Agenda
Utility Advisory Committee Meeting
Tuesday, July 12, 2022
Richland City Shops Building
2700 Duportail Street, Room 110

Committee Members: Chair Gregoire, Vice-Chair Lo Presti and Members Felton, Larkin, Porter, Sanders and Staven

Liaisons: Council Liaison Alternate: Jones
Staff Liaison: Whitney

<u>Regular Meeting - 3:00 p.m.</u>

Call to Order/Attendance:

Approval of Agenda: (Approved by Motion)

Public Comments:

Approval of Minutes: Approved by Motion

Approval of May 10, 2022 Meeting Minutes

Items of Business:

2. Status - Each City Utility (10 Minutes each)
   - Clint Whitney, Energy Services Director
     Tom Huntington, Fire Chief
3. 2021 RES Financial Review (15 minutes)
   - Clint Whitney, Energy Services Director
4. Northwest RiverPartners Lower Snake River Dams Replacement Study (30 minutes)
   - Clint Whitney, Energy Services Director
5. Discussion Refresh on Energy Storage and Demand Response Opportunities (15 minutes - Felton)
   - Clint Whitney, Energy Services Director

Unfinished Business:

Other Informational Items:

6. RES Capital Work Plan Status Report - May 2022
7. Forward Agenda Planning

Adjournment

The Richland City Shops Building is ADA accessible. Any individual who has difficulty attending the meeting in-person may request to provide comments remotely. (Ch. 42.30 RMC) Requests for sign interpreters, audio equipment, and/or other special services must be received 48 hours prior to the meeting by calling the City Clerk's Office at 509-942-7389.

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/12/2022

Agenda Category: Approval of Minutes

Prepared By: Jackie Carpenter, Business Services Assistant

Subject:
Approval of May 10, 2022 Meeting Minutes

Department:
Energy Services

Recommended Motion:
Approve the minutes of the Utility Advisory Committee meeting held on May 10, 2022.

Summary:
Attached are the minutes from the Utility Advisory Committee Meeting held on May 10, 2022.

Fiscal Impact:

Attachments:
1. DRAFT 051022 UAC Meeting Minutes

MINUTES
UTILITY ADVISORY COMMITTEE REGULAR MEETING
Tuesday, May 10, 2022 – Shops Room 110

Utility Advisory Committee Regular Meeting – 3:00 p.m.
Chair Gregoire called the meeting to order at 3:00 p.m.

Attendance: Chair Don Gregoire, Committee Members, Larry Felton, Dave Larkin, Dan Porter, James Sanders, and Harry Staven were present. Also present were Staff Liaison and Energy Services Director Whitney, Public Works Director Rogalsky, Fire & Emergency Services Director Huntington, Fire Battalion Chief Hempstead, and Business Services Manager Edgemon were present.

Approval of Agenda
MEMBER PORTER MOVED AND MEMBER SANDERS SECONDED THE MOTION TO APPROVE THE AGENDA AS PUBLISHED. THE MOTION CARRIED WITH MEMBER STAVEN ABSTAINING.

Approval of Minutes
MEMBER PORTER MOVED AND MEMBER LARKIN SECONDED THE MOTION TO APPROVE THE MARCH 8, 2022 MEETING MINUTES. THE MOTION CARRIED WITH MEMBER STAVEN ABSTAINING.

Public Comments

None.

Items of Business

1. Status – Each City Utility
   Energy Services Director Whitney, Public Works Director Rogalsky and Fire & Emergency Services Director Huntington provided brief updates regarding their respective utilities.

2. Badger South Water Supply
   Public Works Director Rogalsky discussed the proposed contract amendment with Badger Mountain Irrigation District (BMID) as it relates to water supply needs of the Badger Mountain South development area within the City.

   UAC members requested an equivalent water one-line diagram to understand pumping system upgrades.

3. Badger South Fire Station Medical Utility Rate Setting
   Fire & Emergency Services Director Huntington presented the recently completed financial analysis. Staff and UAC discussed possible recommendations for several financial elements that impact the fee structure and monthly rate for 2023.

4. RMC Title 14 – Line Extension Changes
   Energy Services Director Whitney presented staff's recommended changes to RMC Title 14 relating to line extensions associated with cost causation.

Unfinished Business

None.

Other Informational Items
Information on the following items was provided to the committee members for later review:

5. Capital Work Plan Update (RES)
6. BPA Joins the Energy Imbalance Market (EIM)
7. Energy Northwest Update
8. Forward Agenda Planning

UAC members requested future presentations be included in packets whenever possible.

Adjournment

Chair Gregoire adjourned the meeting at 5:02 p.m.

APPROVED:	ATTESTED:
______________________________	______________________________
Don Gregoire, Utility Advisory Committee Chair	Sandi Edgemon, Business Services Manager

DATE APPROVED: July 12, 2022

DATE PUBLISHED:

DRAFT

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/12/2022

Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director
Tom Huntington, Fire Chief

Subject:
Status - Each City Utility (10 Minutes each)

Department:
Energy Services

Recommended Motion:
This item is information only.

Summary:
A representative from each of the City's utilities will provide a status update.

Fiscal Impact:

Attachments:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/12/2022 Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
2021 RES Financial Review (15 minutes)

Department:
Energy Services

Recommended Motion:
This is an informational item only.

Summary:

Attached are the end of year (4Q21) financial statements for Energy Services. In summary, the 2021 financials appear solid with increased unrestricted cash and revenues while operating expenses were lower. Additionally, while total revenue bonds payable increased by $4M in 2021, almost $7.4M in revenue bonds proceeds were received in 2021.

Page 7 of the financial statement includes key metrics that UAC has historically followed along with bond rating agencies. The unrestricted general purpose operating cash (GPOC) of $13.7M in 2021 compared to $6.7M in 2020 is skewed high with accounts payable that had not been processed before the end of 2021. The GPOC will be lower in 1Q23, reflecting the accounts payable transactions being completed. The higher GPOC also skews the utility's operating cash trendline and days cash on hand. However, the days cash on hand metric has continued to trend above 45 days for most of 2021. This is a significant improvement above the 26 days cash in 2018 or 40 days cash in 2020.

Below are a few excerpts from the financial statement comparing it to the previous year:

	12/31/2021	12/31/2020	Difference
Power Sales Revenues	$68,255,563	$65,459,120	4%
Total Purchased Power	$40,212,452	$40,213,416	0%
Total Distribution O&M	$4,906,379	$6,379,640	-23%
BPA - Conservation Program (EEI) Revenue	$1,162,398	$692,908	47%
BPA Conservation Admin Fee (Other Income)	$233,844	$158,640	47%
Work Performed for City Departments (Other Income)	$539,649	$494,482	9%
Accounts Receivable (AR)	$4,734,541	$4,746,381	-0.2%
Total Degree Days	6,070	5,785	5%

Based upon the latest Cost of Service Analysis (COSA), the trend for 2022 is for GPOC to decrease through 2023 with an anticipated rate increase anticipated 4Q23 or 1Q24. Inflation costs on materials and expenses will influence rate increase timing.

Fiscal Impact:

Attachments:
1. RES Dec 2021 Final

CITY OF RICHLAND, WASHINGTON

Electric Utility Financial Statements

For the Quarter Ended
December 31, 2021
(Unaudited)

Prepared by:
Administrative Services Department

Issued on:
June 7, 2022

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY FINANCIAL STATEMENTS
December 31, 2021

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Brief description of notable business activities impacting the operations of the electric utility.

Financial Trend Information…………………………………………………... 5-6
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Presents the assets and liabilities of the utility. Compares current year balances with previous year balances. Reflects the retained earnings of the utility since the beginning of operation.

Comparative Statements of Operations ……………………………….………… 9-11
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Presents monthly trends in degree days. Degree days are indicators of how much energy a typical household will use for heating or cooling.

Detailed FERC Balance Sheet and Trial Balance ………………………………. 21-25
Provides listing of detailed FERC balance sheet, revenue, and expense account balances.

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
December 31, 2021

Current Financial Developments

The following comments address events impacting the Electric utility's financial position. These comments clarify certain financial activity, including the environment in which the financial transactions occur.

1st Quarter

- In response to COVID-19 pandemic, Governor Inslee issued Proclamation 20-23 on February 29, 2020. The proclamation, which prohibited disconnecting utility services for non-payment, has been extended multiple times with the latest extension expected to be the last and expire July 31st. The City is expecting the Governor to require utility payment terms, on past due balances, to be up to 120 days with potential for some utility disconnections to be delayed into 1Q22 because of winter weather.
- Customer past due balances continue to trend approximately $1-1.5M across 1,500 customers. This represents 5.8% of the 25,600 electric customers.
- The Cost of Service Analysis (COSA) model was updated with 2019 financial statements. The COSA is used to provide projections of revenues and expenses. The previous COSA data indicated a potential rate increase necessary in 2020. Proactive decreases in planned expenditures helped offset lower consumption and higher accounts receivable balances caused by COVID-19. This allowed a rate increase to be deferred until 2022. Early projections from BPA indicate a potential 5% rate increase to wholesale power and transmission expenses for the upcoming BP-22 rate period. After BPA projections are final, RES staff will apply them to the Cost of Service Analysis (COSA) to appropriately project future utility rates.
- 2021 Capital Improvement Plan (CIP) is budgeted at $11M with largest investments in Advanced Metering Infrastructure (AMI) of $3.5M, Gateway Substation of $3.7M, Renewal & Replacements of $1.4M, and new development line extensions of $1.3M.
- Capital investment expenditures through March were $1.87M.
- When normalized for weather, 1Q 2021 consumption was up 0.6%, showing consumption was essentially unchanged when compared to the utility's five-year weather adjusted average.

2nd Quarter

- Across all BPA customers, the overall interim power rate for 2022-2023 is projected to be 2.5% lower than the 2020 rate period and transmission costs close to 10% higher. BPA's Administrator will finalize the 2022-2023 rate period with a final record of decision at the end of July 2021. The impacts to the City, during the Federal 2022-2023 rate period, represent a power cost decrease of 3.6% and a transmission cost increase of 9.6%. Modeling these parameters in the COSA indicates no retail rate increase is needed through 2023.
- Governor Inslee extended Proclamation 20-23 through September 30, 2021.
- As a result of the continued pandemic, customer past due balances continue to trend approximately $1.7M across 1,600 customers. This represents 6.3% of the 25,600 electric customers. The City considers most of the past due balances as recoverable.
- The second quarter gross margin ended $48K higher than COSA projections. June's weather was hotter than normal with a coincidental peak demand of 211 MW on June 28th when the ambient temperature was 115F.
- Capital investment expenditures through June were $3.97M.

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
December 31, 2021

Current Financial Developments

3rd Quarter

- In July 2021, Bonneville published its Record of Decision ("ROD") for FFY 2022-2023 wholesale energy rates with BPA transmission costs increasing 9.5% and BPA power costs decreasing 4.64%. After modeling with non-federal wholesale energy, the overall wholesale costs will be 1% lower over the federal 2022-2023 period. No retail rate changes are expected through 2023.
- Governor Inslee's pandemic Proclamation 20-23.16 preventing utilities from shutting off water, electricity and natural gas services for customers ended September 30th. The City is working closely with Benton County to provide utility assistance to those affected by COVID-19.
- Through much of 3rd quarter, past due customer accounts totaled $1.7M across 1,600 customers. The City considers most of the utility balance as recoverable and continues to work with customers on available county and regional funded utility assistance programs.
- The third quarter gross margin ended with $1.3M higher than COSA projections. The YTD variance resulted with actual revenues being higher by $1.1M while actual wholesale power costs were $403K higher than COSA projected. September's weather was a moderately hot month, with an average temperature low of 57°F and high of 78.6°F. The utility load peaked at 159 MW through September.
- The City anticipates financing approximately $7.0M in late 4Q21 for 2022-2023 capital projects. Major capital projects will include completing the Advanced Metering Infrastructure (AMI) implementation, Gateway and Dallas Substations.

4th Quarter

- The fourth quarter gross margin ended with $3M higher than COSA projections. The YTD variance resulted with actual revenues being higher by $1.4M while actual wholesale power costs were $800K lower than COSA projected. December's weather was a moderately cold month, with an average temperature low of 27.4°F and high of 40.8°F. The utility load peaked at 189 MW through December.
- On December 1, 2021, Energy Services issued $7.4M in revenue bonds supporting 2022-2023 capital projects. Major capital projects will include completing the Advanced Metering Infrastructure (AMI) implementation, Gateway Substation and City View (Bank 2) Substation.
- On December 15, 2021, BPA announced a Power Reserves Distribution Clause credit of approximately $272k for FFY 2022.
- The timing of Accounts Payable (AP) transactions in 4Q21 from delays in BPA billings, Itron AMI progress payments, and inventory orders artificially increases the General-Purpose Operating Cash (GPOC). The GPOC will normalize in 1Q22 after the AP is processed.

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
December 31, 2021

Current Business Developments

The following comments address events influencing the operations of the Electric utility. These comments provide additional information not specifically addressed or identified in the financial statement presentation.

1st Quarter

- The 2020 average number of electrical customers was 25,613. RES is officially a 25,000-customer utility and as such complying with the Energy Independence Act (EIA) requirements for obtaining the 3% of renewable energy. Staff is working with consultants for the first deliverable of this requirement which is due to Department of Commerce in 2024.
- The 4 MW solar and 1 MW battery storage project is located north of Richland and began generating October 2020. The City is purchasing the solar generation for $38.50/MWh for energy and approximately $16.00/MWh for shaping. RES will use the renewable energy towards its Energy Independence Act renewable energy requirement.
- US Department of Energy selected Terra Power-GE Hitachi and XEnergy for its Advanced Reactor Demonstration Program. Energy Northwest is a utility partner with both companies. Terra Power-GE Hitachi and XEnergy were awarded $160 million each to test, license, and build advanced reactors.

2nd Quarter

- On April 27, 2021 BPA began communicating its Public Safety Power Shutoff (PSPS) policy which is expected to align with multiple state initiatives on wildland fire policies. BPA has identified 2% of its 15,000 miles of transmission lines as susceptible to PSPS which includes high winds (>60mph) and low moisture conditions. BPA Account Executives have confirmed the City's transmission lines are not part of the 2% of susceptible transmission lines.
- The capital investments in electrical distribution system improvements are resulting in a steady decline in overall outages for Richland customers. While outages overall continue to decline, the duration of outages is higher than normal. This is attributed to longer timeframes necessary to identify and restore underground cable infrastructure. To mitigate longer duration outages on underground infrastructure overshadowing reliability progress, several more years of investment in aging infrastructure will be required.
- RES' contractor, Magnum Power, began construction on the Gateway Substation project. Construction is scheduled to be completed the first part of 2022. Gateway Substation will support growth in the Horn Rapids Industrial Area as well as provide reliability to adjacent substation customers.
- RES is working with a consultant on the automation of a Demand Response by Voltage Reduction (DRVR) project that will help reduce peak loads. Engineering is expecting to have this project online before end of 4Q21.
- The energy storage portion of Horn Rapids Solar Storage and Training (HRSST) supported a portion of the June 28th peak loads before a high temperature caused a controller shutdown. The controller has been replaced and the energy storage device is continuing to recharge during light load hours (LLH) and discharge during the 3pm-7pm peak period of heavy load hours (HHL).

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
December 31, 2021

Current Business Developments

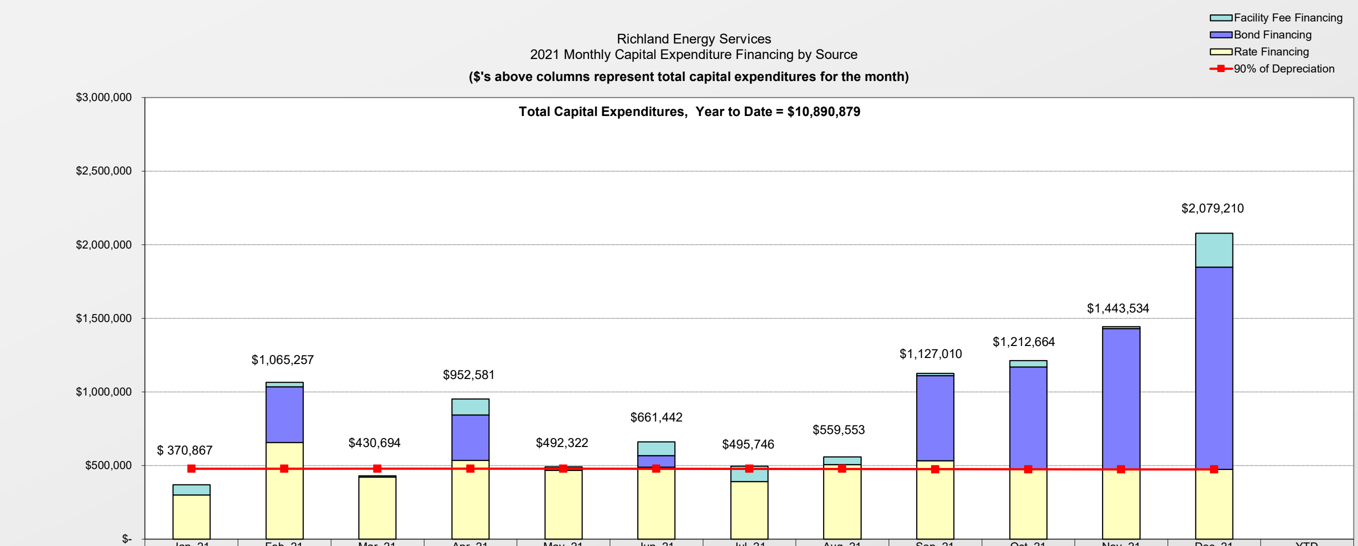
3rd Quarter

- On September 14, 2021, the Utility Advisory Committee (UAC) was presented with reports for consideration of the City's adoption of the Demand Response Potential Assessment (DRPA), Clean Energy Implementation Plan (CEIP), and Conservation Potential Assessment (CPA). The CPA will help the utility determine the most cost-effective energy efficiency opportunities for future years. The DRPA will identify demand response opportunities. The CEIP will help with implementation of energy efficiency programs to meet utility decarbonization targets. RES staff will present these reports for City Councils consideration of adoption at an October 2021 meeting.
- RES' Contractor, Magnum Power, is currently working on rebuilding four (4) overhead powerline projects. These projects are replacing 50+ year old poles and #6 copper conductor.
- RES' Contractor, Palouse Power, has been selected and will soon begin an underground cable replacement project in the Westview Acres area.

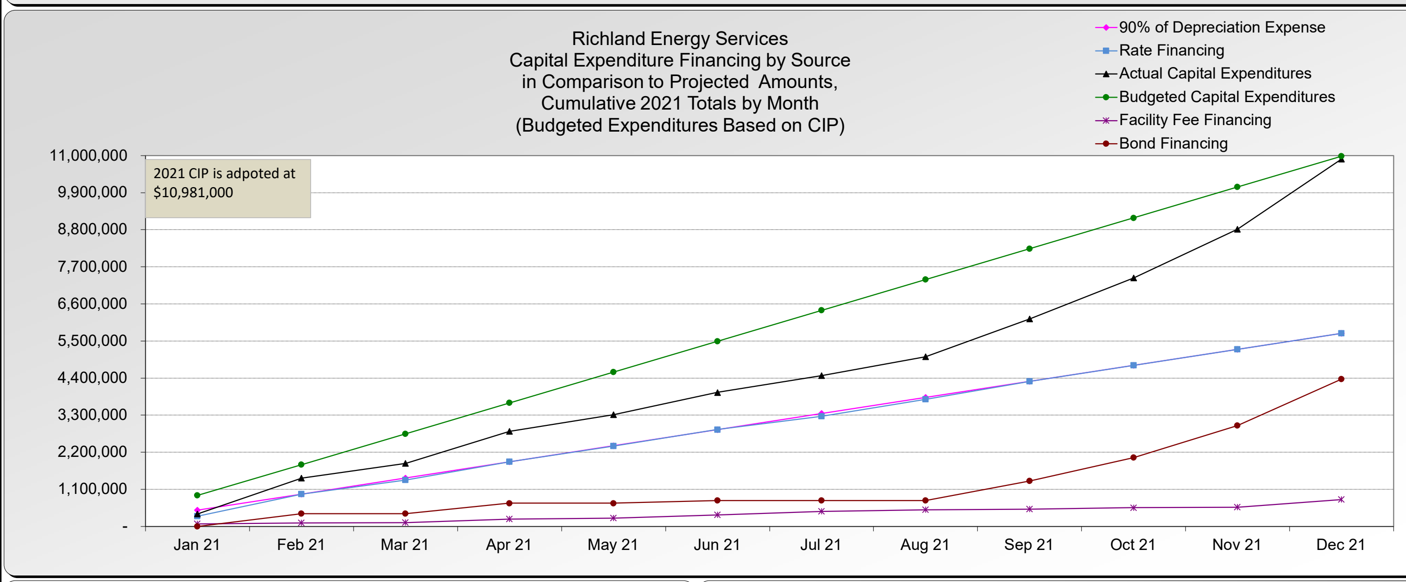
4th Quarter

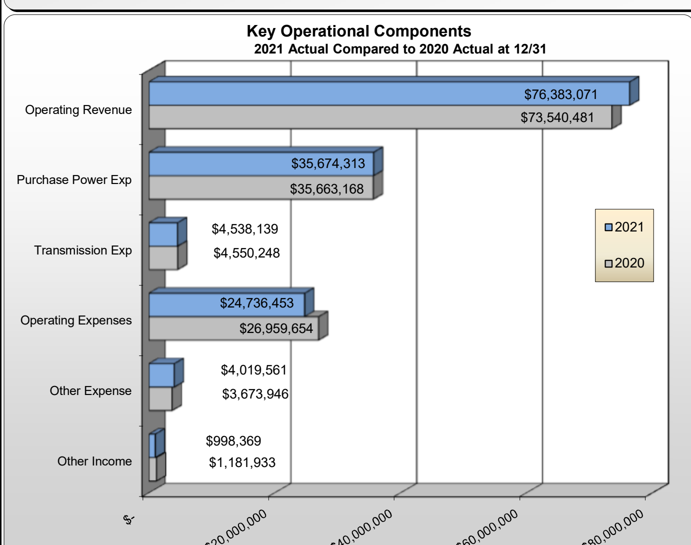
- The 2021 Capital Work Plan (CWP) was completed except for the multi-year Advanced Metering Infrastructure project (AMI). Delivery of meters were expected in December and not received by end of 2021 due to supply chain delays impacting Itron.
- RES' contractor, Magnum Power, completed all six of the overhead rebuilds it was working on throughout the 2021 fiscal year. The project replaced 50+ year old poles and #6 copper conductor.
- RES' contractor, Palouse Power began the underground boring for the Westview Acres Area project. This work will continue through the fiscal year 2022 and will replace underground distribution cable.
- Delays in delivery of distribution transformers continues to be an issue through the end of the 2021 fiscal year and will continue through at least 2022. Current lead times for single phase transformers are currently 6 months and expected to continue to extend in 2022. The utility is managing current inventory to maximize new residential connections for developers while maintaining enough inventory for unplanned outages and damaged equipment. Approximately 150 distribution transformers were ordered in August 2021 with delivery anticipated 1Q22. Typical 50kVA pad mount distribution transformers have increased from $1.5k to $5k each.

