Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

June 14, 2022

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, SE, Suite 100
P.O. Box 1088
Salem, OR 97308-1088

RE: Fourth Supplemental Filing of Advice No. 22-08, UE 394 General Rate Case Compliance Filing

Portland General Electric Company (PGE) submits this supplemental filing pursuant to Oregon Revised Statutes 757.205 and 757.210, and Oregon Administrative Rules (OARs) 860-022-0025(2), and 860-022-0030 for filing proposed tariff sheet associated with Tariff P.U.C. No. 18. PGE initially filed Advice No. 22-08 on April 29, 2022, with an effective date of May 9, 2022. PGE submitted Supplemental Filings on May 4, 5 and 23, 2022.

PGE is submitting this Supplemental Filing requesting updates to three tariffs to correct for inadvertent omissions within the Company's initial compliance filing in UE 394 on April 29, 2022, with a requested effective date of **June 30, 2022**. Detailed context for each tariff is discussed below.

Enclosed are the following additional sheets.

- Fifth Revision of Sheet No. 26-8
- Seventh Revision of Sheet No. 143-1
- Seventh Revision of Sheet No. 143-2
- Eighth Revision of Sheet No. 143-3
- Second Revision of Sheet No. 600-1

Enclosed is the following replacement sheet.

- Fourth Revision of Sheet No. 600-3

All other sheets remain as previously filed.

The update to Schedule 26, Non-Residential Demand Response, simply updates line loss factors to the system-wide values in PGE's current line loss study. Due to pancaking in PGE Advice No. 22-06 that was recently approve and became effective on June 1, 2022, the line losses were not updated.

Schedule 143, Spent Fuel Adjustment, implements in rates any ongoing refunds from the United States Department of Energy (DOE) into the Trojan Nuclear Decommission Trust Fund. In the Fourth Partial Stipulation of UE 394, PGE agreed to refund to customers $2,960,544 reimbursed to PGE by DOE in 2018 plus a residual balance of $352,098 from the Schedule 143 balancing account via Schedule 143 over a one-year period beginning May 9, 2022. Implementation of the agreement was omitted in the initial compliance filing and PGE now proposes to update Schedule 143 reflecting a total refund amount, including interest, of $3,373,229[1] over a one-year period beginning June 2022 (see Attachment A).

The revision to Schedule 600, Energy Service Supplier Charges, updates electricity scheduling requirements for Electricity Service Suppliers (ESSs) to remove transmission losses currently recovered via PGE's Federal Energy Regulatory Commission (FERC)-regulated Open Access Transmission Tariff (OATT), Original Volume No. 8 (PGE-8). Historically, all system losses associated with retail loads served by an ESS were built into the supplier's scheduled energy using loss factors provided in Schedule 600. On January 1, 2022, changes to PGE's OATT took effect as proposed in PGE's Transmission Rate Case (ER22-233) filed with FERC. One such change was to align the terms of transmission service for ESSs with that of other transmission customers, including recovery of energy losses accrued on PGE's transmission system via financial settlement under Schedule 11. To complement this recognition of transmission line loss recovery from ESSs in the OATT, the loss factors in Schedule 600 should be decreased to reflect only losses attributable to PGE's distribution system.

In PGE's recent General Rate Case (GRC, UE 394), the Company submitted a revised version of the Schedule 600 tariff that updated loss factors to current system-wide values, reflecting the reclassification of 115 kV lines from distribution to transmission assets, recent infrastructure investment and increased efficiencies across the system. Inadvertently, PGE did not further adjust the loss factors to remove losses attributed to the Company's transmission network and proposes to correct them in this filing.

PGE submitted its current line loss study as part of UE 394 Reply Testimony, Exhibit 2200 (2022 GRC_TRC Loss Report). While the study includes updated loss factors reflecting an aggregate of transmission and distribution system losses and a stand-alone transmission system loss factor, corresponding distribution-only loss factors were not separately presented. These values can be directedly calculated, however, with similar adjustments to Figure 5 in the study (see Attachment C).

PGE is also recommending removal of detailed language itemizing transmission services within Schedule 600, which is redundant to the direct reference to the Company's OATT. Simplifying this part of the tariff will also mitigate the need to revise Schedule 600 with minor adjustments to the OATT in the future.

1 The total amortization balance includes an amount of $2,960,544 reimbursed by the DOE in 2018 claim year and a residual balance of $412,684 from the Schedule 143 balancing account to be refunded to customers via Schedule 143 over a one-year period beginning June, 2022.

The following attachments are included:

- Attachment A: Schedule 143 workpaper
- Attachment B: Schedule 143 bill impacts
- Attachment C: Schedule 600 workpaper
- Attachment D: PGE's current line loss study (acknowledged in UE 394)

Redline version of Schedule 600 is also attached as a courtesy.

To satisfy the requirements of OAR 860-022-0025, PGE responds as follows:

The proposed revisions to Schedule 26, Non-Residential Demand Response, ensure that customer load reductions motivated by the program will be accurately adjusted for line losses. The proposed revisions to Schedule 600, Electricity Service Supplier Charges, do not directly impact PGE's retail customers. The proposed revisions to Schedule 143 impact approximately 920,000 applicable customers. A typical Schedule 7 Residential customer consuming 780 kWh monthly will see a bill decrease of $0.15 or 0.13%, inclusive of Public Purpose Charge effects (see Attachment B).

Please direct questions to Ashleigh Keene at ashleigh.keene@pgn.com or Teresa Tang at Teresa.tang@pgn.com Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

\s\ *Robert Macfarlane*

Robert Macfarlane
Manager, Pricing & Tariffs

Enclosures
cc: Service List – UE 394

SCHEDULE 26 (Continued)

ENERGY PAYMENTS

The Energy Payment is equal to the Mid-Columbia Electricity Index (Mid-C) as reported by the Powerdex, adjusted for losses based on the Customer's delivery voltage. The Firm Energy Reduction amount can be up to 120% of the Committed Load Reduction.

The monthly energy prices (per MWh) for the months in which the events are called* are:

Jan 2022	Feb 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Nov 2022	Dec 2022
$87.20	$70.30	$38.60	$90.00	$122.80	$97.00	$59.00	$72.80

The Energy Payment rates will be updated by December 1st for the next year beginning in January. Assessment and settlement of the Energy Payment will occur within 60 days of the Firm Load Reduction Event. Energy Payments are not eligible to be paid up-front at the time of commissioning.

LINE LOSSES

Losses will be included by multiplying the applicable price by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416	**(I)**
Primary Delivery Voltage	1.0530	**(I)**
Secondary Delivery Voltage	1.0640	**(R)**

LOAD REDUCTION MEASUREMENT

Load reduction is measured as a reduction of load from a customer baseline load calculation during each hour of the Load Reduction Event. Although the Load Reduction Plan shall specify the customer baseline load calculation methodology to be used, PGE generally uses the following baseline methodology:

Baseline Load Profile

The Baseline Load Profile is based upon the average hourly load of the five highest load days in the last ten Typical Operational Days for the event season period. For Customers choosing the four-hour or 10-minute notification options there is an adjustment to the amounts above to reflect the day-of operational characteristics leading up to the Firm Load Reduction Event if the Firm Load Reduction Event starts at 11 am or later. This adjustment is the difference between the Firm Load Reduction Event day load and the average load of the five highest days used in the Baseline Load Profile during the two-hour period ending four hours prior to the start of the Firm Load Reduction Event.

