Transmission Workshop

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July 7, 2020

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Topics of Discussion

- Introduction
- Transmission System Overview
- Cost of Service Study
- Differences in COSS methodologies
- Return on Equity
- Proposed Transmission Rate
- Response to Stakeholder Concerns
- Wrap up Q&A

Introduction

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Contributors to the COSS Development

- **GDS Consulting** – GDS is providing consulting services for developing Grant's Transmission and Retail COSS. Approved by Commissioners Larry Schaapman and Dale Walker
- **EES Consulting** – Model review
- **Chelan PUD** – discussed transmission cost of service concepts with Chelan PUD finance staff
- **Dave Churchman**, Chief Customer Officer – 30 years of experience in the Electric and Natural Gas energy sector
- **Clark Kaml**, Senior Manager of Rates and Pricing – 30+ years of experience in setting Regulatory Policy and Utility Regulation
- **Rod Noteboom**, Manager of Transmission Services - 29 years of experience with Grant PUD in various positions
- **Bob Brill,** Economist – 35+ years of experience in the Electric and Natural Gas energy sector

Transmission System Overview

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The Interconnected Power System

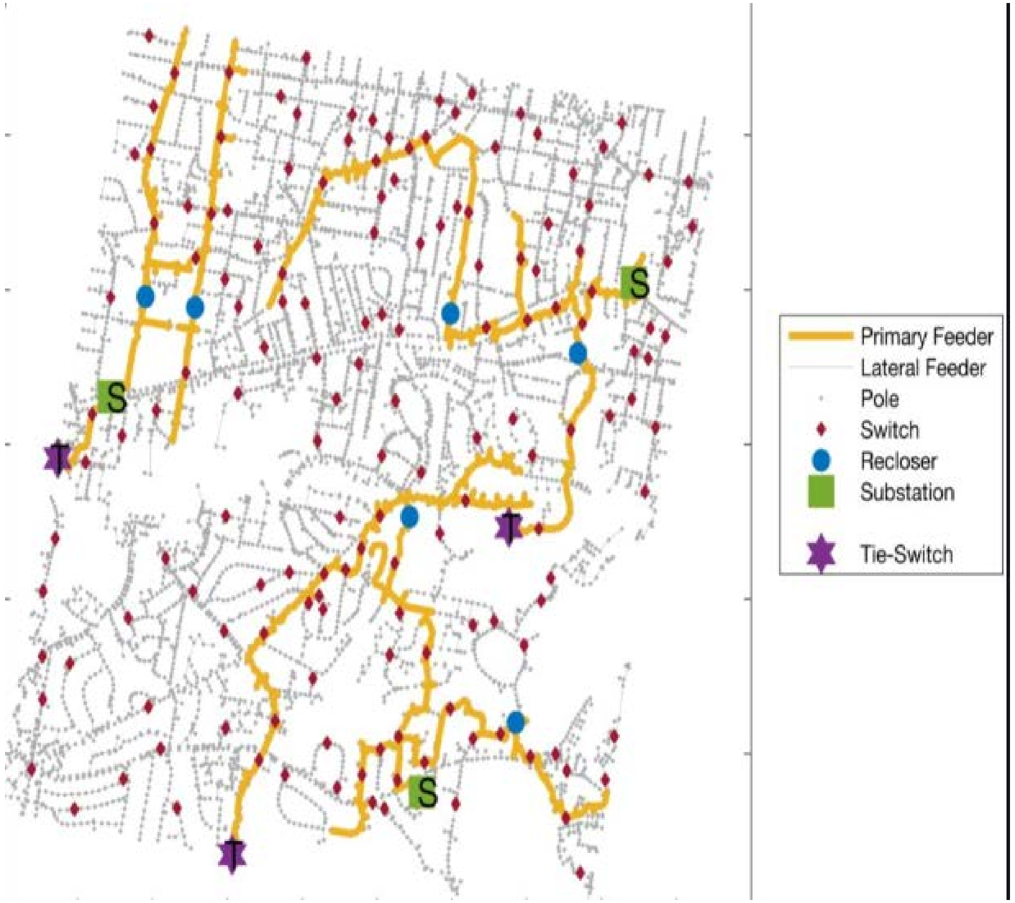
The Grant PUD transmission system is an interconnected network system

This system is used for both “NT” type service and “PTP” type service

- The type of contractual transmission does not change the physics and engineering of the service is supplied

Normal operations and reliability depend on system components that do not show up in “contract path”

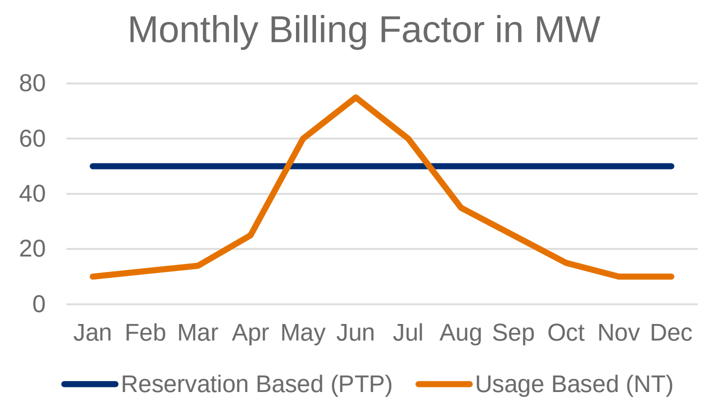
- Load flow follows path of least resistance, not contract path
- The network is needed to meet the NERC contingency requirements
  - o Grant must show that load can be met with a variety of outage conditions

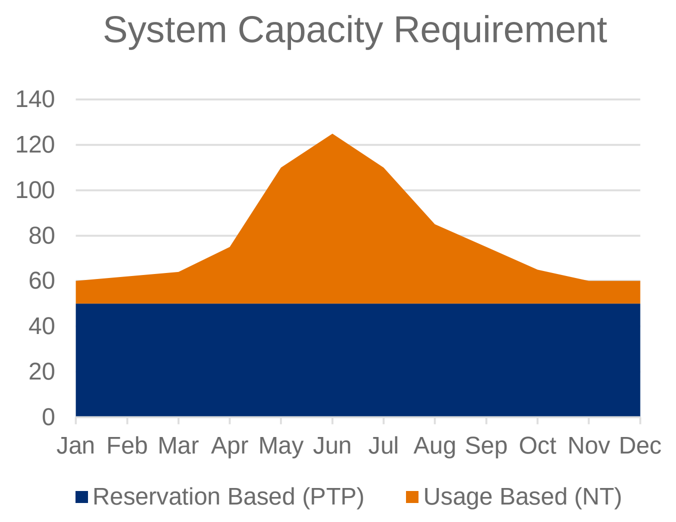


Reservation Based (PTP) verses Usage Based (NT) Rates

- Reservation based rates charge based on fixed reservation in MW that is specified in a contract or in an OASIS reservation
    - Reservation based rates are commonly referred to as Point To Point or PTP
    - Grant refers to this type of service as Transfer Service
    - The rates shown for comparisons are PTP (reservation-based rates) since all jurisdictional entities will have this rate which can be used for general comparison but not for an exact comparison.

- Usage based rates charge based on a monthly measurement of demand
    - Usage based rates are commonly referred to as Network or NT rates
    - Grant refers to this type of service as Transmission "Wholesale" Delivery
    - The rates in Schedules 30 and 31 are usage-based rates and not reservation-based rates.





Reservation Based (PTP) verses Usage Based (NT) Rates

- If a utility has both a Reservation Based(PTP) Rate and a Usage Based (NT) Rate, the Reservation Based Rate will generally be equal to or less than the Usage based rate in terms of $/MW month, but the Usage Based rate can be less costly per MWh depending on the load factor of the usage.

    - The loads that will be using Grant’s Usage Based rate have a low annual load factor and will benefit from the methodology used in a Usage Based rate.

Cost of Service Study

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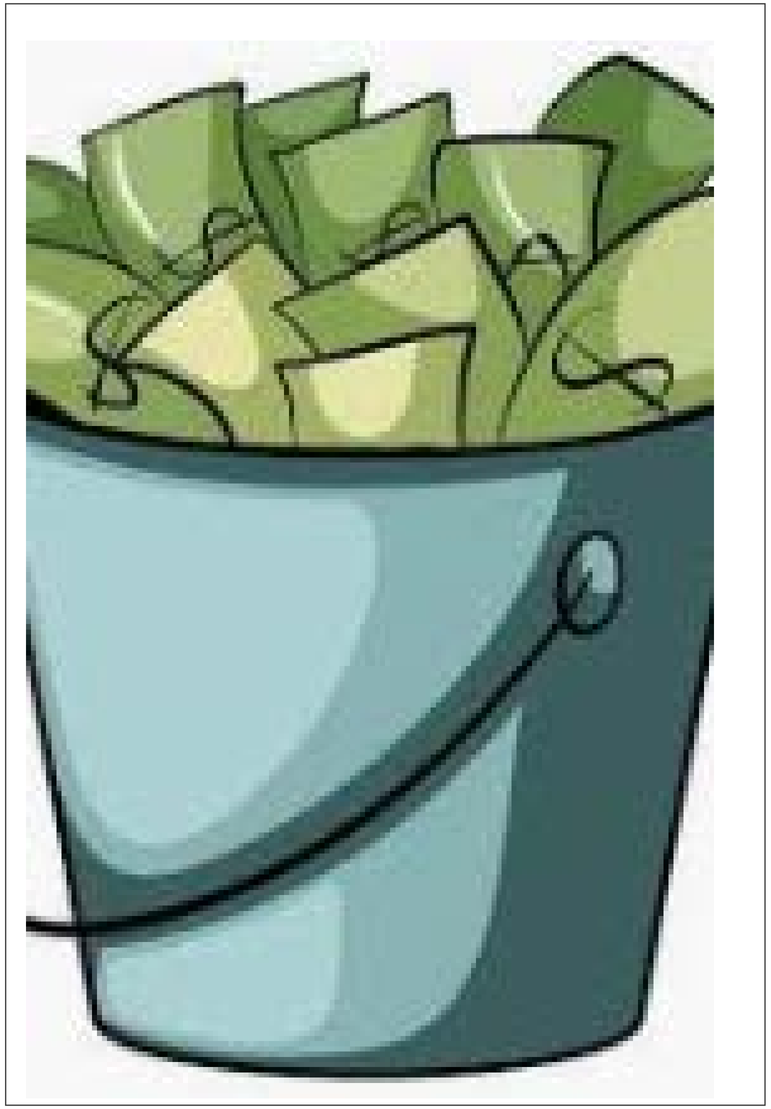


What is a "Cost of Service Study" (COSS)

The "Cost of Service Study" reflects the total amount that must collected in rates for the utility to recover its costs of operations

The objective is to apportion the utility costs among customer classes in a fair and equitable manner

- Frequently referred to as cost causation
- The "cost causer" is the rate payer or customer that receives the service and that causes the cost to be incurred

Fair and Equitable Cost Allocation Methodology

- ✓ ***Step 1*** – Determine time period to review and to develop Cost of Service Study – 2018 was used for the Transmission COSS.
- ✓ ***Step 2*** – Grant uses the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. This allows the analyst to determine what costs are directly assigned and which costs are allocated to the Generation, Transmission, and Distribution functions to develop a cost of service for each function. FERC Uniform System of Accounts provides guidance to determine direct vs. allocated costs.
- ✓ ***Step 3*** – After determining the direct vs. allocated costs. The allocated costs are functionalized to Generation, Transmission, and Distribution function based on each functions direct labor costs as a percentage to the total direct labor. A total cost of service is developed for the Transmission and Distribution functions.
- ✓ ***Step 4*** – By dividing the transmission and distribution cost of service by the appropriate billing units for each function, a rate is developed for each function that is charged to the customer using that service, includes for both retail and transmission customers.
- ✓ ***Step 5*** – The majority of the transmission and distribution costs are recovered from Grant's retail customers. Retail and transmission customers using Grant's 115-230kV electric system are assigned the transmission costs based on their usage. Retail and transmission customers using Grant 13.2kV electric system are assigned the distribution costs based on their usage.

Fair and Equitable Cost Allocation Methodology

- ✓ ***Step 1*** – ***Determine time period*** to review and to develop Cost of Service Study – 2018 was used for the Transmission COSS

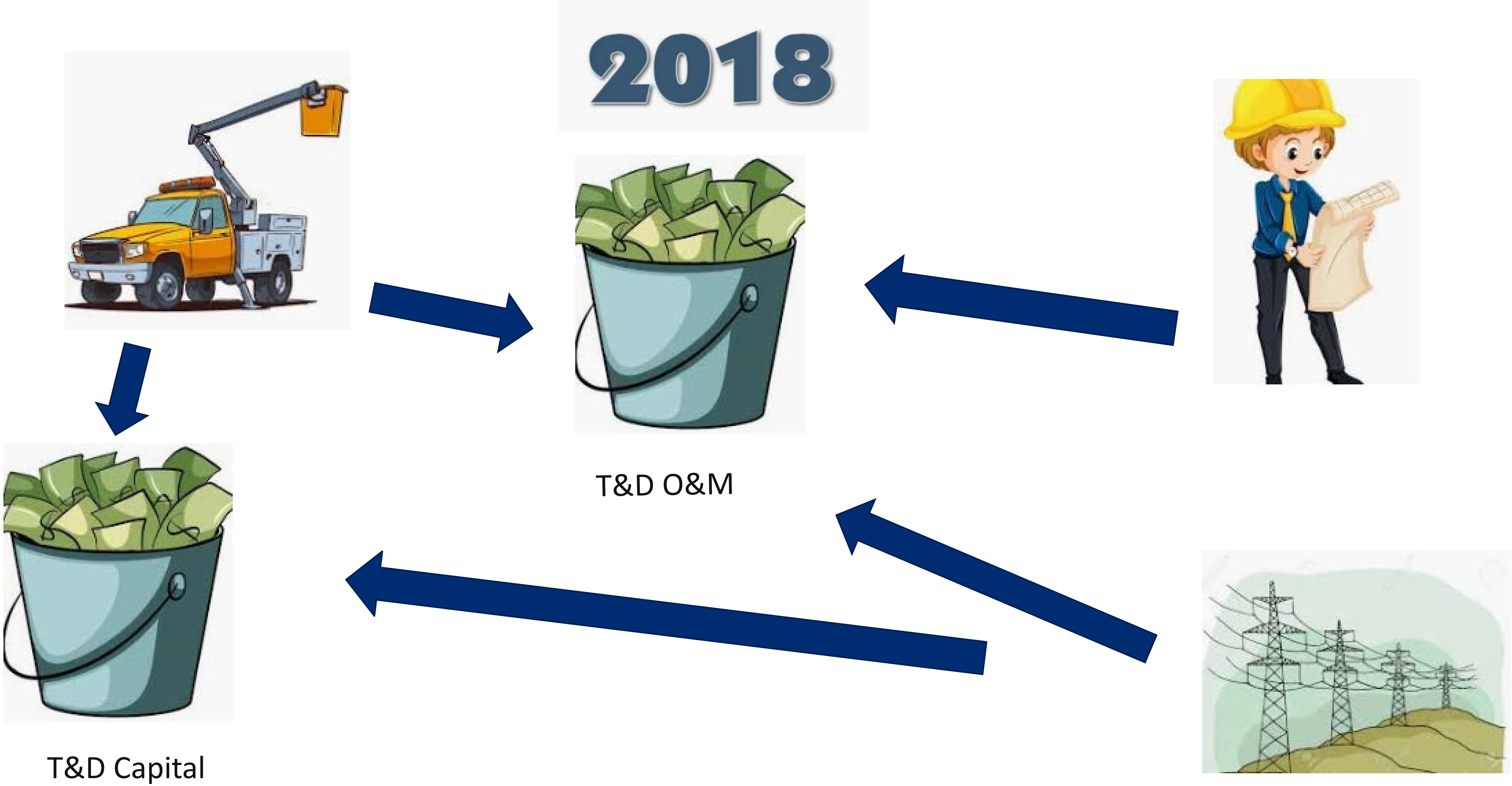
2018

Fair and Equitable Cost Allocation Methodology

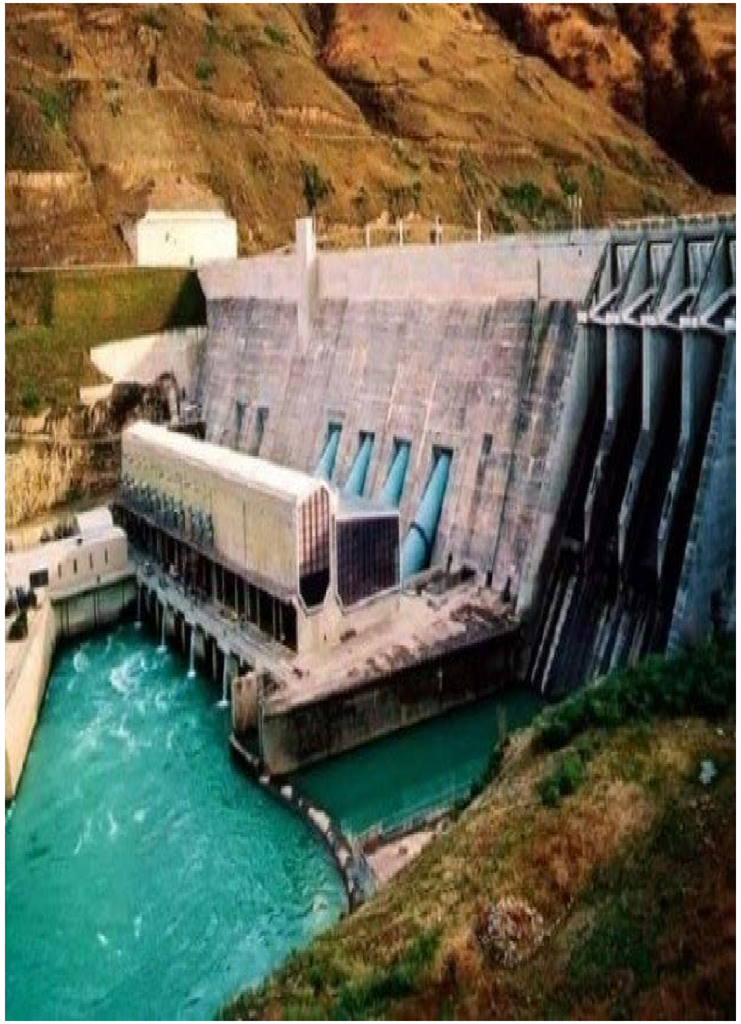
- ✓ ***Step 2*** – Grant uses the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. This allows the analyst to determine what costs are directly assigned and which costs are allocated to the Generation, Transmission, and Distribution functions to develop a cost of service for each function. FERC Uniform System of Accounts provides guidance to determine direct vs. allocated costs.

    - ❖ Costs are broken down between O&M and Capital.
    - ❖ Costs are assigned to Generation, Transmission and Distribution

Capital and O&M Costs are aggregated

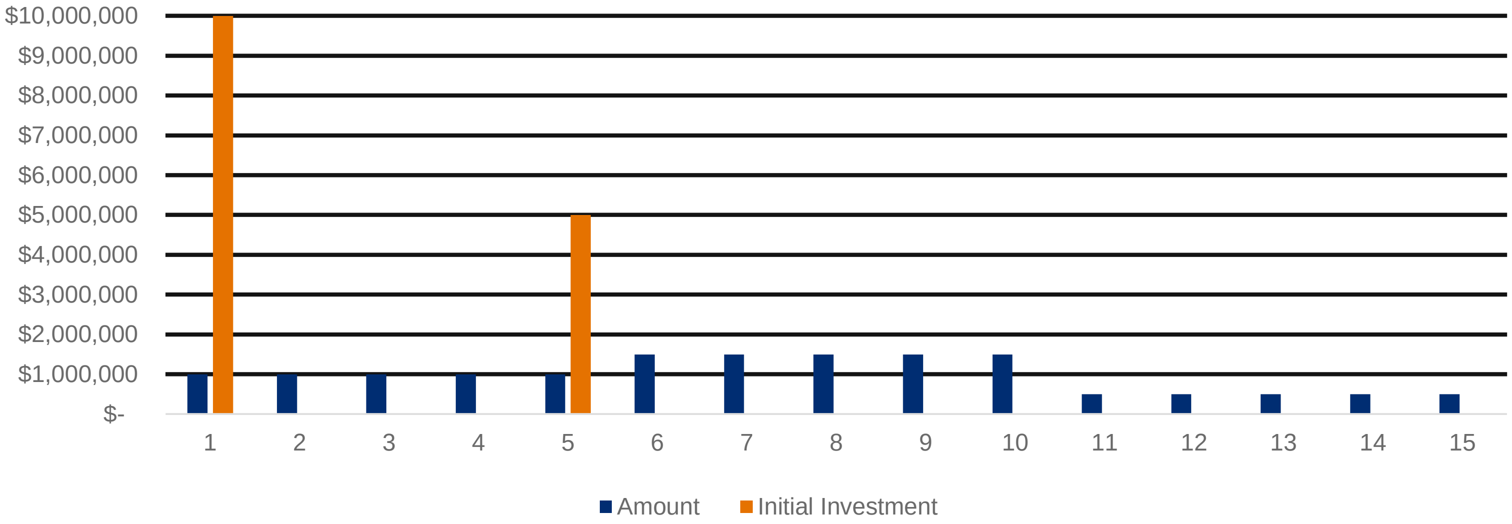


Capital Costs are broken down into annual depreciation costs



For Example Purposes Only

$10M investment in Year 1, $5M investment in year 5



Depreciation (in $Million)	Transmission	13.2kV System
Direct Depreciation	$4.4	$20.0
Allocated Depreciation	$0.9	$1.4
Total Depreciation	$5.3	$21.4
Allocated Depreciation is based on Direct Labor Costs	14.80%	22.66%

Fair and Equitable Cost Allocation Methodology

✓ ***Step 3*** – After determining the direct vs. allocated costs. The allocated costs are functionalized to Generation, Transmission, and Distribution function based on each functions direct labor costs as a percentage to the total direct labor. A total cost of service is developed for the Transmission and Distribution functions.

(in $Millions)	Total	Generation	Transmission	13.2 kV System
Allocated Administrative &General Expenses	$31.6	$19.9	$4.6	$7.1
Allocated A&G and Depreciation are based on Direct Labor Costs	100.00%	62.53%	14.80%	22.66%

Rate Base Functionalized

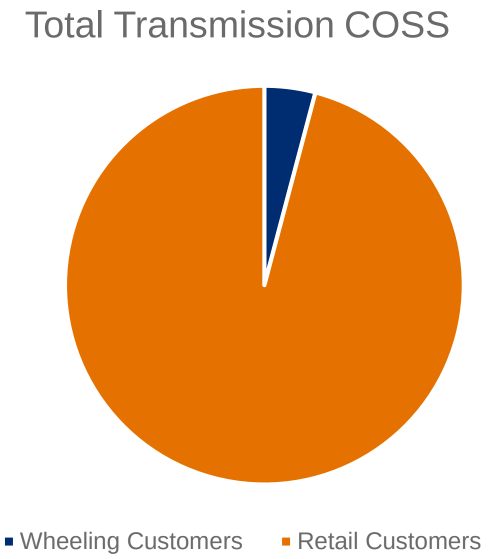
(in $Millions)	Total	Generation	Transmission	13.2kV System
Net Rate Base	$1,888.1	$1,432.5	$120.7	$334.9
Rate of Return on Investments Percentage	6.02%	6.02%	6.02%	6.02%
Return Allowance	$113.7	$86.2	$7.3	$20.2

Transmission COSS	In Millions
Trans. O&M Expenses – Directly Assignable	$6.1
A&G Expense – Allocated to O&M Function	$4.6
Total O&M Expenses	$10.7
Depreciation Expenses	$5.3
Revenue Credits	($0.4)
Trans. Cost of Capital	$7.3
Total Transmission COSS	$22.8

2018 Transmission Costs from Cost of Service Study for 115-230kV large customers

2018 Transmission Costs Paid By Wheeling Customers

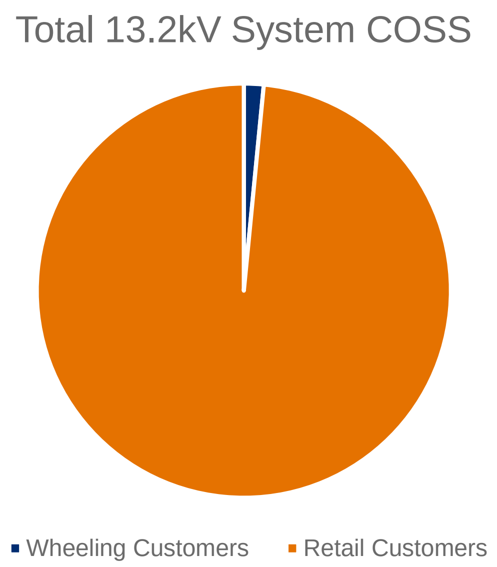
Transmission COSS (in $Millions)	
Total Transmission COSS	$22.8
Wheeling Customers Contribution	$1.0
Retail Customers Contribution	$21.8
Percentage Paid By Wheeling Customers	4.30%
Percentage Paid By Retail Customers	95.70%



13.2kV System COSS	In Millions
Trans. O&M Expenses – Directly Assignable	$13.6
A&G Expense – Allocated to O&M Function	$7.1
Total O&M Expenses	$20.7
Depreciation Expenses	$21.4
Revenue Credit	($4.4)
Cost of Capital	$20.2
Total 13.2kV System COSS	$57.8
13.2 kV System Allocation Factor	68.02%
Total 13.2 kV System COSS	$39.3

2018 13.2kV System Costs Paid By Wheeling Customers

13.2kV System COSS (in $Millions)	
Allocated 13.2kV System COSS	$39.3
Wheeling Customers Contribution	$0.6
Retail Customers Contribution	$38.7
Percentage Paid By Wheeling Customers	1.57%
Percentage Paid By Retail Customers	98.43%



Fair and Equitable Cost Allocation Methodology

✓ ***Step 4*** – By dividing the transmission and 13.2kV system cost of service by the appropriate billing units for each function, a rate is developed for each function that is charged to the customer using that service, includes for both retail and transmission customers.