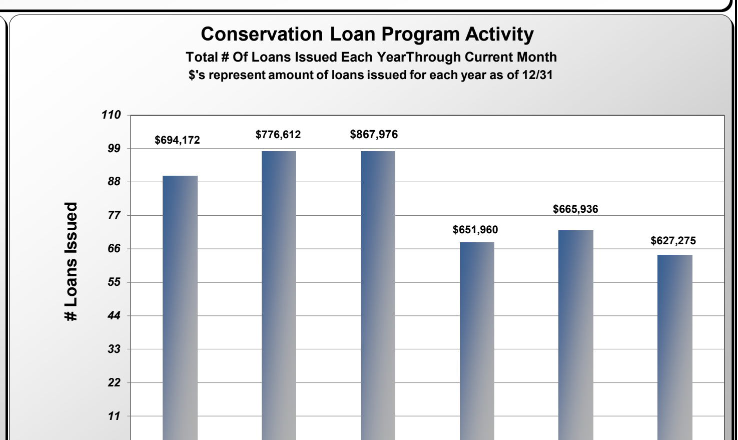
CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY FINANCIAL TREND INFORMATION
December 31, 2021



	Jan 21	Feb 21	Mar 21	Apr 21	May 21	Jun 21	Jul 21	Aug 21	Sep 21	Oct 21	Nov 21	Dec 21	YTD
Facility Fee Financing	70,570	30,870	9,034	108,458	24,159	93,991	103,746	53,478	15,751	42,890	12,357	231,912	797,216
Bond Financing	-	377,684	-	308,782	-	78,614	-	-	577,396	694,836	956,239	1,372,360	4,365,911
Rate Financing	300,297	656,703	421,659	535,341	468,163	488,837	392,000	506,075	533,863	474,938	474,938	474,938	5,727,752
90% of Depreciation	478,500	478,500	478,500	478,500	478,500	478,500	478,500	478,500	474,938	474,938	474,938	474,938	5,727,752

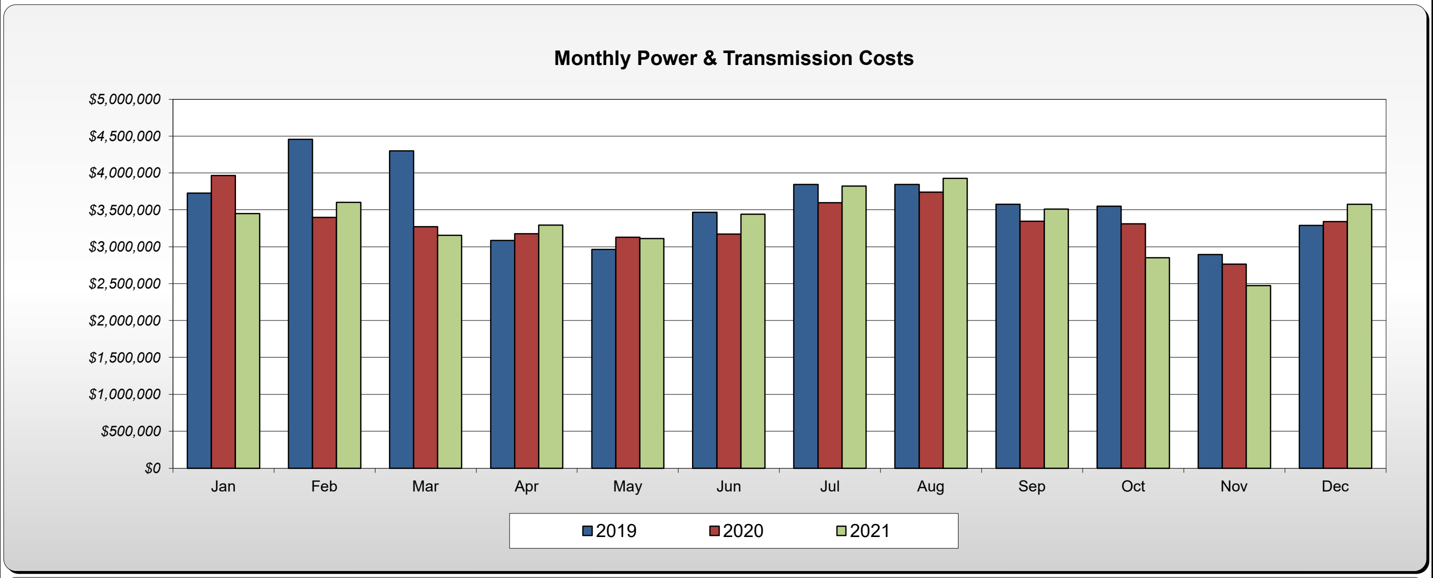


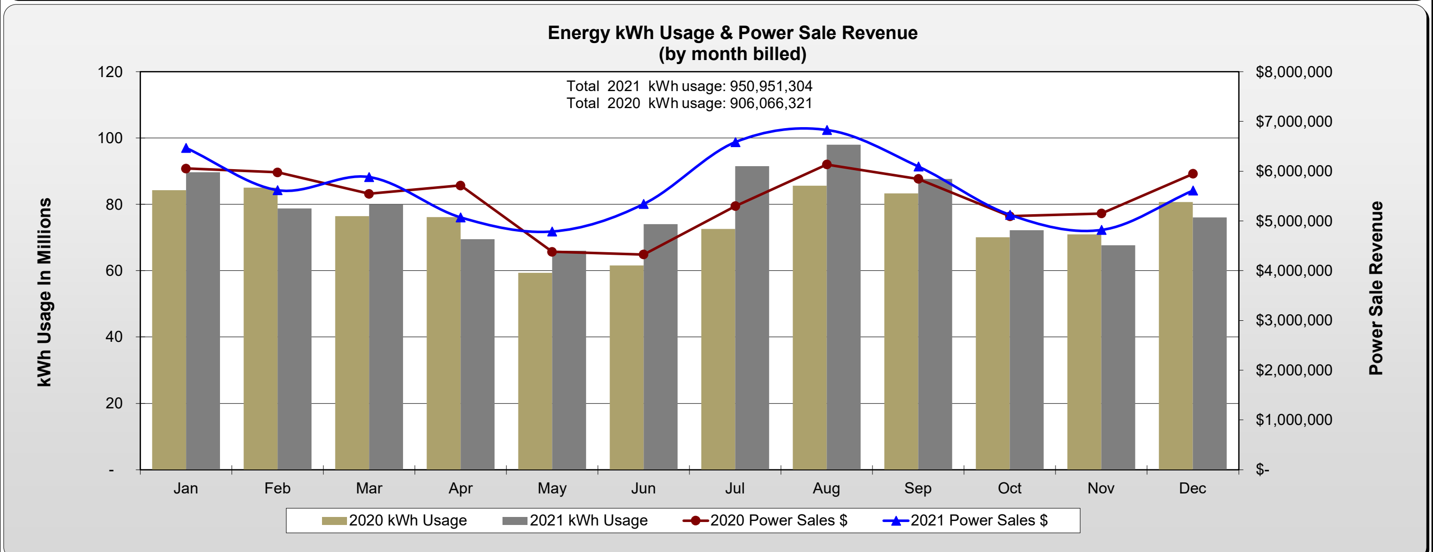


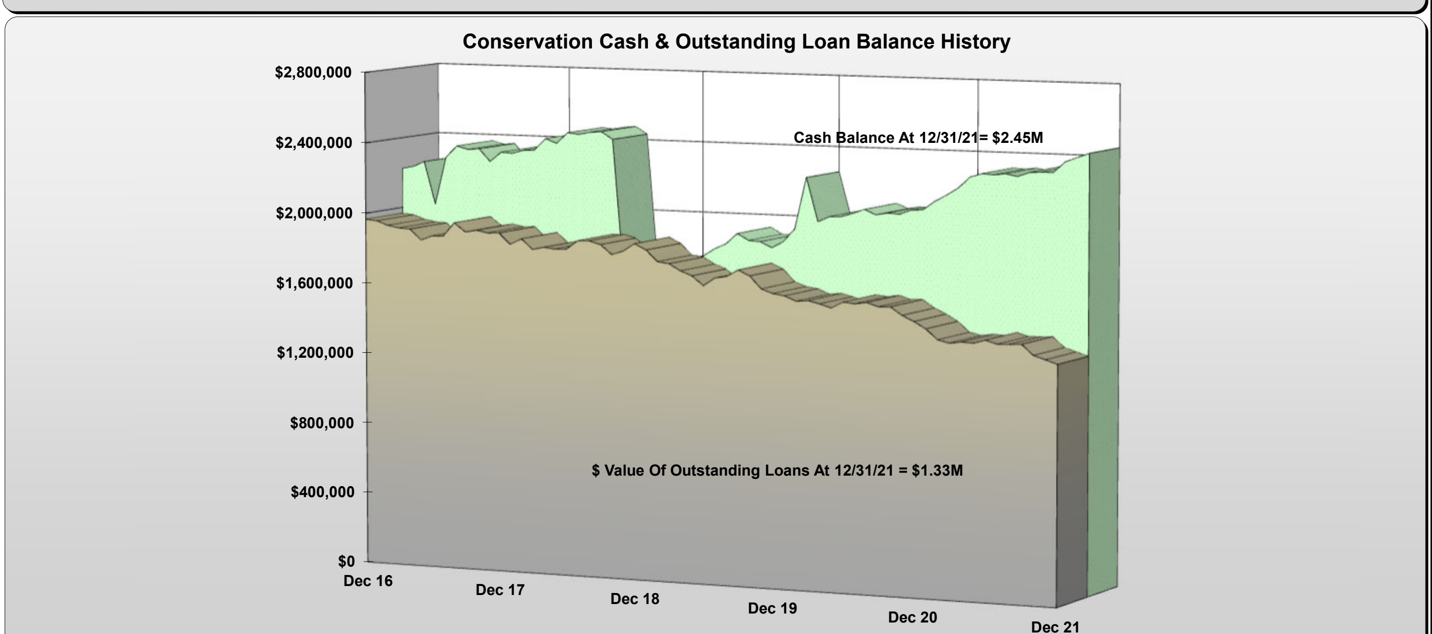


	2016	2017	2018	2019	2020	2021
Heat Pump	64	58	75	54	54	50
Windows	21	36	17	11	15	10
Insulation	5	4	5	3	3	4
Appliance	-	-	1	-	-	-
Total # of Loans	90	98	98	68	72	64

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY FINANCIAL TREND INFORMATION, CONTINUED
December 31, 2021

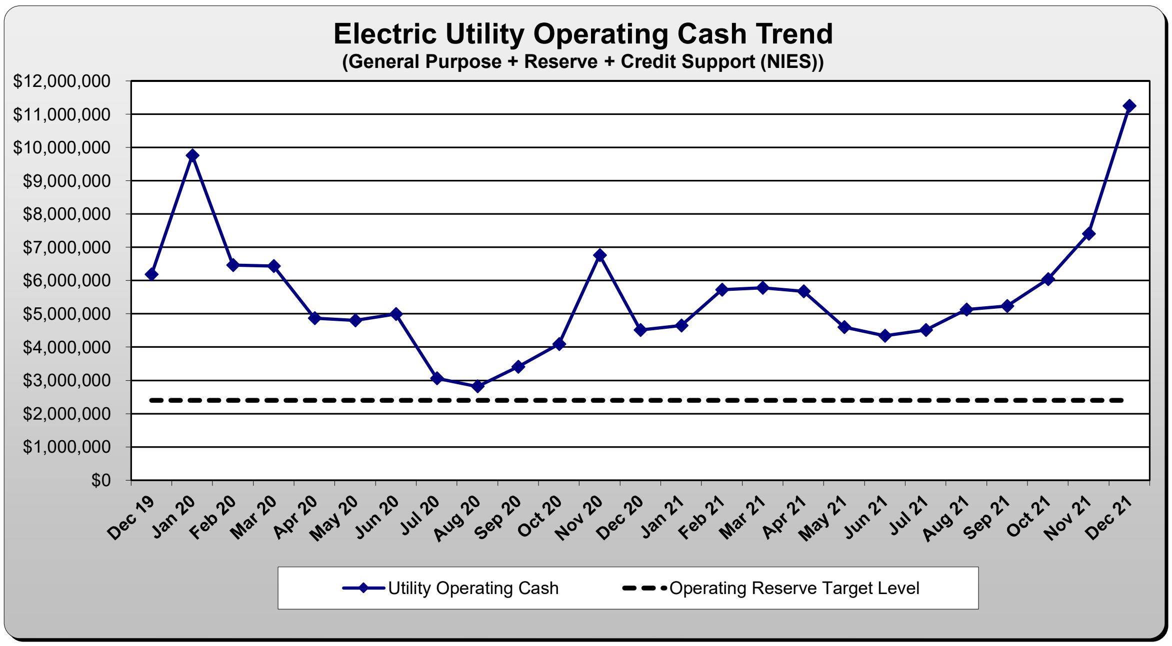


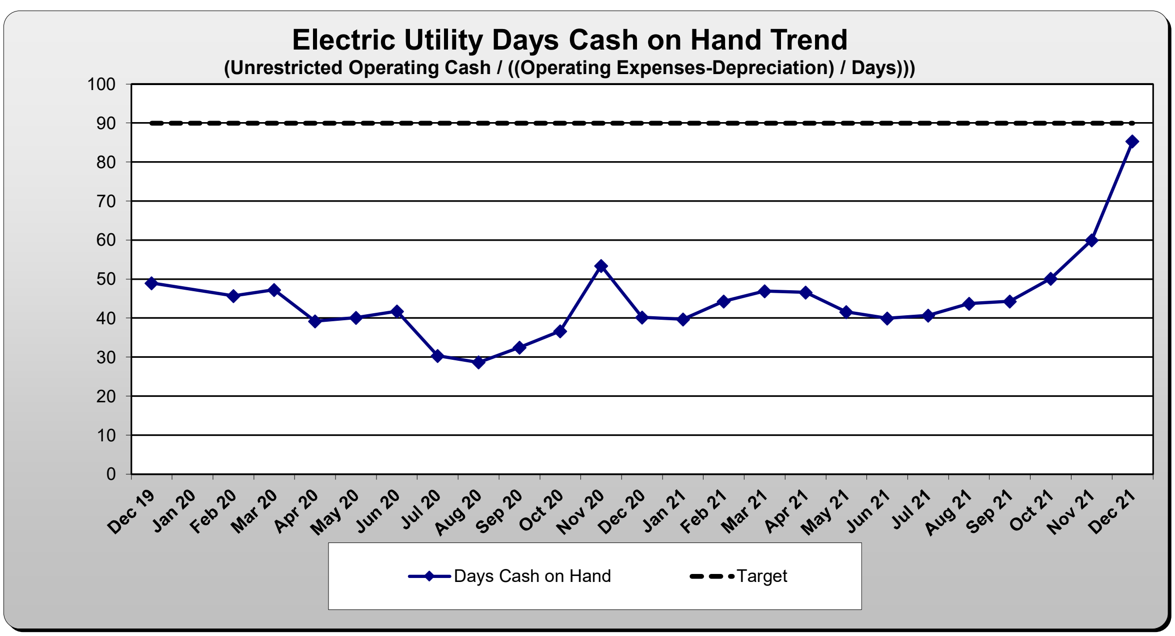




CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
CASH POSITION
December 31, 2021

	December 31, 2021	December 31, 2020
Unrestricted Cash and Investments:		
Operating Cash, General Purpose	$ 8,213,342	$ 1,473,188
Operating Cash, Reserve	2,400,000	2,400,000
Conservation Loan Cash	2,446,847	2,188,104
Credit Support Reserve Cash (NIES)	639,000	639,000
Total Unrestricted Cash and Investments:	13,699,189	6,700,292
Restricted Cash and Investments:		
Revenue Bond Proceeds	8,097,322	5,449,586
Facility Development Fees (Line Extension)	423,684	223,162
Construction Allowances Subject To Refund (Note 1)	640,825	891,642
Bond Redemption Set-Aside	1,168,230	1,148,908
Bond Reserve (Note 12)	5,107,068	4,903,798
Total Restricted Cash and Investments:	15,437,129	12,617,096
Total Cash	$ 29,136,319	$ 19,317,388





CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE BALANCE SHEET
December 31, 2021 and 2020

	2021	2020	2021 - 2020 (+/-)
ASSETS:			
Current Assets			
Cash & Cash Equivalents	$ 13,391,278	$ 5,839,596	$ 7,551,682
Deposits With Third Parties	1,900	1,900	-
Investments	307,911	860,696	(552,785)
Receivables:			
Customer Utility Accounts, (net) (Note 8)	4,734,541	4,746,381	(11,840)
Customer Conservation Loans	1,930,868	2,077,480	(146,612)
Miscellaneous	251,387	71,083	180,304
Prepaid Expenses	290,513	338,028	(47,515)
Inventory	4,864,132	4,468,372	395,760
Total Current Assets	**25,772,530**	**18,403,536**	**7,368,994**
Noncurrent			
Restricted Cash	3,346,715	7,713,298	(4,366,583)
Restricted Investments (Note 12)	12,090,414	4,903,798	7,186,616
Net Pension Asset	4,921,406	-	4,921,406
Capital:			
Land	837,428	837,428	-
Depreciable Assets (net)	1,535,244	728,596	806,648
Infrastructure	115,255,486	110,409,757	4,845,729
Construction in Progress	1,012,900	1,899,284	(886,384)
Total Capital Assets (net)	118,641,058	113,875,065	4,765,994
Total Noncurrent Assets	**138,999,594**	**126,492,161**	**12,507,433**
TOTAL ASSETS	**164,772,124**	**144,895,697**	**19,876,427**
DEFERRED OUTFLOWS OF RESOURCES			
Unamortized Loss - Reacquired Debt (Note 2)	180,775	212,584	(31,809)
Other Deferred Debits (Note 2)	688,162	752,195	(64,033)
Total Deferred Outflows of Resources	**868,937**	**964,779**	**(95,842)**
LIABILITIES:			
Current Liabilities			
Accounts Payable & Accrued Expenses	7,849,646	4,536,996	3,312,650
Due to Other Funds	-	-	-
Current Portion of Compensated Absences	359,155	384,493	(25,338)
Current Portion of Bond Principal Payable	3,260,000	3,120,000	140,000
Total Current Liabilities	**11,468,802**	**8,041,489**	**3,427,312**
Noncurrent Liabilities			
Noncurrent Portion of Compensated Absences	359,155	384,493	(25,338)
Revenue Bonds Payable	74,323,182	70,297,368	4,025,814
Unearned Revenue	766,667	835,717	(69,050)
Net OPEB Liability	968,612	954,207	14,405
Net Pension Liability	344,074	1,954,998	(1,610,924)
Total Noncurrent Liabilities	**76,761,691**	**74,426,783**	**2,334,908**
TOTAL LIABILITIES	**88,230,492**	**82,468,272**	**5,762,220**
DEFERRED INFLOWS OF RESOURCES			
Unamortized Gain - Reacquired Debt (Note 2)	5,216	5,568	(352)
Other Deferred Credits (Note 2)	5,313,803	839,610	4,474,192
Total Deferred Outflows of Resources	**5,319,019**	**845,178**	**4,473,841**
NET POSITION:			
Net Investment in Capital Assets	49,330,757	46,114,299	3,216,458
Restricted For:			
Debt Service	6,275,298	6,052,706	222,592
Capital Improvements	1,064,509	1,114,804	(50,295)
Pension	747,555	-	747,555
Unrestricted	14,673,430	9,265,217	5,408,214
TOTAL NET POSITION	**$ 72,091,550**	**$ 62,547,026**	**$ 9,544,524**

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE STATEMENT OF OPERATIONS
FOURTH QUARTER 2021

