described below. The project ranking outlined here applies to the STB portfolio, which is concerned with

Figure 35. Sustain the business (STB) and grow the business (GTB)



discretionary projects that replace existing assets for the purposes of operational improvement and risk reduction.

Along the second axis, the STB portfolio is split into discretionary and non-discretionary buckets. Currently, decisions about non-discretionary projects in the STB portfolio are made outside of the process described here. The scope of the scoring and ranking framework described here will be expanded to include non-discretionary projects. Once the non-discretionary projects are funded, the discretionary projects must be scored and ranked to help prioritize them for funding.

Discretionary projects in the STB portfolio are scored across eight categories, with responsibility for the two categories of metrics distributed between the T&D Portfolio team and the AMP team.

The T&D Portfolio team provides input and scores for the following metrics which add up to 20% of the total score for a project.

- **Safety (4% weight)** — Projects that reduce incidents and risk exposure to both employees and the public while promoting a safe and healthy workplace.
- **Compliance (4% weight)** — Projects driven by compliance requirement from regulatory agencies such as Federal Energy Regulatory Compliance (FERC), North American Electric Reliability Corporation (NERC), Oregon Public Utility Commission (OPUC), Environmental Protection Agency (EPA), Oregon Department of Environmental Quality (DEQ).
- **Environmental (4% weight)** — Projects that exceeds today's environmental compliance standards or projects identified as an industry best practices that will reduce PGE's environmental impact.
- **Operational (4% weight)** — Projects that address new tools/materials, restoration of non-critical services and improves costs and performance efficiencies.
- **Customer (4% weight)** — Projects that increase capacity to address load growth, or increased demand.

The AMP team uses the asset modeling approach described above to calculate values for each of the following metrics which add up to 80% of the score for a project.

- **Reliability (27% weight)** — The reliability metric is equal to the expected reduction in near-term CMI due to the project.
- **Risk (27% weight)** — This metric is equal to the expected reduction in near-term asset and geographic risk resulting from the project.
- **Financial (27% weight)** — This metric comprises three sub-metrics, each of which are given an equal weight. These are:
  - **BC Ratio (9% weight)** — This is the BC Ratio associated with the project, as described above.
  - **NTR/Capex (9% weight)** — This metric shows the expected reduction in near-term asset and geographic risk for every dollar of capital spend due to project.
  - **Near-term CMI/Capex (9% weight)** — This gives expected reduction in near-term CMI per dollar of capital spend due to the project.

Once analysis is complete for a project and each of these metrics have been calculated, they are transformed from their actual values to a score of 1, 2, 3 or 4. This is done by collecting metric scores on all projects which have been analyzed and determining statistical quartile ranges for each. This allows for a value of one through four to be assigned to each metric accordingly as it falls into the 1st, 2nd, 3rd, or 4th quartile range of values for that metric across all projects.

These scored values of one through four are used with the weighting for each metric to calculate a weighted average value which is the final score of the project. A visual example of this calculation is shown in **Figure 36**.

Figure 36. Sample calculation of a project score

	Score	Weighting	SAM score (avg)	
Reliability	4	27%	1.08	
Risk	4	27%	1.08	**3.2**
Financial	4	27%	1.08	
			Portfolio score (avg)	
Safety	0	4%	0	
Compliance	0	4%	0	
Environmental	0	4%	0	**0.2**
Operational	1	4%	.04	
Customer	1	4%	.16	
Final prioritization score; Optimizes on value			Total value **3.4**	

Priority score

4 – Extreme
3 – Strong
2 – Moderate
1 – Low
0 – None

Following this process for each discretionary project in the STB portfolio allows for ranking based on the final value assigned to each project. PGE's AMP team uses this process to recommend a suite of prioritized projects that help achieve risk reduction and reliability goals for the STB portfolio to the T&D Portfolio team.

5.4 Process for community engagement on large projects

The ongoing transformation in the energy sector will drive the need for large investments in the public, private and utility sectors for years to come. These investments often fuel the economic growth that will pay for them over time. But a large project has consequences that go well beyond a specific substation, wind farm, or electric vehicle charging hub. PGE's DSP partners have emphasized the need to take a hard look at who benefits and who pays in the delivery of infrastructure projects. Getting this analysis right is good for everyone.

PGE's current process for community engagement on large projects is driven largely by the permitting and public notification requirements of the jurisdiction involved. As a result, our communication timelines and deliverables are as diverse and as complicated as our projects. Some projects require simple outreach that may be provided within one week of a project manager's request. Others require over a year of planning, coordination and execution with deliverables conceived and developed specific to the needs of that project. With that said, we do have a current standard project outreach process, which illustrated in **Figure 37**.