SCHEDULE 143
SPENT FUEL ADJUSTMENT

PURPOSE

The purpose of this schedule is to implement in rates the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund and any ongoing refunds from the United States Department of Energy. Also included are pollution control tax credits associated with the Independent Spent Fuel Storage Installation at the Trojan nuclear plant.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – TROJAN NUCLEAR DECOMMISSIONING TRUST FUND

Part A consists of the amortization of the excess funds previously contained in the Trojan Nuclear Decommissioning Trust Fund and any ongoing refunds from the United States Department of Energy.

PART B – ISFSI ADJUSTMENT

Part B consists of the amortization of the payments from the Oregon Department of Energy related to state pollution control tax credits for the Independent Spent Fuel Storage Installation at Trojan.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Part A	Part B	Adjustment Rate		
7	(0.019)	0.000	(0.019)	¢ per kWh	(R)
15	(0.014)	0.000	(0.014)	¢ per kWh	
32	(0.016)	0.000	(0.016)	¢ per kWh	
38	(0.015)	0.000	(0.015)	¢ per kWh	
47	(0.018)	0.000	(0.018)	¢ per kWh	
49	(0.018)	0.000	(0.018)	¢ per kWh	
75					
Secondary	(0.015)	0.000	(0.015)	¢ per kWh[1]	
Primary	(0.015)	0.000	(0.015)	¢ per kWh[1]	
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh[1]	(R)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 143 (Continued)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
83	(0.016)	0.000	(0.016)	¢ per kWh	(R)
85					
Secondary	(0.016)	0.000	(0.016)	¢ per kWh	
Primary	(0.015)	0.000	(0.015)	¢ per kWh	
89					
Secondary	(0.015)	0.000	(0.015)	¢ per kWh	
Primary	(0.015)	0.000	(0.015)	¢ per kWh	
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh	
90					
Primary	(0.014)	0.000	(0.014)	¢ per kWh	(C)
Subtransmission	(0.014)	0.000	(0.014)	¢ per kWh	(N)
91	(0.014)	0.000	(0.014)	¢ per kWh	
92	(0.014)	0.000	(0.014)	¢ per kWh	
95	(0.014)	0.000	(0.014)	¢ per kWh	
485					
Secondary	(0.011)	0.000	(0.011)	¢ per kWh	
Primary	(0.011)	0.000	(0.011)	¢ per kWh	
489					
Secondary	(0.015)	0.000	(0.015)	¢ per kWh	
Primary	(0.015)	0.000	(0.015)	¢ per kWh	
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh	
490					
Primary	(0.014)	0.000	(0.014)	¢ per kWh	(C)
Subtransmission	(0.014)	0.000	(0.014)	¢ per kWh	(N)
491	(0.014)	0.000	(0.014)	¢ per kWh	
492	(0.014)	0.000	(0.014)	¢ per kWh	
495	(0.014)	0.000	(0.014)	¢ per kWh	
515	(0.014)	0.000	(0.014)	¢ per kWh	(M)
532	(0.016)	0.000	(0.016)	¢ per kWh	(M)(R)

SCHEDULE 143 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate		
					(M)
538	(0.015)	0.000	(0.015)	¢ per kWh	(R)
549	(0.018)	0.000	(0.018)	¢ per kWh	
575					
Secondary	(0.015)	0.000	(0.015)	¢ per kWh[(1)]	
Primary	(0.015)	0.000	(0.015)	¢ per kWh[(1)]	
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh[(1)]	
583	(0.016)	0.000	(0.016)	¢ per kWh	
585					
Secondary	(0.016)	0.000	(0.016)	¢ per kWh	
Primary	(0.015)	0.000	(0.015)	¢ per kWh	
589					
Secondary	(0.015)	0.000	(0.015)	¢ per kWh	
Primary	(0.015)	0.000	(0.015)	¢ per kWh	
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh	
590					
Primary	(0.014)	0.000	(0.014)	¢ per kWh	(C)
Subtransmission	(0.014)	0.000	(0.014)	¢ per kWh	(N)
591	(0.014)	0.000	(0.014)	¢ per kWh	
592	(0.014)	0.000	(0.014)	¢ per kWh	
595	(0.014)	0.000	(0.014)	¢ per kWh	
689					
Secondary	(0.015)	0.000	(0.015)	¢ per kWh	
Primary	(0.015)	0.000	(0.015)	¢ per kWh	
Subtransmission	(0.015)	0.000	(0.015)	¢ per kWh	(R)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between the Trojan Nuclear Decommissioning Trust Fund refund, ongoing refunds, and the ISFSI payments and the actual Schedule 143 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts.

SCHEDULE 600
ELECTRICITY SERVICE SUPPLIER CHARGES

AVAILABLE

In all territory served by the Company.

APPLICABLE

To any Electricity Service Supplier (ESS), including an applicant ESS, providing service to Customers. To receive service under this schedule, the ESS must sign an ESS Service Agreement and abide by all provisions of the Company's Tariff.

SERVICES

The following services are offered to an ESS providing Electricity to one or more Direct Access Service Customers.

Transmission Services (Applicable to Scheduling ESS only)

Transmission services are provided to an ESS pursuant to the Company's Open Access Transmission Tariff (OATT), Original Volume No. 8 (PGE-8). **(D)**

ESS Provided Regulation and Imbalance Service

An ESS that self-provides Regulation and Frequency Response and Energy Imbalance Services must provide the Company with a real-time load and power factor signal via electronic metering from the Customer load to the location designated by the Company, consistent with PGE's OATT and business practices. **(C)**

SCHEDULE 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE DISTRIBUTION LOSSES **(C)**

The ESS will schedule sufficient Energy to provide for the following losses on the Company's distribution system: **(C)**

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Losses:	2.34%	1.25%	0.14%	**(C)**

SCHEDULE 600
ELECTRICITY SERVICE SUPPLIER CHARGES

AVAILABLE

In all territory served by the Company.

APPLICABLE

To any Electricity Service Supplier (ESS), including an applicant ESS, providing service to Customers. To receive service under this schedule, the ESS must sign an ESS Service Agreement and abide by all provisions of the Company's Tariff.

SERVICES

The following services are offered to an ESS providing Electricity to one or more Direct Access Service Customers.

Transmission Services (Applicable to Scheduling ESS only)

Transmission services are provided to an ESS pursuant to the Company's Open Access Transmission Tariff (OATT), Original Volume No. 8 (PGE-8). ~~Transmission services include:~~

~~(a)Transmission as further described under Special Conditions;~~
~~(b)Scheduling, System Control and Dispatch Service;~~
~~(c)Reactive Supply and Voltage Control Service;~~
~~(d)Regulation and Frequency Response Service*;~~
~~(e)Energy Imbalance Service*;~~
~~(f)Operating Reserve - Spinning Reserve Service*; and~~
~~(g)Operating Reserve - Supplemental Reserve Service*.~~

~~* When provided by the Company.~~

ESS Provided Regulation and Imbalance Service

An ESS that self-provides Regulation and Frequency Response and Energy Imbalance Services must provide the Company with a real-time load and power factor signal via electronic metering from the Customer load to the location designated by the Company, consistent with PGE's OATT and business practices.