	Quarter Ended 12/31/2021 Actual	Quarter Ended 12/31/2020 Actual	% Variance From 2020 Actual
OPERATING REVENUES:			
Power Sales Revenue	$ 15,560,149	$ 16,188,981	-4%
Utility Occupation Tax	1,443,911	1,502,534	-4%
Other Operating Revenues (Note 3)	500,385	608,170	-18%
Total Operating Revenues	17,504,445	18,299,684	-4%
OPERATING EXPENSES:			
Power (Net of BPA REP Lookback Credit) (Note 11)	7,841,595	8,349,317	-6%
Transmission	1,060,598	1,067,202	-1%
Total Purchased Power	8,902,193	9,416,519	-5%
Distribution Operations and Maintenance (O&M)			
Distribution - Operations	1,159,687	676,112	72%
Distribution - Maintenance	399,504	769,872	-48%
Total Distribution O&M	1,559,191	1,445,984	8%
Customer Accounting			
Meter Reading Expense	332,429	338,245	-2%
Customer Records & Collections	136,961	316,211	-57%
Bad Debt Expense (Note 9)	(254,998)	272,109	-194%
Total Customer Accounting	214,392	926,565	-77%
Conservation & Customer Service (Note 10)	484,038	836,233	-42%
Administration & General	(1,488,564)	14,622	-10280%
Depreciation	1,583,128	1,518,741	4%
Taxes	2,091,599	1,858,594	13%
Operating Transfer to Equipment Replacement Fund	188,253	80,231	0%
Other Operating Expenses (Note 4)	1,018	1,732	-41%
Total Non-Power Operating Expenses	4,633,055	6,682,701	-32%
Total Operating Expenses	13,535,248	16,099,220	-16%
OPERATING INCOME (LOSS):	**3,969,197**	**2,200,464**	**80%**
OTHER INCOME:			
Interest Income	12,246	31,461	-61%
Gain / (Loss) on Fair Market Value (FMV) Adjustment	(182,044)	(59,671)	-205%
Other Income (Note 5)	548,097	323,498	69%
City Shops Rental	-	-	NA
Total Other Income:	378,299	295,288	**28%**
OTHER EXPENSE:			
Interest on Long-Term Debt	730,056	743,665	-2%
Debt Issuance Expense	179,888	-	NA
Amortization of Bond Discount / Premium	(72,945)	(69,108)	-6%
Amortization of Loss on Reacquired Debt	7,864	7,864	0%
Other Expenses (Note 6)	493,963	187,495	163%
Total Other Expense:	1,338,827	869,916	54%
NET INCOME (LOSS) BEFORE CAPITAL CONTRIBUTIONS AND TRANSFERS	**3,008,669**	**1,625,835**	**85%**
Capital Contributions - Facility Development Fees (Note 7)	568,733	639,499	-11%
Transfers From General Fund	-	-	NA
Transfers To Broadband Fund (Note 13)	(7,500)	(7,500)	0%
Total of Capital Contributions and Transfers to Other Funds	561,233	631,999	-11%
CHANGE IN NET POSITION BEFORE PRIOR PERIOD ADJUSTMENTS	**3,569,902**	**2,257,834**	**58%**
Prior Period Adjustments	-	-	
CHANGE IN NET POSITION	**$ 3,569,902**	**$ 2,257,834**	**58%**

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE STATEMENT OF OPERATIONS
December 31, 2021

	12/31/2021 Actual	12/31/2020 Actual	% Variance From 2020 Actual
OPERATING REVENUES:			
Power Sales Revenue	$ 68,255,563	$ 65,459,120	4%
Utility Occupation Tax	6,333,763	6,076,466	4%
Other Operating Revenues (Note 3)	1,793,744	2,004,894	-11%
Total Operating Revenues	76,383,071	73,540,481	4%
OPERATING EXPENSES:			
Power (Net of BPA REP Lookback Credit) (Note 11)	35,674,313	35,663,168	0%
Transmission	4,538,139	4,550,248	0%
Total Purchased Power	40,212,452	40,213,416	0%
Distribution Operations and Maintenance (O&M)			
Distribution - Operations	3,869,806	3,510,490	10%
Distribution - Maintenance	1,036,573	2,869,150	-64%
Total Distribution O&M	4,906,379	6,379,640	-23%
Customer Accounting			
Meter Reading Expense	988,081	882,994	12%
Customer Records & Collections	1,220,812	1,181,514	3%
Bad Debt Expense (Note 9)	(164,728)	365,259	-145%
Total Customer Accounting	2,044,165	2,429,766	-16%
Conservation & Customer Service (Note 10)	1,300,265	1,396,233	-7%
Administration & General	423,023	1,963,602	-78%
Depreciation	6,358,130	6,114,666	4%
Taxes	8,946,719	8,348,663	7%
Operating Transfer to Equipment Replacement Fund	753,014	320,922	135%
Other Operating Expenses (Note 4)	4,758	6,163	-23%
Total Non-Power Operating Expenses	24,736,453	26,959,654	-8%
Total Operating Expenses	64,948,904	67,173,070	-3%
OPERATING INCOME (LOSS):	**11,434,166**	**6,367,411**	**80%**
OTHER INCOME:			
Interest Income	84,904	265,409	-68%
Gain / (Loss) on Fair Market Value (FMV) Adjustment	(182,044)	(59,671)	-205%
Other Income (Note 5)	1,095,510	976,195	12%
City Shops Rental	-	-	NA
Total Other Income:	998,369	1,181,933	**-16%**
OTHER EXPENSE:			
Interest on Long-Term Debt	2,932,258	3,055,031	-4%
Debt Issuance Expense	179,888	-	NA
Amortization of Bond Discount / Premium	(280,269)	(276,432)	-1%
Amortization of Loss on Reacquired Debt	31,458	31,458	0%
Other Expenses (Note 6)	1,156,227	863,890	34%
Total Other Expense:	4,019,561	3,673,946	9%
NET INCOME (LOSS) BEFORE CAPITAL CONTRIBUTIONS AND TRANSFERS	**8,412,974**	**3,875,397**	**117%**
Capital Contributions - Facility Development Fees (Note 7)	1,161,550	1,199,067	-3%
Transfers From General Fund	-	-	NA
Transfers To Broadband Fund (Note 13)	(30,000)	(30,000)	0%
Total of Capital Contributions and Transfers to Other Funds	1,131,550	1,169,067	-3%
CHANGE IN NET POSITION BEFORE PRIOR PERIOD ADJUSTMENTS	**9,544,524**	**5,044,465**	**89%**
Prior Period Adjustments	-	-	
CHANGE IN NET POSITION	**$ 9,544,524**	**$ 5,044,465**	**89%**

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
MONTHLY STATEMENT OF OPERATIONS
CY 2021 ACTUAL

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
OPERATING REVENUES:													
Power Sales Revenue	$ 6,473,488	$ 5,620,098	$ 5,882,312	$ 5,073,893	$ 4,790,098	$ 5,340,856	$ 6,585,227	$ 6,833,143	$ 6,096,298	$ 5,127,333	$ 4,821,601	$ 5,611,216	$ 68,255,563
Utility Occupation Tax	600,838	521,562	545,920	469,919	444,716	495,573	611,298	634,248	565,777	475,786	447,387	520,738	6,333,763
Other Operating Revenues (Note 3)	137,953	126,618	138,937	76,623	64,027	135,857	66,771	226,850	319,723	134,193	110,694	255,498	1,793,744
Total Operating Revenues	**7,212,279**	**6,268,278**	**6,567,169**	**5,620,435**	**5,298,842**	**5,972,286**	**7,263,297**	**7,694,241**	**6,981,799**	**5,737,312**	**5,379,683**	**6,387,451**	**76,383,071**
OPERATING EXPENSES:													
Power (Net of BPA REP Lookback Credit) (Note 11)	3,081,575	3,199,032	2,849,600	2,999,873	2,795,198	2,979,569	3,355,986	3,462,039	3,109,845	2,528,119	2,138,338	3,175,138	35,674,313
Transmission	368,918	403,071	306,878	292,776	316,430	461,645	464,321	462,854	400,648	323,435	335,991	401,172	4,538,139
Total Purchased Power	3,450,493	3,602,103	3,156,478	3,292,649	3,111,628	3,441,214	3,820,307	3,924,893	3,510,493	2,851,554	2,474,329	3,576,310	40,212,452
Distribution Operations and Maintenance (O&M)													
Distribution - Operations	354,389	376,066	326,712	363,045	288,360	259,775	218,406	238,647	284,718	255,811	235,206	668,671	3,869,806
Distribution - Maintenance	32,857	63,142	44,280	97,645	38,107	53,911	63,595	88,589	154,942	103,123	79,749	216,632	1,036,573
Total Distribution O&M	387,247	439,208	370,992	460,690	326,467	313,686	282,001	327,237	439,661	358,934	314,954	885,302	4,906,379
Customer Accounting													
Meter Reading Expense	80,803	74,533	76,507	104,113	68,587	63,657	78,036	49,071	60,345	49,760	56,492	226,177	988,081
Customer Records & Collections	119,855	120,222	119,806	119,976	119,824	121,017	120,709	122,070	120,372	120,329	(143,394)	160,026	1,220,812
Bad Debt Expense (Note 9)	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	(275,058)	(164,728)
Total Customer Accounting	210,688	204,786	206,344	234,120	198,441	194,704	208,774	181,171	190,746	180,119	(76,873)	111,145	2,044,165
Conservation & Customer Service (Note 10)	35,977	46,490	76,325	92,308	58,202	85,323	65,958	217,843	137,802	163,471	64,058	256,509	1,300,265
Administration & General	349,608	192,906	184,742	210,052	180,788	180,908	202,188	188,060	222,336	192,198	80,544	(1,761,306)	423,023
Depreciation	531,667	531,667	531,667	531,667	530,157	530,157	530,157	530,157	527,709	527,709	527,709	527,709	6,358,130
Taxes	871,262	759,528	790,967	678,828	642,007	715,596	883,484	901,173	612,275	688,191	647,332	756,076	8,946,719
Operating Transfer to Equipment Replacement Fund	62,751	62,751	62,751	62,751	62,751	62,751	62,751	62,751	62,751	62,751	62,751	62,751	753,014
Other Operating Expenses (Note 4)	754	-	1,124	310	-	584	343	-	625	263	-	755	4,758
Total Non-Power Operating Expenses	2,449,953	2,237,337	2,224,911	2,270,724	1,998,811	2,083,708	2,235,657	2,408,391	2,193,905	2,173,636	1,620,477	838,942	24,736,453
Total Operating Expenses	**5,900,446**	**5,839,439**	**5,381,390**	**5,563,374**	**5,110,439**	**5,524,922**	**6,055,964**	**6,333,284**	**5,704,398**	**5,025,190**	**4,094,806**	**4,415,251**	**64,948,904**
OPERATING INCOME (LOSS):	**1,311,833**	**428,838**	**1,185,779**	**57,061**	**188,403**	**447,364**	**1,207,333**	**1,360,957**	**1,277,400**	**712,121**	**1,284,876**	**1,972,199**	**11,434,166**
OTHER INCOME :													
Interest Income	12,583	11,428	8,814	5,384	3,432	5,818	10,947	5,075	9,177	4,452	2,529	5,265	84,904
Gain / (Loss) on Fair Market Value (FMV) Adjustment	-	-	-	-	-	-	-	-	-	-	-	(182,044)	(182,044)
Other Income (Note 5)	37,686	58,029	87,923	37,255	66,386	52,428	57,121	59,831	90,754	98,043	53,847	396,207	1,095,510
City Shops Rental	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Income	**50,269**	**69,458**	**96,737**	**42,639**	**69,818**	**58,247**	**68,068**	**64,906**	**99,930**	**102,495**	**56,376**	**219,428**	**998,369**
OTHER EXPENSE :													
Interest on Long-Term Debt	244,689	244,689	244,689	244,689	244,689	244,689	244,689	244,689	244,689	244,689	233,568	251,798	2,932,258
Debt Issuance Expense	-	-	-	-	-	-	-	-	-	-	-	179,888	179,888
Amortization of Bond Discount / Premium	(23,036)	(23,036)	(23,036)	(23,036)	(23,036)	(23,036)	(23,036)	(23,036)	(23,036)	(23,036)	(23,036)	(26,873)	(280,269)
Amortization of Loss on Reacquired Debt	2,621	2,621	2,621	2,621	2,621	2,621	2,621	2,621	2,621	2,621	2,621	2,621	31,458
Other Expenses (Note 6)	57,012	68,198	70,066	96,792	75,365	70,947	61,701	66,532	95,650	74,070	71,173	348,721	1,156,227
Total Other Expense:	**281,287**	**292,473**	**294,341**	**321,067**	**299,640**	**295,221**	**285,976**	**290,806**	**319,925**	**298,344**	**284,326**	**756,156**	**4,019,561**
NET INCOME (LOSS) BEFORE CAPITAL CONTRIBUTIONS AND TRANSFERS	**1,080,815**	**205,824**	**988,175**	**(221,367)**	**(41,419)**	**210,390**	**989,425**	**1,135,056**	**1,057,406**	**516,272**	**1,056,926**	**1,435,471**	**8,412,974**
Capital Contributions - Facility Development Fees (Note 7)	2,397	178,874	51,656	7,482	105,412	109,014	113,130	9,359	15,492	41,064	6,146	521,523.35	1,161,550
Transfers To Broadband Fund (Note 13)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(30,000)
Total of Capital Contributions and Transfers to Other Funds	(103)	176,374	49,156	4,982	102,912	106,514	110,630	6,859	12,992	38,564	3,646	519,023	**1,131,550**
CHANGE IN NET POSITION BEFORE PRIOR PERIOD ADJUSTMENTS	**1,080,712**	**382,197**	**1,037,332**	**(216,385)**	**61,494**	**316,904**	**1,100,055**	**1,141,915**	**1,070,398**	**554,837**	**1,060,572**	**1,954,494**	**9,544,524**
Prior Period Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
CHANGE IN NET POSITION	**$ 1,080,712**	**$ 382,197**	**$ 1,037,332**	**$ (216,385)**	**$ 61,494**	**$ 316,904**	**$ 1,100,055**	**$ 1,141,915**	**$ 1,070,398**	**$ 554,837**	**$ 1,060,572**	**$ 1,954,494**	**$ 9,544,524**

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
STATEMENT OF CASH FLOWS
December 31, 2021

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Year To Date
Cash Flows From Operating Activities													
Receipts from power sales to customers	$ 6,462,635	$ 6,671,140	$ 6,891,866	$ 5,967,208	$ 5,310,770	$ 5,453,874	$ 6,312,958	$ 7,224,509	$ 6,648,560	$ 6,709,572	$ 5,645,845	$ 5,478,064	$ 74,777,001
Other operating cash receipts	(149,180)	293,932	181,551	207,063	95,247	168,486	226,407	159,592	329,214	571,342	88,729	134,825	2,307,208
Receipts from interfund rents and services	-	-	-	-	-	-	-	-	-	-	-	-	-
Other cash payments	-	-	-	-	-	-	-	-	-	-	-	-	-
Payments for power	(2,913,341)	(2,905,294)	(3,257,047)	(2,832,979)	(3,012,161)	(2,812,251)	(2,961,541)	(3,352,897)	(3,453,596)	(3,064,845)	(2,515,398)	(171,013)	(33,252,364)
Payment for transmission	(415,225)	(415,225)	(403,071)	(306,878)	(292,776)	(316,430)	(461,645)	(464,321)	(462,854)	(400,648)	(323,435)	-	(4,262,508)
Payments to suppliers	(1,024,221)	(426,979)	(1,550,085)	(1,171,730)	(1,446,385)	(897,148)	(1,025,249)	(958,227)	(924,881)	(1,170,759)	(372,502)	80,065	(10,888,101)
Payments for utility tax	(601,318)	(522,041)	(546,400)	(471,224)	(444,959)	(496,096)	(611,705)	(634,728)	(566,276)	(476,265)	(447,864)	(521,216)	(6,340,093)
Payments to employees	(86,463)	(86,512)	(39,578)	(159,516)	(58,823)	(58,597)	(84,518)	(44,970)	(147,646)	(40,552)	(119,326)	(91,839)	(1,018,340)
Payments for interfund services	(299,607)	(288,721)	(279,982)	(303,413)	(265,490)	(298,603)	(284,730)	(298,820)	(296,337)	(284,051)	409,711	33,637	(2,456,406)
Net Cash Provided (Used) by Operating Activities	**973,280**	**2,320,300**	**997,254**	**928,531**	**(114,577)**	**743,235**	**1,109,978**	**1,630,137**	**1,126,184**	**1,843,793**	**2,365,761**	**4,942,523**	**18,866,397**
Cash Flows From Noncapital Financing Activities													
Interfund Loan Repayments Received	-	-	-	-	-	-	-	-	-	-	-	-	-
Transfer (to) / from Broadband Fund (Note 13)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(30,000)
Transfer (to) / from General Fund (Note 13)	-	-	-	-	-	-	-	-	-	-	-	-	-
Transfer (to) / from Industrial Development (Note 13)	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Used by Noncapital Financing Activities	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(30,000)**
Cash Flows From Capital and Related Financing Activities													
Proceeds from Issuance of Debt	-	-	-	-	-	-	-	-	-	-	65,000	7,501,084	7,566,084
Bond Issuance costs (Paid) Refunded	-	-	-	-	-	-	-	-	-	-	-	(179,888)	(179,888)
Principal Paid on Long-Term Debt	-	-	-	-	-	-	-	-	-	-	(3,120,000)	-	(3,120,000)
Interest Paid on Long-Term Debt	-	-	-	-	(1,468,135)	-	-	-	-	-	(1,468,135)	-	(2,936,269)
Capital Contributions	2,397	178,874	51,656	7,482	97,612	109,014	113,130	9,359	15,492	41,064	6,146	288,278	920,505
Deferred Capital Contributions	-	36,600	-	-	-	24,600	32,400	-	-	-	-	63,000	156,600
Capital Contributions Refunded	-	-	-	-	(212,816)	-	-	-	-	-	-	-	(212,816)
Sale of Land	-	-	-	-	-	-	-	-	9,583	-	-	-	9,583
Acquisition and Construction of Capital Assets	(370,867)	(1,065,257)	(430,694)	(952,581)	(492,322)	(661,442)	(495,746)	(559,553)	(1,127,010)	(1,212,664)	(1,443,534)	(2,312,455)	(11,124,124)
Net Cash Provided (Used) by Capital and Related Financing Activities	**(368,470)**	**(849,783)**	**(379,037)**	**(945,099)**	**(2,075,661)**	**(527,828)**	**(350,216)**	**(550,194)**	**(1,101,934)**	**(1,171,600)**	**(5,960,523)**	**5,360,019**	**(8,920,326)**
Cash Flows From Investing Activities													
Interest Received on Investments	12,583	11,428	8,814	5,384	3,432	5,818	10,947	5,075	9,177	4,452	2,529	5,265	84,904
Premium Received on Investments	-	-	-	-	-	-	-	-	-	-	-	-	-
Investments Sold *	5,764,493	-	-	-	-	-	-	-	-	-	-	(64,762)	5,699,732
Investments Purchased *	-	-	-	-	-	-	-	-	-	-	-	(12,515,608)	(12,515,608)
Net Cash Provided (Used) by Investing Activities	**5,777,077**	**11,428**	**8,814**	**5,384**	**3,432**	**5,818**	**10,947**	**5,075**	**9,177**	**4,452**	**2,529**	**(12,575,104)**	**(6,730,972)**
Net Change in Cash and Cash Equivalents	**6,379,386**	**1,479,445**	**624,531**	**(13,684)**	**(2,189,306)**	**218,726**	**768,209**	**1,082,517**	**30,927**	**674,145**	**(3,594,734)**	**(2,275,063)**	**3,185,099**
Cash and Cash Equivalents at Beginning of Period	**13,552,895**	**19,932,281**	**21,411,726**	**22,036,257**	**22,022,572**	**19,833,267**	**20,051,992**	**20,820,201**	**21,902,718**	**21,933,645**	**22,607,790**	**19,013,057**	**13,552,895**
Cash and Cash Equivalents at End of Period	**$ 19,932,281**	**$ 21,411,726**	**$ 22,036,257**	**$ 22,022,572**	**$ 19,833,267**	**$ 20,051,992**	**$ 20,820,201**	**$ 21,902,718**	**$ 21,933,645**	**$ 22,607,790**	**19,013,057**	**16,737,994**	**$ 16,737,994**
Reconciliation of Operating Income to Net Cash Provided (Used) by Operating Activities													
Net Operating Income	$ 1,311,833	$ 428,838	$ 1,185,779	$ 57,061	$ 188,403	$ 447,364	$ 1,207,333	$ 1,360,957	$ 1,277,400	$ 712,121	$ 1,284,876	$ 1,972,199	$ 11,434,166
Adjustments to reconcile net operating income to net cash provided by operating activities:													
Depreciation & Amortization	531,667	531,667	531,667	531,667	530,157	530,157	530,157	530,157	527,709	527,709	527,709	527,709	6,358,130
Accrued Pension Expense	-	-	-	-	-	-	-	-	-	-	-	(1,979,699)	(1,979,699)
Other Income, Net	(19,327)	(10,169)	17,857	(59,538)	(8,979)	(18,518)	(4,581)	(6,701)	(14,480)	23,974	(17,325)	280,731	162,944
Changes in operating assets and liabilities:													
(Increase) / Decrease in Receivables	(683,232)	672,849	379,927	532,494	38,464	(474,724)	(802,470)	(362,145)	(105,875)	1,476,394	334,082	(1,027,615)	(21,852)
(Increase) / Decrease in Inventory	87,569	93,850	81,900	(503,955)	(195,265)	(35,498)	(186,762)	122,288	(12,301)	16,650	29,617	106,146	(395,760)
(Increase) / Decrease in Prepaid Expenses	(159,597)	5,635	29,911	16,099	2,069	10,867	21,331	15,727	15,520	15,099	43,023	31,831	47,515
Increase / (Decrease) in Power & Transmission AP	129,799	155,035	(507,081)	155,215	(186,253)	334,818	373,871	104,586	(405,894)	(664,543)	(353,450)	3,374,554	2,510,657
Increase / (Decrease) in Accounts Payable	(113,763)	543,730	(617,101)	354,311	(364,464)	80,852	140,879	(36,744)	17,733	(148,830)	378,733	555,970	791,307
Increase / (Decrease) in Accrued Wages	(13,847)	560	-	-	-	-	-	-	-	(2,198)	-	(20,492)	(35,978)
Increase / (Decrease) in Unearned Facility Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
Increase / (Decrease) in Prepaid Leases	-	-	-	-	-	-	-	-	-	-	-	(5,034)	(5,034)
(Increase) in Expired Construction Allowances (Note 1)	-	-	-	-	-	-	-	-	-	-	-	-	-
(Increase) / Decrease in Deferred Charges	(97,823)	(101,695)	(105,604)	(154,823)	(118,709)	(132,083)	(169,780)	(97,987)	(173,630)	(112,583)	138,495	1,126,222	(0)
Prior Period Adjustments	-	-	-	-	-	-	-	-	-	-	-	- -	-
Net Cash Provided (Used) by Operating Activities	**$ 973,280**	**$ 2,320,300**	**$ 997,254**	**$ 928,531**	**$ (114,577)**	**$ 743,235**	**$ 1,109,978**	**$ 1,630,137**	**$ 1,126,184**	**$ 1,843,793**	**$ 2,365,761**	**$ 4,942,523**	**$ 18,866,397**
Contribution of Capital Assets	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 233,245**	**$ 233,245**

* The Electric Utility's cash is invested along with the City's cash in pooled investments. Pooled cash and investments are maintained in a separate fund for investment and are shown in individual funds as purchased on December 31 and sold on January 1.
The rest of the year pooled cash and investments are shown as a component of cash and cash equivalents on interim cash flow statements.