Proposed Rate Schedule 30 – Wholesale Transmission Delivery for Large Loads

30-A: For loads that take delivery at a nominal voltage of 115 kV

Basic Charge: $32 per month
Delivery: $2.67 per kW of Billing Demand

30-B: For loads that utilize only the Districts 13.2 kV system

Basic Charge: $32 per month
Delivery: $4.66 per kW of Billing Demand

30-C: For loads that utilize the District's 115/230 kV system and take delivery at a nominal voltage of 13.2 kV and for loads at voltages below 13.2 kV as determined by Grant PUD.

Basic Charge: $32 per month
Delivery: $7.33 per kW of Billing Demand

Fair and Equitable Cost Allocation Methodology

Rate Schedule No. 31 – Wholesale Transmission Delivery for Small Load Customers

31-A: For single family dwelling, individual apartment or farmhouse for single-phase service

Delivery: $0.03873 per kWh
Basic Charge: Currently no charge

31-B: For loads *not exceeding 500 kW* (as measured by Billing Demand) for general service, commercial, multi-residential and miscellaneous outbuilding lighting, heating and power (excepting irrigation service) requirements.

Delivery: $0.02432 per kWh
Basic Charge: Currently no charge

31-C: For irrigation, orchard temperature control or soil drainage loads not exceeding 2,500 horsepower and other miscellaneous power needs including lighting.

Delivery: $0.02622 per kWh
Basic Charge: Currently no charge

Fair and Equitable Cost Allocation Methodology

✓ ***Step 5*** – The majority of these transmission and 13.2kV system costs are recovered from Grant's retail customers. Retail and wheeling customers using Grant's 115-230kV electric system are assigned the transmission costs based on their usage. Retail and wheeling customers using Grant 13.2kV electric system are assigned the costs based on their usage.

Sample Customer Transmission Charges

Handout

Difference in Cost of Service Methodology

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2019 COSS vs. 2017 COSA Methodology

Significant differences:

- The 2019 COSS based upon industry standard FERC methodology for Transmission "Wholesale" customers. This methodology is widely used throughout the United States, and across other different energy utility industries.
- The 2019 COSS is based on 2018 *actual costs and actual transmission usage* rather than *forecasted costs and forecasted transmission usage* as the 2017 COSA was prepared (five-year average into the future).
- Cost of Capital requirements are calculated differently to provide reliable, stable, and predictable rates.

Why did Grant PUD Changes Methodologies?

- **Customers requested a standard cost of service approach to developing the transmission rates.**
- **New methodology creates more *stable and predictable rates* over time by smoothing costs rather than using forecasted costs. Because transmission expenses are "lumpy" the prior methodology can result in erratic rate changes.**
- **New potential transmission customers such as solar developers are accustomed to the proposed COSS methodology and will provide potential new transmission revenue.**

Why did the new COSS transmission rates increase?

- Total O&M expenses is $4.4M higher, with A&G expenses $1.4M higher
- Capital Related Costs are $6.4M lower (New COSS includes 9.8% ROE)
- Total Costs are approximately $2.0M lower in 2019 COSS (O&M Expenses and Capital Cost)
- The actual 2018 Transmission usage is lower than 2017 COSA forecasted estimates

2017 COSA	VS	2019 COSS

O&M Expense:

(includes transmission and A&G O&M expenses)

$6.3M

O&M Expense:

(includes transmission and A&G O&M expenses)

$10.7M

(Difference is positive $4.4M)

2017 COSA VS 2019 COSS

Depreciation Expenses:

Not calculated when using the cash approach

$0

Est Capital Costs:

Calculated using “debt and cash” approach

$19.0M

Total Capital Related:

$19.0M

Depreciation Expense:

Included in calculation when using accrual accounting

$5.3M

Return on Investment:

Calculated on a “net plant position”

$7.3M Includes Debt and Equity

Total Capital Related:

$12.6M (Difference is negative $6.4M)

2017 COSA	VS	2019 COSS
O&M Expense: (includes transmission and A&G O&M expenses) **$6.3M**		**O&M Expense:** (includes transmission and A&G O&M expenses) **$10.7M**
Capital: Calculated using “debt and cash” approach **$19.0M**		**Capital:** Standard FERC methodology including ROE **$12.6M Includes Depr. and Return**
Total Costs: **$25.3M**		**Total Costs:** **$23.3M** (Difference of a negative $2.0M)

2017 COSA VS 2019 COSS

Load: Used a 5 Year average based on projected load growth. The forecast had a **much *larger* load and denominator.**

Load: Used historic 2018 load

Return on Equity and Return on Investment

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Return on Equity

= Return on Retail Customer Equity

Money from retail customers used to construct infrastructure.

Return on Investment (Rate of Return)-6.02%

Return on Equity- 9.80%

	Capitalization Structure	Cost of Capital	Weighted Avg. of Cost of Capital
Debt	60%	3.50%	2.10%
Return on Customer Equity	40%	9.80%	3.92%
Total	100%		6.02%

Support for Grant's 9.8% ROE

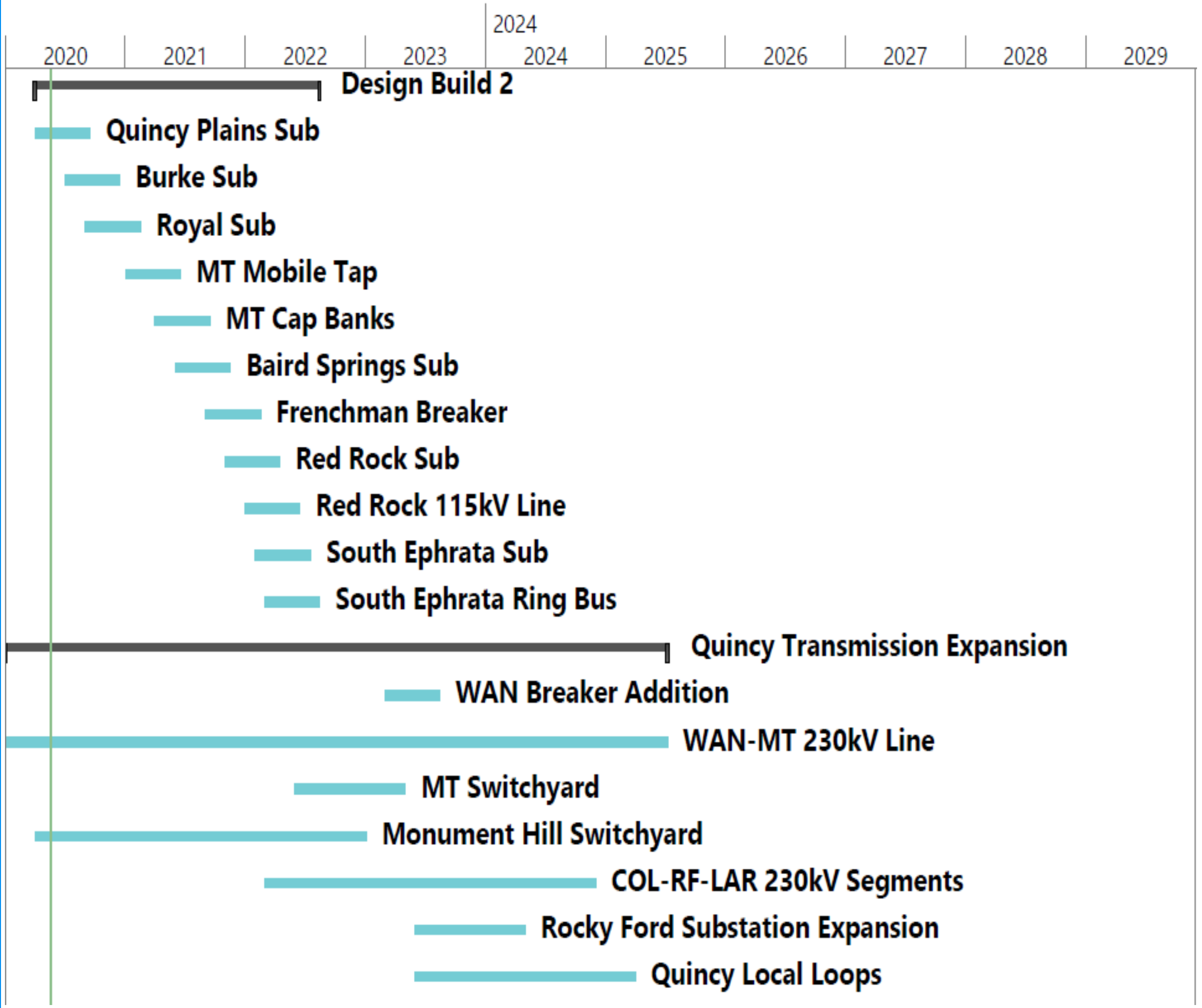
- ✓ For proposed ROE of 9.8%, staff used an average of FERC approved ROEs for Puget and PacifiCorp
- ✓ FERC Opinion 569 – originally issued in November 2019, FERC modified its ROE calculation to set a zone of reasonableness using the DCF and CAPM ROE methodology, in its Opinion 569, FERC recommended an ROE of 9.88%. On May 21, 2020, FERC revised its ROE methodology to include the risk premium ROE method, this revised their ROE recommendation to 10.02%.
- ✓ Multiple Washington State electric and natural gas utilities approved by the state commission, the simple average return on investment was 7.33% with a supporting ROE of 9.45%.

MIT Paper discussion

Why have a Return on Equity (ROE)?

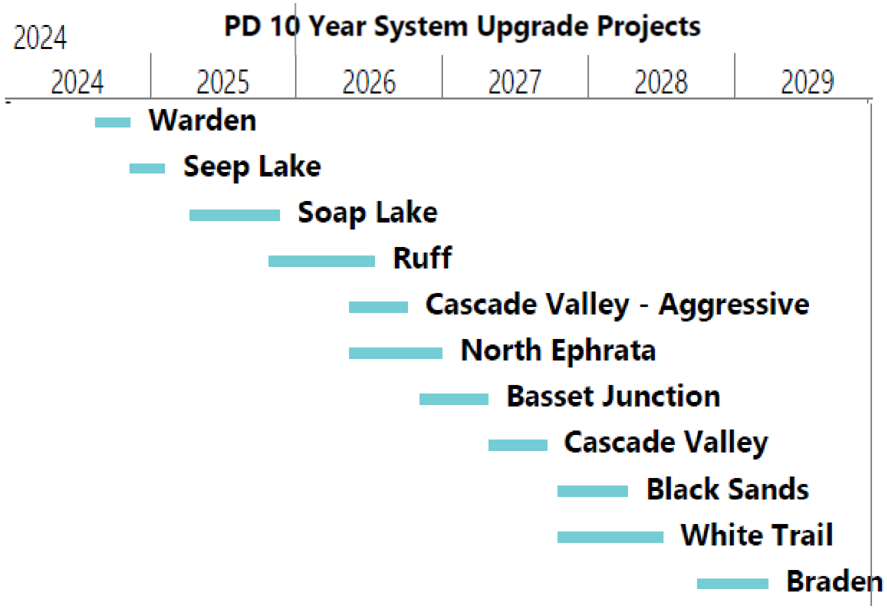
Fair Return - compensates retail customers for their investment in transmission facilities and provides a fair return on their investment used by non-retail customers.

Why have a Return on Equity (ROE)?



Future investment **- Provides *funds for future costs* for system enhancement or replacement above study year costs.**

Having an *ROE at or above the historical growth rate* is one way to ensure adequate funds are available for future transmission investment growth.



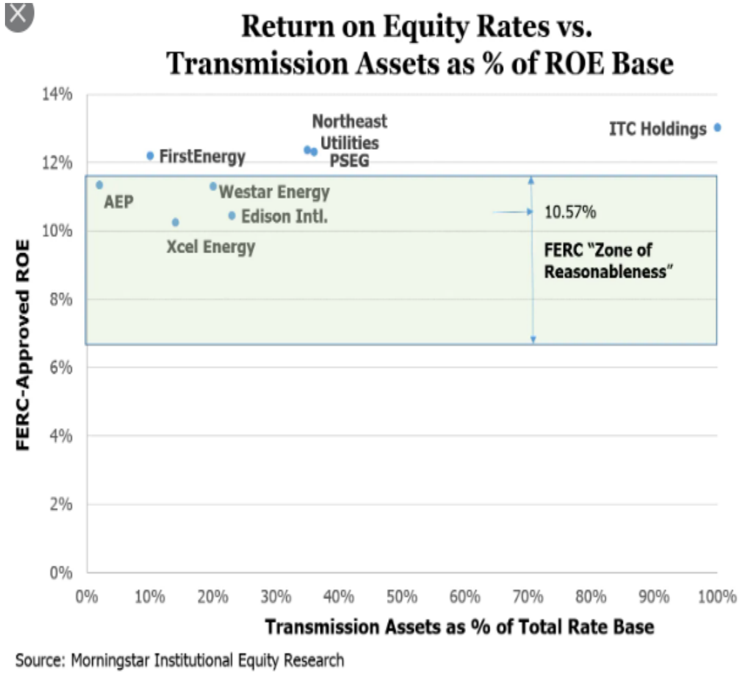
Why have a Return on Equity (ROE)?

Risk - Retail customers carry the risk of building and maintaining infrastructure used to provide transmission. An ROE provides financial cushion for unanticipated costs such as:

- Credit risk – transmission customer bankruptcy
- High cost emergencies – fire, wind, catastrophic failure such as Ephrata Substation
- Reduced transmission usage – network customers pay on actual, not contract so if they transmit less power retail customers cover the revenue shortfall
- Increased operational expense compared to 2018.

Why have a Return on Equity (ROE)?

***PUD is Required to Provide Service* – If the PUD did not provide service, the customer could appeal to FERC who requires transmission owners to provide transmission service to network customers. However, FERC supports transmission owners being fairly compensated through a rate of return on their investment.**



Why have a Return on Equity (ROE)?

Stable Financial Position

- If risks come to pass resulting in increased costs, there is financial flexibility to cover these costs.
- Over time this money can be used to pay down debt, maintain cash reserves, and reduce the amount of retail rate increases.
- This leads to a more fiscally sound organization that can weather the risks that do occur in the future.
- This flexibility could be from cash reserves or capacity to acquire additional debt to cover costs without jeopardizing the PUD's financial metrics.

Grant PUD's Financial Metrics

Metric	Target	2020	2021	2022	2023	2024	2025
Liquid Cash	>$105M > 250 days	Maintain above target	Maintain above target	Maintain above target	Maintain above target	Maintain above target	Maintain above target
Consolidated Debt Service Coverage	>1.80x	Maintain above target	Maintain above target	Maintain above target	Maintain above target	Maintain above target	Maintain above target
Debt to Net Plant	<60% Debt	Maintain below target	Maintain below target	Maintain below target	Maintain below target	Maintain below target	Maintain below target
Return on Net Assets	>4%	3.00%	3.0%	3.6%	3.5%	3.1%	2.5%
Retail Operating Ratio	<100%	108%	105.9%	105.1%	101.5%	99.1%	Maintain below target

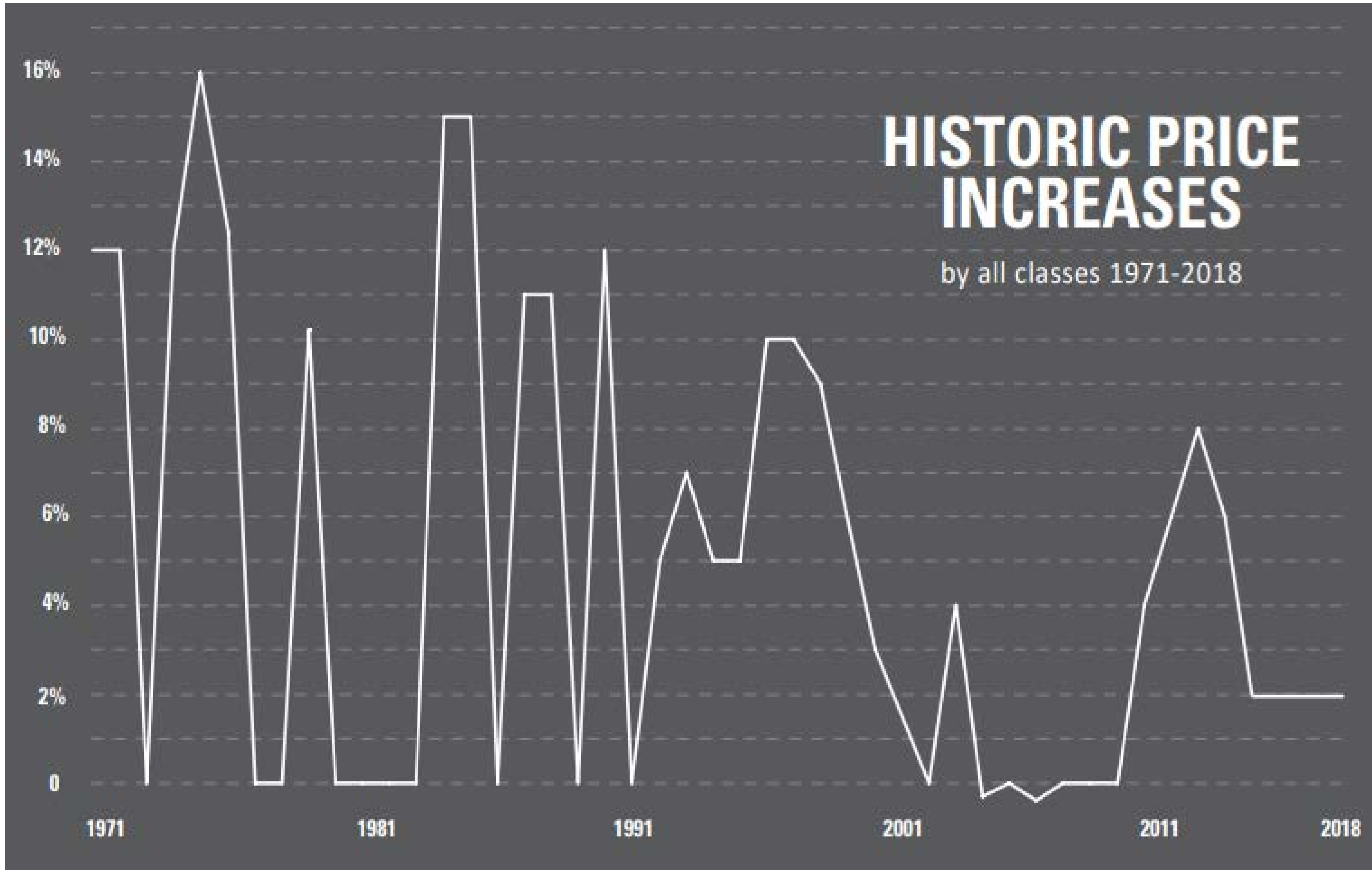
Red denotes not achieving metric in current forecast

Yellow denotes achieving interim metric, but not final metric target

Why have a Return on Equity (ROE)?

More Stable Rates over time for both retail and transmission customers.

- Greater likelihood of stable and predictable rates for both retail and transmission customers.
- Smooths out cost recovery compared to cash methodology.



Impacts of not having an ROE

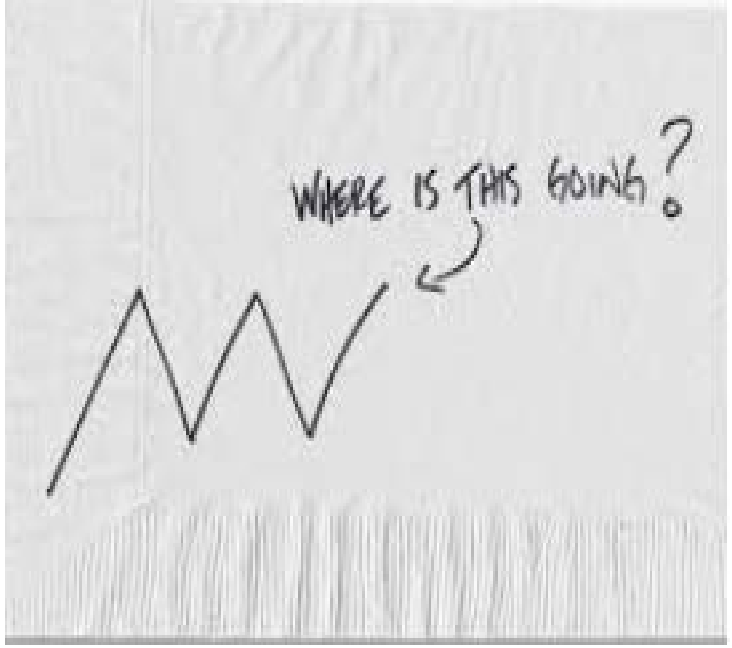
Inequity **- Retail customers commit cash through rates to fund long term infrastructure. If retail customers don't receive a return from transmission customers, they are funding the infrastructure used by transmission customers without a return on their investment. Creates a "free rider" on Grant's electric system.**

Impacts of not having an ROE

Retail Rate Risk **- If risks come to pass then the PUD will cover those costs by taking on additional debt, or from customer funded cash. These actions will increase retail rates. A return on investment is not a guarantee that adequate money will be collected to cover risks, but it does allow for *some* money to be available.**

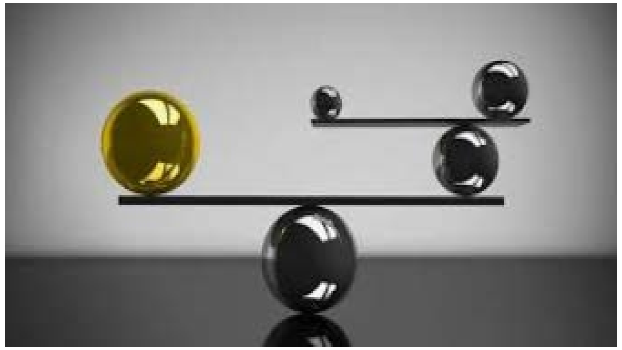
Impacts of not having an ROE

Erratic transmission rates **- Costs associated with these risks can be large and unpredictable such as the Central Ephrata Substation. Collecting a return on customer investment helps offset these large unpredictable costs for assets used to provide transmission service and provides more stable and predictable rates.**



What is a reasonable rate of return?

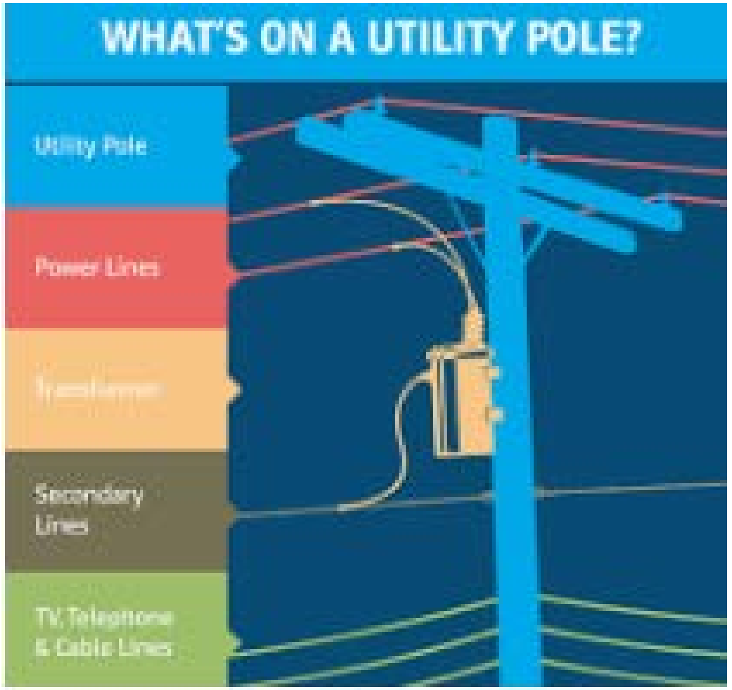
Comparable FERC and WA State Regulated ROEs Between 2017 and 2019



Company	Comparable FERC ROEs	Comparable WA State Regulated ROEs	Comparable WA State Regulated Rate of Return (Debt + Equity Avg)
	(1)	(2)	(3)
Avista – 2018	9.90%	9.40%	7.21%
Avista - 2019	9.90%	9.50%	7.50%
Puget Sound	9.50%		
PacifiCorp	10.02%		
Cascade Natural Gas-2018		9.40%	7.24%
Cascade Natural Gas-2020		9.40%	7.31%
NW Natural Gas		9.40%	7.16%
Pacific Power - 2015		9.50%	7.30%
Pacific Power - 2016		9.50%	7.30%
PSE - 2017		9.50%	7.60%
Average Washington State	9.83%	9.45%	7.33%
Proposed ROR			6.02%

Note: Per S&P Global (4/1) – the national ROE average for electric utilities is 9.64%.