SCHEDULE 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE ~~SYSTEM~~ DISTRIBUTION LOSSES

The ESS will schedule sufficient Energy to provide for the following losses on the Company's distribution system:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Losses:	~~4.20~~2.34%	~~3.09~~1.25%	~~1.96~~0.14%

PGE Advice No. 22-08
Fourth Supplemental Filing of Advice No. 22-08
UE 394 General Rate Case Compliance Filing

Attachment D

Portland General Electric
2022 Test Year Line Loss Study

Table of Contents

Summary

In advance of its planned rate cases with the Oregon Public Utility Commission (OPUC) and the Federal Energy Regulatory Commission (FERC), Portland General Electric Company (PGE) is updating its estimated line losses from those developed for a 2015 test year as part of UE 283. These updated average energy loss factors will be used in load forecasting, pricing design and financial settlements with Electricity Service Suppliers (ESS) starting in 2022.

Average energy loss factors for each customer delivery class are shown in Figure 1. These factors are based on line loss functions derived from 2019 hourly profiles and a loss allocation analysis that used 2015-2019 historical data.

Figure 1. Average Energy Losses

Customer Delivery Class	Internal Average Loss Factor	External Average Loss Factor	Combined Average Loss Factor
Subtransmission	1.96%	2.20%	4.16%
Primary	3.09%	2.20%	5.30%
Secondary	4.20%	2.20%	6.40%

Note: Combined Average Loss Factors may differ from the sum of Internal and External Average Loss Factors due to rounding.

The following sections provide assessments of system-wide historical losses and how losses are allocated to customer classes based on delivery voltage. A detailed description of how system component loss functions were developed is provided in Appendix A and transmission and distribution system asset classifications are provided in Appendix B.

Historical System Losses

The high-level approach to estimating system-wide line losses follows that of past studies. Total system losses are calculated by subtracting delivered retail energy from system energy. Measured as Net System Load (NSL), system energy reflects aggregate generation, including PGE plants and third-party sources, netted for non-PGE load within PGE's control area and PGE load within Bonneville Power Administration's (BPA) control area, along with associated losses within BPA's system. Retail energy is the combined energy deliveries to Cost of Service (COS) and Direct Access (DA) customers and is calculated as the sum of all revenue-generating customer meters. The following equations reflect columns in Figure 2.

Total Losses (5) = System Energy (1) – Retail Energy (4)

where,

Retail Energy (4) = COS Retail Energy (2) + DA Retail Energy (3)

Total losses are separated between 1) internal losses within PGE's networked transmission and distribution systems; and 2) external losses, which are contractual losses incurred by PGE from wheeling power over other systems en route to PGE's network. External losses are contractually accounted and constitute annual losses returned to BPA for network transmission and intertie losses. Internal losses are calculated as the remaining portion of total losses after subtracting external losses.

Internal Losses (7) = Total Losses (5) – External Losses (6)

Loss factors are calculated by dividing estimated losses by attributable retail energy. External losses are applicable to COS customers only. DA customers do not incur external losses because the ESS is responsible for delivering sufficient energy to the bounds of PGE's control area. Internal losses are attributable to COS and DA customers because PGE incurs line losses within its system from all sources of energy.

External Loss Factor (8) = External Losses (6) ÷ COS Retail energy (2)

Internal Loss Factor (9) = Internal Losses (7) ÷ Total Retail Load (4)

Shown in Figure 2, the five-year average for internal losses is 758,756 MWh, or 3.92% of total retail energy, and provides the basis on which losses by customer delivery voltage are calculated for the 2022 test period.

Figure 2. Historical System Energy and Losses

Year	(1) System Energy	(2) Cost-of-Service Retail Energy	(3) Direct Access Retail Energy	(4) = (2) + (3) Total Retail Energy	(5) = (1) - (4) Total Losses
2015	20,537,029	17,846,388	1,559,390	19,405,778	1,131,250
2016	20,089,652	17,065,204	1,606,057	18,671,261	1,418,390
2017	20,924,057	17,864,063	1,857,295	19,721,358	1,202,699
2018	20,342,905	17,432,760	1,950,087	19,382,847	960,057
2019	20,530,550	17,483,302	2,033,532	19,516,833	1,013,717
Average	**20,484,83**	**17,538,343**	**1,801,272**	**19,339,616**	**1,145,223**

Year	(6) External Losses	(7) = (5) - (6) Internal Losses	(8) = (6) ÷ (2) External Loss Percentage	(9) = (7) ÷ (4) Internal Loss Percentage	(10) = (8) + (9) Total Loss Percentage
2015	385,773	745,477	2.16%	3.84%	6.00%
2016	395,473	1,022,917	2.32%	5.48%	7.80%
2017	382,625	820,074	2.14%	4.16%	6.30%
2018	385,759	574,298	2.21%	2.96%	5.17%
2019	382,703	631,014	2.19%	3.23%	5.42%
Average	**386,467**	**758,756**	**2.20%**	**3.92%**	**6.13%**

Allocation of Internal Losses by Customer Class

Internal line losses are allocated to customers based on the voltage at which energy is delivered to the customer, indicating which components of PGE's distribution system are used to route the energy. PGE customers can receive service at one of three distribution voltage levels: subtransmission, primary, or secondary (defined in Figure 3).

All customers incur transmission losses. Customers receiving service at one of the lower voltage levels incur losses upstream as well. For example, secondary customers incur losses from all levels of PGE's system. Alternatively, subtransmission customers are allocated only transmission and subtransmission losses.

The first step in allocating internal losses to customer delivery voltage levels is calculating the proportion of internal losses attributable to each system component. Loss equations developed by PGE Transmission and Distribution engineers are used to estimate system component losses as a function of energy flowing into each component. A detailed discussion of the loss equations is presented in Appendix A.

Figure 3. Transmission and Distribution Component Definitions[1]

PGE System Component	Description
Transmission	Non-radial line segments of 100 kV or higher and substation assets (e.g., circuit breakers) that are part of the path that connects the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission.
Subtransmission	Non-radial line segments above 35 kV and below 100 kV and associated Substation assets are distribution. Additionally, radial lines at any voltage above 35 kV are included as distribution.[2]
Primary	Facilities below 35 kV that are radial to either the transmission system or the high voltage distribution system that serve the primary purpose of delivering electricity to customers.
Secondary	Facilities below 480V that serve the primary purpose of delivering electricity to customers.

[1] More detailed definitions are provided in Appendix B.
[2] Subtransmission also includes the Summit-Welches 24 kV line that provides service to Mt. Hood.

The sum of system component losses is calibrated to the 5-year historical average internal loss value (Figure 2, Column 7) and each system component loss estimate is adjusted such that the relative proportions are maintained. Figure 4 presents adjusted system component losses as a percentage of the energy flowing out of each component.

- The transmission loss percentage reflects losses on the transmission system as a percentage of total retail energy plus losses attributable to all downstream system components (subtransmission, primary and secondary).