1. The construction allowance is the portion of line extension costs paid for by the Utility, assuming the expected number of permanent connections to the system result. The developer bears the full cost of the line extension up front, and the Utility pays its portion by refunding the developer based on the number of permanent connections to the line extension over a five-year period.

   The refundable portion of fees collected is a deposit to guarantee connections to the line extension. Deposits are not characterized as revenue. Instead, a Deferred Revenue: Facility Fee Deposits account is included in the liability section of the balance sheet to offset the cash balance of these potentially refundable amounts. Five years from the date the line extension is energized, unused deposits expire and are recognized as revenue.

   Year-to-date facility fees collected from customers totaled $1,077,105 of which $920,505 was recognized as revenue and $156,600 represents refundable construction allowances recorded as unearned revenue.

2. Deferred outflows of resources represent expenses of the Utility that apply to future periods. The primary purpose of the deferred outflow of resources accounts is to accumulate expenditures that are to be recognized in future periods or allocated to more than one account number. Deferred outflow of resources includes unamortized loss on reacquired bond debt. Other Deferred Debits includes clearing accounts that are used to hold warehousing, overhead, and equipment costs pending final allocation.

   GASB Statement 68, *Accounting and Financial Reporting for Pensions*, requires reporting the fund's proportionate share the State's retirement plan net pension assets and liabilities. Other Deferred Debits also includes contributions after the State retirement plan measurement date and Other Deferred Credits include the net difference between projected and actual investments earnings on pension plan investments.

3. Other Operating Revenue includes the items listed below, with year-to-date comparisons to the prior year.

Other Operating Revenue YTD Through:	December 2021	December 2020	Difference
Permanent Service Fees	$ 275,848	$ 262,275	$ 13,574
New Account Fees	84,735	85,695	(960)
Rewire / Charges to Repair Damage	38,511	63,059	(24,548)
Delinquent Account Fees	(3,765)	56,699	(60,464)
Disconnect Fees	1,650	50,092	(48,442)
Pole Contracts	100,864	100,864	-
BPA - Conservation Program (EEI)	1,162,398	692,908	469,490
COVID Assistance	-	519,127	(519,127)
Other	133,503	174,176	(40,673)
Total Other Operating Revenue	$ 1,793,744	$ 2,004,894	$ (211,150)

4. Other Operating Expenses as reported on the Comparative Statement of Operations consist of power costs paid to Benton PUD for three customer accounts provided power through the Benton PUD system.

5. Other Income as reported on the Comparative Statement of Operations includes Federal interest subsidies received relative to 2009 Build America Bonds issued as well as the following revenue sources:

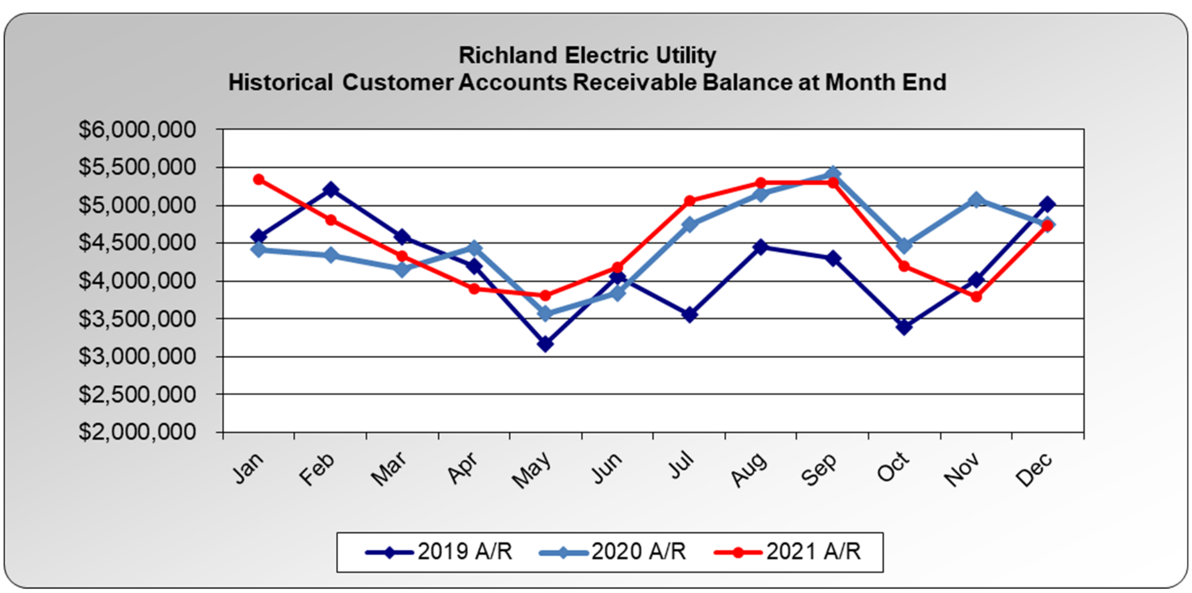
Other Income YTD Through:	December 2021	December 2020	Difference
Interest Collected on Conservation Loan Payments	$ 45,934	$ 51,894	$ (5,960)
BPA - Conservation Admin Fee	233,844	158,640	75,204
Meter Reading Revenue	253,874	244,374	9,500
Work Performed for City Departments	539,649	494,482	45,167
Gain / (Loss) on Land sales and Disposition of Assets	17,174	20,825	(3,650)
Other	5,034	5,981	(947)
Total Other Income	$ 1,095,510	$ 976,195	$ 119,314

Other Income also includes revenues allocated to the Electric Utility for its share of Horn Rapids Industrial Park sale proceeds. In 1982, work was undertaken by the City to develop the Horn Rapids Industrial Park, Phase One. Proceeds from the sale of land at Horn Rapids Industrial Park are allocated to City Utility Funds from the Industrial Development Fund based on each utility's proportionate share of total improvement costs. The remaining maximum reimbursement due to the Electric Utility, contingent upon sale of Horn Rapids Industrial Park Phase One property as of December 2021 is $145,377.

6. The Other Expenses reported on the Comparative Statement of Operations includes the cost of Non-Electric Utility Operations work. Some of the Non-Utility Operations costs are those charged to other City departments through the Interdepartmental Billing (IDB) process.

7. The Electric Utility recognized $333,743 in facility development fee revenue (capital contributions) in the fourth quarter of 2021. According to Governmental Accounting Standard Board (GASB) Statement No. 33, capital contributions from external sources are to be recognized as revenue in the current year rather than as a direct increase to contributed capital. Year-to-date facility development fee revenue of $928,305 is comprised of $920,505 fees paid during the year and $7,800 of expired refundable construction allowances.

8. The outstanding utility accounts receivable balance, net of allowance for doubtful accounts on December 31, 2021, is $4,734,541. This represents a $569,904 decrease from the previous quarter. The following graph presents month-end customer accounts receivable balances during the last three calendar years.



Write-offs, recoveries, and accounts receivable balances for the year-to-date, with prior year comparisons are as follows:

Accounts Receivable YTD Through:	December 2021	December 2020	Difference
Write-Offs	$ 3,900	$ 216,422	$ (212,522)
Recoveries	6,793	12,573	(5,780)
Balance	$ 4,734,541	$ 4,746,381	$ (11,840)

9. Customer Accounting Expense includes bad debt expense. Customer accounts receivable are written off using the allowance method as prescribed by generally accepted accounting principles. Under this method, the projected uncollectible portion of customer accounts receivable is presented on the balance sheet based on a study of prior years' actual write-offs. Uncollectible accounts are written off against this estimated allowance rather than to bad debt expense. The monthly expense is 1/12 of the estimated annual allowance. Periodically, actual write-offs as a percentage of billings are analyzed, and the allowance is adjusted with an offset to bad debts expense, or the monthly entry may be suspended if the allowance becomes too high.

10. Conservation expenses may vary greatly from month-to-month and from budgeted amounts, as expenses for conservation supplies, educational materials, and payment of incentives to customers do not follow a regular schedule. In the third quarter of 2021, a total of $522,225 was spent on ductless heat pumps, windows, insulation, and commercial conservation programs. Year-to-date expenses on conservation measures total $1,140,243.

11. In 2008, the Electric Utility received Residential Exchange Program (REP) payments totaling $3,662,901 from the Bonneville Power Administration (BPA) as part of a return to public utilities of wholesale power overcharges during fiscal years 2007-2008. An additional payment of $204,686 was received in November 2009. Between May 2009 and June 2010, $3,740,631 of the proceeds were utilized to reduce customers' bills through a monthly billing credit program. Due to the nature of the billing schedule and billing software design, an exact cutoff of the credit sufficient to bring the balance to zero was not possible.

    In addition to the above payments, BPA applies a "look-back" credit to Richland's monthly wholesale power bills. This is a return of overcharges related to the REP program in years prior to 2007. These billing credits reimburse for overcharges during fiscal years 2001-2006. Following recent industry negotiations, the monthly credit changed from $98,575 to $98,427 and should remain at this level through September 2020. The related settlement agreement resolves issues associated with overcharge reimbursement while limiting the amount of REP payments to Investor-Owned Utilities (IOUs). The look-back credit is reported as a net of purchased power to be consistent.

12. Bond ordinances require either maintenance of a cash Bond Reserve or purchase of bond insurance with an AAA rated provider to ensure debt is serviced in the event of financial hardship. The utility has historically purchased bond sureties to fulfill this requirement. However, due to the current economic climate, none of the surety companies currently enjoy an AAA rating. As a result, the utility funded a Bond Reserve, in 2008, in order to stay in compliance until the bond surety companies' ratings recover. The bond reserve was initially funded using $993,000 in Facility Fee cash and $2,111,575 in unrestricted cash. The amount of the bond reserve is adjusted annually and when additional debt is issued.

13. Monthly transfers to the Broadband Fund are presented in the financial statements as non-operating transfers to other funds.

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE MONTHLY ENERGY ACTIVITY
FOR THE PERIOD ENDED
December 2021

REVENUES: (Net of Utility Tax)	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total To Date	Budget	Variance	% Budget Variance
Residential	$ 3,761,665	$ 2,864,479	$ 3,265,811	$ 2,338,960	$ 2,031,979	$ 2,404,994	$ 3,228,776	$ 3,239,269	$ 2,700,645	$ 2,112,319	$ 2,015,751	$ 2,812,047	$ 32,776,694	$ 32,613,204	$ 163,489	1%
Small General Service	583,604	576,952	540,718	515,153	482,187	517,776	623,190	659,065	604,925	503,472	479,387	520,678	6,607,107	6,760,495	(153,388)	-2%
Medium General Service	689,999	704,988	702,976	678,407	649,788	701,679	810,035	897,596	859,304	754,921	698,685	752,236	8,900,616	9,731,894	(831,278)	-9%
Large General Service	665,438	696,763	630,003	700,259	682,778	713,443	789,152	826,852	776,207	694,453	645,822	663,602	8,484,772	10,173,364	(1,688,591)	-17%
Small Industrial	262,210	260,928	268,429	258,628	316,457	323,361	347,085	369,314	355,641	373,747	338,985	326,703	3,801,487	1,641,049	2,160,438	132%
Large Industrial	455,887	466,992	424,887	473,449	453,666	462,991	485,328	495,106	507,290	457,583	486,864	470,566	5,640,609	6,465,547	(824,938)	-13%
Small Irrigation	1,144	695	937	19,386	12,756	6,914	16,421	19,053	19,357	16,403	11,138	2,959	127,164	146,623	(19,459)	-13%
Large Irrigation	2,357	2,277	(930)	41,376	110,941	160,762	235,783	276,982	224,019	163,725	95,770	10,831	1,323,894	1,255,232	68,662	5%
Cable TV Amp	5,620	5,620	5,620	5,620	5,620	5,620	5,620	5,620	5,620	5,620	5,620	5,620	67,446	52,744	14,701	28%
Street Lighting	31,537	27,282	30,197	29,306	30,346	29,367	30,346	30,422	29,462	30,749	29,896	30,892	359,798	350,211	9,588	3%
Rental Lighting	10,499	9,384	10,141	10,183	10,408	10,856	10,462	10,906	10,568	11,079	10,326	11,601	126,413	126,863	(450)	0%
Traffic Lights	3,529	3,738	3,522	3,166	3,171	3,093	3,029	2,957	3,261	3,262	3,356	3,480	39,562	42,801	(3,239)	-8%
TOTAL REVENUES	$ 6,473,488	$ 5,620,098	$ 5,882,312	$ 5,073,893	$ 4,790,098	$ 5,340,856	$ 6,585,227	$ 6,833,143	$ 6,096,298	$ 5,127,333	$ 4,821,601	$ 5,611,216	$ 68,255,563	$ 69,360,027	$ (1,104,464)	-2%

CONSUMPTION (kWh):	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total To Date	Budget	Variance	% Budget Variance
Residential	42,961,552	32,653,469	37,341,171	24,940,097	21,125,515	25,314,073	36,208,801	36,373,806	29,298,314	22,255,864	20,848,763	30,691,029	360,012,454	353,365,793	6,646,661	2%
Small General Service	7,779,373	7,469,306	6,905,812	6,476,957	6,064,756	6,428,885	8,108,563	8,955,264	8,498,312	6,416,984	6,039,814	6,549,444	85,693,470	87,698,409	(2,004,939)	-2%
Medium General Service	12,162,982	11,921,031	11,465,540	11,256,256	10,488,859	11,759,542	13,301,710	16,054,935	15,258,787	12,549,015	11,830,679	12,021,842	150,071,178	165,253,045	(15,181,867)	-9%
Large General Service	13,056,640	12,933,980	11,423,420	12,765,020	12,289,580	12,879,680	14,141,600	15,151,200	14,000,340	12,381,300	11,663,940	11,404,860	154,091,560	182,929,421	(28,837,861)	-16%
Small Industrial	4,685,200	4,653,600	4,830,200	4,607,200	5,672,400	5,836,400	6,182,600	6,703,400	6,444,400	6,807,400	6,072,000	5,853,400	68,348,200	30,094,145	38,254,055	127%
Large Industrial	8,343,600	8,580,000	7,447,200	8,732,400	8,337,600	8,667,600	9,037,200	9,279,600	9,560,400	8,481,600	9,216,000	8,749,200	104,432,400	120,630,641	(16,198,241)	-13%
Small Irrigation	17,719	10,685	14,422	22,364	88,955	196,765	252,630	293,120	297,801	242,759	180,958	45,373	1,663,551	1,937,705	(274,154)	-14%
Large Irrigation	22,252	19,252	17,673	278,619	1,570,589	2,622,592	3,852,844	4,716,033	3,762,517	2,507,068	1,212,151	82,111	20,663,701	18,994,497	1,669,204	9%
Cable TV Amp	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	1,285,104	953,785	331,319	35%
Street Lighting	451,268	332,116	323,068	264,321	231,601	201,080	219,033	257,236	294,270	354,826	388,245	426,343	3,743,407	4,214,140	(470,732)	-11%
Rental Lighting	74,381	49,652	48,313	39,480	34,529	29,978	32,655	38,276	43,763	52,462	57,280	62,901	563,670	817,093	(253,423)	-31%
Traffic Lights	35,436	38,640	35,325	29,882	29,952	28,759	27,778	26,685	31,328	31,347	32,788	34,689	382,609	433,377	(50,768)	-12%
TOTAL CONSUMPTION (kWh):	89,697,495	78,768,823	79,959,236	69,519,688	66,041,428	74,072,446	91,472,506	97,956,647	87,597,324	72,187,717	67,649,710	76,028,284	950,951,304	967,322,051	(16,370,747)	-2%

METERS: (Active meters at month end)	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Monthly Avg	Budget	Variance	% Budget Variance
Residential	24,929	24,997	25,008	25,083	25,147	25,146	25,146	25,142	25,129	25,122	25,122	25,094	25,089	25,514	(425)	-2%
Small General Service	2,448	2,449	2,457	2,460	2,471	2,474	2,477	2,475	2,470	2,468	2,468	2,470	2,466	2,555	(89)	-4%
Medium General Service	301	302	301	301	289	291	299	299	302	304	304	309	300	334	(34)	-10%
Large General Service	54	54	54	55	55	55	52	52	53	53	53	51	53	67	(13)	-20%
Small Industrial	7	7	7	7	8	8	9	9	9	9	9	9	8	4	5	130%
Large Industrial	3	3	3	3	3	3	3	3	3	3	3	3	3	3	(0)	-8%
Small Irrigation	85	84	83	83	83	83	82	82	82	82	82	81	83	88	(6)	-6%
Large Irrigation	22	20	20	19	19	20	20	20	20	20	20	20	20	26	(6)	-24%
Cable TV Amp	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	0%
Street Lighting (unmetered)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	0%
Rental Lighting (Accounts)	400	400	400	400	400	400	400	400	400	400	400	400	400	400	-	0%
Traffic Lights	56	56	56	56	56	56	56	56	56	56	56	56	56	58	(2)	-3%
TOTAL ACTIVE METERS:	28,307	28,374	28,391	28,469	28,533	28,538	28,546	28,540	28,526	28,519	28,519	28,495	28,480	29,051	(571)	-2%

METERED DEMAND (kW):	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total To Date	Budget	Variance	% Budget Variance
Residential	338	338	352	265	302	311	257	278	266	246	246	276	3,475	-	3,475	
Small General Service	17,941	22,130	18,916	17,703	19,050	19,192	28,323	25,490	27,146	22,764	22,764	18,024	259,443	-	259,443	
Medium General Service	32,085	31,222	34,165	31,545	32,637	33,633	39,998	41,010	39,560	35,402	35,402	33,475	420,134	475,598	(55,464)	-12%
Large General Service	24,138	23,998	23,874	25,452	26,632	27,136	30,737	29,641	29,480	27,367	27,367	23,535	319,357	411,316	(91,959)	-22%
Small Industrial	9,511	9,538	9,522	9,489	11,266	11,220	12,594	12,559	12,175	12,565	12,565	25,931	148,935	57,802	91,133	158%
Large Industrial	18,278	18,487	19,615	18,456	17,766	16,954	18,004	17,890	17,965	17,317	17,317	17,827	215,876	245,091	(29,215)	-12%
Small Irrigation	114	85	91	210	456	568	613	629	629	587	587	294	4,863	-	4,863	
Large Irrigation	42	186	41	2,333	5,583	6,466	9,512	10,103	8,479	7,615	7,615	904	58,879	59,702	(823)	-1%
TOTAL METERED DEMAND (kW):	102,447	105,984	106,576	105,453	113,692	115,480	140,038	137,600	135,700	123,863	123,863	120,266	1,430,962	1,249,509	181,453	15%

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
ELECTRIC UTILITY CUSTOMERS:	26,025	26,006	26,118	26,227	26,334	26,601	26,604	26,702	26,803	26,774	26,827	26,794

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE REVENUE AND CONSUMPTION
FOR THE PERIOD ENDED
December 2021