Federal Communication Commission (FCC)
Rate of Return
(Compares to GPUD’s proposed 6.02%)



FCC Authorized Rate of Return (Can be used for Pole Attachment Charge calculation)

- Effective July 1, 2020 = 10.0%
- Effective July 1, 2021 = 9.75%

Source: https://docs.fcc.gov/public/attachments/FCC-16-33A1.pdf Para. 326

California ISO Transmission Return on Equity – 11.0% (Compares to GPUD's proposed 9.8% ROE)

California ISO

2018-2019 ISO Transmission Plan — March 29, 2019

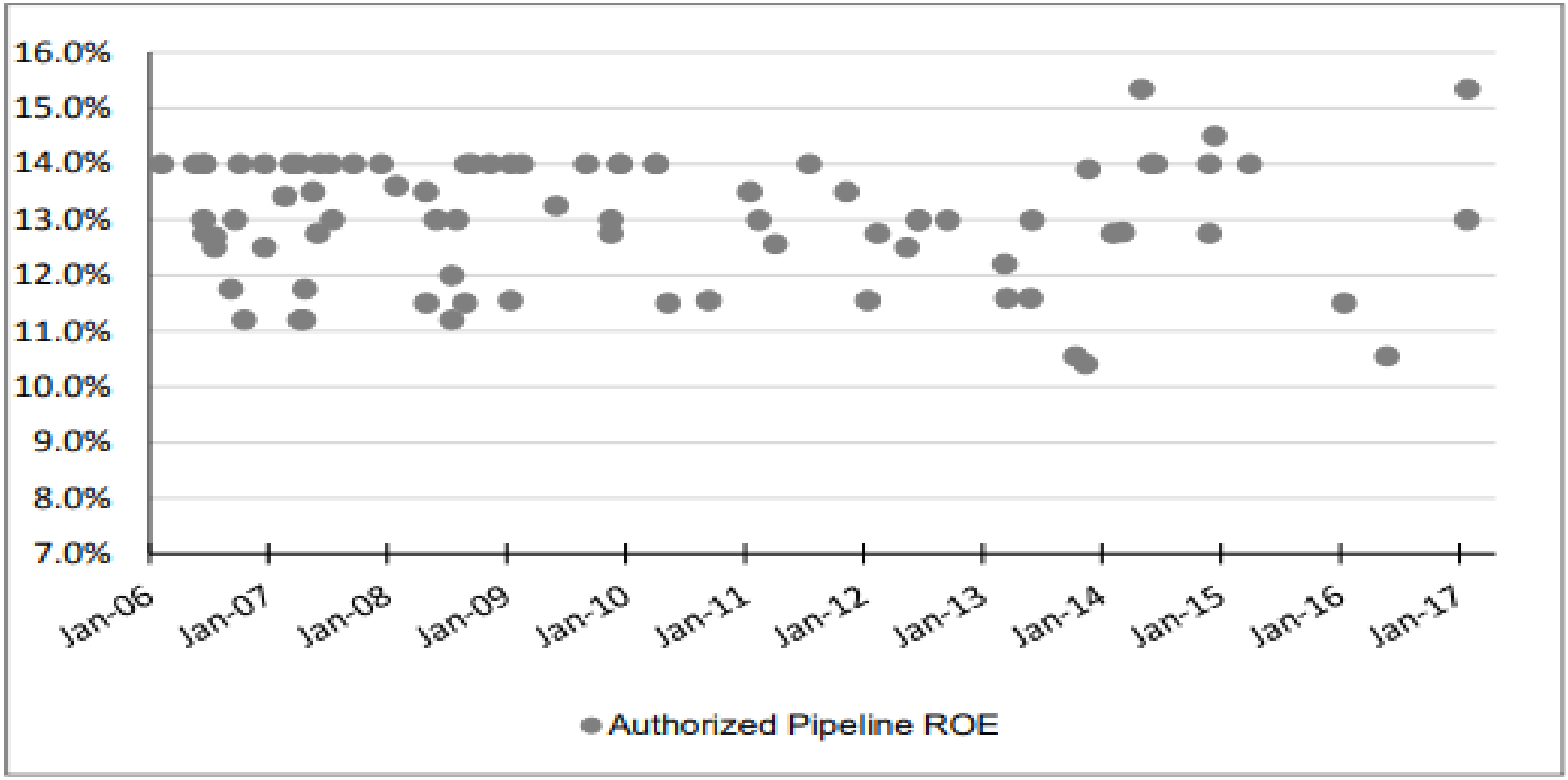
Table 4.3-1: Parameters for Revenue Requirement Calculation

Parameter	Value in TAC model
Debt Amount	50%
Equity Amount	50%
Debt Cost	6.0%
Equity Cost	11.0%
Federal Income Tax Rate	21.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Depreciation Tax Treatment	15 year MACRS
Depreciation Rate	2% and 2.5%

http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf p.230

FERC approved Natural Gas Pipeline Return on Equity (Compares to GPUD’s proposed 9.8%)

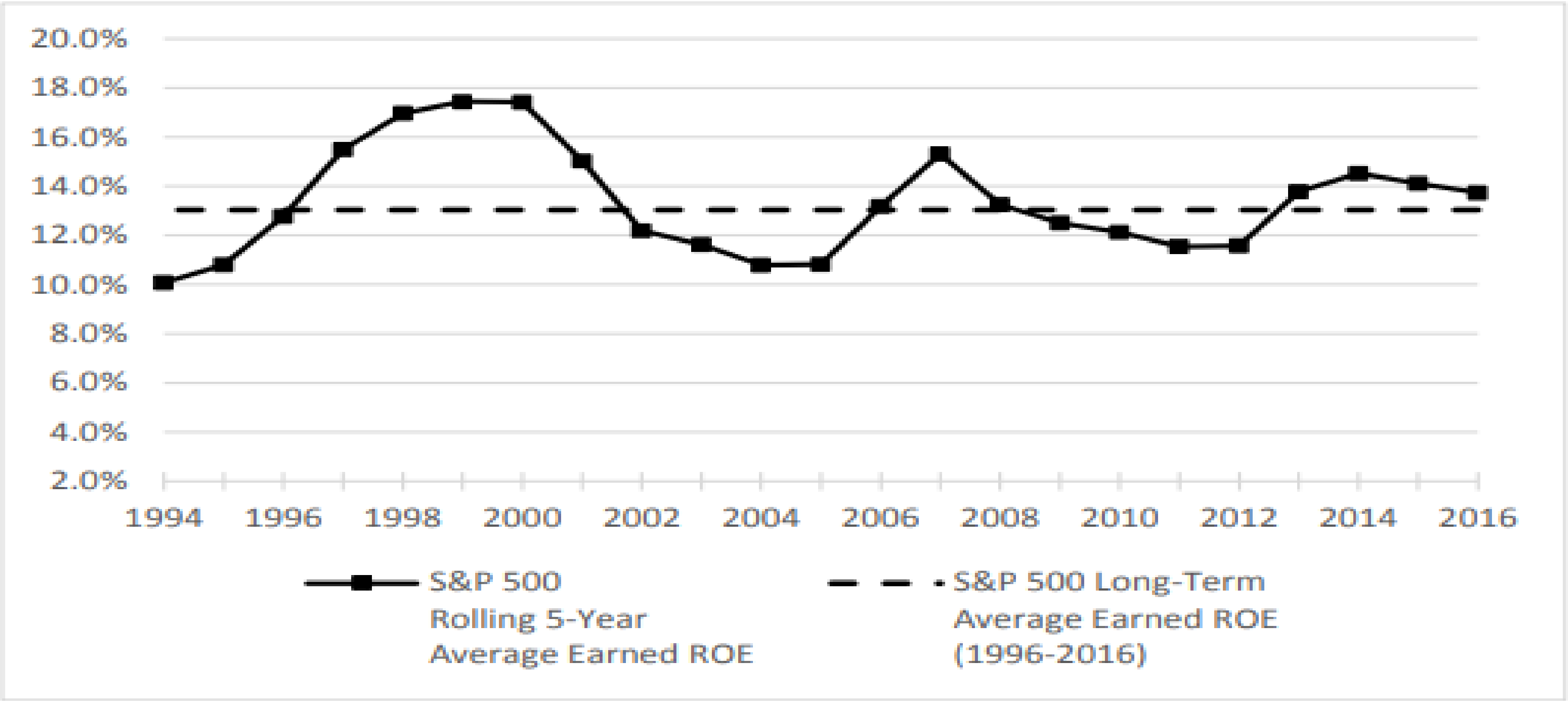
Chart 3: Commission-Authorized Natural Gas Pipeline ROEs over Time[41]



https://www.eei.org/issuesandpolicy/transmission/Documents/ROE%20White%20Paper.pdf

Residential Customer Opportunity Cost – Return from S&P

Chart 4: Moving 5-year Average Earned Return on Common Equity for S&P 500



https://www.eei.org/issuesandpolicy/transmission/Documents/ROE%20White%20Paper.pdf

Commercial Customer Opportunity Cost

http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/roe.html

Industry Name	Number of firms	ROE (unadjusted)	ROE (adjusted for R&D)
Advertising	47	26.08%	23.47%
Aerospace/Defense	77	31.42%	22.58%
Air Transport	18	28.20%	27.87%
Apparel	51	16.72%	16.51%
Auto & Truck	13	12.43%	7.79%
Auto Parts	46	12.56%	9.42%
Bank (Money Center)	7	12.80%	12.80%
Banks (Regional)	611	12.05%	12.05%
Beverage (Alcoholic)	21	6.88%	6.88%
Beverage (Soft)	34	40.25%	38.76%
Broadcasting	27	93.39%	93.36%
Brokerage & Investment Banking	39	14.06%	14.05%
Building Materials	42	14.05%	13.05%
Business & Consumer Services	165	10.24%	10.04%
Cable TV	14	11.76%	11.77%
Chemical (Basic)	43	9.16%	8.35%
Chemical (Diversified)	6	10.07%	8.91%
Chemical (Specialty)	94	5.68%	5.32%
Coal & Related Energy	22	11.59%	11.36%
Computer Services	106	17.29%	14.50%
Computers/Peripherals	48	39.99%	26.60%
Construction Supplies	44	24.78%	20.62%
Diversified	23	7.86%	7.36%
Drugs (Biotechnology)	503	-0.94%	3.83%
Drugs (Pharmaceutical)	267	21.51%	12.65%
Education	35	12.90%	12.49%
Electrical Equipment	113	20.08%	17.43%
Electronics (Consumer & Office)	20	-10.11%	-5.32%
Electronics (General)	153	11.29%	8.87%
Engineering/Construction	54	3.43%	3.42%
Entertainment	107	17.66%	15.73%
Environmental & Waste Services	82	10.68%	10.66%
Farming/Agriculture	31	9.14%	8.09%
Financial Svcs. (Non-bank & Insurance	232	0.07%	0.07%
Food Processing	88	1.90%	1.85%
Food Wholesalers	17	15.51%	15.51%
Furn/Home Furnishings	35	16.97%	14.58%
Green & Renewable Energy	22	-5.80%	-5.48%
Healthcare Products	242	9.78%	8.58%
Healthcare Support Services	128	13.16%	13.12%
Heathcare Information and Technology	129	11.17%	9.53%
Homebuilding	32	15.26%	15.26%
Hospitals/Healthcare Facilities	36	62.13%	62.12%
Hotel/Gaming	65	16.23%	16.05%
Household Products	127	10.59%	9.34%
Information Services	69	30.52%	28.03%
Insurance (General)	19	7.42%	7.42%
Insurance (Life)	24	10.44%	10.44%
Insurance (Prop/Cas.)	51	10.58%	10.58%
Investments & Asset Management	192	13.31%	13.21%
Machinery	120	20.03%	17.80%
Metals & Mining	92	3.27%	3.23%
Office Equipment & Services	22	18.22%	15.00%
Oil/Gas (Integrated)	4	7.85%	7.76%
Oil/Gas (Production and Exploration)	269	6.36%	6.35%
Oil/Gas Distribution	24	3.91%	3.91%
Oilfield Svcs/Equip.	136	-8.40%	-8.03%
Packaging & Container	24	15.96%	15.30%
Paper/Forest Products	15	2.05%	2.02%
Power	52	5.71%	5.71%
Precious Metals	83	12.90%	12.54%
Publishing & Newspapers	31	-3.79%	-3.75%
R.E.I.T.	234	5.49%	5.49%
Real Estate (Development)	20	3.37%	3.37%
Real Estate (General/Diversified)	12	5.71%	5.71%
Real Estate (Operations & Services)	57	11.92%	11.85%
Recreation	63	4.27%	3.63%
Reinsurance	2	5.00%	5.00%
Restaurant/Dining	77	NA	NA
Retail (Automotive)	26	34.60%	34.60%
Retail (Building Supply)	17	94.81%	93.82%
Retail (Distributors)	80	16.47%	16.45%
Retail (General)	18	18.14%	18.14%
Retail (Grocery and Food)	13	18.11%	18.11%
Retail (Online)	70	22.41%	9.00%
Retail (Special Lines)	89	19.92%	19.64%
Rubber& Tires	4	3.70%	3.10%
Semiconductor	72	20.29%	13.35%
Utility (General)	16	11.07%	11.06%
Utility (Water)	17	9.90%	9.90%
Total Market	7053	13.63%	12.25%
Total Market (without financials)	5878	13.30%	11.61%

ROE impact on Transmission Rate

Source	Return on Equity	Rate of Return	Resulting /$kW-month
Proxy	9.80%	6.02%	$2.67
Grant Historic Growth	6.89%	4.86%	$2.50
Debt Equivalent	3.50%	3.50%	$2.31
Free	0.00%	2.10%	$2.11

Proposed Transmission Rate

Grant PUD

Powering our way of life.

Factors that effect cost of wheeling

- PTP versus NT – Reservation vs. Actual
- Capital Investment
- System density (e.g. customers/mile)
- System load factor (transmission usage)
- Transfer Customers (PTP Customers)
- Economies of scale
- Age of system

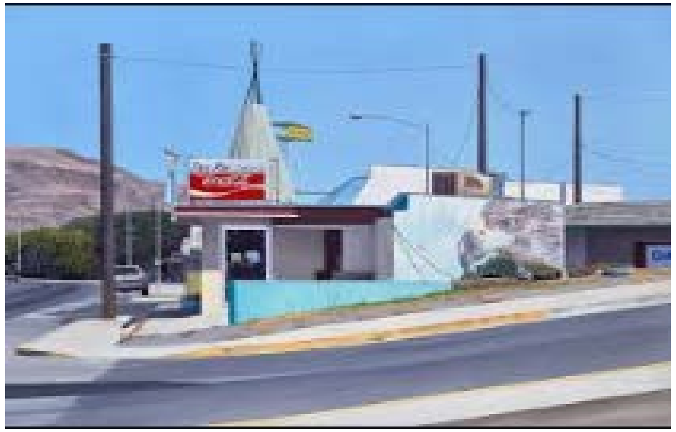
Factors that effect cost of wheeling

PTP versus NT – Contract vs. Actual

Grant PUD has the following transmission contracts with BPA

- PTP contract with a reservation of 12 MW to deliver Nine Canyon power from the Nine Canyon wind plant to Grant PUD

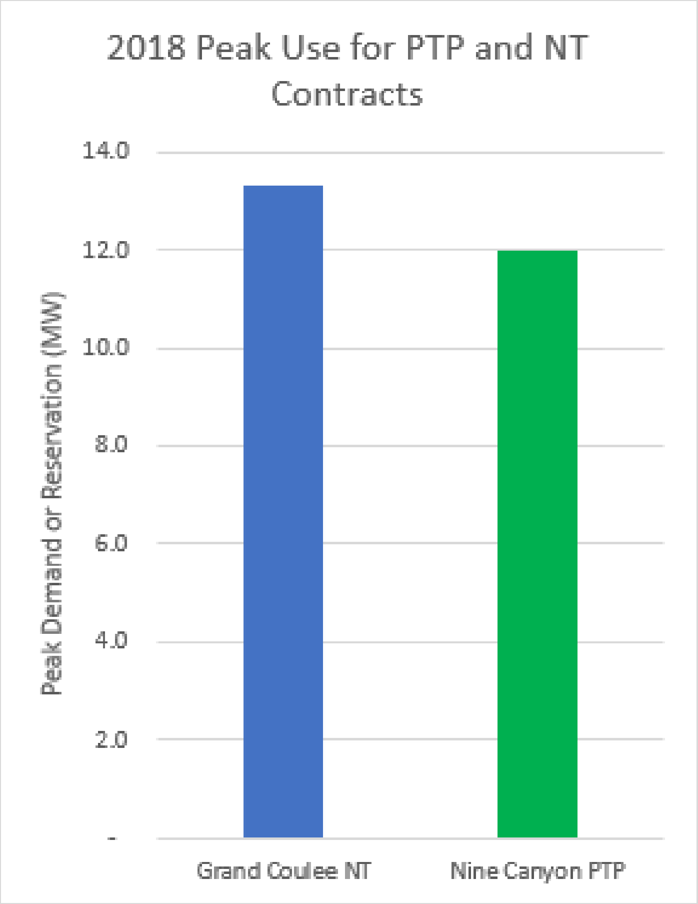
- An NT contract to deliver power from BPA resources to the loads in the Grand Coulee area.

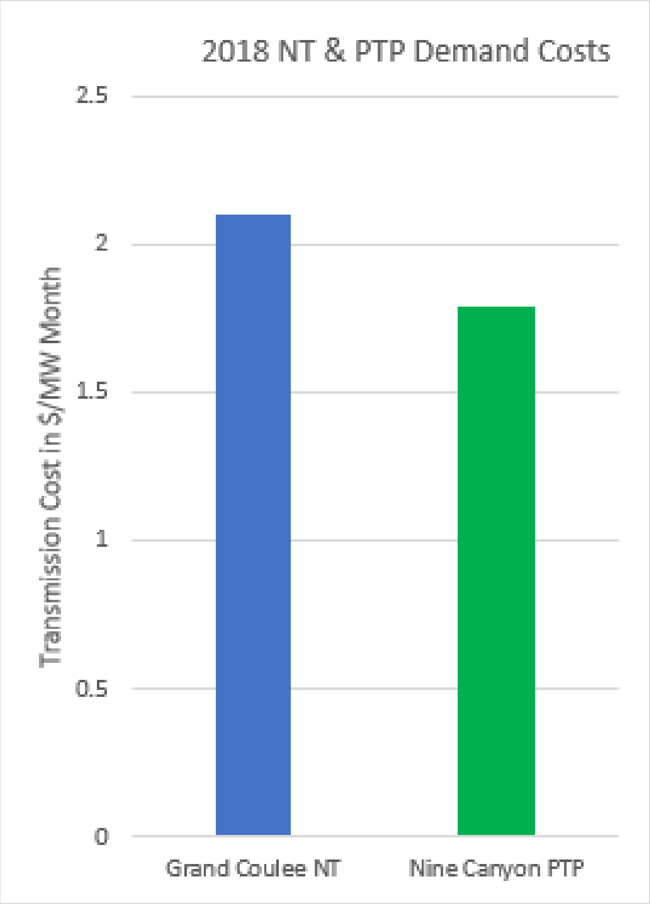


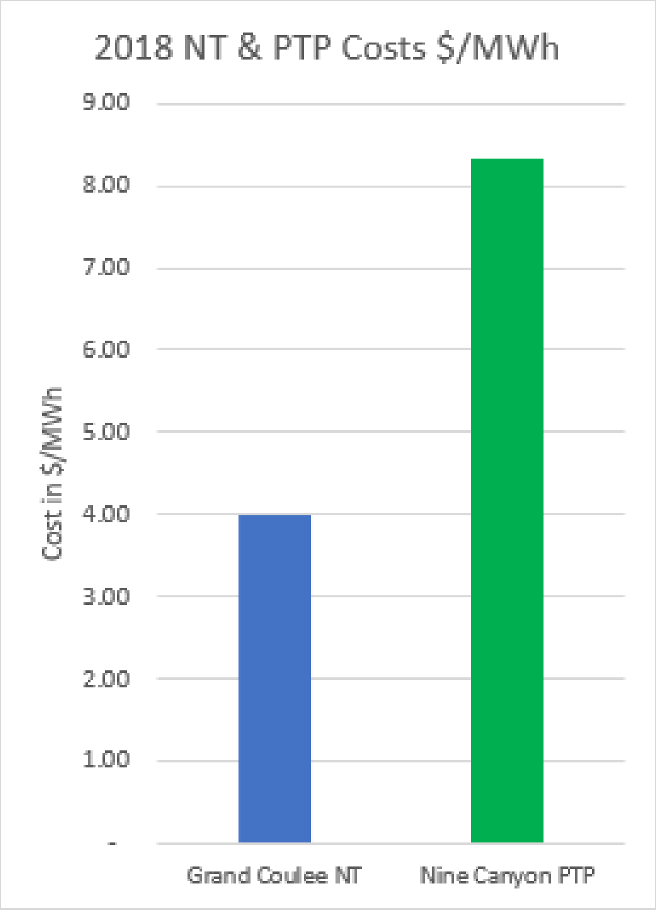
Factors that effect cost of wheeling

PTP versus NT – Reservation vs. Actual

Comparison of actual costs in 2018 for Grant's Nine Canyon PTP purchase and Grand Coulee area NT purchase







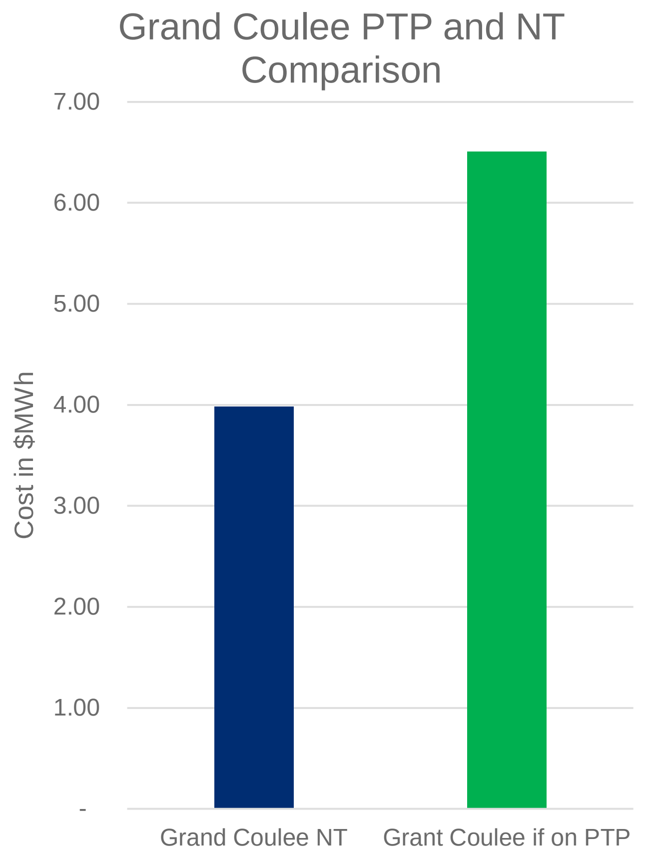
Factors that effect cost of wheeling

PTP versus NT – Reservation vs. Actual

Comparison of the Grand Coulee Load on BPA NT vs BPA PTP in 2018

A reservation quantity of 14 MW was used for the PTP comparison, which is the lowest possible reservation to meet this load

- In reality, the reservation would likely have been higher since you cannot use hindsight to determine a PTP reservation and exceeding the reservation results very high fees



Factors that effect cost of wheeling

Capital Investment - Grant has done significant transmission work in the last several years

Completed Infrastructure 2016-current

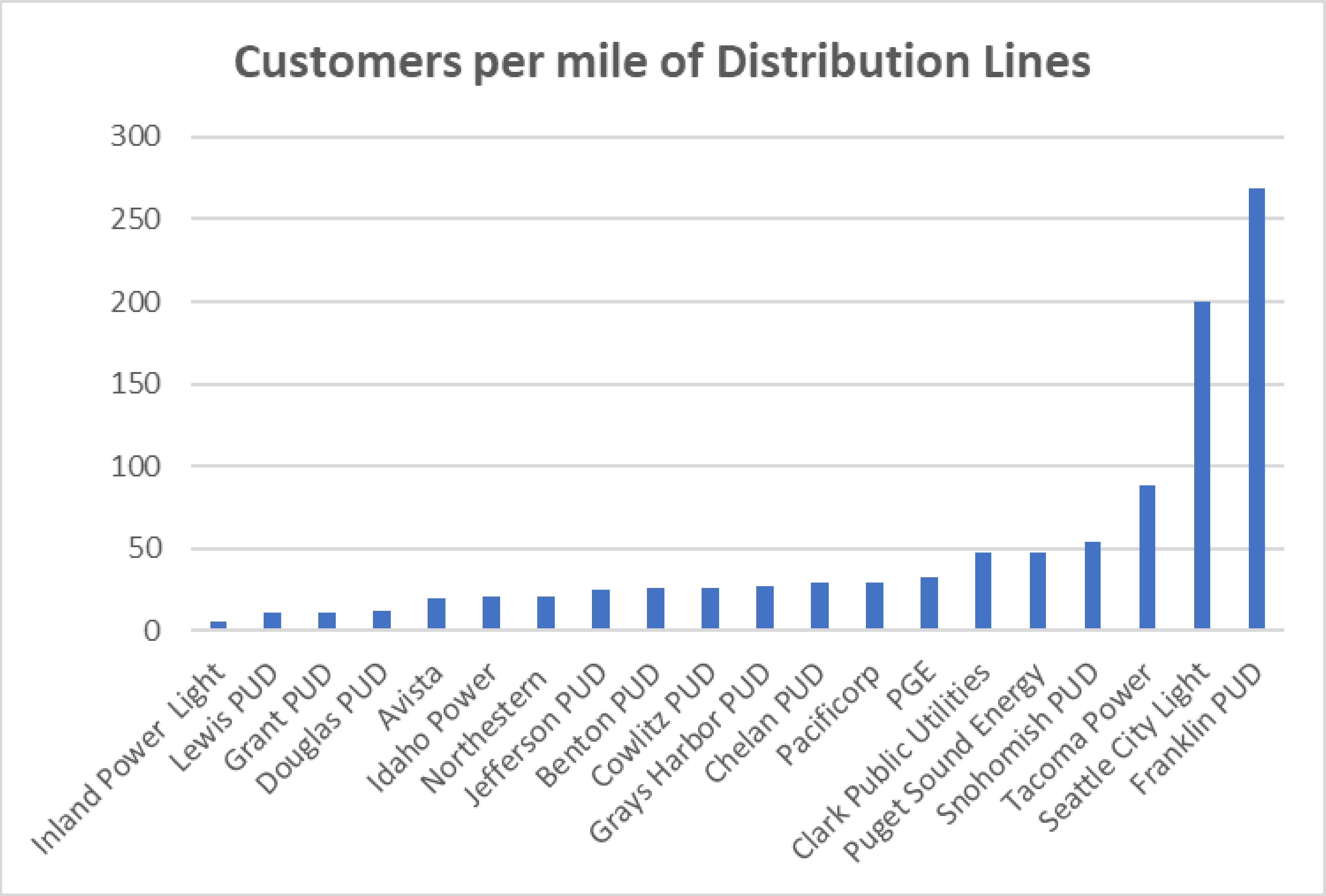
<u>DB1</u>
Nelson Road Sub – Added Transformer
Peninsula Sub – Partial Upgrade – Replaced Outdated Switchgear
Babcock Sub – Full Rebuild
Coulee City Sub – Full Rebuild
Quincy Plains Sub – New Substation
Winchester Sub – Full Rebuild
Cloud View Sub – New Substation
Central Ephrata Sub – 80% Rebuild after fire