- The subtransmission loss percentage reflects losses on the subtransmission system component as a percentage of total retail energy plus losses attributed to the primary and secondary system components.

- The primary loss percentage reflects losses on the primary system component as a percentage of retail energy delivered to customers at the primary and secondary service levels, plus losses attributed to the secondary system component.

- The secondary loss percentage reflects losses on the secondary system component as a percentage of retail energy delivered to customers at the secondary service level.

Figure 4. Adjusted Loss Factors for Each System Component

PGE System Component	Loss percentages of component outflow
Transmission	1.82%
Subtransmission	0.14%
Primary	1.11%
Secondary	1.07%

Using the adjusted loss percentages in Figure 4, system component losses are calculated for each customer delivery class in Figure 5. Subtransmission customers do not incur losses within the primary or secondary system components, hence the values are zero. Similarly, primary customers do not incur losses within the secondary component.

The sum of system component losses for each customer class, is divided by the class retail energy (metered kWh) to calculate class-level loss factors. Average internal losses over the 5-year window were 3.92% of delivered retail energy (Column 7 below, aligning with Column 9 in Figure 2).

Figure 5. System Component Losses by Customer Delivery Service, 5-year average

Customer Delivery Class	(1) Secondary Losses	(2) Primary Losses	(3) Subtransmission Losses	(4) Transmission Losses
Subtransmission	0	0	596	7,851
Primary	0	44,038	5,520	72,694
Secondary	160,531	168,414	21,109	278,003
System-wide	160,531	212,452	27,225	358,548

Customer Delivery Voltage	(5) = (1)+(2)+(3)+(4) Total Internal Losses	(6) Retail Energy	(7) = (5) / (6) Internal Loss Factors
Subtransmission	8,448	431,664	1.96%
Primary	122,251	3,952,593	3.09%
Secondary	628,057	14,955,359	4.20%
System-wide	758,756	19,339,616	3.92%

Transmission System Losses

It is important to note that the transmission system loss rate, when applicable to retail energy measured at the meter, is slightly higher than that applicable to component outflow in Figure 4. For the context of PGE's Transmission Rate Case, the transmission system loss rate that should be applied to retail energy is 1.85. This is calculated by dividing the 5-year average system-wide transmission losses (Figure 5, column 4) by corresponding retail energy (Figure 5, column 6).

Average System Cost Losses for BPA's Residential Exchange

Estimated losses on retail energy within the context of Average System Cost (ASC), a key metric for BPA's Residential Exchange, encompass distribution system losses only. Transmission losses (i.e., losses at 115 kV and above) should be excluded. Referencing Figure 2, Column 9, the 5-year average for internal losses as a percentage of total retail energy is 3.92%. From this figure, losses incurred PGE's transmission system can be subtracted yielding an average distribution loss of 2.07% for use in ASC filings (Figure 5, sum of Columns 1-3 divided by Column 6).

Appendix A: Distribution and Transmission System Loss Equations

Prepared by PGE Distribution Planning and Transmission Planning Teams

This section explains the development of the line loss equations for the 2021 PGE distribution and transmission system components. The resulting equations are based 2019 load profiles produced by PGE's load research function, 2019 PGE generation dispatch, and the 2021 system topography. In a change from the previous line loss study, certain 115 kV facilities have been reclassified from distribution assets to transmission assets as of year-end 2019. Additionally, it should be noted that while PGE's subtransmission component is considered part of the company's distribution system, subtransmission loss equations are presented with transmission equations, following the analysis for primary and secondary loss equations.

The four loss equations are applicable to aggregate, class-level energy and are expressed in average hourly kWh. This approach allows for loss factor calculations at a range of intervals: annual, seasonal, hour of day, etc., so long as the energy values are expressed as an hourly average.

Study Scope

This study identifies the line loss equations for secondary distribution, distribution feeders, substation transformers, subtransmission system, and transmission system using power flow software automation to calculate line losses. The distribution line losses are calculated for each 2019 Net System Load value. The transmission line losses are calculated for each 2019 hour with the associated PGE Net System Load and PGE generation dispatch for that hour. The following objectives are met in this study:

- Identification of the system elements to be studied;
- Calculation of the loss equation for the secondary distribution;
- Calculation of the loss equation for the distribution feeders;
- Calculation of the loss equation for the distribution power transformers;
- Calculation of the loss equation for the subtransmission system; and,
- Calculation of the loss equation for the transmission system.

Study Assumptions

This study includes the following assumptions:

- The secondary system component losses include all utilization transformers with a secondary voltage of 480 volts and below, and secondary service drops operating at 480 volts and below;
- The distribution feeder losses include all main-line and tap line feeders operating between 11 kV and 35 kV and their associated distribution power transformers;
- The substation transformer losses include all substation transformers with a secondary voltage less than 57 kV[3];
- The subtransmission system component includes non-radial line segments above 35 kV[4] and below 100 kV and radial lines at any voltage above 35 kV;
- The transmission system component includes non-radial line segments of 100 kV or higher and transformers with a secondary voltage higher than 100 kV;
- Distribution retail energy was determined by adding primary and secondary retail energy;
- Transmission load incudes total retail load, secondary and primary losses, and excludes internal and external transmission system losses;
- Primary and secondary losses assume a constant power factor for scaled loads; and,
- PGE generation dispatch was extracted from PI on an hourly average basis.

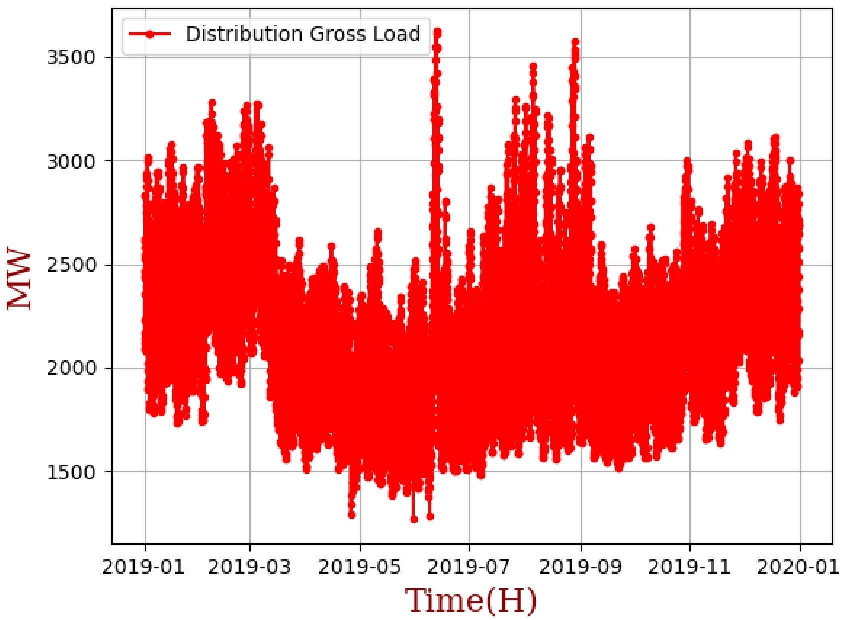
Primary and Secondary Distribution System Loss Results

As described in the Study Assumptions, primary distribution losses include all distribution feeders at operating voltages ranging from 11 kV to 35 kV and their connected distribution power transformers. Secondary distribution losses include service conductors operating at 480 V or less and their connected service utilization transformers.