POWER SALE REVENUE (Net of City Utility Tax):	CURRENT QUARTER	BUDGET	VARIANCE FROM BUDGET	% VARIANCE FROM BUDGET	2021 - 2020 CURRENT QTR. (+/-)	2021 YEAR TO DATE	2021 - 2020 YTD (+/-)
Residential	$ 6,940,116	$ 7,923,986	$ (983,870)	-12%	(835,955)	$ 32,776,694	$ 969,834
Small General Service	1,503,537	1,741,760	(238,222)	-14%	(16,904)	6,607,107	501,917
Medium General Service	2,205,842	2,526,739	(320,897)	-13%	66,542	8,900,616	315,466
Large General Service	2,003,877	2,770,568	(766,691)	-28%	(221,465)	8,484,772	(31,461)
Small Industrial	1,039,435	472,292	567,143	120%	241,070	3,801,487	648,033
Large Industrial	1,415,013	1,751,528	(336,514)	-19%	111,418	5,640,609	174,999
Small Irrigation	30,501	35,533	(5,032)	-14%	(92)	127,164	2,700
Large Irrigation	270,326	276,785	(6,459)	-2%	26,912	1,323,894	194,635
Cable TV Amp	16,861	14,443	2,418	17%	2,019	67,446	20,188
Street Lighting	91,537	88,272	3,264	4%	(2,520)	359,798	1,943
Rental Lighting	33,006	33,700	(694)	-2%	477	126,413	(2,049)
Traffic Lights	10,098	11,648	(1,551)	-13%	(333)	39,562	236
TOTAL POWER SALE REVENUE:	$ 15,560,149	$ 17,647,254	$ (2,087,104)	-12%	$ (628,831)	$ 68,255,563	$ 2,796,443
CONSUMPTION (kWh):							
Residential	73,795,656	85,132,028	(11,336,372)	-13%	(10,395,109)	360,012,454	11,933,314
Small General Service	19,006,242	22,647,050	(3,640,808)	-16%	(323,274)	85,693,470	7,206,276
Medium General Service	36,401,536	42,726,692	(6,325,156)	-15%	1,364,045	150,071,178	5,312,691
Large General Service	35,450,100	49,552,184	(14,102,084)	-28%	(4,016,520)	154,091,560	(9,300)
Small Industrial	18,732,800	8,694,999	10,037,801	115%	4,355,200	68,348,200	12,497,000
Large Industrial	26,446,800	32,749,346	(6,302,546)	-19%	2,859,600	104,432,400	3,920,400
Small Irrigation	469,090	546,669	(77,579)	-14%	(8,833)	1,663,551	590
Large Irrigation	3,801,330	3,977,820	(176,490)	-4%	416,187	20,663,701	4,117,157
Cable TV Amp	321,276	261,175	60,101	23%	32,479	1,285,104	324,790
Street Lighting	1,169,414	1,438,362	(268,948)	-19%	(106,597)	3,743,407	(264,977)
Rental Lighting	172,643	279,526	(106,883)	-38%	(38,329)	563,670	(150,346)
Traffic Lights	98,824	122,195	(23,371)	-19%	(5,105)	382,609	1,394
TOTAL CONSUMPTION (kWh):	215,865,711	248,128,046	(32,262,335)	-13%	(5,866,256)	950,951,304	44,888,989
METERED DEMAND (kW):							
Residential	768	-	768		(199)	3,475	(10,736)
Small General Service	63,552	-	63,552		10,309	259,443	46,524
Medium General Service	104,279	125,297	(21,018)		1,953	420,134	20,229
Large General Service	78,269	114,323	(36,054)		(4,956)	319,357	(762)
Small Industrial	51,061	16,387	34,674		23,016	148,935	32,446
Large Industrial	52,461	65,895	(13,434)		(1,353)	215,876	(2,064)
Small Irrigation	1,468	-	1,468		(229)	4,863	(344)
Large Irrigation	16,134	14,594	1,540		3,108	58,879	5,327
TOTAL METERED DEMAND (kW):	367,992	336,496	31,496		31,649	1,430,962	90,620

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE REVENUE AND CONSUMPTION
FOR THE PERIOD ENDED
December 2021

	CURRENT QUARTER	QUARTERLY BUDGET	% VARIANCE FROM BUDGET	MONTHLY AVERAGE Y-T-D ACTUAL	MONTHLY AVERAGE Y-T-D BUDGET	% VARIANCE FROM BUDGET
POWER SALE REVENUE PER METER:						
(Net of Utility Tax)						
Residential	$ 276	$ 309	-12%	$ 109	$ 107	2%
Small General Service	609	677	-11%	223	220	1%
Medium General Service	7,216	7,551	-5%	2,471	2,429	2%
Large General Service	38,300	43,064	-12%	13,237	12,735	4%
Small Industrial	115,493	115,486	0%	38,791	38,433	1%
Large Industrial	471,671	535,000	-13%	156,684	164,574	-5%
Small Irrigation	372	403	-8%	128	138	-8%
Large Irrigation	13,516	10,454	23%	5,516	3,964	28%
Cable TV Amp	16,861	14,443	14%	5,620	4,395	22%
Street Lighting	91,537	88,272	4%	29,983	29,184	3%
Rental Lighting	83	84	-2%	26	26	0%
Traffic Lights	180	200	-11%	59	62	-5%
System Average Per Meter	$ 546	563	-3%	$ 200	$ 199	0%
POWER SALE REVENUE PER KILOWATT HOUR:	($/kWh)	($/kWh)		($/kWh)	($/kWh)	
(Net of Utility Tax)						
Residential	$ 0.2832	$ 0.2852	-1%	$ 0.0910	$ 0.0923	-1%
Small General Service	0.2373	0.2314	2%	0.0771	0.0771	0%
Medium General Service	0.1818	0.1776	2%	0.0593	0.0589	1%
Large General Service	0.1696	0.1677	1%	0.0551	0.0556	-1%
Small Industrial	0.1665	0.1630	2%	0.0556	0.0545	2%
Large Industrial	0.1606	0.1604	0%	0.0540	0.0536	1%
Small Irrigation	0.1943	0.1950	0%	0.0764	0.0757	1%
Large Irrigation	0.2762	0.2903	-5%	0.0641	0.0661	-3%
Cable TV Amp	0.1574	0.1659	-5%	0.0525	0.0553	-5%
Street Lighting	0.2361	0.1902	19%	0.0961	0.0831	14%
Rental Lighting	0.5759	0.3717	35%	0.2243	0.1553	31%
Traffic Lights	0.3067	0.2882	6%	0.1034	0.0988	4%
System Average Per Meter	$ 0.0721	$ 0.0711	1%	$ 0.0718	$ 0.0717	0%
KILOWATT HOURS PER METER:	(kWh)	(kWh)		(kWh)	(kWh)	
Residential	2,939	3,318	-13%	1,196	1,154	3%
Small General Service	7,699	8,808	-14%	2,896	2,860	1%
Medium General Service	119,102	127,687	-7%	41,663	41,239	1%
Large General Service	677,308	770,200	-14%	240,392	228,997	5%
Small Industrial	2,081,422	2,126,810	-2%	697,431	704,792	-1%
Large Industrial	8,815,600	10,003,214	-13%	2,900,900	3,070,530	-6%
Small Irrigation	5,727	6,194	-8%	1,677	1,830	-9%
Large Irrigation	190,067	150,235	21%	86,099	59,991	30%
Cable TV Amp	321,276	261,175	19%	107,092	79,482	26%
Street Lighting	1,169,414	1,438,362	-23%	311,951	351,178	-13%
Rental Lighting	432	699	-62%	117	170	-45%
Traffic Lights	1,765	2,097	-19%	569	627	-10%
System Average Per Meter	2,524	2,836	-12%	2,783	2,775	0%

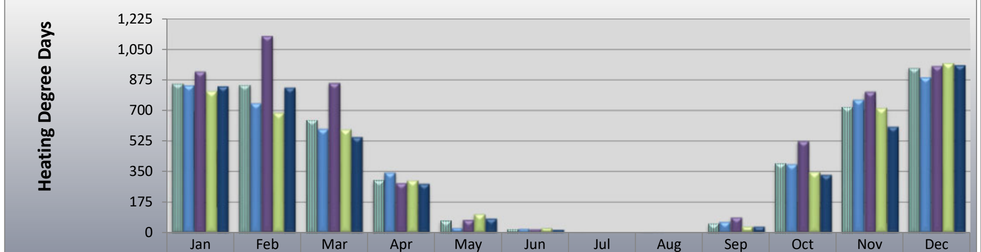
CITY OF RICHLAND, WASHINGTON
KWH SALES
MONTHLY ACTIVITY
December 31, 2021

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	**2017**	62,048,398	47,914,464	35,158,691	24,005,005	22,086,610	23,313,198	30,040,964	31,916,160	25,818,412	19,779,494	22,955,082	30,937,579	375,974,057
	2018	44,374,772	31,993,720	34,871,383	25,266,717	19,017,436	23,993,782	28,296,950	31,865,796	25,663,042	19,633,583	21,153,863	32,499,588	338,630,632
	2019	39,597,871	38,129,336	49,830,822	28,493,781	19,279,665	23,183,854	27,717,749	31,968,874	26,186,935	19,605,925	24,790,993	38,278,466	367,064,271
	2020	38,935,267	33,391,001	32,026,840	30,053,283	19,718,645	19,423,100	26,873,074	34,593,924	28,873,241	23,502,098	24,628,883	36,059,784	348,079,140
	2021	42,961,552	32,653,469	37,341,171	24,940,097	21,125,515	25,314,073	36,208,801	36,373,806	29,298,314	22,255,864	20,848,763	30,691,029	360,012,454
Small General Service	**2017**	9,516,305	9,620,357	7,665,378	5,943,461	6,074,129	6,364,762	6,955,841	8,097,137	7,076,428	6,809,698	6,227,992	6,864,170	87,215,658
	2018	8,282,479	7,819,252	7,116,595	6,473,358	6,110,969	6,809,052	7,084,700	8,231,129	7,717,449	6,561,513	6,346,530	7,322,110	85,875,136
	2019	8,130,451	7,935,304	9,050,455	7,192,512	5,743,845	6,419,529	6,990,012	7,704,998	7,359,460	6,192,677	6,580,247	7,100,470	86,399,960
	2020	7,922,069	7,873,541	6,785,986	6,098,899	4,868,686	5,097,523	5,986,353	7,517,741	7,006,880	6,158,758	6,446,476	6,724,282	78,487,194
	2021	7,779,373	7,469,306	6,905,812	6,476,957	6,064,756	6,428,885	8,108,563	8,955,264	8,498,312	6,416,984	6,039,814	6,549,444	85,693,470
Medium General Service	**2017**	14,498,561	16,065,806	13,455,268	12,017,254	11,697,162	12,516,825	13,720,718	15,680,702	14,813,311	13,421,127	12,265,681	12,288,448	162,440,863
	2018	14,411,016	13,579,218	11,530,411	11,809,374	11,208,347	12,781,338	13,002,108	14,762,239	14,539,444	12,562,350	11,880,108	11,934,156	154,000,109
	2019	12,583,823	12,900,908	13,137,528	12,793,248	11,301,161	12,017,764	12,753,141	13,546,771	15,933,091	12,978,479	12,569,284	12,930,762	155,445,960
	2020	11,981,289	14,945,342	12,184,535	11,649,312	10,181,464	10,224,047	11,570,896	13,356,128	13,627,983	11,466,564	11,744,235	11,826,692	144,758,487
	2021	12,162,982	11,921,031	11,465,540	11,256,256	10,488,859	11,759,542	13,301,710	16,054,935	15,258,787	12,549,015	11,830,679	12,021,842	150,071,178
Large General Service	**2017**	13,636,920	13,685,920	12,525,427	12,599,360	11,867,240	13,875,580	13,946,060	15,888,520	15,981,960	14,894,600	15,821,600	14,629,520	169,352,707
	2018	15,686,900	15,428,040	11,964,760	18,052,600	14,250,080	16,637,480	17,241,620	15,692,000	18,372,360	16,688,460	15,502,420	14,253,100	189,769,820
	2019	14,179,400	14,566,240	14,378,780	14,352,800	14,082,660	14,663,810	15,265,520	13,721,600	18,037,640	15,659,300	12,704,360	12,017,960	173,630,070
	2020	11,477,460	13,461,220	11,357,660	12,005,980	11,191,560	11,811,640	12,659,220	14,427,140	16,242,360	13,425,600	13,387,580	12,653,440	154,100,860
	2020	13,056,640	12,933,980	11,423,420	12,765,020	12,289,580	12,879,680	14,141,600	15,151,200	14,000,340	12,381,300	11,663,940	11,404,860	154,091,560
Small Industrial	**2017**	2,020,400	2,100,200	2,007,400	2,139,000	1,977,000	2,176,800	2,256,400	6,286,200	(209,400)	2,291,400	2,037,400	1,909,400	26,992,200
	2018	2,751,400	1,976,400	1,817,200	2,023,800	1,883,800	2,080,600	2,087,400	2,352,800	2,466,400	2,216,000	2,229,000	2,236,000	26,120,800
	2019	1,498,800	1,509,000	1,319,400	1,537,200	1,412,400	1,363,800	1,493,400	4,682,400	16,668,600	2,940,800	4,021,600	4,685,600	43,133,000
	2020	3,868,600	4,583,600	4,541,600	5,963,200	4,181,600	3,903,200	4,886,400	3,735,400	5,810,000	5,149,600	4,522,400	4,705,600	55,851,200
	2021	4,685,200	4,653,600	4,830,200	4,607,200	5,672,400	5,836,400	6,182,600	6,703,400	6,444,400	6,807,400	6,072,000	5,853,400	68,348,200
Large Industrial	**2017**	9,616,800	10,699,200	8,971,200	9,086,400	8,995,200	9,428,400	8,878,800	5,421,600	12,558,000	9,220,800	9,660,000	8,791,200	111,327,600
	2018	9,766,800	10,026,000	9,039,600	9,325,200	7,748,400	8,210,400	9,072,000	9,872,400	9,625,200	9,250,800	9,825,600	8,470,800	110,233,200
	2019	5,408,400	5,833,200	5,516,400	5,796,000	4,767,600	4,852,800	4,741,200	5,331,600	4,844,400	4,980,000	5,392,800	5,275,200	62,739,600
	2020	9,568,800	10,219,200	8,959,200	9,716,400	7,278,000	8,372,400	7,125,600	7,981,200	7,704,000	7,100,400	8,516,400	7,970,400	100,512,000
	2021	8,343,600	8,580,000	7,447,200	8,732,400	8,337,600	8,667,600	9,037,200	9,279,600	9,560,400	8,481,600	9,216,000	8,749,200	104,432,400
Small Irrigation	**2017**	19,522	29,705	165,519	(30,862)	(11,077)	203,830	272,632	284,799	322,849	270,502	155,614	57,261	1,740,294
	2018	30,131	24,302	34,936	21,708	77,967	207,491	287,611	323,463	331,831	239,926	193,005	48,773	1,821,144
	2019	23,238	22,794	25,687	17,563	50,723	163,292	270,616	290,701	307,021	258,217	168,801	58,328	1,656,981
	2020	25,840	14,998	10,035	20,824	110,048	188,869	251,090	274,364	288,970	290,624	140,492	46,807	1,662,961
	2021	17,719	10,685	14,422	22,364	88,955	196,765	252,630	293,120	297,801	242,759	180,958	45,373	1,663,551
Large Irrigation	**2017**	19,222	22,361	21,361	102,846	769,215	2,285,135	3,226,036	4,407,551	3,047,384	2,940,334	1,325,655	79,290	18,246,390
	2018	26,048	25,242	21,682	333,680	1,031,450	2,728,856	3,337,388	4,139,524	3,731,862	2,347,586	1,464,697	59,173	19,247,188
	2019	20,621	22,794	25,687	17,563	50,723	163,292	270,616	290,701	307,021	258,217	168,801	58,328	1,654,364
	2020	18,246	20,251	108,912	163,069	1,370,968	2,098,460	2,758,538	3,323,710	3,299,247	2,347,097	981,071	56,975	16,546,544
	2021	22,252	19,252	17,673	278,619	1,570,589	2,622,592	3,852,844	4,716,033	3,762,517	2,507,068	1,212,151	82,111	20,663,701
Cable	**2017**	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	895,356
	2018	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	895,356
	2019	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	895,356
	2020	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	107,092	74,613	107,092	960,314
	2021	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	1,285,104
Street Lighting	**2017**	460,269	375,296	365,180	298,416	260,988	226,594	246,826	289,485	331,223	395,949	434,446	477,325	4,161,997
	2018	462,136	375,583	364,920	298,085	260,289	226,269	246,456	288,889	329,117	393,028	428,748	471,381	4,144,901
	2019	455,089	370,412	359,994	294,148	257,166	223,276	244,547	286,641	327,733	392,879	303,597	303,597	3,819,079
	2020	303,597	303,597	303,597	303,597	303,597	303,597	303,597	303,597	303,597	387,102	422,742	466,167	4,008,384
	2021	451,268	332,116	323,068	264,321	231,601	201,080	219,033	257,236	294,270	354,826	388,245	426,343	3,743,407
Security Lighting	**2017**	83,729	67,678	65,828	53,793	47,046	40,846	44,493	52,152	59,628	71,481	78,046	85,737	750,457
	2018	89,248	67,578	65,684	53,675	46,943	40,757	44,371	52,009	59,465	71,285	77,062	84,450	752,527
	2019	83,149	67,628	65,552	53,567	46,849	40,675	44,306	51,933	59,378	71,181	84,011	92,255	760,484
	2020	89,311	72,822	65,550	48,568	42,476	42,090	42,090	46,658	53,479	64,109	69,997	76,866	714,016
	2021	74,381	49,652	48,313	39,480	34,529	29,978	32,655	38,276	43,763	52,462	57,280	62,901	563,670
Traffic Lights	**2017**	38,732	41,487	35,428	37,418	32,159	30,207	32,024	28,411	22,338	32,217	35,001	36,281	401,703
	2018	37,503	37,305	35,392	35,074	28,008	29,053	28,739	28,764	29,586	31,496	35,325	36,589	392,834
	2019	37,845	39,800	39,852	31,278	29,546	27,772	26,305	27,225	30,744	28,229	31,421	38,419	388,436
	2020	34,040	39,820	35,212	31,086	31,698	26,067	25,910	26,001	27,452	30,845	33,623	39,461	381,215
	2021	35,436	38,640	35,325	29,882	29,952	28,759	27,778	26,685	31,328	31,347	32,788	34,689	382,609
Total System	**2017**	112,033,471	100,697,087	80,511,293	66,326,704	63,870,285	70,536,790	79,695,407	88,427,330	79,896,746	70,202,215	71,071,130	76,230,824	959,499,282
	2018	95,993,046	81,427,253	76,937,176	73,767,884	61,738,302	73,819,691	80,803,956	87,683,626	82,940,369	70,070,640	69,210,971	77,490,733	931,883,647
	2019	82,090,925	81,469,486	93,907,995	70,799,779	58,417,196	65,129,645	72,379,947	81,011,066	93,128,862	65,529,397	67,702,798	80,912,645	912,479,741
	2020	84,303,138	85,000,005	76,453,740	76,128,831	59,353,355	61,565,606	72,557,381	85,660,476	83,311,822	70,029,889	70,968,512	80,733,566	906,066,321
	2021	89,697,495	78,768,823	79,959,236	69,519,688	66,041,428	74,072,446	91,472,506	97,956,647	87,597,324	72,187,717	67,649,710	76,028,284	950,951,304

City of Richland, Washington
Electric Utility
December 31, 2021

Climatological Data From Hanford Meteorology Station Located 25 Miles N.W. of Richland, WA

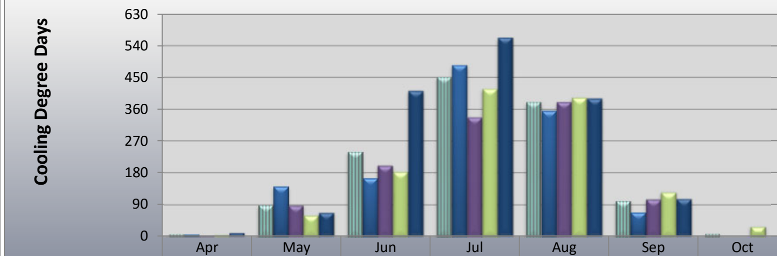
Heating Degree Days By Month



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Four Year Avg	854	846	647	301	70	20	-	1	53	398	722	943
2018 Degree Days	843	740	593	344	25	20	-	2	60	391	761	889
2019 Degree Days	923	1,127	857	282	71	18	-	-	85	524	807	954
2020 Degree Days	811	686	590	297	105	24	-	-	33	345	714	971
2021 Degree Days	839	830	548	279	80	16	-	-	35	330	606	959

Four Year Avg 2018 Degree Days 2019 Degree Days 2020 Degree Days 2021 Degree Days

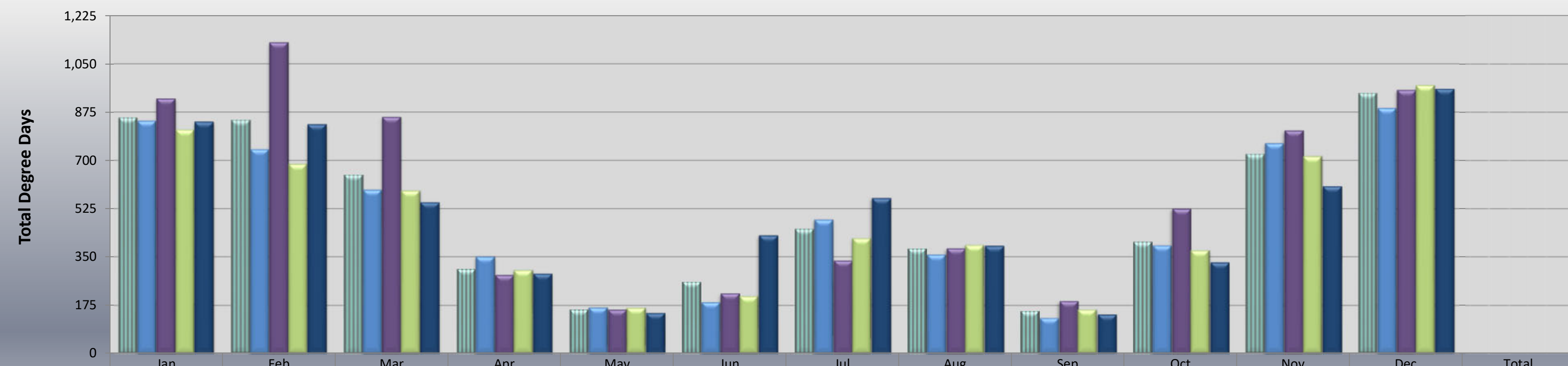
Cooling Degree Days By Month



	Apr	May	Jun	Jul	Aug	Sep	Oct
Four Year Avg	6	89	240	451	380	101	7
2018 Degree Days	6	141	165	485	356	68	-
2019 Degree Days	2	88	200	337	380	105	-
2020 Degree Days	4	60	183	417	392	125	28
2021Degree Days	10	67	412	563	390	106	-

Four Year Avg 2018 Degree Days 2019 Degree Days 2020 Degree Days 2021Degree Days

Total Degree Days By Month



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Four Year Avg	854	846	647	306	159	260	451	380	154	405	722	943	6,127
2018 Degree Days	843	740	593	350	166	185	485	358	128	391	761	889	5,889
2019 Degree Days	923	1,127	857	284	159	218	337	380	190	524	807	954	6,760
2020 Degree Days	811	686	590	301	165	207	417	392	158	373	714	971	5,785
2021 Degree Days	839	830	548	289	147	428	563	390	141	330	606	959	6,070

Four Year Avg 2018 Degree Days 2019 Degree Days 2020 Degree Days 2021 Degree Days

Degree days are indicators of how much energy a typical household will use for heating or cooling. Degree days are based on the assumption that when the outside temperature is 65° F, a household would not need heating or cooling to be comfortable. An increase in heating or cooling degrees days correlates with increased energy consumption. Degree days are the difference between the average daily temperature and 65° F. Cooling degree days result when the daily temperature average is above 65°F. Heating degree days result when the daily temperature average is below 65°F.