<u>Other</u>
Wheeler Rd 115kV Line – 5 Mile Rebuild
Mountain View Sub – Added two transformers
Randolph Rd Sub – Expanded Existing Site – Added transformer and foundation for an additional future transformer
Rocky Ford-Dover 115kV – New Transmission line into Moses Lake
Rocky Ford Switchyard Breaker Addition – Added 115kV Breaker to Support RF-Dover Line

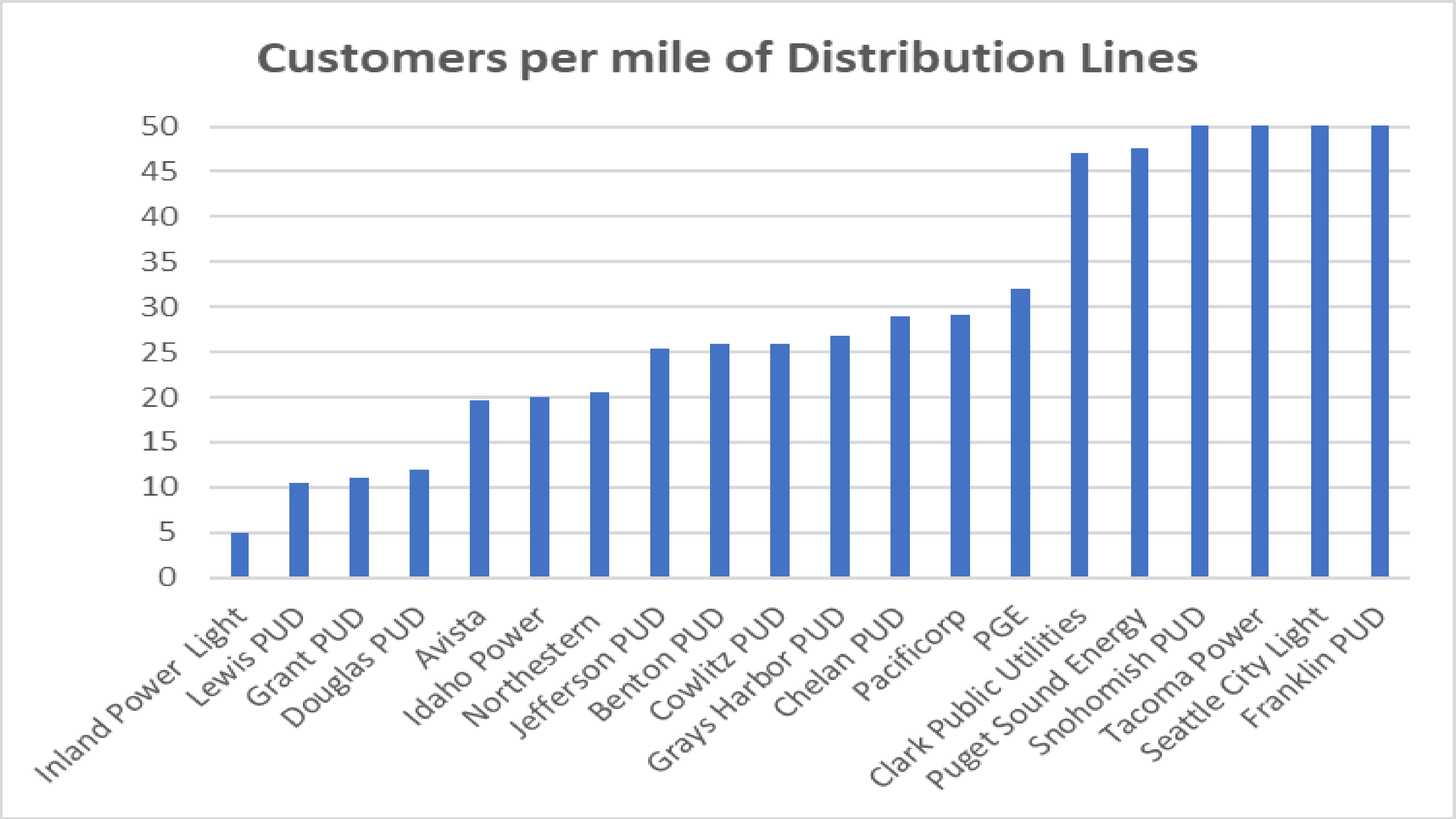
Factors that effect cost of wheeling

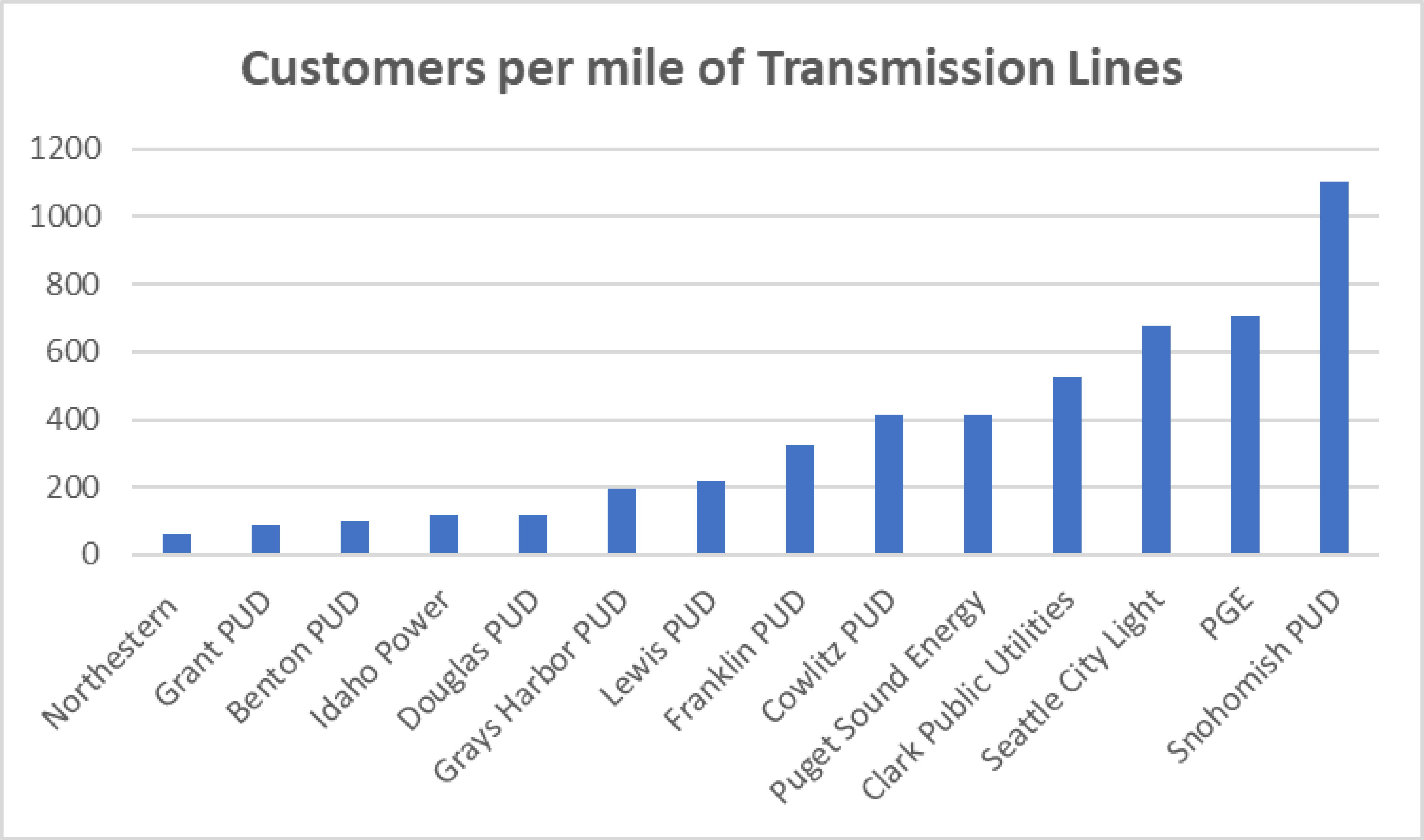
System Density

Grant PUD has one of the lowest density of customers when compared to miles of both transmission and distribution lines compared to other mid-size and large utilities in the Northwest.

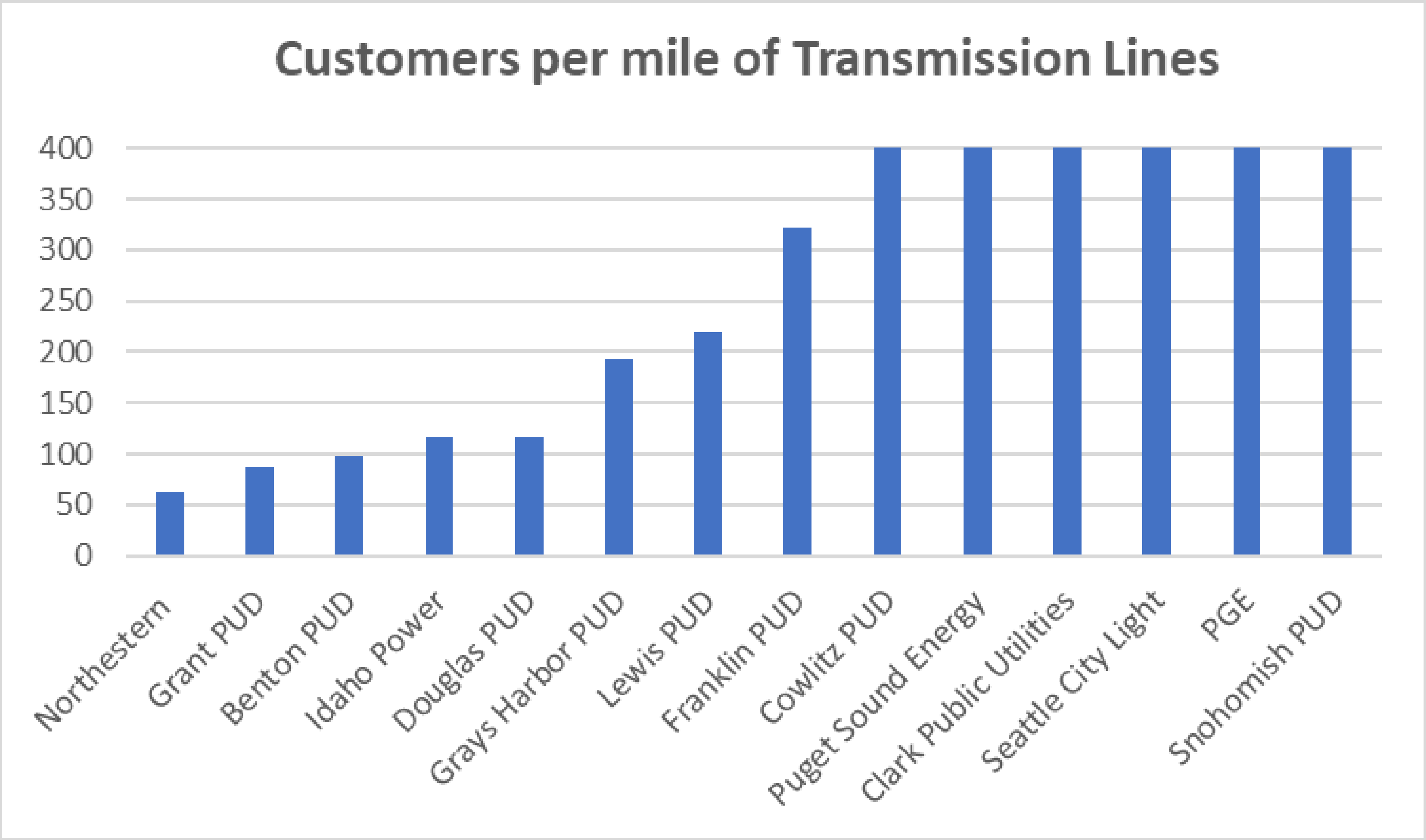

Customers per mile of Distribution Lines
300
250
200
150
100
50
0
Inland Power Light
Lewis PUD
Grant PUD
Douglas PUD
Avista
Idaho Power
Northestern
Jefferson PUD
Benton PUD
Cowlitz PUD
Grays Harbor PUD
Chelan PUD
Pacificorp
PGE
Clark Public Utilities
Puget Sound Energy
Snohomish PUD
Tacoma Power
Seattle City Light
Franklin PUD

Magnified Scale




Customers per mile of Transmission Lines
1200
1000
800
600
400
200
0
Northestern
Grant PUD
Benton PUD
Idaho Power
Douglas PUD
Grays Harbor PUD
Lewis PUD
Franklin PUD
Cowlitz PUD
Puget Sound Energy
Clark Public Utilities
Seattle City Light
PGE
Snohomish PUD

Magnified Scale



Factors that effect cost of wheeling

Load Factor - The system must be built to meet the peak

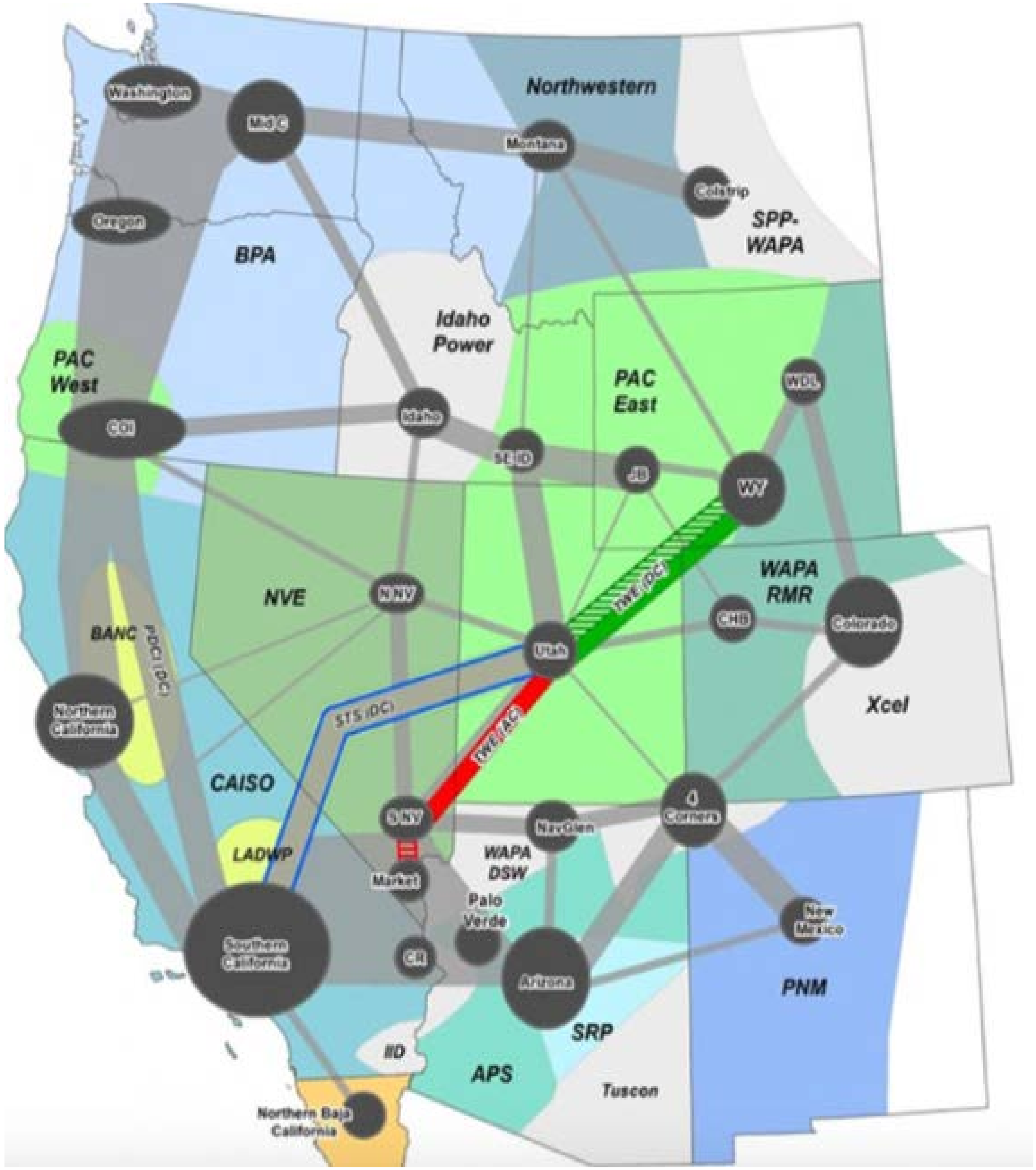
- Grant had an average BA load of 595 MW and a Peak of 848 MW in 2018
- The system peaks in different locations in summer verses winter, and each area of the system must be built to meet a local peak load
- Local areas can have much lower load factors then the system load factor, which includes the industrial load

Factors that effect cost of wheeling

Transfer Customers

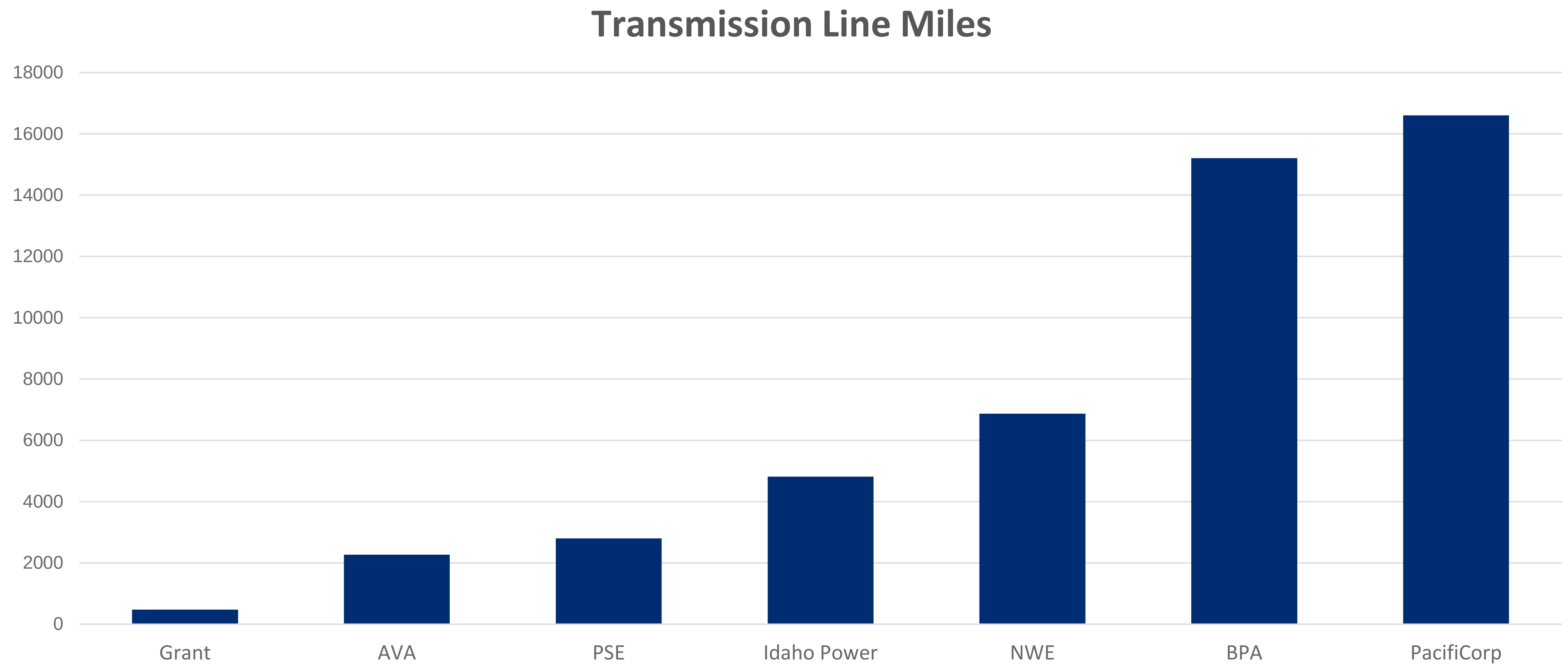
Grant does not have any significant wheel throughs at this time, which can significantly lower the cost to serve on a per unit basis.

- This may change in the coming years as there is significant interest from Independent Power Producers to build solar plants in Grant County



Factors that effect cost of wheeling

Economies of Scale



Wholesale PTP & NT Transmission Rates of Similarity Situated Area Electric Utilities

PTP Rates ($/kW Month)

- BPA $1.85*
- Avista $2.00
- Idaho $2.604
- Puget $2.9171*
- PacifiCorp $2.53882*
- Northwestern $4.93*

NT Rates ($/kW Month)

- Grant Proposed NT type rate: $2.67
- BPA: $2.136*
- Northwestern: $4.93*

Rates that include a Scheduling Charge indicated with *, other rates do not have a Scheduling Charge

Response to Stakeholder Comments

Grant PUD

Powering our way of life.

USBR Questions & Comments

- ✓ Technical Questions – April 27th Submittal.
- ✓ Responses have been completed and posted.
- ✓ Approximately half of questions were regarding documentation and labeling of the model.
- ✓ There was one O&M expense change to remove scuba diving inspections. The result was a reduction to the transmission rate of $0.01/kW-mo.
- ✓ There were five plant balances adjusted moving plant to generation, hereby, a reduction to the transmission rate of $0.39/kW-mo. All staff adjustments totaled $0.40/kW-mo. or a 13.03% reduction from the May 12th transmission rate

USBR Questions & Comments

Policy Questions – May 12th Commission Meeting Submittal

9.8% ROE is not just and reasonable

IOU's are not appropriate for comparison because they are private and GPUD is public
Business model is substantively the same
GPUD's transmission risk profile is different than PSE/PAC
Risk Profile is substantively the same, no example of different risks
GPUD has no need to attract equity investors
Grant has a need for capital and those that provide capital deserve to be compensated
GPUD has not demonstrated a need for an ROE above 0%
False. The capital recovery in this proposed rate is below the current rate. Significant reliability and growth expansions are planned. Failure to recover an ROE results in higher risk to customers, higher debt, and higher retail rates. Need for an ROE has been clearly demonstrated.
GPUD has no investors seeking a return
Retail customers providing capital to Grant seek low, stable rates. They strongly advocate and their interests should not be ignored simply because they invest in the PUD through rates.
GPUD does not pay a dividend to investors
GPUD's return to investors is through lower debt costs and lower, stable rates.
GPUD has not conducted a comprehensive ROE analysis required by FERC
GPUD's recommendation is clearly within FERC's zone of reasonableness and is below most comparable utilities. FERC's November 19, 2019 ROE ruling for MISO transmission owners was 9.88%
GPUD has not met "it's burden of proof", and that 9.8% is just and reasonable
GPUD does not have a regulatory responsibility to meet a burden of proof. However, it has provided significant information showing that 9.8% is at or below comparable utilities and that it is reasonable.

Investor Owned versus PUD

	Investor Owned Utility	PUD	Comments
Stakeholder	Stockholder	Retail Customer	Both provide investment capital used by third parties
Return	Dividends/Stock Appreciation	Lower Rates, Stable and Predictable Rates	Both provide benefit to individual providing the capital
Governance Body	Appointed State Commission	Elected Commission	Both IOU's and PUD have governance oversight with rate setting authority
FERC Oversight	Mandatory	Non-Jurisdictional	While not directly regulated by FERC, PUD's face risk of FERC intervention in the event of discriminatory transmission practices. FERC oversight reduces risk of transmission rate recovery as there is accepted methodology that provides certainty.
Risks:			
Transmission Customer Credit	X	X	Similar - transmission customer default or bankruptcy
Increasing Transmission Costs associated with maintaining reliability and growing transmission system through time	X	X	Similar Risk, both use a historical year as basis for cost recovery. Change in State or Federal policies, siting challenges, cultural costs, inflation, labor scarcity.
Significant costs from uncontrollable events or catastrophic failure	X	X	Fire, Wind, Equipment Failure, Vegetation or Animal contacts
Regulatory Cost Risk	X	X	NERC and WECC Regulatory Requirements
Transmission Revenue	X	X	Similar risk due to change in customer load or load factor, varying transfer revenue.
Market Evolution	X	X	Similar cost exposures related to transition to Energy Imbalance Markets, RTO's, reliability organizations, etc.
Technology Transformation	X	X	Impacts to load usage from technology changes such as LED lighting

USBR Policy Comments

May 12th Commission Meeting

ROE has unreasonable impact on the rates

9.8% compared to 0% increases to 115-230kV rates by 29%

9.8% compared to 0% increases to 13.2kV rates by 31%

29% and 31% are “pure profit”

Any ROE above 0% represents “pure profit” earned by PUD that is in excess of its actual long-term distribution system debt costs. Rates should be set at level that allows for recovery of actual annual T&D debt interest expenses only.

False, the returns from wheeling benefit retail customers for their investment in the transmission system and for assuming the ongoing risks associated with that investment. The total capital portion of the 2019 Cost of Service including the Return on Customer Equity is less than the 2017 Cost of Service. Return on Customer Equity is valid for many reasons: 1) provides retail customers a return for their investment in the system used by a wheeling customer that did not invest in the system, 2) retail customers bear the costs above 2018 study year of future system enhancements and replacements including inflation, 3) retail customers bear the replacement cost risk due to catastrophic failure of infrastructure due to emergency events such as wind or fire, 4) FERC policy requires comparable transmission access and allows for a rate of return to compensate those that provided the initial capital investment in the system, 5) supports commission strategy of stable and predictable rates.

USBR Policy Comments

May 12th Commission Meeting

FERC's approval of non-zero ROE for publicly owned utilities that are members of an RTO or ISO are not relevant to GPUD
False. FERC has clearly demonstrated that it encourages transmission expansion and has provided consistent policy to ensure transmission owners are adequately compensated. This includes publics such as Grant that are members of the MISO. FERC has also approved a rate of return for the California ISO which has several public transmission owners as members including PUD's, Municipals, and Irrigation Districts.