Figure 37. Current standard project outreach process

Outreach begins	The need for outreach based upon permit requirements and an assessment of impacts to those in the surrounding area is identified.
Outreach distribution	An outreach distribution area along or within proximity of the work location is identified. This might be a transmission or distribution line corridor, substation or any other project required to support our transmission and distribution infrastructure.
Notification	At least two weeks prior to the project's construction start date, a customer letter (or mailer) is sent to those within the outreach distribution area. This mailer includes a weblink to our website that has more information as well as a phone number and email address for any questions, concerns and/or feedback. If an outage is planned, customers will receive a doorhanger notice with the anticipated date and time of the outage.
Signage	If necessary or helpful, additional signage is created along the corridor or near the project site providing useful information. This may include a QR code with a link specific to the project, a project area map, construction and/or closure dates and times as well as messaging that warns individuals of risks for their and our crews' safety.

To supplement these communication activities, PGE creates and maintains a website for each large project. An example of a website is included in **Figure 38** and additional project websites can be accessed through the Neighborhood Projects page.[49]

49. Neighborhood projects page, available at: https://portlandgeneral.com/about/who-we-are/innovative-energy/neighborhood-projects

Figure 38. Neighborhood projects web page

Neighborhood Projects

Learn how we're building a brighter energy future for you

Home > About > ··· > Neighborhood improvem...

Keeping your energy safe, reliable and affordable

Wondering what the construction in your neighborhood is all about? As we work toward Oregon's clean energy future, we're strengthening the energy grid to make it smarter, more efficient and more reliable for you. This includes replacing aging equipment to increase resiliency, reduce outages, keep energy affordable for you and your neighbors, accommodate growth in our area and allow for better integration of renewable resources.

Learn more about Smart Grid benefits.

System Upgrades

Our energy grid is the backbone structure that brings you safe, affordable energy. We regularly inspect and replace older power lines and equipment with new "smart grid" technology that allows for two-way energy communication. This helps us provide reliable power to you and your neighbors, but it also does so much more!

Got a rooftop solar panel? Now we can connect it to our grid and share energy. Another example is smart meters that let us start or stop service remotely.

Underground Projects

Many of the power lines and equipment in the energy grid are underground. That means there's a lot going on that you can't see! We inspect, and when needed, replace those lines to keep the grid strong and resilient.

By making sure these underground lines are working their best, we can keep up with the growth of all the new homes and businesses in your neighborhood.

Preventative Maintenance

Look up! You might see our crews in your neighborhood removing branches that could otherwise fall on power lines. Keeping you safe and with power is all in a day's work.

By trimming trees and removing other vegetation, we can prevent outages and help improve safety for our workers and you.

PGE intends to continue the current standard project outreach process and supplement it in two ways:

- Expand the number of projects for which we create informational websites, and
- Earlier engagement of affected communities.

With respect to earlier engagement, PGE plans to use our current DSP workshops to present grid needs and proposed solutions. We will work with the partners and the OPUC to identify the projects that are not included in the current process and/or require a level of engagement in excess of the process outlined above.

For those projects that are identified, we plan to use the outreach and engagement approach outlined in **Chapter 2** of this document as well as our Community Engagement Plan described in our DSP Part 1.[50]

50. DSP Part 1 Community Engagement Plan, available at: https://assets.ctfassets.net/416ywc1laqmd/e5oN7SaTG7jQRTGcPzt/576380f14d90a976469968517b187f95/DSP_2021_Report_Chapter3.pdf#page=13

5.5 Evolution

Starting with PGE's 2024 capital planning cycle (which began in spring 2022), solutions for grid needs will consider both traditional wired solutions and non-wires solutions. The criteria for when grid needs will be considered for non-wires solutions is described in **Appendix E**. In addition, we will engage with the community when developing possible solutions to grid needs.

PGE plans to conduct load sensitivity analysis when evaluating grid needs. Currently, studies are conducted using load values we would expect to see once every three years. The summer of 2021 set a new load record for our system and far exceeded the expected loading on the system. Moving forward, after a solution is identified (wired or non-wires), loads will be scaled to the load values we would expect to see once every ten years, or the summer 2021 values, whichever is higher (accounting for new load additions and system changes). Any additional upgrades required because of these higher loads will be considered a sensitivity option that will be evaluated by our AMP team using their IPT tool to determine the benefit/cost ratio.

PGE also will begin to integrate resiliency metrics into the capital decision framework. The framework likely will have a new resiliency improvement category by which projects are evaluated in addition to existing risk reduction, reliability improvement and financial benefit categories.