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED BALANCE SHEET
As of December 31, 2021

Acct. No.	Account Title	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
ASSETS														
12400	Premium on Investments	-	-	-	-	-	-	-	-	-	-	-	-	-
12805	Cash - Insurance Set Aside	-	-	-	-	-	-	-	-	-	-	-	-	-
12809	Cash - Reserved for BPA REP Refund	-	-	-	-	-	-	-	-	-	-	-	-	-
12810	Cash - Bond Redemption	1,148,908.42	1,653,597.53	2,158,286.64	2,662,975.75	3,167,664.86	2,204,219.34	2,708,908.45	3,213,597.56	3,718,286.67	4,222,975.78	4,727,664.89	644,765.20	1,168,230.35
12813	Cash - Conservation Loan (LGIP)	-	307,625.27	307,657.07	307,686.83	307,712.62	307,732.59	307,751.64	307,798.25	307,818.87	307,840.89	307,865.40	307,887.18	-
12814	Cash - Bond Reserve (LGIP)	-	4,904,370.81	4,904,871.07	4,905,339.32	4,905,745.11	4,906,059.30	4,906,358.99	4,907,092.24	4,907,416.63	4,907,763.03	4,908,148.67	4,908,491.38	-
12840	Cash - Operating Reserve	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00
12845	Cash - 2018 Bonds (LGIP)	-	-	-	-	-	-	-	-	-	-	-	-	-
12847	Cash - 2019 Bonds (LGIP)	5,449,585.86	5,450,386.00	5,073,376.31	5,073,854.44	4,765,486.97	4,765,802.31	4,687,453.47	4,688,088.47	4,688,368.44	4,111,271.75	3,416,752.11	2,460,762.45	1,090,840.16
12850	Cash - 2021 Bonds (LGIP)	-	-	-	-	-	-	-	-	-	-	-	65,000.00	23,135.89
12855	Cash - Capital Set Aside Bond	-	-	-	-	-	-	-	-	-	-	-	-	-
12851	Investments - Unrestricted	553,106.87	-	-	-	-	-	-	-	-	-	-	-	-
12857	Investments - Bond Reserve	4,903,797.59	-	-	-	-	-	-	-	-	-	-	-	5,107,067.71
12860	Investments - Conservation Loan	307,588.83	-	-	-	-	-	-	-	-	-	-	-	307,910.91
12861	Investments - Bond Proceeds	-	-	-	-	-	-	-	-	-	-	-	-	6,983,346.31
12870	Cash - Facility Fees	223,162.41	152,592.25	332,267.30	366,331.00	264,654.53	330,659.17	368,043.28	437,964.83	390,293.65	388,397.27	385,169.72	377,505.97	423,684.47
12870	Cash - Facility Fees - Large Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
12870	Cash - Facility Fees Subject To Refund	891,641.70	891,641.70	928,241.70	928,241.70	928,241.70	707,625.55	732,225.55	732,225.55	732,225.55	732,225.55	732,225.55	732,225.55	640,824.55
13100	Cash - Unrestricted	920,081.37	1,610,335.17	2,682,592.45	2,746,420.23	2,642,054.04	1,562,155.16	1,304,087.91	1,472,082.39	2,093,224.03	2,197,041.71	3,002,623.16	4,363,972.71	8,213,342.37
13100	Cash - Credit Support Reserve (NIES)	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00	639,000.00
13130	Cash - Conservation Loan	1,880,514.91	1,922,732.26	1,985,433.59	2,006,407.51	2,002,012.64	2,010,013.30	1,998,162.96	2,022,351.56	2,026,084.43	2,027,129.07	2,088,340.87	2,113,446.35	2,138,936.10
14100	Energy Conservation Loans	1,374,040.57	1,339,925.80	1,281,555.20	1,268,970.58	1,279,404.26	1,274,450.04	1,297,218.22	1,278,114.64	1,287,355.53	1,289,069.83	1,233,571.43	1,211,623.79	1,191,076.57
14101	Energy Conservation Loans Billed Monthly	155,620.19	152,693.54	153,779.44	151,345.19	150,419.16	152,090.38	148,796.35	148,882.09	141,998.22	143,774.20	141,957.27	143,023.29	142,144.43
14200	A/R - Customer Billings	4,959,655.17	5,567,854.65	5,036,801.41	4,574,239.97	4,153,108.49	4,077,590.44	4,463,925.64	5,347,776.11	5,595,524.65	5,610,782.78	4,509,598.12	4,127,226.30	4,785,979.74
14300	A/R - Misc.	71,083.05	190,592.59	113,393.79	157,644.15	72,855.70	99,676.96	161,653.91	96,859.10	272,715.40	382,861.03	62,771.94	141,606.55	251,386.74
14310	A/R - Pole Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-
14320	Due from Other Funds	-	-	-	-	-	-	-	-	-	-	-	-	-
14400	Provision for Uncollectible	(213,274.65)	(223,465.82)	(234,396.11)	(244,869.04)	(256,097.33)	(266,627.20)	(276,805.72)	(285,016.22)	(295,262.27)	(306,562.96)	(316,501.88)	(326,365.01)	(51,439.00)
15400	Materials and Supplies	4,461,969.63	4,374,400.41	4,280,550.46	4,198,650.80	4,702,606.18	4,897,870.75	4,933,368.33	5,120,130.17	4,997,842.62	5,010,143.37	4,993,492.99	4,963,875.90	4,857,729.46
15410	Exempt Materials and Supplies	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69
16300	Stores Expense - Clearing	-	31,600.62	63,329.84	82,250.56	56,539.91	88,087.11	119,727.21	151,899.81	183,634.97	213,267.62	261,033.61	(41,122.06)	-
16500	Prepaid Expenses	338,028.00	497,624.51	491,989.66	462,078.91	445,980.06	443,911.11	433,044.26	411,713.41	395,986.56	380,466.21	365,367.36	322,344.01	290,513.16
16512	WCIA Insurance Deposit	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00
17200	Net Pension Asset	-	-	-	-	-	-	-	-	-	-	-	-	4,921,406.00
18171	Unamortized Prem - 2013 Rev Ref Bonds	(1,470,496.12)	(1,464,904.88)	(1,459,313.64)	(1,453,722.40)	(1,448,131.16)	(1,442,539.92)	(1,436,948.68)	(1,431,357.44)	(1,425,766.20)	(1,420,174.96)	(1,414,583.72)	(1,408,992.48)	(1,403,401.24)
18172	Unamortized Prem - 2015 Bonds	(1,682,395.31)	(1,676,749.69)	(1,671,104.07)	(1,665,458.45)	(1,659,812.83)	(1,654,167.21)	(1,648,521.59)	(1,642,875.97)	(1,637,230.35)	(1,631,584.73)	(1,625,939.11)	(1,620,293.49)	(1,614,647.87)
18173	Unamortized Prem - 2018 Bonds	(994,619.76)	(991,530.88)	(988,442.00)	(985,353.12)	(982,264.24)	(979,175.36)	(976,086.48)	(972,997.60)	(969,908.72)	(966,819.84)	(963,730.96)	(960,642.08)	(957,553.20)
18174	Unamortized Prem - 2019 Bonds	(2,499,856.45)	(2,491,146.15)	(2,482,435.85)	(2,473,725.55)	(2,465,015.25)	(2,456,304.95)	(2,447,594.65)	(2,438,884.35)	(2,430,174.05)	(2,421,463.75)	(2,412,753.45)	(2,404,043.15)	(2,395,332.85)
18175	Unamortized Prem - 2021 Bonds	-	-	-	-	-	-	-	-	-	-	-	-	(1,147,246.70)
18400	Clearing Account - Overhead	0.00	62,837.55	114,866.05	173,919.94	345,039.54	413,020.94	505,731.62	622,409.64	664,927.48	790,135.07	840,800.02	995,193.71	0.00
18410	Clearing Account - Equipment	-	10,809.85	31,497.00	64,164.39	76,396.20	93,379.86	108,536.69	130,049.70	153,829.68	166,230.97	187,768.92	205,135.79	-
18500	Deferred Debits - Temp. Facilities	-	(7,425.00)	(18,675.00)	(26,550.00)	(30,150.00)	(38,700.00)	(46,125.00)	(54,450.00)	(61,425.00)	(70,425.00)	(80,325.00)	(88,425.00)	-
18610	Deferred Debits - Damages & Claims	-	-	8,500.35	11,336.88	12,119.22	22,866.21	22,866.21	30,607.64	37,536.79	52,925.17	55,439.59	55,439.59	-
18620	Deferred Debits - Pension	641,714.00	641,714.00	641,714.00	641,714.00	641,714.00	641,714.00	641,714.00	641,714.00	641,714.00	641,714.00	641,714.00	641,714.00	595,660.00
18630	Deferred Debits - OPEB	110,481.27	110,481.27	110,481.27	110,481.27	110,481.27	110,481.27	110,481.27	110,481.27	110,481.27	110,481.27	110,481.27	110,481.27	92,502.44
18640	Conservation Programs	547,819.43	550,575.38	554,193.87	618,069.93	593,216.69	617,262.06	634,378.52	645,021.45	591,450.16	579,731.39	591,865.79	592,065.79	597,646.83
18916	Unamortized Loss on 2001 Refunded	39,496.52	37,779.28	36,062.04	34,344.80	32,627.56	30,910.32	29,193.08	27,475.84	25,758.60	24,041.36	22,324.12	20,606.88	18,889.64
18925	Unamort Loss 2003 Rev & Rev Ref Bonds	83,582.20	83,042.96	82,503.72	81,964.48	81,425.24	80,886.00	80,346.76	79,807.52	79,268.28	78,729.04	78,189.80	77,650.56	77,111.32
18926	Unamort Loss 2009 Rev & Rev Ref Bonds	89,505.17	89,110.87	88,716.57	88,322.27	87,927.97	87,533.67	87,139.37	86,745.07	86,350.77	85,956.47	85,562.17	85,167.87	84,773.57
	SUBTOTAL ASSETS	25,338,043.56	26,826,404.54	27,655,596.82	27,914,379.03	28,031,265.80	26,135,785.89	27,006,334.26	28,932,609.42	30,357,629.35	30,685,226.28	29,984,197.34	25,864,631.51	39,481,820.55
CWIP														
10200	Electric Plant Purchased	-	-	-	-	-	-	-	-	-	-	-	-	-
10700	Utility Plant Work in Progress	-	-	-	-	-	-	-	-	-	-	-	-	-
10710	Utility Plant Work in Progress	1,899,283.81	2,006,567.40	2,144,445.64	2,308,930.13	2,540,010.28	2,695,255.53	2,848,779.64	2,985,766.27	3,144,314.47	3,375,308.24	3,542,999.21	3,692,957.65	1,012,900.11
10720	Construction W I P Ret	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL CWIP	1,899,283.81	2,006,567.40	2,144,445.64	2,308,930.13	2,540,010.28	2,695,255.53	2,848,779.64	2,985,766.27	3,144,314.47	3,375,308.24	3,542,999.21	3,692,957.65	1,012,900.11

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED BALANCE SHEET
As of December 31, 2021

Acct. No.	Account Title	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
FIXED ASSETS														
34100	Leasehold Structures & Improve - Solar Gen	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88
35000	Land and Land Rights	586,985.87	586,985.87	586,985.87	587,085.71	587,085.71	587,085.71	587,085.71	587,085.71	587,085.71	587,085.71	587,085.71	587,085.71	586,985.87
35300	Station Equipment	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56
35400	Towers & Fixtures	16,360.40	16,360.40	16,360.40	16,360.40	16,360.40	16,494.31	16,494.31	16,494.31	16,494.31	16,494.31	16,494.31	16,494.31	16,360.40
35500	Poles & Fixtures	5,240,815.05	5,241,005.24	5,241,099.37	5,241,545.73	5,242,059.04	5,242,438.44	5,259,888.21	5,260,670.39	5,261,374.54	5,478,568.00	5,507,152.67	5,591,253.66	5,735,664.64
35600	Conductor - Overhead	786,937.08	788,621.59	788,621.59	789,157.22	790,228.48	794,816.96	798,054.51	799,292.65	800,375.27	801,582.45	803,261.36	805,351.20	1,473,916.25
35700	U/G Conduit	89,530.46	91,420.02	93,986.57	98,123.53	99,050.77	99,050.77	100,174.97	101,005.11	101,005.11	101,725.73	101,725.73	101,725.73	101,725.73
35800	Conductor - Underground	1,112,572.79	1,122,611.93	1,133,514.20	1,154,028.92	1,161,092.51	1,172,162.20	1,190,315.76	1,202,363.00	1,217,074.01	1,235,955.08	1,255,647.39	1,268,295.61	1,276,530.67
36000	Land and Land Rights	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,292.42	222,292.42	222,292.42	222,252.42
36100	Structures & Improvements	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15
36200	Station Equipment	5,686,450.82	5,702,065.51	5,738,138.41	5,742,731.89	5,748,459.91	5,751,131.44	5,752,850.98	5,754,594.35	5,757,267.77	5,761,217.84	5,762,234.60	5,767,303.74	5,803,425.17
36210	1st Street Substation	1,993,018.08	1,993,018.08	1,993,644.31	1,993,733.58	1,994,018.11	1,994,330.56	1,994,330.56	1,994,330.56	1,994,330.56	1,994,330.56	1,994,330.56	1,997,815.00	1,993,018.08
36211	1st Street Substation - SCADA	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15
36212	SCADA System - Wide	603,112.26	603,112.26	603,641.03	620,366.51	625,594.64	626,457.37	627,756.48	628,495.65	628,800.57	628,800.57	629,071.61	629,071.61	629,071.61
36220	Tapteal Substation	791,701.40	791,701.40	792,143.79	792,143.79	792,143.79	795,872.79	796,055.25	796,055.25	796,055.25	796,055.25	796,055.25	796,055.25	791,701.40
36221	Tapteal Substation - SCADA	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03
36230	Richland SW Sub-Stn Expa	1,509,675.81	1,510,048.49	1,510,048.49	1,510,048.49	1,510,048.49	1,510,048.49	1,510,048.49	1,510,048.49	1,510,048.49	1,510,048.49	1,510,082.37	1,510,082.37	1,509,675.81
36231	Richland SW Sub-Stn SCADA	76,309.86	76,309.86	76,332.18	76,332.18	76,332.18	76,332.18	76,332.18	76,332.18	76,332.18	76,332.18	76,332.18	76,332.18	76,309.86
36250	Sub Stn Equip - Snyder St	3,626,524.78	3,626,524.78	3,626,827.15	3,626,827.15	3,626,827.15	3,626,827.15	3,626,827.15	3,626,950.02	3,628,516.49	3,629,384.12	3,655,393.62	3,659,237.04	3,659,237.04
36251	Snyder - SCADA	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	126,796.49	127,203.05	127,203.05	125,836.45
36260	Stevens Sub	2,105,149.25	2,105,149.25	2,105,854.75	2,106,935.97	2,106,935.97	2,106,935.97	2,153,539.42	2,154,045.28	2,154,045.28	2,154,355.66	2,166,168.40	2,192,755.64	2,198,430.76
36261	Stevens Sub - SCADA	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,566.06	178,566.06	178,159.50
36265	Leslie Sub	4,363,563.84	4,363,563.84	4,363,563.84	4,363,748.67	4,363,748.67	4,363,748.67	4,363,748.67	4,363,748.67	4,363,748.67	4,363,748.67	4,363,748.67	4,363,748.67	4,363,563.84
36266	Leslie Sub - SCADA	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64
36270	Thayer Sub	3,965,277.26	3,965,277.26	3,965,450.76	3,965,562.35	3,965,562.35	3,965,562.35	3,965,562.35	3,965,562.35	3,965,562.35	3,965,562.35	3,965,562.35	3,969,046.79	3,965,277.26
36271	Thayer Sub - SCADA	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73
36275	Sandhill Crane Substation	2,931,293.36	2,931,530.52	2,931,888.68	2,931,888.68	2,931,888.68	2,932,192.76	2,932,192.76	2,933,204.48	2,933,204.48	2,933,825.24	2,934,058.01	2,934,058.01	2,931,293.36
36276	Sandhill Crane - SCADA	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08
36281	SCADA Master - Shop	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51
36285	City View Substation	2,337,154.71	2,337,154.71	2,337,154.71	2,337,154.71	2,337,154.71	2,337,154.71	2,337,154.71	2,337,660.57	2,337,660.57	2,337,970.95	2,338,087.35	2,338,087.35	2,337,154.71
36290	SE Richland Substation	1,007,489.82	1,007,489.82	1,665,846.53	1,694,043.03	1,728,670.28	1,837,307.43	1,924,726.70	1,928,104.14	1,947,079.89	2,192,372.86	2,868,608.05	3,816,787.54	4,697,094.59
36292	Dallas Substation	50,000.00	50,000.00	50,000.00	50,000.00	50,000.00	50,000.00	80,790.40	80,790.40	80,790.40	80,790.40	80,790.40	80,790.40	80,790.40
36300	Storage Battery Equipment	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64
36400	Poles, Towers, Fixtures	8,591,595.76	8,593,217.59	8,596,235.93	8,604,074.90	8,652,945.44	8,671,724.43	8,678,291.78	8,723,812.22	8,740,061.34	8,783,327.16	8,805,469.15	8,843,958.85	8,910,803.16
36500	Conductor - Overhead	8,902,697.91	8,903,176.18	8,904,006.19	8,904,601.40	8,907,591.49	8,913,751.47	8,918,172.16	8,922,787.20	8,925,125.34	8,930,287.40	8,934,098.42	8,937,878.16	8,965,324.20
36600	Conduit - Underground	42,488,914.90	42,507,594.28	42,517,377.21	42,530,139.56	42,541,130.08	42,545,991.14	42,552,287.09	42,559,384.52	42,611,943.00	42,664,796.90	42,669,349.86	42,674,142.42	43,477,117.27
36700	Conductor - Underground	42,211,089.96	42,290,161.69	42,341,810.99	42,376,226.85	42,399,118.12	42,431,656.99	42,508,549.24	42,620,047.49	42,704,616.92	42,749,950.90	42,808,157.48	42,839,286.80	44,796,202.14
36710	Underground Cond and Dev	14,870,034.91	14,891,286.43	14,896,968.19	14,952,634.34	15,010,230.04	15,042,809.19	15,079,115.56	15,161,749.59	15,248,350.35	15,283,062.03	15,287,399.54	15,342,672.69	15,394,434.38
36800	Line Transformers	9,784,302.03	9,786,043.57	9,786,043.57	9,786,088.21	9,802,447.87	9,802,447.87	9,803,446.56	9,803,446.56	9,803,446.56	9,803,832.52	9,803,832.52	9,805,231.31	9,816,427.72
36810	Line Transformers - Overhead	1,997,212.93	1,997,212.93	1,997,212.93	1,997,999.06	1,999,215.50	1,999,215.50	2,013,274.55	2,034,521.45	2,034,548.62	2,051,750.43	2,064,749.23	2,064,862.27	2,066,239.04
36820	Line Transformers - Underground	12,463,614.66	12,518,398.26	12,563,609.64	12,579,608.17	12,656,516.64	12,659,999.72	12,712,804.83	12,739,686.55	12,768,973.58	12,794,622.47	12,845,488.76	12,880,990.66	12,953,632.27
36840	Dist Plant Line Transform	50,051.35	50,051.35	50,051.35	50,051.35	50,051.35	50,051.35	50,051.35	50,140.62	50,344.39	50,344.39	50,344.39	50,344.39	50,051.35
36900	Services	6,540,999.97	6,548,579.75	6,556,341.02	6,564,623.38	6,573,832.32	6,585,082.38	6,589,446.33	6,596,241.11	6,605,564.38	6,614,891.51	6,617,223.60	6,629,491.36	6,644,809.13
36910	Services - Overhead	718,958.27	723,102.37	725,432.05	727,006.78	728,594.03	729,429.19	731,798.26	732,598.03	733,056.43	733,840.14	733,840.14	733,967.30	740,148.29
36920	Services - Underground	4,474,038.50	4,488,483.14	4,500,750.17	4,516,210.46	4,528,179.11	4,542,874.52	4,557,013.38	4,571,045.45	4,585,338.95	4,601,463.90	4,614,223.34	4,625,649.32	4,710,117.73
37000	Meters	4,523,995.92	4,553,664.91	4,558,326.00	4,575,524.26	4,592,903.02	4,616,779.66	4,620,817.34	4,630,178.86	4,642,769.39	4,661,862.23	4,666,346.75	4,672,147.12	4,717,720.55
37100	Installation Cust. Premises	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08
37200	Leased Pr. Cust. Premises	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82	1,040,143.56	1,040,143.56	1,040,143.56	1,040,143.56	1,040,143.56	1,040,143.56	1,039,967.82
37300	Lighting and Signal System	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,589,605.01	3,616,801.76
37320	Traffic Signals	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,767.53	805,767.53	805,746.09
37330	Distr Plant Tone Control	144.60	144.60	144.60	144.60	144.60	144.60	144.60	144.60	144.60	144.60	144.60	144.60	144.60
38900	Land and Land Rights	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17
39000	Structures & Improvements	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49
39010	S & I - City Shops Elec	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18
39020	S & I - City Shops Non-Elec	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00
39100	Office Furniture & Fixtures	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11
39200	Transportation Equipment	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05
39300	Stores Equipment	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99
39400	Tools, Shop & Garage Equip	242,174.68	242,174.68	242,265.32	242,265.32	242,265.32	242,265.32	242,265.32	242,265.32	242,265.32	242,265.32	242,265.32	242,265.32	242,174.68
39500	Laboratory Equip	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23
39600	Power Operated Equip	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44
39700	Communication Equip	2,827,733.02	2,827,808.98	2,884,709.92	2,891,744.71	2,956,083.86	2,990,874.04	3,029,150.60	3,034,435.17	3,053,941.97	3,062,793.10	3,140,958.79	3,144,947.33	3,152,369.30
39710	Communication Equip - Shops	216,102.33	216,115.99	216,115.99	216,115.99	216,115.99	216,115.99	216,115.99	216,115.99	216,115.99	216,256.83	216,256.83	216,256.83	216,102.33
39712	Communication Equip - GEMS Software	344,747.22	344,747.22	344,747.22	344,747.22	344,747.22	344,747.22	344,747.22	344,747.22	344,747.22	344,747.22	344,747.22	344,747.22	-
39713	Work Order System	262,799.51	262,799.51	262,799.51	262,799.51	262,799.51	262,799.51	262,799.51	262,799.51	262,799.51	262,799.51	262,799.51	262,799.51	-
39800	Miscellaneous Equipment	521,913.56	521,913.56	537,956.06	549,791.06	873,542.73	894,082.76	932,314.01	932,314.01	965,294.01	1,092,070.48	1,115,868.22	1,115,868.22	1,207,763.63
	TOTAL FIXED ASSETS	223,182,656.29	223,446,239.22	224,373,617.89	224,639,827.04	225,361,327.48	225,698,404.51	226,206,322.39	226,565,082.17	226,966,086.91	227,862,102.64	228,907,076.00	230,200,651.23	234,585,617.37