Grant is not a member of an RTO or ISO. No organization will be formed in the foreseeable future.
Grant is not a member of an RTO or ISO, however membership in an RTO or ISO is not a requisite to earn a return from on customer's investment in transmission assets. FERC policy clearly and consistently supports a regulatory return for transmission owners.

GPUD has not identified any comparable for the ROE's of public utilities that are not members of RTO's or ISO's
Grant provided a letter from Chelan Public Utility District General Manager Steve Wright supporting Grant's methodology including a Return on Equity. Bonneville Power included a rate of return calculation previously as shown in the following slide from 2011.

Bonneville Power 2011 Transmission Revenue Requirement Presentation included an Investment Return equal to

Rate Base X *Rate of Return*

Annual Transmission Revenue Requirement

Annual Transmission Revenue Requirement equals:

- Gross Revenue Requirement:
  - O&M
  - Depreciation & Amortization
  - Taxes Other than Income
  - Investment Return (Rate Base X ROR)
  - Income Taxes (Gross up for State & Federal income taxes)

Minus

- Revenue Credits:
  - Rent from Electric Property
  - Service revenues: load that is not included in the divisor

USBR Policy Comments

May 12th Commission Meeting

Public in an RTO/ISO receives a ROE for additional regulatory risk of FERC jurisdiction. No regulatory risk premium because oversight is Commission
False. USBR fails to describe *any specific* regulatory risk FERC jurisdiction entails. FERC jurisdiction significantly reduces risk because it substantially increases certainty including stated approval to receive a rate of return.

GPUD will not be filing an OATT with FERC
Grant does not have an OATT, although it may at some time in the future. Grant has no obligation to file an OATT with FERC, however the pricing for the proposed rate is consistent with FERC methodology. Grant is required to provide non-discriminatory transmission access under the comparability provisions of those utilities that provide transmission service to the PUD under a FERC OATT. Grant is subject to potential FERC intervention in the event of discriminatory practices. Grant is governed under state law by an elected commission that has the authority to approve rates, including transmission rates.

PSE/PAC – regulatory risk premium results in rates that are not just and reasonable
As above, this is an unfounded claim with no basis. USBR has provided no information to support its assertion that an Investor Owned Utility receives a regulatory risk premium. Regulation provides certainty which reduces risks. Grant PUD’s transmission related risks are similar to those of investor owned utilities as demonstrated previously.

USBR Policy Comments

May 12th Commission Meeting

EES does not support use of 9.8% ROE figure as just and reasonable

False. Page 4 of the EES memo states, “For that reason and to provide equal footing with other wholesale transmission providers in the region, use of the average PSE/PacifiCorp ROE is appropriate.”

East Columbia Irrigation District Technical Comments

Technical Questions May 12th Commission Meeting

There are unanswered questions regarding data and assumptions

Stakeholders have had nearly 12 months to submit questions and work with staff, yet USBR delayed their most recent inquiry until the matter was brought before the Commission. At this point all outstanding questions have been substantively addressed and any findings that result in a change to the proposed rate will be brought to the Commission for consideration. The model has been reviewed by staff as well as two separate consulting firms. The proposed transmission rate proposal is technically sound.

East Columbia Irrigation District Policy Comments

May 12th Commission Meeting

Governor’s proclamations restricts ability to effectively work with the PUD on this topic now and into the foreseeable future
East Columbia has been working throughout this period with both Rod Noteboom and Louis Szablya regarding new transmission and load requests. There is no reason that any COVID related impacts would restrict staffs ability to work effectively with any stakeholder. However, no stakeholder has made an outreach to staff on this since the onset of COVID, outside of written communication and comments at Commission meetings.

Commission presently restricted from taking routine actions such as establishing a new rate
The Commission has continued to take action throughout the COVID period. There is nothing that precludes the Commission from taking action at this time.

ROE is not justifiable – EES says proper development of an ROE is not being performed by GPUD
False. Page 4 of the EES memo states, “For that reason and to provide equal footing with other wholesale transmission providers in the region, use of the average PSE/PacifiCorp ROE is appropriate.”

Don’t “rush” ahead
Staff engaged in initial discussion many years ago. In 2017 the first rate schedule was brought forward for review. Staff has prepared 100’s of pages of support for this approach, engaged two separate consultants which support the approach, conducted multiple stakeholder interactions, and received a letter of support from the Chelan PUD General Manager. During that time, the PUD’s retail customers have borne an unfair share of these transmission costs.

Bonneville Power Administration Policy Comments

May 12th Commission Meeting

ROE is not based on Grant's costs and therefore Commission does not have discretion to choose ROE

RCW 54.24.080 must be cost based

This is not correct and was addressed in the ROE memo previously provided to stakeholders subsequent to this comment.

ROE of 9.8%, rate impact of over $30M per year is an arbitrary number, not tied to Grant's costs

False. $27.5M includes both the debt cost and customer equity cost for both transmission and the 13.2kV system. Of that amount, approximately $10M is debt expense, the remaining $17.5M is return on customer equity. Only 4.3% of the transmission cost of equity is paid by existing transmission customers, or approximately $314k under the proposed rate. ($7.3M*4.3%) The capital requirements in the cost of service using this ROE is lower than the capital costs in the 2017 Cost of Service, and the Capital component using the same cash based approach in the 2017 model updated with current information would result in capital costs that exceed both the 2017 transmission rate and the 2019 proposed rate. Failure to collect these costs will perpetuate the ongoing cost shift to retail customers.

Bonneville Power Administration Policy Comments

May 12th Commission Meeting

Cost based and accrual-based accounting methods should be equal over time, this proposal will over-collect Grant's costs year after year

9.8% is excessive and does not accurately reflect GPUD's risks

$64M accrual method compared to $8M interest payments under cash method, so would need $56M for capital financed by higher rates/principal

BPA did not provide any basis for the statement, however, the entire capital transmission requirement is $7.3M for transmission and $20.2M for 13.2kV transmission including both debt and return on customer equity so it is unclear where the $64M number originates.

Proposal to base upon ROE of other utilities is not consistent with FERC ratemaking, not transparent, and not consistent with Commission authority. There is no generic FERC approved, reasonable ROE.

Proposed rate is clearly within FERC declared zone of reasonableness. When determining reasonableness FERC typically reviews other utility's ROE. When establishing an acceptable rate of return for a reliability authority such as MISO, FERC has provided a rate that applies to all utilities rather than perform a case by case analysis. This rate was updated only a few weeks ago and is 10.2%.

Transmission Costs (Cost of Capital)

Rate Base Functionalized

Description	Transmission	13.2kV System	Total
Net Rate Base	$120.7M	$335.0M	$455.7M
Rate of Return on Investments Percentage	6.02%	6.02%	6.02%
Return Allowance	$7.3M	$20.2M	$27.5M

Return Allowance Spilt Between Equity and Debt

Description	Total Return Allowance	Return on Rate Base Funded by Customer Cash	Estimated Debt Expense
Transmission	$7.3 M	$4.7 M	$2.6 M
13.2kV System	$20.2 M	$13.1 M	$7.1 M
Total	$27.5 M	$17.8 M	$9.7 M

Return as a % of Transmission COSS

Return on Rate Base	$4.7 M
Transmission COSS	$22.8 M
% of Transmission COSS	20.6%

Debt as a % of Transmission COSS

Estimated Debt	$2.6 M
Transmission COSS	$22.8 M
% of Transmission COSS	11.4%

Wrap up / Q&A

Grant PUD

Powering our way of life.

USBR Transmission Charges

	Proposed Change to Large Load Transmission Charges		
	Current	**Proposed**	**Difference**
Large Load 115-230kV Transmission Rate	$1.90/kW-mo.	$2.67/kW-mo.	$0.77/kW-mo.
Est. USBR Transmission Costs per MWh	$3.44/MWh	$4.84/MWh	$1.40/MWh ($0.0014/kWh)
Est. USBR Transmission Costs	$402k	$565k	$163k
Approx. average RS3 across all accounts (Total revenue/total MWh usage)	*$45/MWh*		
Large Load 13.2kV Transmission Rate	$3.12/kW-mo.	$4.66/kW-mo.	$1.54/kW-mo.
Est. Transmission Costs USBR per MWh	$5.83/MWh	$8.70/MWh	$2.87/MWh ($0.0029/kWh)
Est. Transmission Costs USBR	$214k	$319k	$105k

Commissioner Handout

Grant PUD's Response to the USBR's April 27, 2020 Comments

As part of its customer engagement process for developing an updated transmission (wheeling) cost of service study (COSS or Study), Public Utility District No. 2 of Grant County (Grant) requested comments and feedback regarding its draft transmission (wheeling) COSS models.

The initial draft COSS was published on June 19, 2019. Following a review process with stakeholders, written feedback regarding the draft COSS was due to Grant by July 10, 2019. The Irrigation Districts and USBR submitted comments and questions on this date. Grant updated the COSS study and responded to the parties' comments on July 25, 2019. Grant responded to the remaining July 10th questions on August 5, 2019.

The Bonneville Power Authority (BPA) submitted comments and questions on August 5, 2019. Grant responded to these comments and questions on August 12, 2019. USBR submitted additional comments on August 27, 2019 and Grant responded to these comments on September 26, 2019. USBR further submitted additional questions on December 4, 2019 and Grant responded to these questions on January 8, 2020. Now, USBR has submitted additional comments (questions) on April 27, 2020 based on the COSS model released on January 27, 2020. The following are Grant's responses to those comments (questions).

Staff response to Comments 1, 2, 9, and 10, below

Comment 1

Reference: "O&M Expenses – IV", Line 43, FERC # 596, Maintenance of Street lighting
The version released on August 12, 2019 was adjusted to remove this cost with a note that states " Not Included in Wholesale Delivery Rates". Please adjust accordingly or if not, explain why this should be recovered through the transmission rate.

Comment 2

Reference: "O&M Expenses – IV", Line 44, FERC # 597, Maintenance of Meters
The version released on August 12, 2019 was adjusted to remove this cost with a note that states " Not Included in Wholesale Delivery Rates". Please adjust accordingly or if not, explain why this should be recovered through the transmission rate.

Comment 9

Reference: "Gross Plant In Service – V", Line 32, FERC # 366 Underground conduit
Pursuant to the October 11, 2019 response from a public request for information, it appears that all of these costs are unrelated to the wheeling of USBR power. Please explain why this should be recovered through the USBR transmission rate.

Comment 10

Reference: "Gross Plant In Service – V", Line 33, FERC # 367 Underground conductors and devices. Pursuant to the October 11, 2019 response from a public request for information, it appears that all of these costs are unrelated to the wheeling of USBR power. Please explain why this should be recovered through the USBR transmission rate.

In the original June 19, 2019 COSS, staff's COSS approach attempted to develop a 13.2kV cost of service by deleting certain distribution plant accounts and distribution O&M expense accounts. The June 19th study excluded distribution FERC O&M Expense Account #s 596 (Maintenance of Street lighting) and 597 (Maintenance of Meters), and FERC plant account #s 366 (Underground conduit) and 367 (Underground conductors and devices) along with a few other accounts in determining its 13.2 kV transmission wheeling cost of service.

In its August 12, 2019 COSS update, staff changed its 13.2 transmission wheeling cost of service calculation methodology. Rather than reviewing individual accounts one by one, staff developed an estimated allocation factor to apply to the distribution cost of service to estimate 13.2 transmission wheeling costs. This is a common approach in cost of service studies where an extensive effort would be required to aggregate and review a substantive amount of data. This resulted in the Distribution Plant Inclusion Ratio of 68.02% applied to the total distribution cost of service (includes all distribution accounts) to determine the 13.2kV distribution cost of service, which was then used as a basis for determining the 13.2kV transmission wheeling delivery rates. This allocation methodology is consistent with calculations by FERC regulated electricity providers.

The August 12th and all subsequent COSS models have used the Distribution Plant Inclusion Ratio to allocate the distribution cost of service for its 13.2kV transmission wheeling customers. Staff believes that this calculation fairly and reasonably assigned costs to all Grant's retail and transmission customers. In fact, staff believes its current distribution cost of service methodology results in lower delivery costs for the 13.2kV transmission "wholesale" customers than the June 19th methodology would produce. Staff believes this methodology provides a benefit to the 13.2kV transmission wheeling customers. See staff's response to Comment 13 for further discussion on the Distribution Plant Inclusion Ratio.

Comment 3

Reference: "O&M Expenses – IV", Line 38, FERC # 588 Miscellaneous Distribution Pursuant to the September 13, 2019 response from a public request for information, it appears that some of these items pertain to vehicle operations and maintenance. Please explain why these should be 100% recovered through the transmission rate and/or why they should be included. Examples of line items included in the cost, but not limited to: Custom Interior and Boat Upholstery, Landmark Ford – Lincoln, Goodyear Tire and Rubber, among others.

For accounting purposes, Grant utilizes the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts when recording its incurred O&M expenses. FERC Account # 588

Miscellaneous Distribution Expenses is part of Grant's total distribution O&M expense, which in turn is included in the total distribution cost to serve of $57,808,127 (see the attached Appendix A, Cost of Service-Exh. II tab, Col. E, Ln 20). USBR is incorrect in stating that these O&M expenses are 100% recovered through the 13.2kV transmission wheeling rate. Instead, the total distribution cost to serve is allocated to 13.2kV transmission wheeling customers based on the Distribution Plant Inclusion Ratio of 68.02% (see the attached Appendix A, Allocation Factors-Exh. III tab, Lns 9 – 14) for an allocated distribution cost to serve of $39,318,801 (Appendix A, Cost of Service Factors-Exh. 1 tab, Col. D, Lns 10-12.) As further discussion in Grant's response to Comment 13, the 13.2kV transmission wholesale customers using this service will contribute approximately $615,796 towards the allocated distribution cost of service of $39,318,801, or approximately 1.57% ($615,796/$39,318,801) or approximately 1.07% of the total distribution cost of service of $57,808,127 ($615,796/$57,808,127).

USBR's comment highlights O&M expenses that it believes should not be recovered through Grant's 13.2kV transmission wheeling rate. Staff believes these O&M expenses are recoverable from Grant's 13.2kV transmission wheeling customers because these O&M expenses were prudently incurred during the normal business operations. Tire expense is a normal operating cost for vehicles that service Grant's electric system and should recovered as such. Staff believes these O&M expenses have been recorded in accordance with FERC accounting guidelines. This statement is supported in Grant's 2018 annual report, Notes to the Financial Statements, Note 1, on Page 33.

> *"The District maintains its accounts in accordance with accounting principles generally accepted in the United States of America for proprietary funds as prescribed by the Governmental Accounting Standards Board ("GASB"). The District's accounting records generally follow the Uniform System of Accounts for public utilities and licenses prescribed by FERC. The accompanying financial statements are those of the District, which generates, transmits, and distributes electric energy and wholesale fiber optic network services within Grant County, Washington".*

To simply pick and choose which distribution O&M expenses are applicable to 13.2kV transmission wheeling customers would be inappropriate ratemaking and against Grant operation policies for its "networked" system. As frequently mentioned throughout the transmission wheeling rate process, which began on May 1, 2019, Grant's position is that it operates its networked electric system as reflected in Brent Bischoff's (Sr. Manager Power Delivery Engineering) white paper. The paper states in part:

> The Grant County PUD ***electric distribution system is designed as a networked system***. This design practice is common in the electric utilities industry in order to provide the most reliable possible electric service to customers . . . This ensures that outage frequency and duration to utility customers are kept to a minimum . . . The ***distribution system is a networked system*** designed to provide the highest level of reliability and service to each customer regardless of their location in the service territory.

> . . . Since electric distributions systems are networked and provide equal quality of service to all customers, it is ***common utility practice to spread the cost to build, operate and maintain the system equally among customers*** . . . [Emphasis added]

Staff believes that its FERC Account # 588 amounts are properly recorded and allows for fair and reasonable cost recovery from all of Grant's retail and transmission customers.

Staff response to Comments 4, 5, 6, 14, and 15, below

Comment 4

Reference: "Gross Plant In Service – V", Line 40, FERC # 390 Structures and Improvements Pursuant to the September 13, 2019 response from a public request for information, it appears that some of these items are projects located within Priest Rapids (PR) Dam and/or Wanapum Dam (power supply costs). Since they appear to be located within the boundaries of a generating facility, please explain why they should be recovered through the transmission rate. Examples of lines items included in the cost, but not limited to: New Heritage Center, New HED building, Wanapum Main, among others.

Comment 5

Reference: "Gross Plant In Service – V", Line 41, FERC # 391 Office Furniture and Equipment Pursuant to the September 13, 2019 response from a public request for information, it appears that some of these items are equipment located within PR Dam and/or Wanapum Dam (power supply costs). Since they appear to be located within the boundaries of a generating facility, please explain why these should be recovered through the transmission rate. Examples of lines items included in the cost, but not limited to: Wanapum Office Furniture pool, PR office pool, among others.

Comment 6

Reference: "Gross Plant In Service – V", Line 48, FERC # 398 Miscellaneous Equipment Pursuant to the September 13, 2019 response from a public request for information, it appears that some of these items are equipment located within PR Dam and/or Wanapum Dam (power supply costs). Since they appear to be located within the boundaries of a generating facility, please explain why these should be recovered through the transmission rate. Examples of lines items included in the cost, but not limited to: PR Miscellaneous Equipment Pool, Wanapum Miscellaneous Equipment Pool, among others.

Comment 14

Reference: "Gross Plant In Service – V", Line 2, FERC # 302 Franchises and Consents Pursuant to the September 13, 2019 response from a public request for information, it appears that one item is strictly for power supply costs (Line item with "PRP"). Please explain why this should be recovered through the transmission wheeling rate.

Comment 15

Reference: "Gross Plant In Service – V", Line 3, FERC # 303 Miscellaneous Intangible Plant
Pursuant to the September 13, 2019 response from a public request for information, it appears that most of these items are power supply costs (Line items with "PRP", "QC" or "PEC"). Please explain why these should be recovered through the transmission wheeling rate.

Grant reviewed FERC Account #s 302, 303, 390, 391, and 398 and determined that certain intangible and general plant balances in the previous Transmission COSS needed to be revised, these accounts have been adjusted. The plant account deep dive resulted in adjusting certain plant balances; removing plant amounts previously recorded in FERC #s 302, 303, 390, 391, and 398 and reclassifying the plant accounts to the generation function as oppose to allocating the plant balances to generation, transmission, and distribution. These accounts have been adjusted and the cost of service impacts have been calculated (a COSS reduction of $10,241,624) as reflected in Tables 1-5:

Table 1: Gross Plant Amounts Reclassified to Generation Plant

FERC Account # (Amounts in $)	Generation Allocated Plant	Transmission Allocated Plant	Distribution Allocated Plant	Generation Function
302		(8,306,171)	(12,716,392)	21,022,563
303		(10,033,278)	(27,608,076)	37,641,354
390	(103,374,166)	(24,472,547)	(37,466,285)	165,312,998
391	(11,978,541)	(2,835,770)	(4,341,427)	19,155,738
398	(2,348,278)	(555,926)	(851,095)	3,755,299
Total	**(117,700,985)**	**(46,203,692)**	**(82,983,275)**	**246,887,952**

Table 2 Accumulated Depreciation Reclassified to Generation Accumulated Depreciation

FERC Account # (Amounts in $)	Generation Allocated	Transmission Allocated	Distribution Allocated	Generation Function
302		(3,641,606)	(5,575,122)	9,216,738
303		(7,047,715)	(10,789,710)	17,837,425
390	(7,430,017)	(1,758,964)	(2,692,889)	11,881,870
391	(11,866,547)	(2,809,257)	(4,300,837)	18,976,641
398	(1,716,868)	(406,447)	(622,251)	2,745,566
Total	**(21,013,432)**	**(15,663,989)**	**(23,980,809)**	**60,658,240**

Table 3: Net Plant Reclassified to Generation Plant and Return on Investment Calculation

FERC Account # (Amounts in $)	Generation Allocated	Transmission Allocated	Distribution Allocated	Generation Function
302		(4,664,565)	(7,141,270)	11,805,825
303		(2,985,563)	(16,818,366)	19,803,929
390	(95,944,149)	(22,713,583)	(34,773,396)	153,431,128
391	(111,994)	(26,513)	(40,590)	179,098
398	(631,410)	(149,478)	(228,844)	1,009,733
Total	**(96,687,553)**	**(30,539,702)**	**(59,002,466)**	**186,229,713**
Return on Investment		6.02%	6.02%	
Return Impact*		**(1,838,490)**	**(3,551,948)**	

*Return Impact from the May 12th Transmission COSS model

Table 4: Depreciation Expense Impact

(Amounts in $)	Transmission	Distribution
May 12th Depreciation Level	6,826,640	24,448,905
Revised Depreciation	5,301,714	21,355,125
Depreciation Impact	**(1,524,926)**	**(3,093,780)**

Table 5: Total Cost of Service Impacts from Plant Reclassification to Generation

(Amounts in $)	Transmission	Distribution	Total
Return Impact	(1,838,490)	(3,551,948)	(5,390,438)
Depreciation Impact	(1,524,926)	(3,093,780)	(4,618,706)
O&M Expense Impact	(89,051)	(143,429)	(232,480)
Total Impact on COSS	**(3,452,467)**	**(6,789,157)**	**(10,241,624)**

The COSS reductions resulted in lower transmission wheeling rates. (see Appendix A, Cost of Service Factors-Exh. 1 tab Lns. 6 and 15).

In its updated January 27, 2020 COSS model, Grant made two adjustments to reclassify Priest Rapids and Wanapum dam transformers and radial line facilities from transmission to generation. A total of $64,162,060 in plant balances (see May 12, 2020, Appendix A, Gross Plant in Service-Exh. V tab, Lns 24-25) was reclassified to generation, resulting in a cost of service reduction of $4,268,716 (see Appendix A, Adjustment tab, Lns 13-30). This resulted in a lower 115kV transmission wholesale rate. The above total plant account adjustments result in total cost of service reduction of $14,510,340 ($10,241,624+$4,268,716).

<u>Comment 7</u>

Reference: “Gross Plant In Service – V”, Line 29, FERC # 362 Station Equipment
Pursuant to the October 11, 2019 response from a public request for information, it appears that some of these items are costs resulting from potential server farm substation upgrades and localized costs that are unrelated to the wheeling of USBR power. Please explain why this should be recovered through the USBR transmission rate.

For accounting purposes, Grant utilizes FERC Uniform System of Accounts when recording its capital plant expenditures. FERC Account # 362 Station equipment is a directly assigned distribution plant account to the distribution function and FERC states:

> This account shall include the cost installed of station equipment, including transformer banks, etc., which are used for the purpose of changing the characteristics of electricity in connection with its distribution.

Items

1. Bus compartments, concrete, brick and sectional steel, including items permanently attached thereto.
2. Conduit, including concrete and iron duct runs not part of building.

3. Control equipment, including batteries, battery charging equipment, transformers, remote relay boards, and connections.
4. Conversion equipment, indoor and outdoor, frequency changers, motor generator sets, rectifiers, synchronous converters, motors, cooling equipment, and associated connections.
5. Fences.
6. Fixed and synchronous condensers, including transformers, switching equipment, blowers, motors, and connections.
7. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
8. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment, etc.
9. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.
10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lightning arresters, cable and wire runs from and to outdoor connections or to manholes and the associated regulators, reactors, resistors, surge arresters, and accessory equipment.
11. Switchboards, including meters, relays, control wiring, etc.
12. Switching equipment, indoor and outdoor, including oil circuit breakers and operating mechanisms, truck switches, disconnect switches.

NOTE: The cost of rectifiers, series transformers, and other special station equipment devoted exclusively to street lighting service shall not be included in this account, but in account 373, Street Lighting and Signal Systems.

USBR's comment highlights capital plant investment resulting from potential server farm substation upgrades and localized costs. USBR did not provide any further detail. Staff believes Grant's plant expenditures are recorded in accordance with FERC accounting guidelines. This statement is supported in Grant's 2018 annual report, Notes to the Financial Statements, Note 1, on Page 33.

> *"The District maintains its accounts in accordance with accounting principles generally accepted in the United States of America for proprietary funds as prescribed by the Governmental Accounting Standards Board ("GASB"). The District's accounting records generally follow the Uniform System of Accounts for public utilities and licenses prescribed by FERC. The accompanying financial statements are those of the District, which generates, transmits, and distributes electric energy and wholesale fiber optic network services within Grant County, Washington".*

FERC Account # 362 is part of Grant's distribution cost to serve. USBR argues that some of Account # 362 plant balance amounts are not applicable to transmission customers.

Staff believes that USBR is attempting to segment Grant's electric system by picking and choosing certain plant assets that appear to provide no benefit to them. To simply pick and choose which plant account balances that are applicable to 13.2kV transmission wheeling customers is against Grant operation policies for its "networked" system (for further details, see staff's response to Comment 3) and would be inappropriate ratemaking. As further discussed in Grant's response to Comment 13, the 13.2kV transmission wholesale customers using this service will contribute approximately $615,796 towards the allocated distribution cost of service of $39,318,801, or approximately 1.57% ($615,796/$39,318,801) or approximately 1.07% of the total distribution cost of service of $60,505,551 ($615,796/$57,318,801).

Staff believes that its FERC Account # 362 is properly recorded and allows for fair and reasonable cost recovery from all of Grant's retail and transmission customers.

Comment 8

Reference: "Gross Plant In Service – V", Line 30, FERC # 364 Poles, towers and fixtures Pursuant to the October 11, 2019 response from a public request for information, it appears that all of these costs are unrelated to the wheeling of USBR power. Please explain why this should be recovered through the USBR transmission rate.

For accounting purposes, Grant utilizes FERC Uniform System of Accounts when recording its capital plant expenditures. FERC Account # 364 Poles, towers, and fixtures is a directly assigned distribution plant account to the distribution function and FERC states:

> This account shall include the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.
>
> **Items**
>
> Anchors, head arm, and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc.
>
> 1. Brackets.
> 2. Crossarms and braces.
> 3. Excavation and backfill, including disposal of excess excavated material.
> 4. Extension arms.
> 5. Foundations.
> 6. Guards.
> 7. Insulator pins and suspension bolts.
> 8. Paving.
> 9. Permits for construction.
> 10. Pole steps and ladders.
> 11. Poles, wood, steel, concrete, or other material.
> 12. Racks complete with insulators.
> 13. Railings.