Distribution gross load is defined as the total load flowing into PGE's primary distribution system, reflecting primary and secondary retail electricity, and losses incurred within the distribution system. Values are determined by subtracting hourly radial subtransmission retail load and presumed associated losses from hourly Net System Load values. Figure A-1 below provides a chart depicting the hourly load flowing into the primary distribution system.

[3] The Welches 57/24 kV transformer is included in the Subtransmission category.
[4] Subtransmission also includes the Summit-Welches 24 kV line that provides service to Mt. Hood.

Figure A-1: PGE Hourly Primary System Loading, 2019



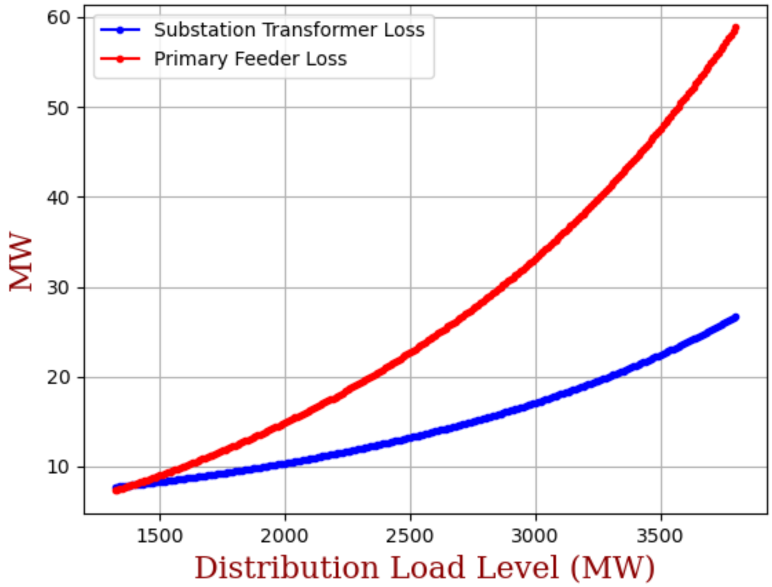
Primary feeder losses and distribution power transformer losses are determined using the following methods, tools, and observations:

- CYME software is used to run power flows for PGE's primary distribution system, which include nearly 650 feeders and nearly 270 distribution power transformers. Power flows are run at 10 MW increments from PGE's calendar year minimum gross distribution load of 1314 MW to the maximum load of 3735 MW.
- In CYME, load allocations are performed on each feeder based on its percentage of net distribution load. For this analysis, the power factor is constant. For each 10 MW increment of gross distribution load, primary distribution line and substation transformer losses are recorded.
- All above processes are performed using Python coding to iteratively run load allocations and power flow analyses[5].

Figure A-2 shows primary system feeder and substation transformer losses as a function of gross distribution load.

[5] This iterative process took nearly 48 continuous hours of computing to complete.

Figure A-2: Primary System Feeder and Substation Transformer Losses per 10 MW Loading Increments, 2019



For each loss curve, a 4th order polynomial curve fitting method with least squares algorithm is calculated. The polynomial curve fitting method uses a mathematical function with least squares algorithm to construct a curve that has the best fit to a series of data points.

Below are the 4th order polynomial curve fitting equations identified for distribution feeders and distribution substation transformers:

DISTRIBUTION FEEDER KW LOSSES:

$$y = 3.638 * 10^{-22}x^4 - 2.312 * 10^{-15}x^3 + 8.923 * 10^{-9}x^2 - 0.006048\,x + 3957$$

DISTRIBUTION SUBSTATION TRANSFORMER KW LOSSES:

$$y = 1.722 * 10^{-22}x^4 - 1.241 * 10^{-15}x^3 + 4.82 * 10^{-9}x^2 - 0.005011x + 8274$$

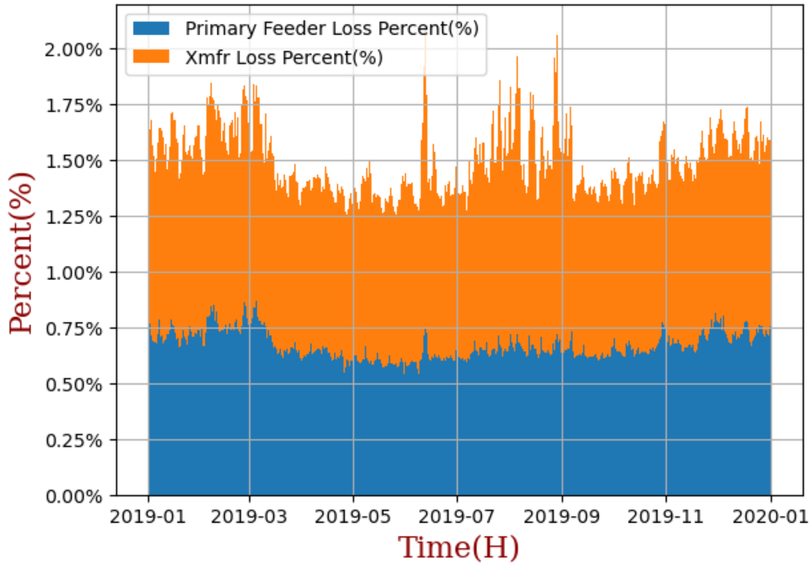
THE TOTAL PRIMARY DISTRIBUTION KW LOSSES (FEEDER + SUBSTATION TRANSFORMER LOSSES):

$$y = 5.36 * 10^{-22}x^4 - 3.553 * 10^{-15}x^3 + 13.743 * 10^{-9}x^2 - 0.011059\,x + 12231$$

In the above equations, x can represent the distribution load flowing into the substation transformers (gross distribution load) or the load leaving the feeders (primary retail + gross secondary load); y represents corresponding losses.

Figure A-3 provides a snapshot of hourly primary system losses as a percentage of gross hourly distribution load for calendar year 2019.

Figure A-3: Primary System Hourly Losses (stacked) as a Percentage of Gross Hourly Distribution Load, 2019



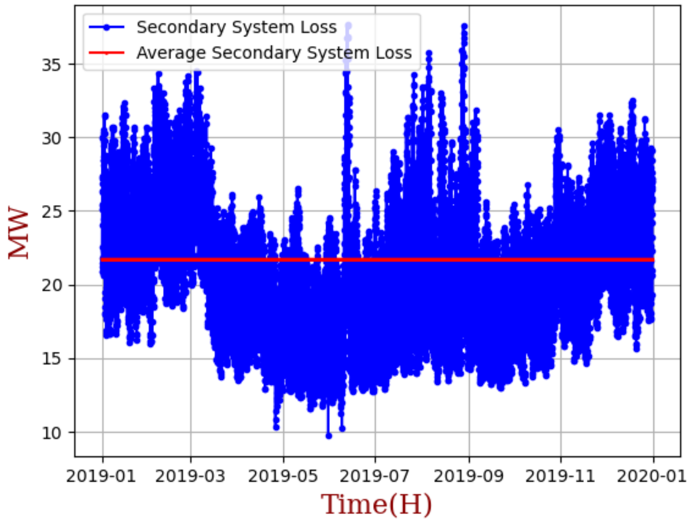
PGE's secondary distribution losses include conductors and service drops operating at 480V or less and their connected distribution utilization transformers. To calculate these losses, the primary retail load and associated losses are removed from 2019 gross distribution values.