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED BALANCE SHEET
As of December 31, 2021

Acct. No.	Account Title	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
ACCUMULATED DEPRECIATION														
10810	Accum Depr - Transmission	(858,210.40)	(874,904.59)	(891,598.77)	(908,292.96)	(924,987.14)	(941,681.33)	(958,375.51)	(975,069.70)	(991,763.88)	(1,008,458.07)	(1,025,152.25)	(1,041,846.44)	(1,058,540.62)
10812	Accum Depr - Distribution	(92,647,850.64)	(93,144,829.93)	(93,641,809.17)	(94,138,788.47)	(94,635,767.70)	(95,132,747.01)	(95,629,726.24)	(96,126,705.55)	(96,623,684.78)	(97,118,216.73)	(97,612,748.61)	(98,107,280.56)	(98,601,812.44)
10814	Accum Depr - General Plant	(5,902,227.86)	(5,920,221.16)	(5,938,214.45)	(5,956,207.75)	(5,974,201.04)	(5,990,684.18)	(6,007,167.32)	(6,023,650.46)	(6,040,133.60)	(6,056,616.74)	(6,073,099.88)	(6,089,583.02)	(5,498,519.43)
10816	Accum Depr - City Shops	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)
10820	Cost of Property Retired	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22
10830	Ut Plant - Cost of Removal	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74
10840	Utility Plant - Salvage	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)
	TOTAL ACCUMULATED DEPR	(111,206,875.53)	(111,738,542.31)	(112,270,209.02)	(112,801,875.81)	(113,333,542.51)	(113,863,699.15)	(114,393,855.70)	(114,924,012.34)	(115,454,168.89)	(115,981,878.17)	(116,509,587.37)	(117,037,296.65)	(116,957,459.12)
LIABILITIES														
22143	Cur Ptn LTD - 2009 Bonds	-	-	-	-	-	-	-	-	-	-	-	-	-
22148	Cur Ptn LTD - 2013 Rev Ref Bonds	(635,000.00)	(635,000.00)	(635,000.00)	(635,000.00)	(635,000.00)	(635,000.00)	(635,000.00)	(635,000.00)	(635,000.00)	(635,000.00)	(635,000.00)	(665,000.00)	(665,000.00)
22152	Cur Ptn LTD - 2015 Bonds	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(460,000.00)	(460,000.00)
22153	Cur Ptn LTD - 2018 Bonds	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,775,000.00)	(1,865,000.00)	(1,865,000.00)
22154	Cur Ptn LTD - 2019 Bonds	(255,000.00)	(255,000.00)	(255,000.00)	(255,000.00)	(255,000.00)	(255,000.00)	(255,000.00)	(255,000.00)	(255,000.00)	(255,000.00)	(255,000.00)	(270,000.00)	(270,000.00)
22155	Cur Ptn LTD - 2021 Bonds	-	-	-	-	-	-	-	-	-	-	-	-	-
22161	2013 Rev Ref Bonds Outstanding	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,830,000.00)	(14,165,000.00)	(14,165,000.00)
22162	2015 Rev Bonds Outstanding	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(18,380,000.00)	(17,920,000.00)	(17,920,000.00)
22163	2018 Rev Bonds Outstanding	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(15,320,000.00)	(13,455,000.00)	(13,455,000.00)
22164	2019 Rev Bonds Outstanding	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(15,120,000.00)	(14,850,000.00)	(14,850,000.00)
22165	2021 Rev Bonds Outstanding	-	-	-	-	-	-	-	-	-	-	-	(65,000.00)	(6,415,000.00)
22830	Net Pension Liability	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(1,954,998.00)	(344,074.00)
22840	Net OPEB Liability	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(954,206.73)	(968,612.16)
23200	A/P - Accrued Power Bills	(3,181,877.81)	(3,311,677.12)	(3,466,712.34)	(2,959,631.03)	(3,114,846.11)	(2,928,592.71)	(3,263,410.81)	(3,637,281.79)	(3,741,867.71)	(3,335,973.56)	(2,671,430.94)	(2,317,980.70)	(5,692,534.48)
23209	Accts Pay - Inventory	-	-	-	27.35	27.35	27.35	27.35	27.35	27.35	27.35	27.35	27.35	-
23210	Accts Pay - Payroll	(250,459.87)	(236,612.55)	(237,172.37)	(237,172.37)	(237,172.37)	(237,172.37)	(237,172.37)	(237,172.37)	(237,172.37)	(237,172.37)	(234,974.32)	(234,974.32)	(265,157.83)
23211	Accts Pay - Excise Tax	(250.64)	(270,478.67)	(237,826.46)	(244,917.29)	(208,227.05)	(200,121.06)	(220,354.32)	(272,192.02)	(267,630.31)	(46,227.82)	(212,260.93)	(199,811.76)	(5,946.46)
23212	Accounts Payable	(523,832.24)	(139,841.32)	(716,223.88)	(92,059.43)	(483,060.56)	(126,702.81)	(187,321.33)	(276,362.82)	(244,180.18)	(483,315.92)	(168,453.21)	(559,635.22)	(1,194,321.12)
23214	Deferred Revenue - Fac Fee Deposit	(704,840.70)	(704,840.70)	(741,440.70)	(741,440.70)	(741,440.70)	(520,824.55)	(545,424.55)	(577,824.55)	(577,824.55)	(577,824.55)	(577,824.55)	(577,824.55)	(640,824.55)
23215	Deferred Revenue - Fac Fee Large Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
23216	Due to Other Funds	-	-	-	-	-	-	-	-	-	-	-	-	-
23217	Retainage Payable	-	-	-	-	-	-	-	-	-	-	-	-	(115,122.46)
23750	Accrued Interest - Bonds	(580,575.15)	(825,264.26)	(1,069,953.37)	(1,314,642.48)	(1,559,331.59)	(335,886.07)	(580,575.18)	(825,264.29)	(1,069,953.40)	(1,314,642.51)	(1,559,331.62)	(324,765.26)	(576,563.74)
24200	Accrued Sick and Vacation	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(768,986.84)	(718,310.92)
25300	Deferred Credit - Pension	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(729,165.00)	(5,211,944.00)
25310	Deferred Credit - OPEB	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(110,445.12)	(101,858.58)
25402	Prepaid Lease - BPUD	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(130,876.38)	(125,842.67)
25700	Unamortized Gain on 2007 Refunded	(5,567.56)	(5,538.26)	(5,508.96)	(5,479.66)	(5,450.36)	(5,421.06)	(5,391.76)	(5,362.46)	(5,333.16)	(5,303.86)	(5,274.56)	(5,245.26)	(5,215.96)
	TOTAL LIABILITIES	(76,666,082.04)	(76,912,930.95)	(77,893,516.15)	(77,013,993.68)	(77,768,179.46)	(75,773,371.35)	(76,458,301.04)	(77,250,111.02)	(77,562,612.40)	(77,419,111.31)	(76,848,200.85)	(72,583,887.79)	(86,031,328.93)
NET INCOME & FUND EQUITY														
NI	Net Income - Year to Date	(5,044,464.73)	(1,080,711.81)	(1,462,909.09)	(2,500,240.62)	(2,283,855.50)	(2,345,349.34)	(2,662,253.46)	(3,762,308.41)	(4,904,223.35)	(5,974,621.59)	(6,529,458.24)	(7,590,029.86)	(9,544,523.89)
21500	Ret Earnings - Ins Set Aside	-	-	-	-	-	-	-	-	-	-	-	-	-
21600	Unappro Retained Earnings	(46,006,814.37)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)	(51,051,279.10)
27150	Contributed Capital	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)
27160	Contributed Capital	-	-	-	-	-	-	-	-	-	-	-	-	-
43910	Residual Equity Transfer	-	-	-	-	-	-	-	-	-	-	-	-	-
43900	Adjust to Retained Earnings	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64
	TOTAL NET INCOME & FUND EQUITY	(62,547,026.09)	(63,627,737.90)	(64,009,935.18)	(65,047,266.71)	(64,830,881.59)	(64,892,375.43)	(65,209,279.55)	(66,309,334.50)	(67,451,249.44)	(68,521,647.68)	(69,076,484.33)	(70,137,055.95)	(72,091,549.98)
	TOTAL ASSETS	139,213,108.13	140,540,668.85	141,903,451.33	142,061,260.39	142,599,061.05	140,665,746.78	141,667,580.59	143,559,445.52	145,013,861.84	145,940,758.99	145,924,685.18	142,720,943.74	158,122,878.91
	TOTAL LIABILITIES & FUND EQUITY	(139,213,108.13)	(140,540,668.85)	(141,903,451.33)	(142,061,260.39)	(142,599,061.05)	(140,665,746.78)	(141,667,580.59)	(143,559,445.52)	(145,013,861.84)	(145,940,758.99)	(145,924,685.18)	(142,720,943.74)	(158,122,878.91)
		-	-	-	-	-	-	-	-	-	-	-	-	-

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED REVENUE SHEET
CY 2021 ACTUAL

REVENUES

Acct. No	Account Title	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Year To Date
41900	Interest Income	(12,534.03)	(11,287.81)	(8,692.74)	(5,240.02)	(3,277.68)	(5,717.22)	(10,707.79)	(4,871.92)	(8,855.45)	(4,132.55)	(2,459.81)	(5,229.35)	(83,006.37)
41900	(Gain)/Loss on Fair Market Value (FMV) Adjustment	-	-	-	-	-	-	-	-	-	-	-	182,044.49	182,044.49
41910	Interest (Consv Loan Int Payments)	(4,020.93)	(3,867.03)	(3,820.06)	(3,796.83)	(3,778.21)	(3,892.75)	(3,902.17)	(3,916.84)	(3,907.65)	(3,742.54)	(3,619.86)	(3,669.50)	(45,934.37)
41911	Interest on Conservation Loan Investment	(36.44)	(31.80)	(29.76)	(25.79)	(19.97)	(19.05)	(46.61)	(20.62)	(22.02)	(24.51)	(21.78)	(23.73)	(322.08)
41912	Other Interest Thru Collection Agency	(12.95)	(108.84)	(91.10)	(118.16)	(134.66)	(82.16)	(192.63)	(181.96)	(299.29)	(294.83)	(47.04)	(12.13)	(1,575.75)
41920	BPA - Conservation Admin Fee	(14,704.65)	(14,599.85)	(19,741.34)	(10,537.05)	(2,379.15)	(18,761.83)	(6,751.23)	(21,313.08)	(54,443.61)	(52,184.61)	(9,811.82)	(8,615.81)	(233,844.03)
41921	BPA - Conservation Program (EEI)	(89,287.60)	(88,258.36)	(105,920.32)	(54,899.03)	(30,080.59)	(92,240.18)	(27,245.00)	(183,436.32)	(278,160.28)	(90,687.55)	(54,488.72)	(67,693.84)	(1,162,397.79)
41922	LSO Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-
42100	Miscellaneous Revenue	-	(993.66)	-	-	(391.01)	(20.09)	-	(1.26)	-	-	(1,840.42)	-	(3,246.44)
42100	Other Operating Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-
42100	Transfers From General Fund	-	-	-	-	-	-	-	-	-	-	-	-	-
43400	Insurance Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
43401	Bonneville Power Admin. REP Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
43902	Prior Period Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
44000	Electric Utility Tax	(600,838.06)	(521,561.83)	(545,920.28)	(469,919.27)	(444,716.23)	(495,573.17)	(611,298.19)	(634,248.45)	(565,776.98)	(475,786.07)	(447,387.16)	(520,737.62)	(6,333,763.31)
44010	Energy: Residential	(3,761,664.74)	(2,864,478.83)	(3,265,811.42)	(2,338,959.61)	(2,031,979.38)	(2,404,993.66)	(3,228,776.44)	(3,239,268.53)	(2,700,644.93)	(2,112,318.50)	(2,015,750.57)	(2,812,047.19)	(32,776,693.80)
44210	General Service	-	-	-	-	-	-	857.42	-	-	-	-	(857.42)	-
44211	Small Gen Service	(583,604.18)	(576,952.18)	(540,717.98)	(515,152.54)	(482,186.94)	(517,775.99)	(624,047.53)	(659,065.06)	(604,924.76)	(503,471.71)	(479,387.21)	(519,820.91)	(6,607,106.99)
44212	Medium Gen Service	(689,999.43)	(704,988.31)	(702,975.69)	(678,407.29)	(649,788.24)	(701,679.00)	(810,035.43)	(897,596.46)	(859,304.44)	(754,921.39)	(698,685.07)	(752,235.59)	(8,900,616.34)
44213	Large Gen Service	(665,437.66)	(696,762.90)	(630,003.23)	(700,258.66)	(682,778.19)	(713,443.46)	(789,151.77)	(826,852.49)	(776,206.83)	(694,453.00)	(645,822.44)	(663,601.57)	(8,484,772.20)
44215	Cable TV Amp	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(67,445.64)
44220	Large Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
44221	Small Industrial	(262,209.71)	(260,928.09)	(268,428.51)	(258,628.04)	(316,456.92)	(323,361.19)	(347,085.34)	(369,313.85)	(355,640.59)	(373,746.75)	(338,984.73)	(326,703.32)	(3,801,487.04)
44222	Large Industrial	(455,886.79)	(466,992.26)	(424,887.37)	(473,449.02)	(453,666.36)	(462,990.72)	(485,327.81)	(495,105.70)	(507,289.65)	(457,583.43)	(486,864.28)	(470,565.75)	(5,640,609.14)
44225	Large Irrigation	(2,356.96)	(2,277.06)	929.96	(41,376.45)	(110,941.18)	(160,761.94)	(235,782.90)	(276,981.81)	(224,019.46)	(163,724.63)	(95,770.04)	(10,831.39)	(1,323,893.86)
44230	Small Irrigation	(1,143.89)	(694.72)	(937.44)	(19,386.07)	(12,755.89)	(6,913.90)	(16,421.08)	(19,052.92)	(19,357.19)	(16,403.48)	(11,138.41)	(2,959.12)	(127,164.11)
44410	Street Lighting	(31,536.61)	(27,281.52)	(30,196.79)	(29,305.50)	(30,345.59)	(29,366.70)	(30,345.59)	(30,421.85)	(29,461.50)	(30,748.90)	(29,895.60)	(30,892.12)	(359,798.27)
44420	Traffic Lighting	(3,528.81)	(3,738.03)	(3,521.56)	(3,166.13)	(3,170.70)	(3,092.80)	(3,028.74)	(2,957.37)	(3,260.55)	(3,261.79)	(3,355.89)	(3,480.03)	(39,562.40)
44700	Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
45100	Misc Service Revenue	(675.00)	(675.00)	(675.00)	(1,575.00)	(675.00)	(2,025.00)	(2,025.00)	(1,800.00)	(2,025.00)	(2,250.00)	(3,150.00)	(96,300.00)	(113,850.00)
45110	New Accounts	(5,895.00)	(4,575.00)	(6,555.00)	(7,950.00)	(5,700.00)	(9,315.00)	(8,460.00)	(7,740.00)	(7,770.00)	(6,570.00)	(6,870.00)	(7,335.00)	(84,735.00)
45112	Accounts Transfer Fee	-	-	-	-	-	-	-	-	-	-	-	-	-
45120	Reimb Loan Service Fees	(1,155.00)	(1,562.00)	(2,154.00)	(1,328.00)	(980.00)	(3,738.00)	(1,311.00)	(2,205.00)	(651.57)	(245.00)	(604.00)	(473.00)	(16,406.57)
45121	Temp Service Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
45122	Permanent Service Fees	(20,958.45)	(30,864.25)	(23,023.23)	(10,625.00)	(24,090.60)	(25,561.06)	(25,961.28)	(22,315.25)	(27,145.76)	(27,401.00)	(24,302.25)	(13,600.24)	(275,848.37)
45123	Damages & Claims	-	-	-	-	-	-	-	(6,459.46)	-	-	(25,318.57)	31,778.03	-
45124	Rewires & Underground Conversion	(23,743.79)	(214.46)	(469.31)	(300.00)	(1,750.91)	(2,871.72)	(1,666.31)	-	(4,374.17)	(2,720.71)	(200.00)	(200.00)	(38,511.38)
45125	Facilities Fees	(2,396.57)	(178,873.66)	(51,656.32)	(7,481.78)	(105,412.34)	(109,014.29)	(113,130.36)	(9,358.98)	(15,492.37)	(41,064.35)	(6,145.54)	(288,278.48)	(928,305.04)
45126	Contributed Capital (NonCash)	-	-	-	-	-	-	-	-	-	-	-	(233,244.87)	(233,244.87)
45150	Disconnect/Reconnect Fees	(50.00)	-	-	(50.00)	(250.00)	-	(100.00)	-	(75.00)	-	(475.00)	(550.00)	(1,550.00)
45152	Operations Disconnect/Rec Fees	-	-	-	-	-	-	-	(100.00)	-	-	-	-	(100.00)
45154	Delinquent Account Fees	3,811.60	525.20	(140.40)	104.00	(109.20)	(85.80)	(2.60)	(2,792.40)	478.40	(4,318.60)	6,554.60	(260.00)	3,764.80
45160	Rental Lights Contract	(10,498.84)	(9,384.07)	(10,141.00)	(10,182.98)	(10,408.47)	(10,856.32)	(10,461.62)	(10,906.28)	(10,567.86)	(11,078.75)	(10,326.34)	(11,600.72)	(126,413.25)
45170	Land Sales	-	-	-	-	-	-	-	-	(9,583.20)	-	-	-	(9,583.20)
45440	Pole Contacts-Telecable	-	-	-	-	-	-	-	-	-	-	-	(100,863.50)	(100,863.50)
45601	EECBG/ARRA Grant Funds	-	-	-	-	-	-	-	-	-	-	-	-	-
45602	BAB Federal Interest Subsidy	-	-	-	-	-	-	-	-	-	-	-	-	-
45603	COVID Assistance	-	-	-	-	-	-	-	-	-	-	-	-	-
45610	Gain/Loss on Sale of Scrapped Assets	-	-	-	-	(291.62)	-	(5,391.15)	-	-	-	-	(1,908.39)	(7,591.16)
45629	Meter Reading Revenue	(18,959.99)	(19,625.57)	(23,144.70)	(22,920.77)	(19,965.04)	(22,298.62)	(19,332.48)	(20,565.08)	(21,884.38)	(24,381.84)	(20,630.05)	(20,165.32)	(253,873.84)
45630	Work For City Depts	-	(19,936.85)	(41,217.06)	-	(39,971.73)	(7,475.05)	(21,743.48)	(14,036.18)	(934.85)	(17,734.26)	(19,785.70)	(356,814.05)	(539,649.21)
45653	City Shops Rental	-	-	-	-	-	-	-	-	-	-	-	-	-
45654	Land Lease	-	-	-	-	-	-	-	-	-	-	-	(5,033.71)	(5,033.71)
	TOTAL REVENUES	(7,264,944.95)	(6,516,609.21)	(6,715,562.12)	(5,670,555.46)	(5,474,072.27)	(6,139,547.14)	(7,444,494.58)	(7,768,505.59)	(7,097,221.41)	(5,880,871.22)	(5,442,204.17)	(7,128,401.62)	(78,542,989.74)