14. Reinforcing and stubbing.
15. Settings.
16. Shaving, painting, gaining, roofing, stenciling, and tagging.
17. Towers.
18. Transformer racks and platforms.

USBR suggests that all of these costs are unrelated to the wheeling of USBR power. USBR does not provide any further support for this argument.

Staff disagrees with USBR's argument that these costs are unrelated to the transmitting of electricity and should not apply to USBR. For example, for the electricity to be transmitted from one location to another will require the use of the transmission and distribution plant facilities, such as poles, that support Grant's networked electric system. USBR transmission wheeling customers taking delivery off Grant's 13.2kV system are using the distribution facilities. The facilities recorded in FERC Account # 364 are used by Grant to provide electricity to all its "networked" retail and transmission customers. For more discussion about Grant's "networked" system, see staff response to Comment 3.

Staff believes that its FERC Account # 362 is properly recorded and allows for fair and reasonable cost recovery from all of Grant's retail and transmission customers.

Comment 11

Reference: "O&M Expenses – IV", Line 66, FERC # 921 Office and Supplies
Pursuant to the September 13, 2019 response from a public request for information, it appears that some of these items are power supply costs (Line items with "PR"). Also, please explain why items paid to "Northwest Energy Efficiency Alliance/Northwest Power Pool" should be recovered through the transmission rate.

For accounting purposes, Grant utilizes FERC Uniform System of Accounts when recording its O&M expenditures. Account # 921 is a General and Administrative (A&G) O&M Expense account. These expenses are not directly assignable to any function, such as, Generation, Transmission, and Distribution. But these expenses benefit the entire electric system and should be shared by all Grant customers.

The "PR" labelling in the expense account designation stands for Priest Rapids. Both Grant's generation and transmission functions include O&M expense items related to the operation of Priest Rapids facilities as previously discussed Grant's response to USBR's 12.4.20 Questions and Comments, Question No. 3 and in Grant's opening introduction statement to the July 10, 2019 Questions and Comments, which states:

> *A recurring theme within their comments is the fact that many of Grant PUD's accounting titles include "PRP" in the title, and the misconception that the Priest Rapids Project ("PRP")-related costs are all generation costs. The April 17, 2008 Federal Energy Regulatory Commission's <u>Order Issuing New License</u> for continued*

operation of the Priest Rapids Project (available at https://www.grantpud.org/templates/galaxy/images/images/Downloads/About/Environment/ShorelineManagement/PriestRapidsProjectLicenseh1.pdf) lists several transmission specific components to the project.

Staff believes that the A&G O&M expenses with the "PR" designation should be allocated to the generation, transmission and distribution functions and should be recovered from all customers as providing a benefit to all customers. Further, the costs associated Northwest Power Pool are costs incurred improving Grant's transmission grid reliability and should be recovered from all customers.

To simply pick and choose which "PR" coded O&M expenses included in A&G expenses that are applicable to 13.2kV transmission customers is against Grant's operation policies for its "networked" system (for further details, see staff's response to Comment 3). Staff believes these A&G "PR" costs should be fairly shared with of Grant's retail and transmission customers. The Northwest Power Pool costs were prudently incurred costs where grid reliability is improved. Here again, it appears to staff that USBR is attempting to segment Grant's electric system by picking and choosing certain O&M expenses that are included in A&G expenses that are allocated, that appear to provide no benefit to them. Staff believes that removing these expenses would be inappropriate ratemaking.

Grant PUD's 2019 Transmission COSS allocates the A&G expenses amounts to the Production, Transmission, or Distribution functions for cost recovery by using the direct labor factors (FERC approval allocation methodology), as reflected in staff's response to USBR's 12.4.19 Questions and Comments, Table 1 and in the attached Appendix A, Allocation Factors-Exh. III tab, Lns 15-20. The transmission function is allocated 14.80% and distribution function is allocated 22.66% of Account #921. The generation function is allocated 62.53% of Account #921 (see Appendix A, O&M Expenses-Exh. IV tab, Ln 66).

Staff believes that its FERC Account # 921 O&M amounts are properly recorded and allows for fair and reasonable cost recovery from all of Grant's retail and transmission customers.

Comment 12

Reference: "O&M Expenses – IV", Line 79, FERC # 935 Maintenance of General Plant Pursuant to the September 13, 2019 response from a public request for information, please explain why diving costs should be recovered through the transmission rate.

Staff agrees with USBR that diving costs should not be included in Account #935 Maintenance of General Plant. During 2018, Grant incurred diving expenses of $482,278.65, which are attributable to the generation function. These expenses were recorded in Account #935. The revised Transmission COSS (see Appendix A) has been adjusted and the expenses are directly assigned to the Generation function (see Appendix A, O&M Expenses-Exh. IV tab, Lns 26 and 79). This adjustment reduced the transmission cost to serve by $71,395 and reduced the distribution cost to serve by $109,284. The cost of service adjustment is additive to the adjustments discussed above, see staff response to Comments 4, 5, 6, 14, and 15. These cost to serve changes resulted in a reduction to both transmission wholesale delivery rates (see Appendix A, Cost of Service Factors-Exh. I tab, Lns. 6 and 15).

Comment 13

Plant Distribution Factor. USBR and the Districts believe that the 68.02% allocation factor is an over-recovery. For reference, 45% of the Distribution system is used to transmit 13.2kV and USBR loads only make up about 3% of the wheeling customer base. What rationale is being applied to justify an allocation factor at this percentage to be recovered through USBR wheeling? This allocation factor appears high.

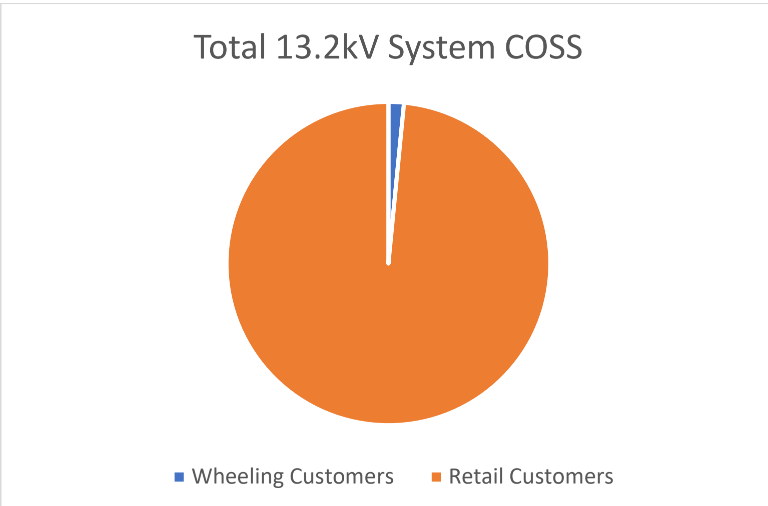
Staff disagrees with USBR that its Distribution Plant Inclusion Ratio of 68.02% is too high. The ratio was developed consistently with FERC guidelines and was reviewed by GDS Consulting and determined to be a reasonable. The calculation began by removing FERC Distribution Plant Account #s 365 (Overhead conductors and devices), 366 (Underground conduit), and 367 (Underground conductors and devices) from its ratio equation because these accounts were not applicable to the transmission wheeling customers making deliveries off of Grant's Sub 13.2kV system. See staff ratio calculation in Table 6:

Table 6: Calculation of Grant's Distribution Plant Inclusion Ratio

Account #s (Amount in $)	Amount	Ratio Calculation
Numerator		
360-Land and Land Rights	853,209	
361-Structures and Improvements	1,052,384	
362-Station equipment	176,101,529	
364-Poles, towers, and fixtures	92,252,171	
Total	**270,259,293**	**270,259,293**
Denominator		
360-Land and Land Rights	853,209	
361-Structures and Improvements	1,052,384	
362-Station equipment	176,101,529	
364-Poles, towers, and fixtures	92,252,171	
368-Line Transformers	75,150,171	
369-Services	21,339,101	
370-Meters	23,489,723	
373-Street lighting and signal systems	7,108,100	
Total	**397,346,388**	**397,346,388**
Distribution Plant Inclusion Ratio		**68.02%**

The Distribution Plant Inclusion Ratio is applied to distribution cost of service $57,808,127 to develop the net 13.2kV transmission wholesale cost of service of $39,318,801 (see Appendix A, Cost of Service Factors-Exh. I tab, Lns 10-12). The cost of service difference of $18,489,326 ($57,808,127-$39,318,801) will be collected solely from Grant's retail customers. The 13.2kV transmission wholesale cost of service of $39,318,801 is divided by total 13.2kV system load of 731 MW to determine 13.2 kV transmission wholesale delivery rate of $4.66/kW-mo. (see Appendix A, Cost of Service Factors-Exh. I, Lns. 10-18). It is worth noting that this rate is only charged to the 13.2 kV transmission "wholesale" customers.

Staff estimates that the 13.2kV transmission wheeling customers using this service will contribute approximately $615,796 towards the allocated distribution cost of service of $39,318,801, or approximately 1.57%, see Chart 1.



The remaining distribution cost of service of $57,192,331 will be pay by Grant's retail customers, see Table 7:

Table 7: Retail and 13.2kV Transmission Wheeling Customers Contributions toward Distribution Cost of Service

Description	Distribution Cost of Service
Total Distribution COSS	$57,808,127
13.2kV Transmission wheeling customers' contribution	$615,796
Remaining Distribution COSS paid by Retail Customers	$57,192,331

USBR argues that it uses 45% of the Distribution system to transmit 13.2kV and that USBR's load only make up about 3% of the wheeling customer base and that staff's 68.02% is too high. USBR did not provide further support for its argument. Staff was unable to determine the origin of USBR's 45% and 3% amounts.

Based on the results of its analysis, staff believes that its COSS model methodology treats all its retail and transmission wheeling customers fairly and reasonably.

Comment 16

Reference: "Cost of Service Factors –I", line 1, Note A is referenced. Please provide Note A or correct the reference.

Note A reference on Line 1 has been removed. The reference was missed in the last clean-up effort. (see the attached Appendix A-revised Transmission COSS model)

Comment 17

Reference: "Cost of Service Factors –I", (Excel line 45), Exhibit IX is referenced. Please provide "Exhibit IX" or correct the reference.

Exhibit IX is included in the Transmission COSS model as the tab labelled Taxes-Other-Exh. IX. For model tab purposes, Exhibit has been abbreviated to Exh. The spreadsheet tab name was revised to Taxes-Other-Exh. IX to provide clarification. (see the attached Appendix A-revised Transmission COSS model)

Comment 18

Reference: "Cost of Service –II", (Excel line 48), refers to "Wages & Salary Allocator (W&S) - Exhibit III". Please provide "Wages & Salary Allocator (W&S) - Exhibit III" or correct the reference.

The Transmission COSS model tab Cost of Service-II has been revised to Cost of Service-Exh. II. The Cost of Service-Exh. II reference to "Wages & Salary Allocator (W&S) – Exhibit III" is reflected in the Allocation Factors-Exh. III tab, see Lines 15-20. The Cost of Service-Exh. II footnote reference language has been enhanced to indicated exactly where the Wages & Salary Allocators are developed. (see the attached Appendix A-revised Transmission COSS model)

Comment 19

Reference: "Cost of Service –II", (Excel line 56), refers to "Gross Plant in Service-Exhibit V". Please provide "Gross Plant in Service-Exhibit V" or correct the reference.

The Transmission COSS model tab "Cost of Service-Exh. II", Col. C, D, and E, Excel Lns. 56-61 calculate the Gross Plant in Service (GPIS) allocation factors. The total, production, transmission, and distribution gross plant information is sourced from the Gross Plant In Service-Exh. V tab, Cols. E, F, G, and H, Ln 51. The Cost of Service-Exh. II footnote reference language has been enhanced to indicated exactly where the Gross Plant In Service information is sourced. (see the attached Appendix A-revised Transmission COSS model)

Comment 20

Reference: “Cost of Service –II", (Excel line 62), refers to “Net Plant in Service-Exhibit VII”. Please provide “Net Plant in Service-Exhibit VII” or correct the reference.

The Transmission COSS model tab “Cost of Service-Exh. II”, Col. C, D, and E, Excel Lns. 62-67 calculate the Net Plant in Service (NPIS) allocation factors. The total, production, transmission, and distribution gross plant information is sourced from the Net Plant In Service-Exh. VII tab, Cols. E, F, G, and H, Ln 52. The Cost of Service-Exh. II footnote reference language has been enhanced to indicated exactly where the Net Plant In Service information is sourced. (see the attached Appendix A-revised Transmission COSS model)

Comment 21

Reference: “Allocation Factors-III", lines 1 and 9), refer to “Exhibit V”. Please provide “Exhibit V” or correct the reference.

The Transmission COSS model’s tab “Allocation Factors-Exh. III", lines 1 and 9) reference to “Exhibit V” has been changed. The spreadsheet tab “Allocation Factors-III” was changed to “Allocation Factors-Exh. III.” The “Exhibit V” language has been enhanced to specify the exact location of the Gross Transmission (Ln 1) and Gross Distribution (Ln 9) plant in service information is sourced. (see the attached Appendix A-revised Transmission COSS model)

Comment 22

Reference: “Allocation Factors-III", lines 6 and 7, refer to “”Exh II – Plant Data”. Please provide “Exh II – Plant Data” or correct the reference.

The Transmission COSS model’s “Allocation Factors-Exh. III” tab line references used on Ln 6 and Ln 7 have been corrected and enhanced to “See Gross Plant in Service-Exh. V tab, Col. G, Lns 27-30” and “See Gross Plant in Service-Exh. V tab, Col. G, Lns 27-30 + Lns 34-37.” This enhanced language specifies the exact location of the sourced data. (see the attached Appendix A-revised Transmission COSS model)

Comment 23

Reference: “O&M Expenses-VI", (Excel line 120), refers to “Wages & Salary Allocator (W&S) - Exhibit III”. Please provide “Wages & Salary Allocator (W&S) - Exhibit III” or correct the reference.

The Transmission COSS model tab 2018 O&M Expenses-IV has been revised to O&M Expenses-Exh. IV. The calculation of the Wages and Salary Allocator is reflected in the Allocation Factors-Exh. III tab, see Lines 15-20. The O&M Expenses-Exh. IV footnote reference language has been enhanced to indicated exactly where the Wages & Salary Allocators are developed. (see the attached Appendix A-revised Transmission COSS model)

Comment 24

Reference: “2018 Gross Plant in Service-V", (Excel line 76), refers to “Wages & Salary Allocator (W&S) - Exhibit III”. Please provide “Wages & Salary Allocator (W&S) - Exhibit III” or correct the reference.

The Transmission COSS model tab 2018 Gross Plant in Service-V has been revised to Gross Plant in Service-Exh. V. The calculation of the Wages and Salary Allocator is reflected in the Allocation Factors-Exh. III tab, see Lines 15-20. The Gross Plant in Service-Exh. V footnote reference language has been enhanced to indicated exactly where the Wages & Salary Allocators are developed. (see the attached Appendix A-revised Transmission COSS model)

Comment 25

Reference: “2018 Accumulated Reserves-VI", (Excel line 76), refers to “Wages & Salary Allocator (W&S) - Exhibit III”. Please provide “Wages & Salary Allocator (W&S) - Exhibit III” or correct the reference.

The Transmission COSS model tab 2018 Accumulated Reserves-VI has been revised to Accumulated Reserves-Exh. VI. The calculation of the Wages and Salary Allocator is reflected in the Allocation Factors-Exh. III tab, see Lines 15-20. The Accumulated Reserves-Exh.VI footnote reference language has been enhanced to indicated exactly where the Wages & Salary Allocators are developed. (see the attached Appendix A-revised Transmission COSS model)

Comment 26

Reference: “2018 NPIS & Rate Base-VII", line 53, refers to “Materials & Supplies – Exhibit VII”. Please provide “Materials & Supplies – Exhibit VII” or correct the reference.

The Transmission COSS model tab 2018 NPIS & Rate Base-VII has been revised to NPIS & Rate Base-Exh. VII. The calculation of the Materials and Supplies is reflected in the M&S & Prepayment-Exh. VIII tab, see Lines 1 - 3. The Materials & Supplies reference language has been enhanced to indicated exactly where the Materials and Supplies are sourced. (see the attached Appendix A-revised Transmission COSS model)

Comment 27

Reference: “2018 NPIS & Rate Base-VII", line 54, refers to “Prepayments – Exhibit VII”. Please provide “Prepayments - Exhibit VII” or correct the reference.

The Transmission COSS model tab 2018 NPIS & Rate Base-VII has been revised to NPIS & Rate Base-Exh. VII. The calculation of the Prepayments is reflected in the M&S & Prepayment-Exh. VIII tab, see Lines 4 - 5. The Prepayments reference language has been enhanced to indicated exactly where the Prepayments are sourced. (see the attached Appendix A-revised Transmission COSS model)

Comment 28

Reference: “2018 NPIS & Rate Base-VII ", (Excel line 83), refers to “Wages & Salary Allocator (W&S) - Exhibit III”. Please provide “Wages & Salary Allocator (W&S) - Exhibit III” or correct the reference.

The Transmission COSS model tab 2018 NPIS & Rate Base-VII has been revised to NPIS & Rate Base-Exh. VII. The calculation of the Wages and Salary Allocator is reflected in the Allocation Factors-Exh. III tab, see Lines 15-20. The NPIS & Rate Base-Exh. VII footnote reference language has been enhanced to indicated exactly where the Wages & Salary Allocators are developed. (see the attached Appendix A-revised Transmission COSS model)

Comment 29

Reference: “2018 M&S & Prepayments-VIII ", (Excel line 7), refers to “Allocators - Exhibit III”. Please provide “Allocators - Exhibit III” or correct the reference.

The Transmission COSS model tab 2018 M&S & Prepayments-VIII has been revised to M&S & Prepayment-Exh. VIII. The calculation of the Wages and Salary Allocator is reflected in the Allocation Factors-Exh. III tab, see Lines 15-20. The M&S & Prepayment-Exh. VIII heading language has been enhanced to indicated exactly where the Wages & Salary Allocators are developed. (see the attached Appendix A-revised Transmission COSS model)

Comment 30

Reference: “2018 Taxes-Other-IX ", (Excel lines 25 and 47), refer to “Exhibit I”. Please provide “Exhibit I” or correct the reference.

The Transmission COSS model tab 2018 Taxes-Other-IX has been revised to Taxes-Other-Exh. IX. Excel lines 25 and 47 language has been enhanced to indicate the location of the Cost of Services Factors in the Cost of Service Factors-Exh. I tab. (see the attached Appendix A-revised Transmission COSS model)

Appendix A

Line No.	**Adjustments Made to the Transmission Cost of Service Study (COSS) from the August 12, 2019 COSS**	Amounts
		$
1	**Plant in Service Adjustments**	
2	1) Adjustment to General Plant Account No. 397 - Communication Equip	
3	to remove plant balances associated with Wholesale Fiber	
4	Communication Equipment	
5	O&M Allocation Factor Change caused by General Plant Adj.	(1,628)
6	Transmission Return Impact	(631,294)
7	Transmision Depreciation Impact	(812,432)
8	Total Cost of Service for this Adjustment	(1,445,354)
9	2) Adjustment to Account No. 353 to remove Transformers at PRP	
10	to be recovered in the Generation Function	
11	O&M Allocation Factor Change caused by Transmission Plant Adj.	(19,270)
12	Transmission Return Impact	(2,009,706)
13	Transmision Depreciation Impact	(913,807)
14	Total Cost of Service for this Adjustment	(2,942,783)
15	3) Adjustment to remove Radial Lines at PRP	
16	to be recovered in the Generation Function	
17	O&M Allocation Factor Change caused by Transmission Plant Adj.	(7,105)
18	Transmission Return Impact	(744,975)
19	Transmision Depreciation Impact	(573,853)
20	Total Cost of Service for this Adjustment	(1,325,933)
21	4) Adjustment to remove "QC" and "PEC" Plant Balances	
22	included in Account No. 303 - Intangible Plant from Trans. COSS	
23	O&M Allocation Factor Change caused by Transmission Plant Adj.	(4,629)
24	Transmission Return Impact	(481,600)
25	Transmision Depreciation Impact	(495,896)
26	Total Cost of Service for this Adjustment	(982,125)
27	5) Adjustment to reclassified certain plant from transmission to	
28	generation. Account #s include 302, 303, 390, 391, and 398,	
29	previously these accounts were allocated to generation, transmission,	
30	distribution functions based on the direct labor allocation factors. It	
31	was determined that certain amounts were directly assignable to the	
32	generation functions.	

Line No.	**Adjustments Made to the Transmission Cost of Service Study (COSS) from the August 12, 2019 COSS**		Amounts
33	O&M Allocation Factor Change caused by Transmission Plant Adj.		(17,656)
34	Transmission Return Impact		(1,838,491)
35	Transmision Depreciation Impact		(1,524,926)
36	Total Cost of Service for this Adjustment		(3,381,073)
37	**Taxes - Other Than Income Taxes**		
38	Removed all Taxes - Other except Elect Revenue - Taxes Privilege		
39	and Elect Revenue - Taxes Fire District. All other taxes have been		
40	removed from the Transmission Cost per Unit Calculation.		
41	Amount of this adjustment is:		(950,859)
42	**Operation and Maintenance Expenses**		
43	Transmission COSS adjustment for diving costs - transmission only ($482,278 * 14.80%)		(71,395)
44	Total Transmission Cost of Service Reduction from August 12, 2019		**(11,099,522)**
45	Total Transmission Cost per Unit Reduction from 8/12/20 COSS ($3.81-$2.56)	$/kW-mo.	**(1.25)**
46	The remaining two Taxes - Other Than Income were converted to a		
47	rate add-on, similar to the 2017 COSA.		
48	2017 COSA		
49	Transmission Rate Before Tax Gross-up	$/kW-mo.	1.83
50	Public Utilities Tax Gross-up	$/kW-mo.	0.07
51	2017 COSA Wholesale Transmission Rate	$/kW-mo.	1.90
52	2019 COSS		
53	Transmission Rate Before Tax Gross-up	$/kW-mo.	**2.56**
54	Public Utilities Tax Gross-up	$/kW-mo.	**0.11**
55	2017 COSA Wholesale Transmission Rate	$/kW-mo.	**2.67**

Grant County Public Utility District
Development of the Transmission Cost per Unit

Line No.	Description	Units	Wholesale Cost of Service: Amounts	Wholesale Cost of Service: Amounts after Tax Gross-up	Source / Comment
	(a)	(b)	(c)	(d)	(e)
	115kV - 230kV WHOLESALE COST OF SERVICE				
	Annual Cost of Service:				
1	Net Transmission Cost of Service	($)	22,839,942		Cost of Service-Exh. II tab
2	Transmission Plant Inclusion Ratio		100.00%		
3	Net 115kV-230kV Wholesale Cost of Service		22,839,942		Line 1 * Line 2
	Load Divisor:				
4	Total System Load Plus Firm Point to Point	MW	742		System Load-Exh. XII tab
	115kV - 230kV Wholesale Cost of Service: 1/				
5	Yearly	$/kW-yr	$ 30.76	**$ 31.99**	Line 3 ÷ (Line 4 *1000)
6	Monthly	$/kW-mo.	$ 2.56	**$ 2.67**	Line 5 ÷ 12 months
7	Weekly	$/kW-wk.	$ 0.59	**$ 0.62**	Line 5 ÷ 52 weeks
8	Daily	$/kW-day	$ 0.08	**$ 0.09**	Line 5 ÷ 7 days
9	Hourly	$/kWh	$ 0.00351	**$ 0.00365**	Line 5 ÷ 8760 hours
	13.2kV WHOLESALE COST OF SERVICE				
	Annual Cost of Service:				
10	Total Distribution Cost of Service	($)	57,808,127		Cost of Service-Exh. II tab
11	Distribution Plant Inclusion Ratio		68.02%		Allocation Factors-Exh. III tab
12	13.2kV Wholesale Cost of Service		39,318,801		Line 10 * Line 11
	Load Divisor:				
13	13.2kV System Load	MW	731		
	13.2kV Wholesale Cost of Service 1/				
14	Yearly	$/kW-yr	**$ 53.82**	**$ 55.96**	Line 12 ÷ (Line 13 *1000)
15	Monthly	$/kW-mo.	**$ 4.48**	**$ 4.66**	Line 14 ÷ 12 months
16	Weekly	$/kW-wk.	**$ 1.03**	**$ 1.08**	Line 14 ÷ 52 weeks
17	Daily	$/kW-day	**$ 0.15**	**$ 0.15**	Line 14 ÷ 7 days
18	Hourly	$/kWh	**$ 0.00614**	**$ 0.01**	Line 14 ÷ 8,760 hours

1/ Taxes-Other Than Income Taxes are calculated as a percentage of revenue collected for the 2019 COSS. The taxes include the Public Utility Tax and the Fire Protection District Tax. For study purposes these taxes are stated as a percentage and have been added to the calculated Cost of Service Factors to determine the total Factor.
The total tax gross factor is 3.984%, see Taxes-Other-Exh. IX tab.