Using load research data, secondary losses are calculated using the following equation:

Secondary System Losses = Net System Load − Transmission & Subtransmission System Losses − Subtransmission Retail Load − Primary System Losses − Primary Retail Load − Secondary Retail Load

With the above equation applied, the 2019 hourly secondary losses are shown in Figure A-4 below.

Figure A-4: Hourly Secondary System Hourly Losses, 2019



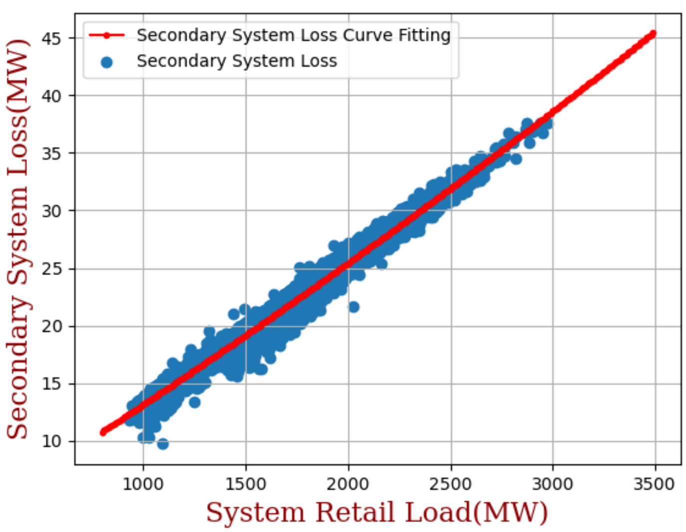
A small percentage of the output data included outliers to a degree that the 4th order polynomial curve fitting method was rendered ineffective. A more simplistic 2nd order polynomial curve fitting method with least squares algorithm is thus used to find the approximate secondary loss equation, shown below. Underlying data and the curve fitting the secondary loss equation is shown in Figure A-5.

SECONDARY KW LOSSES EQUATION:

$y = 4.551 * 10^{-10}x^2 + 0.01091\ x + 1759$

As with the primary system loss equations, *x* can represent the distribution load flowing into the secondary system or the retail load delivered to customers; y represents corresponding losses.

Figure A-5: Hourly Secondary System Losses per Retail Load, 2019



Transmission System Loss Results

Western Electricity Coordinating Council (WECC) base cases are utilized as the starting point for studying the line losses on the subtransmission and transmission systems. WECC base cases include models for the entire Western Interconnection including facility representation of voltage levels at the subtransmission level. WECC collects the data for the Western Interconnection through its members who provide the representation and equivalent data for elements in their systems, including: the initial conditions for the base case, up-to-date line parameters, load information, generation unit parameters, and equivalent representation consistent with the time period being studied. The WECC base cases used in this study were modified for use in the PGE NERC TPL 001 4 Transmission Planning Assessment (TPL), to reflect the PGE 2021 transmission system. These cases will be referred to as study cases. The WECC base cases used in this study are:

- The summer peak case is based on the WECC 2020 Heavy Summer 3 case;
- The winter peak case is based on the WECC 2020-21 Heavy Winter 2 case; and,
- The spring off-peak case is based on the WECC 2020 Light Spring 1a Scenario case.

The subtransmission and transmission system line losses are calculated for each hour of the year based on PGE's 2019 transmission net system load and PGE's 2019 generation dispatch associated with that hour. The hourly data is separated into four seasonal data sets based on the following dates:

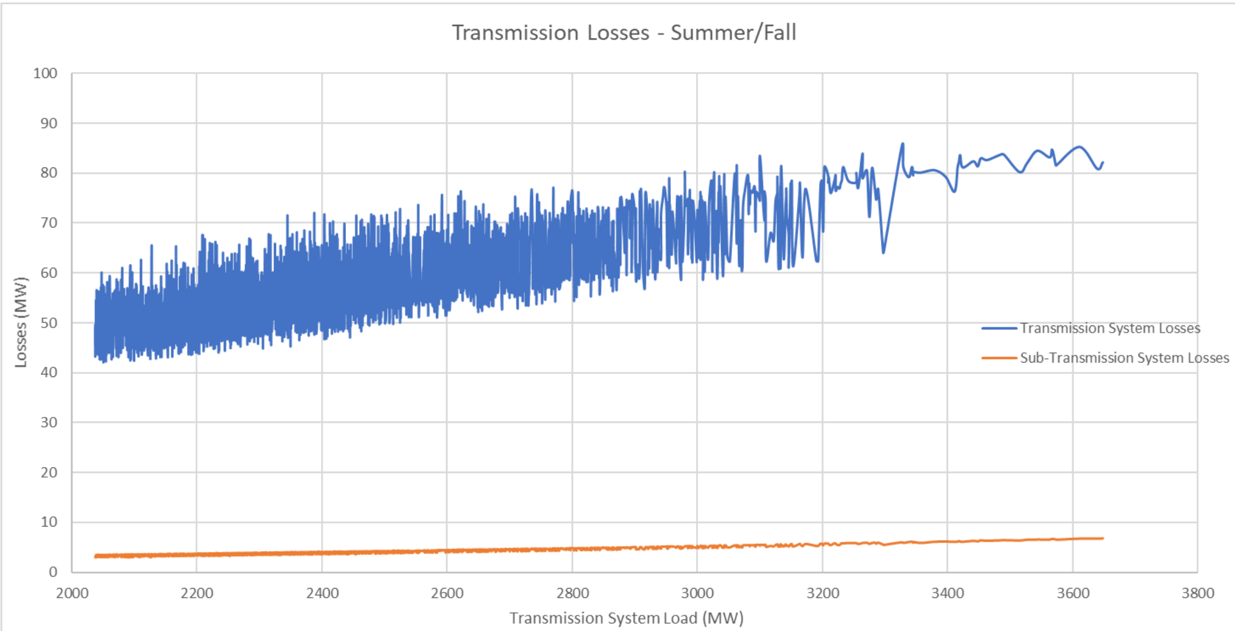
- Winter: December 1-February 28/29;
- Spring: March 1-May 31;
- Summer: June 1-September 30; and,
- Fall: October 1-November 30.

The spring and winter seasonal data sets are applied to the Light Spring and Heavy Winter study cases, respectively. Both the summer and fall season data sets are applied to the Heavy Summer study case. WECC typically does not produce base cases for the fall, and the generation dispatch in fall is similar to the summer season. PGE load and generation dispatch are changed in each seasonal case to represent actual values. It is important to utilize the seasonal cases for the appropriate time frame. This is because the base case generation profile for WECC is different for each season and the loop flow in the system will have a larger or smaller impact on PGE transmission system losses.