Grant County Public Utility District

Development of Transmission Cost of Service

Line No.	Description		Total Cost of Service (1) $	Transmission/Wholesale Transmission Cost of Service (2) $	Transmission/Wholesale Distribution Cost of Service (3) $
	Operation and Maintenance Expense				
1	Transmission (net of Acct. 565)		6,097,746	6,097,746	
2	Distribution		13,561,222	0	13,561,222
3	Administrative and General (net of Acct. 924)	2/	30,538,164	4,520,798	6,921,123
4	Administrative and General (Acct. 924)	4/	1,076,544	67,499	189,795
5	Total Operational and Maintenance Expense		51,273,676	10,686,043	20,672,140
	Depreciation Expense				
6	Transmission	1/	4,379,064	4,379,064	
7	General	1/ 2/	5,311,826	786,350	1,203,864
8	Intangible		8,849,329	136,300	208,669
9	Distribution		19,942,592	0	19,942,592
10	Total Depreciation		38,482,811	5,301,714	21,355,125
	Taxes - Other Than Income				
11	Plant Related		0	0	0
12	Labor Related		0	0	0
13	Other Related		0	0	0
14	Total Taxes-Other Than Income		0	0	0
15	Return		113,665,194	7,267,181	20,164,359
	Revenue Credits				
16	Production		0	0	0
17	Transmission		(414,996)	(414,996)	0
18	Distribution		(4,383,497)	0	(4,383,497)
19	Total Revenue Credits		(4,798,493)	(414,996)	(4,383,497)
20	Total Cost of Service		198,623,188	22,839,942	57,808,127

Original Intangible Plant Allocation Factor			
Intangible Amortization	8,849,329		
Intangible Plant	198,567,970		
Percentage	4.46%	136,300	208,669

	General	Transmission
1/ Total Depreciation Expense Before Adjs.	16,521,951	5,866,724
Amount After Adjustments	5,311,826	4,379,064

2/ **WAGES & SALARY ALLOCATOR (W&S) - See Allocation Factor-Exh. III tab, Lines 15-20.**

	($ / Allocation)		
Production - Allocation Factors-Exh. III, Ln 15	51.30%		
Transmission - Allocation Factor-Exh. III, Ln 16	14.80%	(WST)	
Distribution - Allocation Factor-Exh. III, Ln 17	22.66%	(WSD)	
Other - Non General - Allocation Factor-Exh. III, Ln 18	11.23%		(Hydro-Product
Total	100.00%	62.53%	+ Other)

See Allocation Factors-Exh. III Tab.

3/ **Gross Plant In Service (GPIS)-Allocation Factor** 2,848,134,079

Production - see GPIS-Exh. V, Col. E, LN. 71	1,976,969,748	69.41%
Transmission - see GPIS-Exh. V, Col. F, LN. 71	217,789,394	7.65%
Distribution - see GPIS-Exh. V, Col. G, LN. 71	653,374,934	22.94%
Total	2,848,134,076	100.00%

See Gross Plant in Service-Exh. V Tab for plant balances

4/ **Net Plant In Service (NPIS) - NPIS and Rate Base-Exh. VII** 1,862,151,547

Production - see NPIS and Rate Base-Exh.VII, Col. E, LN. 52	1,417,124,045	76.10%
Transmission - see NPIS and Rate Base-Exh. VII, Col. F, LN. 52	116,708,213	6.27%
Distribution - see NPIS and Rate Base-Exh. VII, Col. G, LN.52	328,319,289	17.63%
Total	1,862,151,547	100.00%

See NPIS and Rate Base-Exh. VII Tab for plant balances

Grant County Public Utility District

Development of Allocation Factors

Line No.	(a)	Source/Reference (b)	Total Electric (c)	Allocator Type (d)	Allocator % (e)
	TRANSMISSION PLANT INCLUDED IN COST OF SERVICE:				
1	Total Transmission Gross Plant	See Gross Plant in Service-Exh. V tab, Col. F, Ln 26			188,867,008
2	Less Distribution Plant Included in Transmission Accounts	Note A			0
3	Less Transmission Plant Included in Ancillary Services	Note B			0
4	Transmission Plant Included in Cost of Service	Line 1 - Line 2 - Line 3			188,867,008
5	Transmission Plant Inclusion Ratio	Line 1 / Line 4		**TPI=**	100.00%
	WHOLESALE GROSS DISTRIBUTUION PLANT:				
6	Accounts 360-364	See Gross Plant in Service-Exh. V tab, Col. G, Lns 27-30			$ 270,259,292
7	Accounts 360-364 plus Accounts 368-373	See Gross Plant in Service-Exh. V tab, Col. G, Lns 27-30 + Lns 34-37			$ 397,346,387
8	Wholesale Gross Distribution Plant Allocator	Line 6 / Line 7		**WSDP=**	68.02%
	DISTRIBUTION PLANT INCLUDED IN COST OF SERVICE:				
9	Total Distribution Gross Plant	See Gross Plant in Service-Exh. V tab, Col. G, Ln 38			609,096,159
10	Plus Distributuion Plant Included in Transmission Accounts	Note A			0
11	Less Distribution Plant Included in Ancillary Services	Note B			0
12	Total Distribution Plant Included in Cost of Service	Line 1 - Line 2 - Line 3			609,096,159
13	Percentage of Gross Distribution Plant Included in Cost of Service	Line 9 / Line 12		**DP=**	100.00%
14	Distribution Plant Inclusion Ratio	Line 8 * Line 13		**DPI=**	68.02%

Line No.	**WAGES & SALARY ALLOCATOR (W&S):**	$	Allocator		T/D Allocation		($ / Allocation)
15	Production	21,922,195	NA	100%	21,922,195		51.30%
16	Transmission	6,325,809	NA	100%	6,325,809	**WST =**	14.80%
17	Distribution	9,684,508	NA	100%	9,684,508	**WSD =**	22.66%
18	Other - Non General	4,798,574	NA	100%	4,798,574		11.23%
19	Total Sum of Lines 15 - 18	42,731,085			42,731,085		100.00%
20	**Hydro-Production and Other Allocation Factor - Line 15 + Line 18**						62.53%

Notes

A Removes transmission plant determined to be state-jurisdictional by FERC order according to the seven-factor test (e.g., radial facilities), unti balances on Grant PUD's books are adjusted to reflect the removal of such costs from the transmission function.

B Removes dollar amount of plant included in the development of ancillary services cost of service analysis (e.g., generation step-up facilities)

Grant County Public Utility District

Operations & Maintenance Expenses and Administrative & General Expenses

Line No	FERC Acct No	FERC Acct Name	Total Expenses	Adjustments	Adjusted Expenses	Hydro-Production	Transmission - Wholesale Transmission	Transmission - Wholesale Distribution	Comments re: Adjustments
	(a)	(b)	(c)	(d) 1/	(e)	(f)	(g)	(h)	(f)
		Hydraulic Power Generation O&M Expenses							
1	535	Operation supervision and engineering	4,219,244	0	4,219,244	4,219,244	0	0	Not Included in Wholesale Delivery Cost of Service
2	536	Water for power	3,361,162	0	3,361,162	3,361,162	0	0	Not Included in Wholesale Delivery Cost of Service
3	537	Hydraulic O&M Expensess (Major only)	1,776,764	0	1,776,764	1,776,764	0	0	Not Included in Wholesale Delivery Cost of Service
4	538	Electric O&M Expensess (Major only)	53,139	0	53,139	53,139	0	0	Not Included in Wholesale Delivery Cost of Service
5	539	Miscellaneous hydraulic power generation O&M Expensess (Major only)	6,618,470	(2,605,568)	4,012,903	4,012,903	0	0	Not Included in Wholesale Delivery Cost of Service
6	540	Rents	127,624	0	127,624	127,624	0	0	Not Included in Wholesale Delivery Cost of Service
7	540	Operation supplies and O&M Expensess (Nonmajor only)	0	0	0	0	0	0	Not Included in Wholesale Delivery Cost of Service
8	541	Maintenance supervision and engineering (Major only)	3,297,122	0	3,297,122	3,297,122	0	0	Not Included in Wholesale Delivery Cost of Service
9	542	Maintenance of structures (Major only)	78,604	0	78,604	78,604	0	0	Not Included in Wholesale Delivery Cost of Service
10	543	Maintenance of reservoirs, dams and waterways (Major only)	2,177,603	0	2,177,603	2,177,603	0	0	Not Included in Wholesale Delivery Cost of Service
11	544	Maintenance of electric plant (Major only)	8,778,426	0	8,778,426	8,778,426	0	0	Not Included in Wholesale Delivery Cost of Service
12	545	Maintenance of miscellaneous hydraulic plant (Major only)	19,393,909	(16,204,120)	3,189,790	3,189,790	0	0	Not Included in Wholesale Delivery Cost of Service
13	545	Maintenance of hydraulic production plant (Nonmajor only)	0	0	0	0	0	0	Not Included in Wholesale Delivery Cost of Service
		Adjustment for Diving Expenses included in Acct. 935	0	482,279	482,279	482,279	0	0	Not Included in Wholesale Delivery Cost of Service
14		**Total Hydraulic Power Generation O&M Expenses**	49,882,066	(18,327,409)	31,554,658	31,554,658	0	0	
		Transmission O&M Expenses:							
15	560	Operation Supervision and Engineering	93,447	0	93,447	0	93,447	0	
16	561	Load Dispatching	5,094,974	0	5,094,974	0	5,094,974	0	
17	562	Station Expenses	0	0	0	0	0	0	
18	563	Overhead Lines Expenses	0	0	0	0	0	0	
19	564	Underground line expenses	0	0	0	0	0	0	
20	565	Transmission of Electricity by Others	581,439	(581,439)	0	0	0	0	Not Included in Wholesale Delivery Cost of Service
21	566	Miscellaneous Transmission Expenses	177,897	0	177,897	0	177,897	0	
22	567	Rents	0	0	0	0	0	0	
23	568	Maintenance supervision and engineering	28,408	0	28,408	0	28,408	0	
24	569	Maintenance of Stuctures/Computer	0	0	0	0	0	0	
25	570	Maintenance of Station Equipment	520,435	0	520,435	0	520,435	0	
26	571	Maintenance of Overhead Lines	182,585	0	182,585	0	182,585	0	
27	572	Maintenance of Underground Lines	0	0	0	0	0	0	
28	573	Maintenance of Miscellaneous Transmission Plant	0	0	0	0	0	0	
29	574	Maintenance of Transmision Plant (Non-Major)	0	0	0	0	0	0	
30		**Total Transmission O&M Expenses**	6,679,185	(581,439)	6,097,746	0	6,097,746	0	
		Distribution O&M Expenses:							
31	580	Operation supervision and engineering	140,617	0	140,617	0	0	140,617	
32	581	Load dispatching	1,089	0	1,089	0	0	1,089	
33	582	Station expenses	235,742	0	235,742	0	0	235,742	
34	583	Overhead line expenses	13,424	0	13,424	0	0	13,424	
35	584	Underground line expenses	12,095	0	12,095	0	0	12,095	
36	586	Meter expenses	0	0	0	0	0	0	
37	587	Customer installations expenses	485,547	0	485,547	0	0	485,547	
38	588	Miscellaneous distribution expenses	5,275,842	0	5,275,842	0	0	5,275,842	
39	590	Maintenance supervision and engineering	397,709	0	397,709	0	0	397,709	
40	592	Maintenance of station equipment	1,526,914	0	1,526,914	0	0	1,526,914	
41	593	Maintenance of overhead lines	3,108,277	0	3,108,277	0	0	3,108,277	
42	594	Maintenance of underground lines	2,086,933	0	2,086,933	0	0	2,086,933	
43	596	Maintenance of street lighting and signal systems	146,247	0	146,247	0	0	146,247	
44	597	Maintenance of meters	130,786	0	130,786	0	0	130,786	
45		**Total Distribution O&M Expenses**	13,561,222	0	13,561,222	0	0	13,561,222	
		Customer Accounts Expense							
46	901	Supervision (Major only)	565,042	0	565,042	0	0	0	Not Included in Wholesale Delivery Cost of Service
47	902	Meter reading expenses	829,123	0	829,123	0	0	0	Not Included in Wholesale Delivery Cost of Service
48	903	Customer records and collection expenses	2,411,399	0	2,411,399	0	0	0	Not Included in Wholesale Delivery Cost of Service

Grant County Public Utility District

Operations & Maintenance Expenses and Administrative & General Expenses

Line No	FERC Acct No	FERC Acct Name		Total Expenses	Adjustments	Adjusted Expenses	Hydro-Production	Transmission - Wholesale: Transmission	Transmission - Wholesale: Distribution	Comments re: Adjustments
	(a)	(b)		(c)	(d) 1/	(e)	(f)	(g)	(h)	(f)
49	904	Uncollectible accounts		122,514	0	122,514	0	0	0	Not Included in Wholesale Delivery Cost of Service
50	905	Miscellaneous customer accounts expenses (Major only)		0	0	0	0	0	0	Not Included in Wholesale Delivery Cost of Service
51		**Total Customer Accounts Expense**		3,928,077	0	3,928,077	0	0	0	Not Included in Wholesale Delivery Cost of Service
		Customer Service and Information System Expense								
52	906	Customer service and informational expenses (Nonmajor only)		1,282,173	0	1,282,173	0	0	0	Not Included in Wholesale Delivery Cost of Service
53	907	Supervision (Major only)		0	0	0	0	0	0	Not Included in Wholesale Delivery Cost of Service
54	908	Customer assistance expenses (Major only)		554,390	0	554,390	0	0	0	Not Included in Wholesale Delivery Cost of Service
55	909	Informational and instructional advertising expenses (Major only)		0	0	0	0	0	0	Not Included in Wholesale Delivery Cost of Service
56	910	Miscellaneous customer service and informational expenses (Major only)		1,470	0	1,470	0	0	0	Not Included in Wholesale Delivery Cost of Service
57		**Total Customer Service and Information System Expense**		1,838,033	0	1,838,033	0	0	0	
		Licensing Compliance and Related Agreements								
58	539.R1	Miscellaneous hydraulic power generation O&M Expensess (Major only)		0	2,605,568	2,605,568	0	0	0	Reclass from Acct. 539; Not Included in Wholesale Cost of Service Template
59	545.R1	Maintenance of miscellaneous hydraulic plant (Major only)		0	16,204,120	16,204,120	0	0	0	Reclass from Acct. 545; Not Included in Wholesale Cost of Service Template
60	928.R1	Regulatory commission expenses		0	1,135,678	1,135,678	0	0	0	Reclass Yakama Settlement Expense from Acct. 928; Not Included in Wholesale COS
61		**Total Licensing Compliance and Related Agreements**		0	19,945,366	19,945,366	0	0	0	
		Fiber Optic Network O&M								
62	935.R1	Maintenance of general plant		0	1,733,338	1,733,338	0	0	0	Reclass from Acct. 935; Not Included in Wholesale Cost of Service Template
63	930.2R1			0	531,855	531,855	0	0	0	Reclass from Acct 930.2; Not Included in Wholesale Cost of Service Template
64		**Total Sales Expense**		0	2,265,193	2,265,193	0	0	0	
		Administrative & General Expenses								
65	920	Administrative and general salaries	2/	1,756,283	0	1,756,283	1,098,245	259,996	398,041	
66	921	Office supplies and expenses	2/	20,884,611	0	20,884,611	13,059,646	3,091,709	4,733,256	
67	922	Administrative expenses transferred—Credit		0	0	0	0	0	0	
68	923	Outside services employed	2/	2,009,101	0	2,009,101	1,256,339	297,423	455,340	
69	924	Property insurance-Allocated on Net Plant in Service	3/	1,076,544	0	1,076,544	819,250	67,499	189,795	
70	925	Injuries and damages	2/	3,823,008	0	3,823,008	2,390,618	565,949	866,441	
71	926	Employee pensions and benefits	2/	(5,815,611)	0	(5,815,611)	(3,636,640)	(860,929)	(1,318,041)	
72	927	Franchise requirements		0	0	0	0	0	0	
73	928	Regulatory commission expenses	2/	2,961,406	(1,135,678)	1,825,728	1,141,671	270,276	413,780	Reclass Yakama Settlement Exp to Licensing and Agreements
74	929	Duplicate charges—Credit	2/	(6,370,151)	0	(6,370,151)	(3,983,408)	(943,022)	(1,443,721)	
75	930	General advertising expenses	2/	1,285,999	(1,285,999)	0	0	0	0	Exclude General Advertising
76	930	Miscellaneous general expenses	2/	3,453,623	(531,855)	2,921,768	1,827,051	432,532	662,185	Fiber Optic Expense Included in Acct 930
77	931	Rents		198,973	0	198,973	124,422	29,455	45,095	
78	933	Transportation expenses (Nonmajor only)		0	0	0	0	0	0	
79	935	Maintenance of general plant	2/	11,520,072	(2,215,616)	9,304,456	5,818,298	1,377,410	2,108,748	Remove Fiber Optic Expense and Diving Expenses included in Acct. 935
80		**Total A&G Expenses**		36,783,857	(5,169,149)	31,614,708	19,915,492	4,588,298	7,110,919	
81		Total Operation & Maintenance Expenses		112,672,441	(1,867,438)	110,805,003	51,470,150	10,686,044	20,672,141	
	1/	Adjustments to be identified in column (f)						3,649,128		
								871,671		
	2/	**WAGES & SALARY ALLOCATOR (W&S) - See Allocation Factor-Exh. III tab, Lines 15-20.**						4,520,799		
		Production		($ / Allocation)						
		Transmission -- WST		51.30%						
		Distribution -- WSD		14.80%						
		Other - Non General		22.66%						
		Total		11.23%	62.53%					
				100.00%						
	3/	**Net Plant In Service (NPIS) - NPIS and Rate Base-Exh. VII**		1,862,151,547						
		Production - see NPIS and Rate Base-Exh.VII, Col. E, LN. 52			1,417,124,045	76.10%				

Grant County Public Utility District

Operations & Maintenance Expenses and Administrative & General Expenses

Line No	FERC Acct No	FERC Acct Name	Total Expenses	Adjustments	Adjusted Expenses	Hydro-Production	Transmission - Wholesale Transmission	Transmission - Wholesale Distribution	Comments re: Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)
				1/					
		Transmission - see NPIS and Rate Base-Exh. VII, Col. F, LN. 52		116,708,213	6.27%				
		Distribution - see NPIS and Rate Base-Exh. VII, Col. G, LN.52		328,319,289	17.63%				
		Total		1,862,151,547	100.00%				
		See NPIS and Rate Base-Exh. VII Tab for plant balances							

Exhibit V

Grant County Public Utility District
Gross Plant In Service

Line No.	Account Number	Description		Total Plant In Service	Hydro - Production	Transmission	Distribution		
				(1)	(2)	(3)	(4)		
				$	$	$	$		
		Intangible Plant							
1	301	Organization	1/	30,373	18,993	4,496	6,884		
2	302	Franchises and consents	1/	56,112,071					
3	302	Assignable Directly to Generation		56,108,707	56,108,707				
4	302	Net 302 Allocated to all functions		3,364	2,104	498	762		
5	303	Miscellaneous intangible plant	1/	142,425,526					
6	303	Adjustment for OC&PEC Plant to Hydro		35,034,370	35,034,370		0		
7	303	Adjustment for Hatchery Intangible Plant		29,633,996	29,633,996				
8	303	FERC Relicensing Costs		57,147,122	57,147,122				
9	303	Net 303 Allocated to all functions		20,610,038	12,887,949	3,051,061	4,671,027		
10		**Subtotal Intangible Plant**		198,567,970	190,833,241	3,056,055	4,678,673		
		Hydro Production							
11	330	Land and Land Rights		19,685,660	19,685,660				
12	331	Structures and improvements		144,112,918	144,112,918				
13	332	Reservoirs, dams, and waterways		511,074,821	511,074,821				
14	333	Water sheels, turbines and generators		625,533,457	625,533,457				
15	334	Accessory electric equipment		59,024,861	59,024,861				
16	335	Miscellaneous power plant equipment		63,234,736	63,234,736				
17	336	Roads, railroads and bridges		1,792,668	1,792,668				
18		Adjustment for PRP Transformer Plant to Hydro		39,412,060	39,412,060				
19		Adjustment for PRP Radial Lines to Hydro		24,750,000	24,750,000				
20		Adj. to Remove Generation Function Plant		165,312,998	165,312,998				
21		Adj. to Office Furniture and Equipment		19,155,739	19,155,739				
22		Adj. to Misc. Equipment		3,755,299	3,755,299				
23		**Subtotal Hydro Production Plant**		1,676,845,217	1,676,845,217				
		Other Production (Wind)							
24	346	Miscellaneous power plant equipment		29,656	29,656				
25		**Subtotal Production Plant**		29,656	29,656				
		Transmission Plant							
26	350	Land and Land Rights		2,002,732		2,002,732			
27	352	Structures and improvements		5,906,796		5,906,796			
28	353	Station Equipment		87,642,273		87,642,273			
29	354	Towers and fixtures		9,747,602		9,747,602			
30	355	Poles and fixtures		87,273,369		87,273,369			
31	356	Overhead conductors and devices		60,374,025		60,374,025			
32	359	Roads and trails		82,270		82,270			
24		Adjustment for PRP Transformer Plant to Hydro		(39,412,060)		(39,412,060)			
25		Adjustment for PRP Radial Lines to Hydro		(24,750,000)		(24,750,000)			
33		**Subtotal Transmission Plant**		188,867,008		188,867,008			
		Distribution Plant							
34	360	Land and Land Rights		853,209			853,209		
35	361	Structures and improvements		1,052,384			1,052,384		
36	362	Station equipment		176,101,529			176,101,529		
37	364	Poles, towers and fixtures		92,252,171			92,252,171		
38	365	Overhead conductors and devices		92,966,521			92,966,521		
39	366	Underground conduit		22,305,267			22,305,267		
40	367	Underground conductors and devices		96,477,984			96,477,984		
41	368	Line Transformers		75,150,171			75,150,171		
42	369	Services		21,339,101			21,339,101		
43	370	Meters		23,489,723			23,489,723		
44	373	Street lighting and signal systems		7,108,100			7,108,100		
45		**Subtotal Distribution Plant**		609,096,159			609,096,159		
		General Plant							
46	389	Land and Land Rights	1/	2,377,716	1,486,842	351,991	538,882		
47	390	Structures and improvements	1/	220,763,261	138,048,540	32,681,273	50,033,448		
48	391	Office furniture and equipment	1/	43,672,057	27,309,180	6,465,108	9,897,768		
49	392	Transportation equipment	1/	22,411,805	14,014,637	3,317,791	5,079,377		
50	393	Stores equipment	1/	210,944	131,908	31,228	47,808		
51	394	Tools, shop and garage equipment		9,052,841	5,660,958	1,340,161	2,051,722		
52	395	Laboratory equipment	1/	493,371	308,517	73,037	111,817		
53	396	Power operatied equipment	1/	368,134	230,203	54,498	83,433		
54	397	Communication equipment	1/	238,587,872	149,194,695	35,319,987	54,073,190		
55	398	Miscellanious equipment	1/	5,537,724	3,462,871	819,792	1,255,061		
56	397	Adj. to Remove Fiber Plant Costs		(180,523,620)	(112,885,731)	(26,724,292)	(40,913,597)		
57	390	Adj. to Remove Generation Function Plant		(165,312,998)	(103,374,166)	(24,472,547)	(37,466,285)		
58	391	Adj. to Office Furniture and Equipment		(19,155,739)	(11,978,541)	(2,835,770)	(4,341,427)		
59	398	Adj. to Misc. Equipment		(3,755,299)	(2,348,278)	(555,926)	(851,095)		
60		**Subtotal General Plant**	2/	174,728,069	109,261,635	25,866,331	39,600,102		
61		**Total Plant**		2,848,134,079	1,976,969,748	217,789,394	653,374,934	2,848,134,076	(3)
					69.41%	7.65%	22.94%		

1/ **WAGES & SALARY ALLOCATOR (W&S) - See Allocation Factor-Exh. III tab, Lines 15-20.**

	($ / Allocation)	
Production	51.30%	
Transmission -- WST	14.80%	
Distribution -- WSD	22.66%	
Other - Non General	11.23%	62.53%
Total	100.00%	

	General	Intangible	Transmission
2/ Total Gross Plant before Adjustments	543,475,725	254,680,041	253,029,068

Grant County Public Utility District
Accumulated Reserves for Depreciation

Line No.	Account Number	Description		Accumulated Reserves (1) $	Hydro - Production (2) $	Transmission (3) $	Distribution (4) $	
		Intangible Acc. Reserves						
1	301	Organization		0	0	0	0	
2	302	Franchises and consents		24,600,660				
3		Assignable Directly to Generation		24,599,185	24,599,185	0	0	
4		Net 302 Allocated to all functions		1,475	923	218	334	
5	303	Miscellaneous intangible plant		52,493,606				
6		Adjustment for OC&PEC Plant to Hydro		27,034,370	27,034,370	0	0	
7		Adjustment for Hatchery Intangible Plant		7,025,336	7,025,336	0	0	
8		FERC Relicensing Costs		13,547,876	13,547,876	0	0	
9		Net 303 Allocated to all functions		4,886,024	3,055,348	723,315	1,107,361	
10		**Subtotal Intangible Acc. Reserves**		77,094,267	75,263,038	723,533	1,107,695	77,094,266
		Hydro Production						
11	330	Land and Land Rights		0	0			
12	331	Structures and improvements		24,852,508	24,852,508			
13	332	Reservoirs, dams, and waterways		115,100,840	115,100,840			
14	333	Water sheels, turbines and generators		166,883,997	166,883,997			
15	334	Accessory electric equipment		27,726,895	27,726,895			
16	335	Miscellaneous power plant equipment		32,362,644	32,362,644			
17	336	Roads, railroads and bridges		1,047,412	1,047,412			
18		Adjustment for PRP Transformer Plant to Hydro		6,028,246	6,028,246			
19		Adjustment for PRP Radial Lines to Hydro		12,375,000	12,375,000			
20		Adj. to Remove Generation Function Plant		11,881,870	11,881,870			
21		Adj. to Office Furniture and Equipment		18,976,641	18,976,641			
22		Adj. to Misc. Equipment		2,745,566	2,745,566			
23		**Subtotal Hydro Production Acc. Reserves**		419,981,619	419,981,619			
		Other Production (Wind)						
24	346	Miscellaneous power plant equipment		20,759	20,759			
25		**Subtotal Production Acc. Reserves**		20,759	20,759			
		Transmission Acc. Reserves						
26	350	Land and Land Rights		0		0		
27	352	Structures and improvements		3,250,108		3,250,108		
28	353	Station Equipment		43,619,606		43,619,606		
29	354	Towers and fixtures		5,675,684		5,675,684		
30	355	Poles and fixtures		33,534,451		33,534,451		
31	356	Overhead conductors and devices		17,334,507		17,334,507		
32	359	Roads and trails		57,961		57,961		
33		Adjustment for PRP Transformer Plant to Hydro		(6,028,246)		(6,028,246)		
34		Adjustment for PRP Radial Lines to Hydro		(12,375,000)		(12,375,000)		
35		**Subtotal Transmission Acc. Reserves**		85,069,071		85,069,071		
		Distribution Acc. Reserves						
36	360	Land and Land Rights		0			-	
37	361	Structures and improvements		833,037			833,037	
38	362	Station equipment		67,203,015			67,203,015	
39	364	Poles, towers and fixturs		58,325,367			58,325,367	
40	365	Overhead conductors and devices		40,533,789			40,533,789	
41	366	Underground conduit		5,303,765			5,303,765	
42	367	Underground conductors and devices		35,724,309			35,724,309	
43	368	Line Transformers		56,494,426			56,494,426	
44	369	Services		18,201,946			18,201,946	
45	370	Meters		12,440,718			12,440,718	
46	373	Street lighting and signal systems		5,481,504			5,481,504	
47		**Subtotal Distribution Acc. Reserves**		300,541,877			300,541,877	
		General Reserves						
48	389	Land and Land Rights		0	0	0	0	
49	390	Structures and improvements	1/	28,196,102	17,631,696	4,174,085	6,390,322	
50	391	Office furniture and equipment	1/	43,429,163	27,157,293	6,429,151	9,842,719	
51	392	Transportation equipment	1/	20,261,896	12,670,247	2,999,523	4,592,125	
52	393	Stores equipment	1/	210,944	131,908	31,228	47,808	
53	394	Tools, shop and garage equipment	1/	4,423,303	2,765,997	654,815	1,002,491	

GPIS			24,600,660
302 Generation	56,108,707	99.994005%	24,599,185
302 Generation	2,104	0.003750%	923
302 Transmission	498	0.000888%	218
302 Distribution	762	0.001358%	334
Total GPIS	56,112,071	100.000001%	24,600,660

GPIS			25,459,236
303 Generation	29,633,996	27.594448%	7,025,336
303 Generation	57,147,122	53.213993%	13,547,876
303 Generation	12,887,949	12.000941%	3,055,348
303 Transmission	3,051,061	2.841073%	723,315
303 Distribution	4,671,027	4.349545%	1,107,361
Total GPIS	107,391,155	100.000000%	25,459,236

54	395	Laboratory equipment	1/	493,371	308,517	73,037	111,817
55	396	Power operatied equipment	1/	368,134	230,203	54,498	83,433
56	397	Communication equipment	1/	144,966,009	90,650,708	21,460,427	32,854,875
57	398	Miscellanious equipment	1/	4,216,259	2,636,527	624,165	955,566
58	397	Adj. to Remove Fiber Plant Costs		(109,686,165)	(68,589,379)	(16,237,682)	(24,859,105)
59	390	Adj. to Remove Generation Function Plant		(11,881,870)	(7,430,017)	(1,758,964)	(2,692,889)
60	391	Adj. to Office Furniture and Equipment		(18,976,641)	(11,866,547)	(2,809,257)	(4,300,837)
61	398	Adj. to Misc. Equipment		(2,745,566)	(1,716,868)	(406,447)	(622,251)
62		**Subtotal General Acc. Reserves**		103,274,939	64,580,285	15,288,579	23,406,074
63		**Total Accumulated Reserves**		985,982,532	559,845,701	101,081,183	325,055,646

1/ **WAGES & SALARY ALLOCATOR (W&S) - See Allocation Factor-Exh. III tab, Lines 15-20.**

	($ / Allocation)	
Production	51.30%	
Transmission -- WST	14.80%	
Distribution -- WSD	22.66%	
Other - Non General	11.23%	62.53%
Total	100.00%	

Grant County Public Utility District

Net Plant In Service

Line No.	Account Number	Description		Net Plant In Service	Hydro - Production	Transmission	Distribution	
				(1)	(2)	(3)	(4)	
				$	$	$	$	
		Intangible Net Plant In Service						
1	301	Organization	1/	30,373	18,993	4,496	6,884	
2	302	Franchises and consents	1/	31,511,411	0	0	0	
3	302	Assignable Directly to Generation		31,509,522	31,509,522	0	0	
4	302	Net 302 Allocated to all functions		1,889	1,181	280	428	
5	303	Miscellaneous intangible plant	1/	89,931,920	0	0	0	
6	303	Adjustment for OC & PEC Plant to Hydro		8,000,000	8,000,000	0	0	
7	303	Adjustment for Hatchery Intangible Plant		22,608,660	22,608,660	0	0	
8	303	FERC Relicensing Costs		43,599,246	43,599,246	0	0	
9	303	Net 303 Allocated to all functions		15,724,014	9,832,601	2,327,746	3,563,666	
10		**Subtotal Intangible Net Plant In Service**		121,473,704	115,570,203	2,332,522	3,570,978	121,473,703
		Hydro Production						
11	330	Land and Land Rights		19,685,660	19,685,660			
12	331	Structures and improvements		119,260,410	119,260,410			
13	332	Reservoirs, dams, and waterways		395,973,981	395,973,981			
14	333	Water sheels, turbines and generators		458,649,460	458,649,460			
15	334	Accessory electric equipment		31,297,966	31,297,966			
16	335	Miscellaneous power plant equipment		30,872,093	30,872,093			
17	336	Roads, railroads and bridges		745,255	745,255			
18		Adjustment for PRP Transformer Plant to Hydro		33,383,814	33,383,814			
19		Adjustment for PRP Radial Lines to Hydro		12,375,000	12,375,000			
20		Adj. to Remove Generation Function Plant		153,431,128	153,431,128			
21		Adj. to Office Furniture and Equipment		179,098	179,098			
22		Adj. to Misc. Equipment		1,009,733	1,009,733			
23		**Subtotal Hydro Production Net Plant In Service**		1,256,863,598	1,256,863,598			
		Other Production (Wind)						
24	346	Miscellaneous power plant equipment		8,897	8,897			
25		**Subtotal Production Net Plant In Service**		8,897	8,897			
		Transmission Net Plant In Service						
26	350	Land and Land Rights		2,002,732		2,002,732		
27	352	Structures and improvements		2,656,688		2,656,688		
28	353	Station Equipment		44,022,667		44,022,667		
29	354	Towers and fixtures		4,071,918		4,071,918		
30	355	Poles and fixtures		53,738,919		53,738,919		
31	356	Overhead conductors and devices		43,039,518		43,039,518		
32	359	Roads and trails		24,309		24,309		
33		Adjustment for PRP Transformer Plant to Hydro		(33,383,814)		(33,383,814)		
34		Adjustment for PRP Radial Lines to Hydro		(12,375,000)		(12,375,000)		
35		**Subtotal Transmission Net Plant In Service**		103,797,937		103,797,937		
		Distribution Net Plant In Service						
36	360	Land and Land Rights		853,209			853,209	
37	361	Structures and improvements		219,347			219,347	
38	362	Station equipment		108,898,514			108,898,514	
39	364	Poles, towers and fixturs		33,926,803			33,926,803	
40	365	Overhead conductors and devices		52,432,732			52,432,732	
41	366	Underground conduit		17,001,502			17,001,502	
42	367	Underground conductors and devices		60,753,675			60,753,675	
43	368	Line Transformers		18,655,745			18,655,745	
44	369	Services		3,137,155			3,137,155	
45	370	Meters		11,049,005			11,049,005	
46	373	Street lighting and signal systems		1,626,597			1,626,597	
47		**Subtotal Distribution Net Plant In Service**		308,554,282			308,554,282	
		General Net Plant In Service						
48	389	Land and Land Rights	1/	2,377,716	1,486,842	351,991	538,882	
49	390	Structures and improvements	1/	192,567,159	120,416,844	28,507,189	43,643,126	
50	391	Office furniture and equipment	1/	242,894	151,887	35,957	55,049	
51	392	Transportation equipment	1/	2,149,909	1,344,390	318,268	487,252	
52	393	Stores equipment		0	0	0	0	
53	394	Tools, shop and garage equipment	1/	4,629,538	2,894,960	685,346	1,049,231	
54	395	Laboratory equipment		0	0	0	0	
55	396	Power operatied equipment		0	0	0	0	
56	397	Communication equipment	1/	93,621,863	58,543,987	13,859,560	21,218,316	
57	398	Miscellanious equipment	1/	1,321,466	826,344	195,627	299,495	
58	397	Adj. to Remove Fiber Plant Costs	1/	(70,837,455)	(44,296,353)	(10,486,610)	(16,054,492)	
59	390	Adj. to Remove Generation Function Plant		(153,431,128)	(95,944,149)	(22,713,583)	(34,773,396)	
60	391	Adj. to Office Furniture and Equipment		(179,098)	(111,994)	(26,513)	(40,590)	
61	398	Adj. to Misc. Equipment		(1,009,733)	(631,410)	(149,478)	(228,844)	
62		**Subtotal General Net Plant In Service**		71,453,130	44,681,348	10,577,754	16,194,029	
63		**Total Net Plant In Service**		1,862,151,547	1,417,124,045	116,708,213	328,319,289	

64	**Materials & Supplies - See M&S Prepayments-Exh.VIII**	1/	17,955,612	11,228,073	2,658,106	4,069,432
65	**Prepayments - See M&S Prepayments-Exh. VIII**		1,584,123	1,584,123		
66	**Cash Working Capital**		6,434,865	2,516,491	1,350,966	2,567,408
67	**Net Rate Base**		1,888,126,146	1,432,452,732	120,717,285	334,956,129
68	**Rate Of Return**		6.02%	6.02%	6.02%	6.02%
69	**Return**		113,665,194	86,233,654	7,267,181	20,164,359

1/ **WAGES & SALARY ALLOCATOR (W&S) - See Allocation Factor-Exh. III tab, Lines 15-20.**

	($ / Allocation)	
Production	51.30%	
Transmission -- WST	14.80%	
Distribution -- WSD	22.66%	
Other - Non General	11.23%	62.53%
Total	100.00%	

Grant County Public Utility District
Materials and Supplies and Prepayments

Line No.	FERC Acct No.	FERC Acct Name	Total Expenses	Adjustments	Adjusted Expenses	WAGES & SALARY ALLOCATOR (W&S) See Allocation Factor-Exh. III tab, Lines 15-20. Transmission	Distribution	Production	Wages and Salareis Allocator Transmission	Distribution	Production	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
									(e)*(f)	(e)*(g)	(e)*(h)	(i)+(j)+(k)
		Materials and Supplies:										
1	154	Plant Materials and Operating Supplies	16,397,482	-	16,397,482	14.80%	22.66%	62.53%	2,427,445	3,716,300	10,253,737	16,397,482
2	163	Stores Expense Undistributed	1,558,130	-	1,558,130	14.80%	22.66%	62.53%	230,662	353,132	974,336	1,558,130
3		**Total Materials and Supplies**	17,955,612	-	17,955,612				2,658,106	4,069,432	11,228,073	17,955,612
		Prepayments										
4	165	Prepayments	1,584,123		1,584,123	0.00%	0.00%	100.00%	-	-	1,584,123	1,584,123
5		**Total Prepayments**	1,584,123	-	1,584,123				-	-	1,584,123	1,584,123

Grant County Public Utility District

Taxes Other Than Income Taxes

Line No.	Description	FERC Account #s	December 2018
	Per Books for 2018		
1	Elect Revenue-Taxes Fiber	1001-408050	18,723.93
2	Elect Revenue-Taxes Utility	1001-408100	7,936,039.41
3	Elect Revenue-Taxes Privilege	1001-408200	4,201,527.01
4	Elect Revenue-Taxes City	1001-408400	2,448,395.24
5	Elect Revenue-Taxes Fire District	1001-408501	219,476.16
6	Elect Revenue-Taxes Privilege QC	1001-408510	6,769.79
7	Elect Revenue-Taxes Privilege PEC	1001-408600	4,233.51
8	PRP Revenue-Taxes Privilege	7001-408200	1,966,134.08
9	PRP Revenue-Taxes Water Utility	7001-408210	0.00
10	PRP Revenue-Taxes Wastewater Utility	7001-408220	0.00
11	Total		16,801,299.13

Amounts included in the Cost of Service Factors in Cost of Service Factors-Exh. 1 tab

The 2017 COSA determined that the only Taxes-Other Than Income related to Transmission services were Public Utility Tax. In the 2019 COSS, this tax was used to calculate Taxes-Other, but also included was the Fire Protection District Tax. Both of these taxes are based on a percentage of revenue. See the below calculation:

Line No.	Description	Tax Percentage Based on Revenue	Tax Percentage Based on Amount of Public Utility Tax Paid
	Taxes Attributable to Transmission Services		
12	*Elect Revenue-Taxes Privilege* -the formula is: (Total retail revenue +Other Retail Rev+ Other Power Service revenue + 28% of CIAC - total PEC & QC costs - .154% of retail revenue) X .03873 = Total Tax	3.873%	
13	*Elect Revenue-Taxes Fire District* -the formula is: Amount established by the state based on amount of public utility tax paid by the utility. PUT X .028545832		0.111%
14	**Total Percentage Assessed to Transmission Cost of Service**		**3.984%**

This percentage will be applied to the Per Unit Cost of Service factor developed in Cost of Service Factors-Exh. I tab

Grant County Public Utility District
Change in Net Position

Line No.	Capital Component		Capitalization Ratio (Note A)	Cost of Capital	Weighted Average Cost of Capital
	(a)		(b)	(c)	(d)
	Return/Capitalization Calculations:				
1	Long Term Debt	(Note B)	60.0%	3.50%	2.10%
2	Proprietary Capital	(Note C)	40.0%	9.80%	3.92%
3	Total		100.0%		6.02%

Notes

A Target capitalization ratio established by Grant County PUD.

B Average cost of Grant County PUD's outstanding long-term debt.

C Cost of equity based on the FERC approved return on equities (ROE) of PacifiCorp and Puget Sound Energy, which are both interconnected with Grant County PUD. Avista Corporation is also interconnected to the Grant County PUD transmission system. However, Avista's transmission rate is currently based on a stated rate and, therefore, there is no specific ROE that has been identified in the determination of the transmission rate (i.e., based on a settled black box).

Grant County Public Utility District
Revenue Credits

Line No.	FERC Acct No.	FERC Acct Name	Description	Allocation 1 Transmission	1 Distribution	Plant	Labor	Other	Total	Comments re: Allocation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Other Revenues:								
1	450	Forfeited Discounts	Elect Revenue-Penalty For Late Payment		1,129,692				1,129,692	Related to retail service.
2	451	Miscellaneous Service Revenues	Elect Revenue-Misc Service Revenue		2,870,955				2,870,955	Related to retail service.
3	454	Rent from Electric Property	Elect Revenue-Other Electric Revenues		382,850				382,850	Related to retail service.
4		**Total Other Revenues**		0	4,383,497	0	0	0	4,383,497	
		Wheeling Revenues:								
5	456	Other Electric Revenues	Puget Sound Energy	165,252					165,252	Facilities with DSO
6	456	Other Electric Revenues	Vantage Energy	142,608					142,608	Facilities with DSO
7	456	Other Electric Revenues	Seattle City Light	53,568					53,568	Exchange/PTP-LTF
8	456	Other Electric Revenues	Tacoma Power	53,568					53,568	Exchange/PTP-LTF
9		**Total Wheeling Revenues**		414,996	0	0	0	0	414,996	

Grant County Public Utility District
System Load

		BA Load		Loads - NCP (Note A)					System Load			USBR Large	(Note B)	Adjusted System Load	
Line No.	Month	Calc'd GCPD_BA_LOAD MMAX	Calc'd GCPD_BA_LOAD MMAX TIME	Schrag	Kittitas	Palisades	USBR Large Loads	USBR Small Loads Estimate	Calc'd GCPD_SYST_LOAD MMAX	Calc'd GCPD_SYST_LOAD MMAX TIME	Total System Load	115/230 Only Load During Peak	Firm Point to Point Load	13.2kV System Load	Total System Load Plus Firm Point to Point
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
											(h) - (j)			(k)-(l)	(k)+(l)
1	Jan	661.2	3.08	1.7	1.1	2.4	1.1	1.1	672.2	3.1	679.6	0.2	-	679.4	679.6
2	Feb	730.0	21.07	2.9	1.0	2.4	1.1	0.3	746.1	21.1	753.8	0.2	-	753.6	753.8
3	Mar	651.8	7.07	3.7	1.8	2.5	18.8	0.4	665.0	7.1	692.3	12.2	-	680.1	692.3
4	Apr	632.2	2.07	6.8	1.4	2.2	21.7	0.4	627.4	2.1	659.9	14.7	-	645.2	659.9
5	May	728.8	16.16	14.6	1.0	3.0	26.8	2.4	712.0	16.2	759.7	18.5	-	741.2	759.7
6	Jun	772.5	21.16	14.9	1.1	4.1	30.9	1.9	747.4	21.2	800.3	21.6	-	778.7	800.3
7	Jul	847.6	26.16	14.4	1.3	4.7	33.7	1.2	819.4	26.2	874.7	23.5	-	851.2	874.7
8	Aug	831.3	9.16	12.3	1.2	5.2	32.8	2.6	807.5	9.2	861.7	22.6	-	839.1	861.7
9	Sep	701.5	7.17	12.9	0.9	5.1	24.7	1.7	681.7	6.2	727.0	17.3	-	709.7	727.0
10	Oct	646.5	19.08	10.5	0.7	3.9	18.1	1.2	636.7	19.1	671.1	12.1	-	659.0	671.1
11	Nov	682.3	19.08	2.4	0.8	3.3	1.1	0.1	694.0	19.1	701.6	0.2	-	701.4	701.6
12	Dec	707.4	7.08	2.6	0.7	2.1	1.0	0.9	721.0	7.1	728.3	0.2	-	728.1	728.3
13	**Average**	716.1		8.3	1.1	3.4	17.6	1.2	710.9		742.5	11.9	-	730.6	742.5

Notes

A Loads reflect NCP billing determinants

B Grant County PUD has no firm point to point customers as of December 31, 2018.

Explanation of Differences Between the 2019 COSS and the 2017 COSA

Transmission Differences-$

The primary difference between the 2019 COSS and the 2017 COSA per unit cost calculation is the methodology used to calculate the results. The 2019 COSS employs a traditional FERC cost of service model which analyzes the embedded data in developing the cost components, such as O&M expenses, Depreciation expense, Taxes - Other Than Income Taxes, Return on Investment, and Revenue Credits. This methodolgy used the accrual basis of accounting. Where as the 2017 COSA is primary based on 2015 forecasted data averaged over a 5-year period to develop a cash basis revenue requirement. This method used cost components such as O&M (transmission and allocated A&G), Debt and Cash used in Plant Investment, Power - Sales to Other Utilities, Broadband Network Sales, Interest/JLB payments/Misc., and Contributions In Aid of Construction.

	Transmission Differences-$
2019 COSS cost $/kW-month	2.67
2017 COSA cost $/kW-month	1.90
Difference	0.77

2019 COSS - cost of service approach	22,839,942
2017 COSA - cash revenue requirement approach	18,099,953
Difference	4,739,989

Rate Impact of Increased Cost	0.48

Explanation of Differences

O&M Expenses differences

For details of the dollar differences between the two methodologies, see the attached sheet detailing the differences. Of note, is the difference between O&M expenses.

2019 COSS O&M expenses (includes transmission and A&G O&M expenses)	10,686,043
2017 COSA O&M expenses (includes transmission and A&G O&M expenses)	6,359,279
Difference	4,326,764

It was discovered through analysis that the 2017 COSA O&M expenses was not only a 5-year forecasted amount, but the transmission amount declined from $4.5 m in 2015 to $3.0 m in 2019, which is a 34% reduction in transmission O&M expense. For the 2017 COSA it was projected these expenses would decrease over time. But, as can seen in staff's analysis these expenses have increased over time.

Depreciation Differences

Under accrual accounting, depreciation expense is calculated and is part of the cost of service calculation, where as depreciation expense is not calculated under the cash approach

2019 COSS depreciation expenses	5,301,714
2017 COSA depreciation expenses	0
Difference	5,301,714

Taxes - Other Than Income

The COSS model calculated transmission taxes - other based on 2018 actuals, while 2017 COSA did not calculate Taxes - other

2019 COSS taxes - other expenses	0
2017 COSA taxes - other expenses	0
Difference	0

For the 2019 COSS, the Taxes-Other Than Income Taxes have been calculated to be consistent with 2017 COSA and are a percentage of revenue added to the Cost of Service Factors. Taxes include the Public Utility Tax and the Fire Protection District at 3.984% of revenues.

Return on Investment

Staff calculated a return on investment on a net plant position in the 2019 COSS, where the 2017 COSA used a combination of debt and cash used in plant investment.

2019 COSS return on investment approach	7,267,181
2017 COSA debt and cash approach	19,002,613
Difference	(11,735,432)

By using the net transmission investment, the 2019 COSS model produces a rate of return of 6.02%. By using the same net transmission investment, the 2017 COSA model produces a rate return of 9.27%, a higher return on investment, a 53.99% increase.

Revenue Credits

2019 COSS Other Revenue Credits	(414,996)
2017 COSA Other Revenue Credits	(547,513)
Difference	132,517

In addition, the 2017 COSA used the following other items to calculate the required cash revenue requirement - these items where not included in the 2019 COSS model

2017 COSA	
Fiber Optic Network differences	(542,905)
Other Expenses differences	(5,526,618)
Other Revenue From Others differences	7,257,331
CIAC differences	0
Tax Removal differences	5,526,618
Subtotal	6,714,426
Total Differences	4,739,989

Another primary driver in the rate increase reflected above is the volume used to calculate the unit cost. The 2019 COSS model used the historic 2018 system load. The 2017 COSA used a 5-year average based on projected load growth

2019 COSS - Annual MW	8,910
2017 COSA - Annual MW	9,912
Difference	(1,002)

This resulted in a larger load and denominator in the design of the cost per unit. To illustrate the impact, using the same cost of service - the 2019 COSS of $26,221,015

2019 COSS per unit cost	2.56
2017 COSA per unit cost	2.30
Increase caused by volume	0.26

Cost of Service Comparison

		Transmission/Wholesale					
Line No.	Description	New Transmission Cost of Service ("COSS")	Old Transmission Cost of Service ("COSA")	Difference	New Distribution Cost of Service ("COSS")	Old Distribution Cost of Service ("COSA")	Difference
		(1)	(2)	(3)	(4)	(5)	(6)
		$	$	$	$	$	$
	Operation and Maintenance Expense						
1	Transmission (net of Acct. 565)	6,097,746	3,083,165	3,014,581	0	0	0
2	Distribution	0	0	0	13,561,222	11,324,518	2,236,704
3	Administrative and General (net of Acct. 924)	4,520,798	3,276,114	1,244,684	6,921,123	8,950,571	(2,029,448)
4	Administrative and General (Acct. 924)	67,499	0	67,499	189,795		189,795
5	Total Operational and Maintenance Expense	10,686,043	6,359,279	4,326,764	20,672,140	20,275,089	397,051
	Depreciation Expense						
6	Transmission	4,379,064	0	4,379,064	0	0	0
7	General	786,350	0	786,350	1,203,864	0	1,203,864
8	Intangible	136,300	0	136,300	208,669	0	208,669
9	Distribution	0	0	0	19,942,592	0	19,942,592
10	Total Depreciation	5,301,714	0	5,301,714	21,355,125	0	21,355,125
	Taxes - Other Than Income						
11	Plant Related	0	0	0	0	0	0
12	Labor Related	0	0	0	0	0	0
13	Other Related	0	0	0	0	0	0
14	Total Taxes-Other Than Income	0	0	0	0	0	0
15	Return	7,267,181	19,002,613	(11,735,432)	20,164,359	30,370,828	(10,206,469)
	Revenue Credits						
16	Production	0	0	0	0		0
17	Transmission	(414,996)	(547,513)	132,517	0		0
18	Distribution	0	0	0	(4,383,497)	(6,381,665)	1,998,168
19	Total Revenue Credits	(414,996)	(547,513)	132,517	(4,383,497)	(6,381,665)	1,998,168
	2015 COSA Items Used in Development Not Used in 2019 COSS						
20	Fiber Optic Network	0	542,905	(542,905)	0	950,229	(950,229)
21	Other Expenses	0	5,526,618	(5,526,618)	0	8,049,490	(8,049,490)
22	Other Revenue From Others	0	(7,257,331)	7,257,331	0	(10,963,222)	10,963,222
23	CIAC	0	0	0	0	(4,871,162)	4,871,162
24	Tax Removal	0	(5,526,618)	5,526,618	0	(8,049,490)	8,049,490
25	Subtotal	0	(6,714,426)	6,714,426	0	(14,884,155)	14,884,155
26	Total Cost of Service	22,839,942	18,099,953	4,739,989	57,808,127	29,380,097	28,428,030

2015 COSA and Rates for Transmission and Distribution

	Transmission 2015 ("COSA")	Distrubution 2015 ("COSA")
Transmission/Distrubtion O&M	3,083,165	11,324,518
Fiber Optic Network	542,905	950,229
Administrative & General O&M	3,276,114	8,950,571
Debt Service Existing	6,064,004	8,503,566
Debt Service Proposed	1,250,254	1,753,235
Other Expenses	5,526,618	8,049,490
Cash Financed Capital Projects	11,688,355	20,114,027
Total Revenue Requirement	31,431,415	59,645,636
Other Revenue From Others	(7,257,331)	(10,963,222)
CIAC	0	(4,871,162)
Total Net Revenue Requirements	24,174,084	43,811,252
Tax Removal	(5,526,618)	(8,049,490)
Total Net Revenue Requirements, Less Taxes	18,647,466	35,761,762
<u>Other Revenues and Deductions</u>		
Small Load Revenue	(48,304)	(190,020)
Nine Canyon Wind - Transmission Removal	(317,168)	
QC - Transmission Removal	(1,123)	
PEC - Transmission Removal	(918)	
Kittitas Distribution Revenue		(14,000)
Schrag Revenue	(70,000)	
Palisades Revenue	(3,000)	
SCL/TCL Exchange	(107,000)	
Line Transformers	0	(6,177,645)
Total	(547,513)	(6,381,665)
Total Net Revenue Requirement	18,099,953	29,380,097

	Rate Design 115 kV	Rate Design 13.2kV	
USBR Billing Units	221	70	MW/month
System Load Billing Units	9,691	9,691	MW/month
Total Billing Units	9,912	9,761	MW/month
Revenue Requirement	18,099,953	29,380,097	
Monthly Billing Rate	1.83	3.01	
WA State Public Utility Tax	3.8%	3.8%	
Billing Rate with Tax Included	1.90	3.12	