The PGE load in the seasonal study cases is scaled to the PGE hourly load value. PGE loads identified as industrial are not scaled. The generator dispatch for each PGE unit is set to its average dispatch for that hour. The remainder of the WECC load in the study cases is scaled proportionally to the change in PGE load. The remainder of the WECC generation in the study cases is changed by the MW value of the WECC load change to minimize changes to the system slack bus. These changes to WECC generation and load in the study cases represent the change in transmission system loop flow magnitude that is a contributing factor to transmission system losses.

The PowerWorld Simulator, utilizing the Sim-Auto module, is used to calculate the line losses for all PGE subtransmission and transmission system elements for each hour of each seasonal data set. The total line losses for PGE subtransmission and transmission elements for each hour is recorded. The summer/fall, winter[6], and spring line losses are shown below in Figures A-6, A-7 and A-8.

Figure A-6: Transmission and Sustransmission Losses, Summer/Fall 2019



[6] The winter case failed to solve for some of the lowest net system loads in the data set. This condition was expected since the range of generation and load modifications across all of WECC was very large.

Figure A-7: Transmission and Sustransmission Losses, Winter 2019

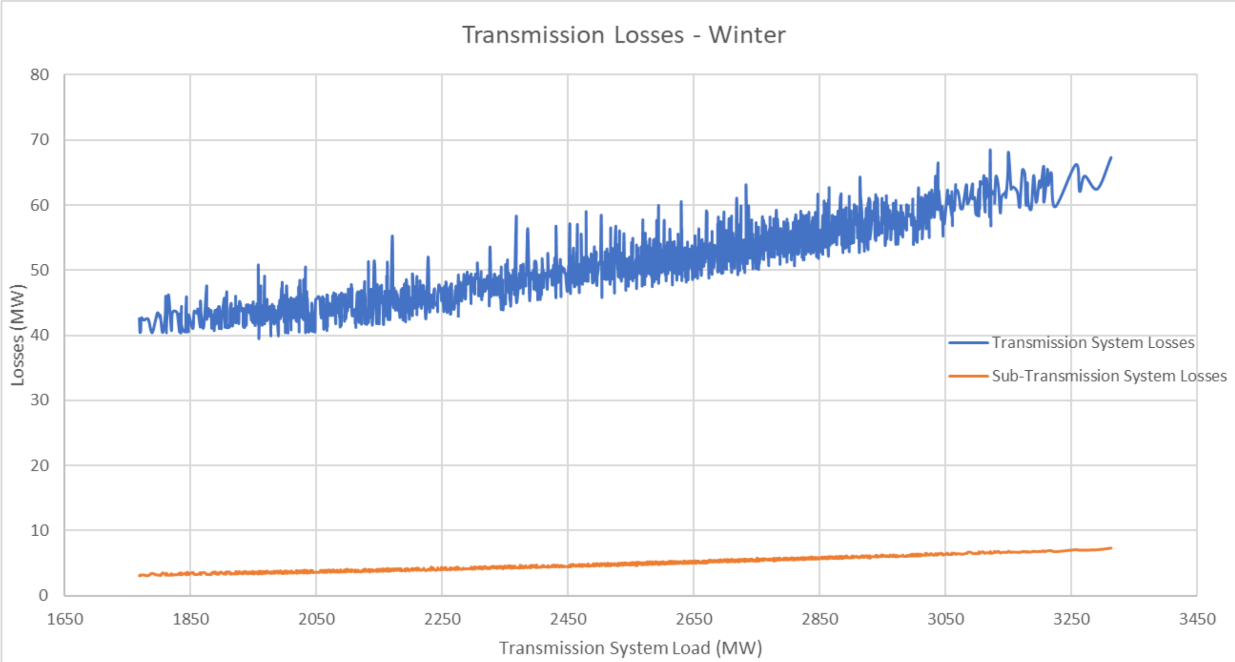
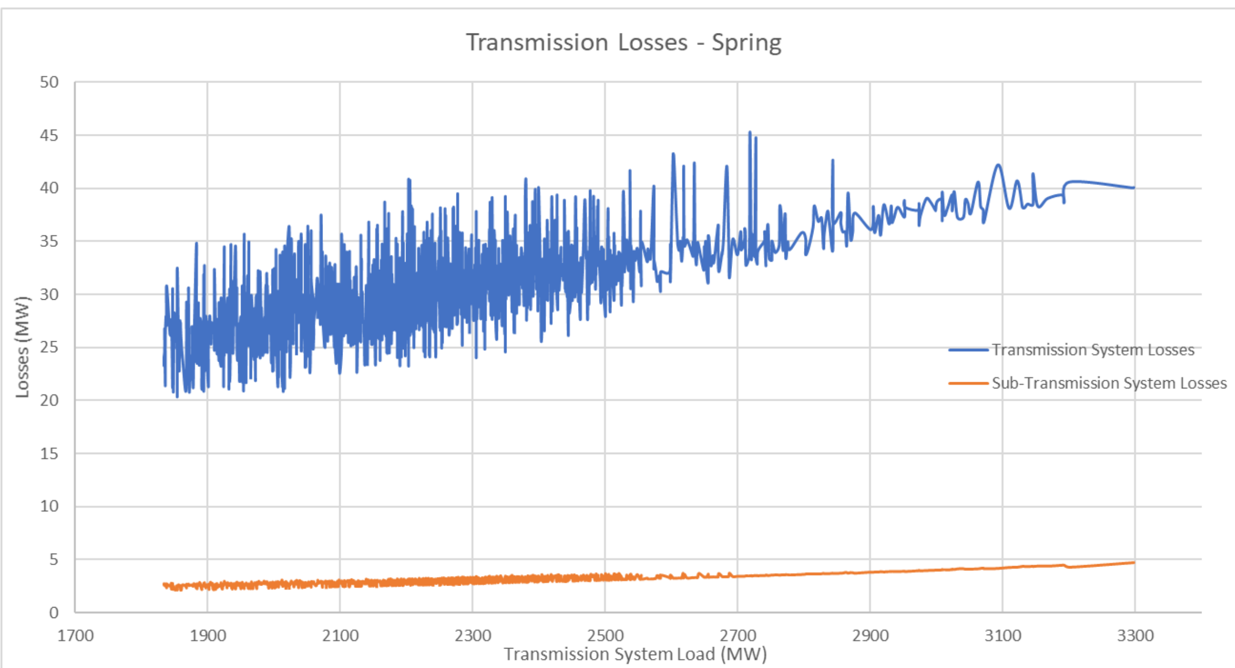


Figure A-8: Transmission and Sustransmission Losses, Spring 2019



The seasonal transmission system loss values are recombined into one data set representing a full year of hourly loss values. From this data set, transmission losses as a percent of transmission load is calculated. Figure A-9, shown below, presents the percent loss value along with a trendline and trendline equation.

Figure A-9: Transmission and Sustransmission Losses as a Percentage of System Loading, 2019

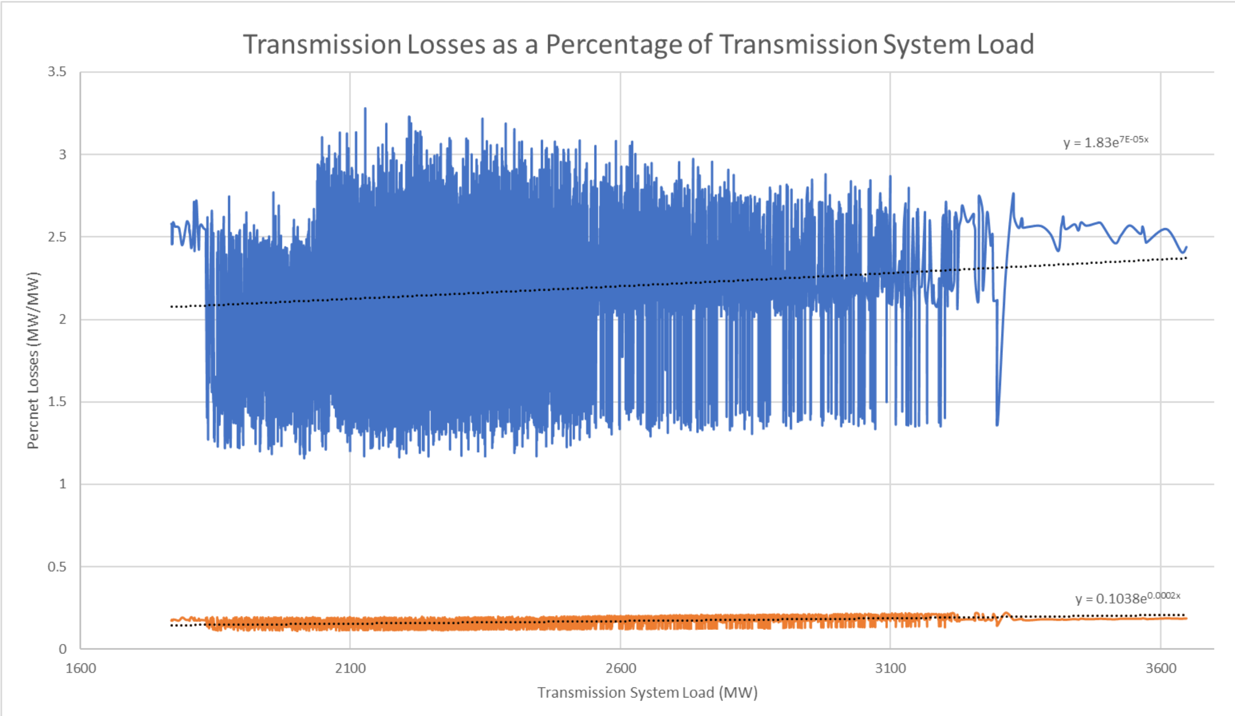


Figure A-9 shows that the transmission system losses can vary significantly for a single transmission system load value. The variation is due to loop flow across the transmission system. Generation patterns and transfers between the Northwest and other regions changes significantly from season to season. The spring season represents lower system loads and less transfers across WECC. This results in overall lower losses on the PGE transmission system than a similar transmission load value in the summer or winter when transfers into and out of the Northwest are very high. A more refined transmission loss value could be calculated if more WECC-wide system dispatch and load combinations were studied. Unfortunately, WECC only creates several base case scenarios each year. It is possible that future improvements to the WECC Anchor Data Set might provide additional dispatch scenarios to study.

The trend line shown in Figure A-9 is nearly linear as opposed to the exponentially increasing loss functions show for the distribution system. The distribution system losses are a direct result of the load on the distribution system. As distribution load approaches 0 MW, the distribution losses will also approach 0 MW. The transmission system losses, however, are partially dependent on the transmission system loop flow in addition to PGE transmission system load. As PGE transmission system load approaches 0 MW, the transmission losses also reduce, but do not approach 0 MW which results in the loss curve flattening out. The transmission system loss equations are shown below; y represents transmission losses as a percentage of transmission load and x represents transmission system load.

- The subtransmission system loss equation is $y = 0.1038e^{2E-04x}$
- The transmission system loss equation is $y = 1.83e^{7E-05x}$
- The combined loss equation for the subtransmission system and the transmission system loss is $y = 1.9295e^{8E-05x}$

Conclusion

Transmission system losses vary significantly from season to season for the same transmission system load value. This variation is due to loop flow on the transmission system created by generation and load remote to the PGE system. WECC creates several base cases each year and applying PGE seasonal load and generation patterns can produce an approximate transmission loss curve that can be applied to other load patterns to develop average loss values. A reliable 8,760 data set for remote load and generation dispatch is not currently available but may be available in the future.

In contrast, distribution system (primary and secondary) losses do not produce as much variation as these circuits are radial in nature. Due to this, techniques used to determine losses for certain levels of system loading was more predictable. Although loss values could not be produced on an 8,760 basis due to a lack of computing power, similar results would be expected.

Appendix B: Classification of Assets

The classification of assets between transmission and distribution has changed since PGE's previous loss study. Specifically, PGE has reclassified its networked 115 kV assets from distribution to transmission, with approval from both the Oregon PUC[7] and the Federal Energy Regulatory Commission[8] (FERC). The reclassification of these facilities is based on an application of FERC's Seven-Factor Test[9].

In the performance of the Seven Factor Test, certain patterns or approaches emerged, and were recognized by the OPUC in Order No 19-400. These patterns can be summarized by the following characteristics:

A. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;
B. Non-radial line segments of 100 kV or higher voltage tend to be transmission;
C. Transformers with a secondary voltage under 100 kV tend to be distribution; and
D. Substation assets (e.g., circuit breakers) that are part of the path that connects the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission.

Losses Study Definitions

Based on the Seven-Factor Test and the characteristics adopted by the OPUC, this study utilizes the following definitions:

Transmission: Non-radial line segments of 100 kV or higher and substation assets (e.g., circuit breakers) that are part of the path that connects the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission.

Note: PGE also provides transmission service over two jointly owned transmission facilities: the California-Oregon Intertie and the Colstrip Transmission System. These transmission

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[7] Portland General Electric Company. Application for Support for the Reclassification of Plant in Service. Order No. 19-400, entered on Nov 21, 2019.
[8] *Portland General Electric Company*. 169 FERC ¶ 61,266. December 31, 2019.
[9] The Seven Factors are: 1. Local distribution facilities are normally in close proximity to retail customers. 2. Local distribution facilities are primarily radial in character. 3. Power flows into local distribution systems; it rarely, if ever, flows out. 4. When power enters a local distribution system, it is not re-consigned or transported on to some other market. 5. Power entering a local distribution system is consumed in a comparatively restricted geographical area. 6. Meters are based at the transmission/local distribution interface to measure flows into the local distribution system. 7. Local distribution systems will be of reduced voltage.

facilities have separate loss rates that are established through the agreements governing the ownership and operation of these facilities.

Subtransmission (High Voltage Distribution): Non-radial line segments above 35 kV[10] and below 100 kV and associated Substation assets are distribution. Additionally, radial lines at any voltage above 35 kV are included as distribution.

Primary Delivery: Facilities below 35 kV that are radial to either the transmission system or the high voltage distribution system that serve the primary purpose of delivering electricity to customers.

Secondary Delivery: Facilities below 480V that serve the primary purpose of delivering electricity to customers.

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[10] Subtransmission also includes the Summit-Welches 24 kV line that provides service to Mt. Hood.