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED EXPENSE SHEET
CY 2021 ACTUAL

EXPENSES

Acct. No	Account Title	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Year To Date
40300	Depr Exp Transmission	15,873.44	15,873.43	15,873.44	15,873.43	15,873.44	15,873.43	15,873.44	15,873.43	15,873.44	15,873.43	15,873.44	15,873.43	190,481.22
40302	Depr Exp Distribution	497,800.04	497,799.99	497,800.05	497,799.98	497,800.06	497,799.98	497,800.06	497,799.98	495,352.70	495,352.63	495,352.70	495,352.63	5,963,810.80
40304	Depr Exp Misc	17,993.30	17,993.29	17,993.30	17,993.29	16,483.14	16,483.14	16,483.14	16,483.14	16,483.14	16,483.14	16,483.14	16,483.14	203,838.30
40306	Depr Exp City Shops	-	-	-	-	-	-	-	-	-	-	-	-	-
40310	Transfer To Equip Replacement Fund	62,751.17	62,751.17	62,751.17	62,751.17	62,751.17	62,751.17	62,751.17	62,751.17	62,751.17	62,751.17	62,751.17	62,751.13	753,014.00
40311	Transfer To Broadband Fund	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	30,000.00
40810	Taxes-City Occupation	601,317.72	522,041.12	546,399.69	471,224.02	444,959.24	496,096.48	611,704.66	634,728.26	566,276.39	476,265.10	447,864.00	521,216.02	6,340,092.70
40830	Taxes-Social Security	-	-	-	-	-	-	-	-	-	-	-	-	-
40910	Taxes-State B&O	595.32	4,605.99	1,599.57	(61.34)	2,497.41	2,714.94	2,776.92	899.27	1,052.88	1,566.23	690.68	6,667.05	25,604.92
40920	Taxes-State Public Utility	269,348.67	232,881.26	242,967.73	207,665.16	194,549.85	216,784.70	269,002.67	265,545.36	44,945.99	210,359.22	198,777.77	228,193.00	2,581,021.38
41600	Contract Work Locator	-	-	-	-	-	-	-	-	-	-	-	-	-
41710	Non-Utility Operations	57,012.26	68,173.11	70,012.22	96,713.06	75,364.97	70,946.71	61,646.84	66,227.93	95,107.71	74,069.57	71,172.52	348,609.33	1,155,056.23
41711	Non-Billable Work For Other Depts	-	24.96	54.26	79.22	-	-	54.26	303.86	542.60	-	-	111.78	1,170.94
42750	Accrued Interest Bonds	244,689.11	244,689.11	244,689.11	244,689.11	244,689.11	244,689.11	244,689.11	244,689.11	244,689.11	244,689.11	233,568.27	251,798.48	2,932,257.85
42756	Interest Exp-1999 Bonds	-	-	-	-	-	-	-	-	-	-	-	-	-
42765	Interest Exp-Notes	-	-	-	-	-	-	-	-	-	-	-	-	-
42800	Amort of Debt Discount	-	-	-	-	-	-	-	-	-	-	-	-	-
42800	Debt Issuance Expense	-	-	-	-	-	-	-	-	-	-	-	179,888.09	179,888.09
42810	Amort of Loss on Reacquired Debt	2,621.48	2,621.48	2,621.48	2,621.48	2,621.48	2,621.48	2,621.48	2,621.48	2,621.48	2,621.48	2,621.48	2,621.48	31,457.76
42900	Amort of Debt Premium	(23,036.04)	(23,036.04)	(23,036.04)	(23,036.04)	(23,036.04)	(23,036.04)	(23,036.04)	(23,036.04)	(23,036.04)	(23,036.04)	(23,036.04)	(26,872.99)	(280,269.43)
43901	Prior Period Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
55500	Purchased Power	2,911,511.00	3,057,157.00	2,649,710.00	2,816,604.00	2,599,641.00	2,766,959.00	3,161,404.00	3,270,546.00	2,883,532.00	2,346,806.00	1,969,746.00	2,981,308.00	33,414,924.00
55520	Purchased Power WPPSS	-	-	-	-	-	-	-	-	-	-	-	-	-
55550	Purchased Power For Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
55501	BPUD Energy Charges For City Customers	754.49	-	1,124.18	309.57	-	583.72	343.21	-	624.90	262.64	-	755.47	4,758.18
55503	Purchased Power - Non Federal	162,192.00	146,496.00	176,003.90	156,960.00	162,192.00	180,189.22	162,192.00	162,192.00	200,223.18	162,564.00	157,538.50	185,380.75	2,014,123.55
55504	Purchased Power - Renewable	7,872.31	(4,621.23)	23,886.32	26,309.40	33,365.00	32,420.88	32,390.08	29,301.00	26,089.67	18,749.23	11,053.76	8,448.78	245,265.20
56500	Transmission Expense	368,918.00	403,071.00	306,878.00	292,776.00	316,430.00	461,645.00	464,321.00	462,854.00	400,648.00	323,435.00	335,991.00	401,172.00	4,538,139.00
58000	Oper-Supervision & Engineering	182,130.63	113,652.84	104,966.93	132,130.26	97,278.23	107,169.47	104,695.70	107,568.04	143,788.72	87,537.05	111,456.62	299,425.57	1,591,800.06
58100	Oper-Load Dispatching	14,054.86	14,886.64	17,114.02	21,074.00	13,921.77	17,488.62	17,803.36	25,304.13	35,625.74	23,782.12	18,699.57	61,855.01	281,609.84
58200	Oper-Station Expense	-	-	4,065.58	1,165.23	3,995.67	1,422.06	1,421.01	-	-	-	-	-	12,069.55
58300	Oper-Overhead Line	14,626.85	81,554.56	65,229.54	51,823.52	44,787.60	30,418.40	28,413.27	16,845.74	27,258.77	41,053.37	40,030.47	101,187.35	543,229.44
58350	Oper-PCB Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
58400	Oper-Underground Line	1,334.12	10,444.79	1,936.26	5,768.37	6,284.38	16,547.05	4,484.79	3,525.23	476.97	1,376.59	506.96	576.44	53,261.95
58500	Oper-Street Light & Signal	13.58	-	-	-	-	4,312.73	-	-	-	125.59	-	619.91	5,071.81
58510	Oper-Street Lights	39,749.63	26,733.01	39,761.25	35,862.72	15,929.22	5,604.20	6,009.38	18,736.93	20,909.44	24,812.24	8,940.82	56,894.99	299,943.83
58520	Oper-Telemeter Systems	474.75	27.13	73.01	1,101.34	-	-	667.89	113.08	27.13	43.60	15.65	(42.84)	2,500.74
58530	Oper-Traffic Signals	-	-	-	-	-	-	-	302.75	-	-	-	551.09	853.84
58550	Oper-Rental Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-
58600	Oper-Meter Expense	4,635.99	6,702.15	7,590.33	23,664.28	8,305.19	8,881.39	2,947.28	-	-	-	-	10,312.07	73,038.68
58700	Oper-Customer Install	1,642.06	-	-	-	-	-	-	-	-	-	-	-	1,642.06
58800	Oper-Misc Distribution	95,726.84	120,579.91	84,490.49	90,455.09	97,115.58	66,446.39	51,221.03	66,251.50	55,146.82	76,231.59	55,555.49	137,291.18	996,511.91
58900	Oper-Rents	-	1,484.62	1,484.62	-	742.31	1,484.62	742.31	-	1,484.62	848.74	-	-	8,271.84
59000	Maint-Supervision & Engineering	1,842.94	3,938.18	3,347.65	4,455.44	3,857.92	2,777.68	2,539.35	2,738.87	5,714.54	4,189.84	769.06	8,014.68	44,186.15
59100	Maint-Structures	978.05	-	-	7,752.87	-	-	-	-	-	-	-	(131.00)	8,599.92
59200	Maint-Station Equip	998.99	11,998.03	7,471.05	16,106.04	796.82	6,753.76	5,709.10	7,693.71	10,932.39	17,989.42	17,635.62	21,963.61	126,048.54
59300	Maint-Overhead Lines	6,278.90	4,737.65	4,162.58	30,203.50	18,658.93	16,274.82	8,317.66	8,978.63	19,503.61	7,533.46	10,820.78	42,173.50	177,644.02
59400	Maint-Underground Lines	7,581.38	15,700.74	16,046.59	12,578.61	4,044.26	12,130.19	27,208.10	44,138.87	60,173.92	22,714.44	35,580.79	58,813.99	316,711.88
59500	Maint-Line Transformers	1,119.97	15,776.76	892.13	303.88	-	543.83	5,083.15	12,438.63	37,888.85	36,788.19	313.38	40,728.91	151,877.68
59510	Maint-Line Transformers OH	27.17	48.52	212.02	466.96	-	-	-	163.49	-	-	865.99	-	1,784.15
59520	Maint-Line Transformers Underground	-	-	150.63	4,087.71	-	239.05	1,218.70	256.46	4,403.69	-	472.36	1,623.89	12,452.49
59600	Maint-Street Lighting	605.50	-	200.84	3,849.10	-	389.60	-	-	307.11	-	-	1,023.44	6,375.59
59620	Other Maintenance	108.68	808.79	45.32	1,490.71	-	67.98	147.78	110.34	-	-	-	-	2,779.60
59700	Maint-Meters	204.42	704.37	704.37	1,630.95	76.66	2,884.52	2,173.30	893.20	2,195.53	2,292.43	457.76	5,574.57	19,792.08
59800	Maint-Misc Distr Plant	12,238.16	9,429.39	11,046.64	14,719.22	10,672.14	11,849.55	11,198.12	11,177.18	13,822.71	11,615.55	12,833.16	37,632.00	168,233.82
59810	Maint-Vehicles	873.22	-	-	-	-	-	-	-	-	-	-	(785.90)	87.32
90200	Meter Reading Expense	80,802.78	74,533.42	76,507.43	104,113.47	68,586.92	63,656.60	78,035.55	49,071.38	60,344.64	49,760.04	56,491.77	226,176.83	988,080.83
90300	Customer Records & Collections	119,854.77	120,222.25	119,806.31	119,976.10	119,823.88	121,017.35	120,708.93	122,069.61	120,371.61	120,329.41	(143,394.31)	160,026.39	1,220,812.30
90400	Uncollectible Accounts	10,030.00	10,030.00	10,030.00	10,030.00	10,030.00	10,030.00	10,030.00	10,030.00	10,030.00	10,030.00	10,030.00	(275,058.22)	(164,728.22)
90840	Customer Assistance Cons Program	35,976.66	46,490.41	76,324.67	92,307.81	58,201.58	85,322.52	65,958.08	217,842.72	137,802.21	163,471.35	64,058.19	256,508.70	1,300,264.90
90841	BPA reimbursement	-	-	-	-	-	-	-	-	-	-	-	-	-
92000	Admin & General Salaries	42,926.13	42,788.92	44,694.60	70,939.31	42,628.14	39,165.28	38,974.23	41,056.80	64,489.88	40,817.72	43,186.47	50,200.38	561,867.86
92100	Office Supplies & Expense	972.65	2,419.72	1,491.23	2,709.20	1,377.36	1,624.44	2,074.34	977.91	1,167.62	3,059.41	3,034.24	3,027.26	23,935.38
92300	Outside Service Employees	40,256.25	38,663.75	47,833.51	41,812.52	46,271.41	47,127.94	60,975.88	56,327.04	61,107.25	53,209.29	(12,560.52)	75,106.75	556,131.07
92301	Service Territory Relations	-	-	-	-	-	-	-	-	-	-	-	-	-
92400	Insurance	16,098.79	16,098.85	16,098.85	16,098.85	16,098.85	16,098.85	16,098.85	16,098.85	16,098.85	16,098.85	16,098.85	16,098.85	193,186.14
92500	Injuries & Damages	-	-	-	-	-	-	-	-	-	-	-	-	-
92600	Employee Pension & Benefits	23,802.91	24,002.12	23,921.55	27,784.41	23,850.27	23,773.21	23,317.62	23,008.60	26,306.35	23,040.56	22,965.89	(1,956,712.01)	(1,690,938.52)
93000	Misc General Expenses	2,500.00	396.10	355.54	360.93	214.84	2,411.33	4,997.34	244.34	2,819.21	5,625.14	953.81	385.00	21,263.58
93021	Organizational Dues	172,704.57	18,190.00	-	-	-	360.00	5,402.86	-	-	-	3,452.00	241.00	200,350.43
93022	Information Systems Services	50,346.67	50,346.67	50,346.67	50,346.67	50,346.67	50,346.67	50,346.67	50,346.67	50,346.67	50,346.67	3,413.29	50,346.63	557,226.62
93100	Rents	-	-	-	-	-	-	-	-	-	-	-	-	-
93200	Maint Of General Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL EXPENSES	6,184,233.14	6,134,411.93	5,678,230.59	5,886,940.58	5,412,578.43	5,822,643.02	6,344,439.63	6,626,590.65	6,026,823.17	5,326,034.57	4,381,632.55	5,173,907.59	68,998,465.85
	Net Income	1,080,711.81	382,197.28	1,037,331.53	(216,385.12)	61,493.84	316,904.12	1,100,054.95	1,141,914.94	1,070,398.24	554,836.65	1,060,571.62	1,954,494.03	9,544,523.89

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/12/2022 | Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Northwest RiverPartners Lower Snake River Dams Replacement Study (30 minutes)

Department:
Energy Services

Recommended Motion:
This item is for UAC discussion and input for next steps that protect the City's interests.

Summary:
On June 9, 2022, U.S. Senator Murray and WA Governor Inslee released their report to influence recommendations regarding the Lower Snake River Dams (LSRD). City Staff are not aware of any new scientific data or analysis included in the report compared to the Columbia River System Operations Environmental Impact Statement (CRSO EIS) completed in September 2020. However, the Murray-Inslee LSRD report will be heavy with public input comments that close on July 11th.

Northwest RiverPartners (NWRP) commissioned Energy GPS Consulting LLC to perform a full power cost replacement analysis for the LSRD, using an Aurora-based model. The study was finalized in late June. Attached is the complete NWRP analysis with an executive summary on page 3 as well as a presentation of the analysis.

Significant findings from the NWRP analysis include:

- Existing electric sector decarbonization laws require an unprecedented buildout of 160,000 MW of new resources by 2045, with a cost of $142 billion within the Western Power Pool (formerly the Northwest Power Pool).
- The replacement of LSRD power generation capacity would require an *additional* 14,900 MW of new resources (i.e., wind, solar, storage, and demand response) at an *incremental* cost of $15 billion (Net Present Value).
- It is unlikely that state decarbonization requirements are met until 2076, even if WPP *doubles* its historic pace of renewable buildout, causing emissions in the Pacific Northwest to increase by132 million metric tons (MMT) of CO_2 to maintain grid reliability.
- Removing LSRD capacity puts further stress on the ability to achieve state policy mandates, likely adding an additional 5 MMT – 8.5 MMT of CO_2 released into the atmosphere.

What is unclear are the next steps, as the Murray-Inslee report is not a congressional item.

Fiscal Impact:

Attachments:
1. EGPSC__LSRD Power Cost Replacement Study_6_29_2022_Final
2. 2022-06-29 NWRP Presentation_EGPSC - Lower Snake River Dam Power Supply Replacement Analsyis

Lower Snake River Dams Power Supply Replacement Analysis

Prepared for

Northwest RiverPartners

Prepared by

Energy GPS Consulting (EGPSC), LLC

6/29/2022

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1. Executive Summary

This study evaluates the power supply-related financial and CO_2 emissions impacts of breaching the four Federal dams on the lower Snake River. This analysis assesses the loss of the U.S. Amy Corps of Engineers owned dams (Ice Harbor Dam, Lower Monumental Dam, Little Goose Dam, and Lower Granite Dam) on the lower Snake River (LSRD) within the context of the most recent electric sector clean energy laws.[1]

Key Findings:

- Multiple prior studies have modeled LSRD replacement costs and impacts without considering existing grid decarbonization laws. The material impacts of losing the LSRD can only be properly understood by modeling the requirements of reaching a zero-carbon grid, both with and without the LSRD in place and then measuring the change in operating requirements to maintain grid reliability.
- Existing electric sector decarbonization laws require an unprecedented buildout of 160,000 MW of new resources by 2045, with a cost of $142 billion within the Western Power Pool (WPP - formerly the Northwest Power Pool).[2]
- **The replacement of LSRD power generation capacity would require an *additional* 14,900 MW of new resources** (i.e., wind, solar, storage, and demand response) and **at an additional $15 billion in cost**. The high costs of LSRD replacement are driven by the following key factors:
    - Initial resource additions are required to address existing laws.
    - The more on-demand generation the region loses (i.e., coal, natural gas, hydro, nuclear), the more variable generation (solar/wind) plus storage (batteries/pumped storage) must be built to ensure sufficient generation is always available.
    - The overbuild of renewables is not useful in many parts of the year and, by 2045, 35% of the annual energy from renewable resources is unusable and is curtailed.
    - To fulfill clean energy mandates, renewables and storage are built to replace the loss of the LSRD peak capacity, but due to curtailments, only 9 to 12% of the new resources can be utilized to meet demand.
- Even if the WPP region *doubles* its historic pace of renewable buildout, **it is unlikely that state requirements are met until 2076**, **causing emissions in the Pacific Northwest to increase by 132 million metric tons (MMT) of CO_2 to maintain grid reliability.**
- Requiring an additional 14,900 MW of resources to be built to replace the carbon-free LSRD capacity puts further stress on the ability to achieve state policy mandates, likely adding an additional 5 MMT – 8.5 MMT of CO_2 released into the atmosphere.

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[1] This study assumes the following laws as part of the baseline for the electric system: Washington's 2019 Clean Energy Transformation Act, Oregon's Emissions Reduction House Bill 2021, California's Senate Bill 100, Colorado's 2019 Clean Energy Legislation, Nevada's 2019 Clean Energy Legislation

[2] Western Power Pool states assumed for this study include Washington, Oregon, Montana, Idaho, Wyoming, Nevada, Utah, Colorado, and a small portion of California.

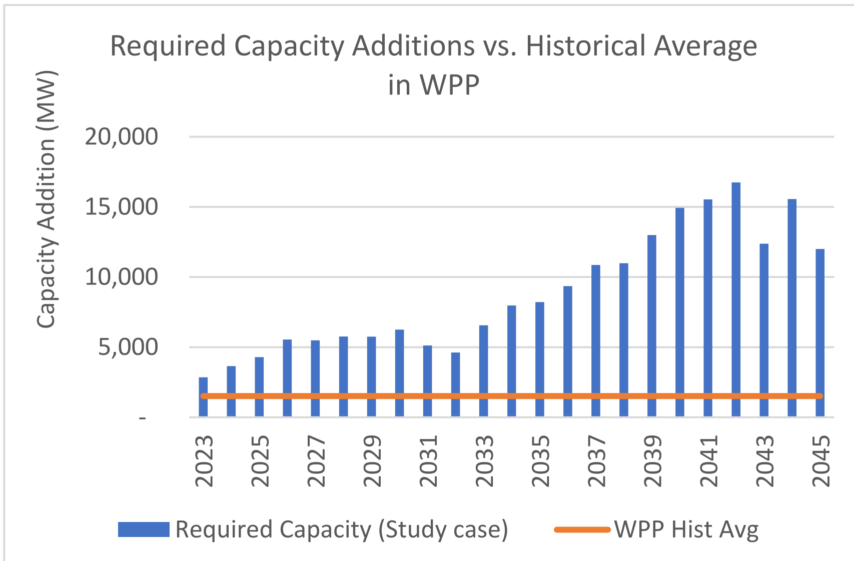
Table 1. Summary of results.

Name	Type	Renewable and Storage Capacity	Total Cost (NPV) †
Base Case (with LSRD)	Base expansion case to meet state clean energy laws and maintain reliability with the lower Snake River dams	160 GW	$142 B
Study Case (Base Case without LSRD)	Study expansion case to meet state clean energy laws and maintain reliability without the lower Snake River dams	175 GW	$157 B
Difference	***Impact of Breaching***	***15 GW***	***$15 B***

†NPV corresponds to 2023 using 2% inflation and discount rate.

Additional Details:

- More than 7,600 MW of renewable and battery storage additions are needed *every year* from 2023 – 2045 to meet WPP state requirements and replace the capacity of the LSRD.
- This requirement significantly exceeds the average build of 1,500 MW per year from 2007 – 2021 in the WPP, putting achievement of state policy mandates at risk.



The table and graphic below compare the required pace of build needed to meet the Study Case (7,600 MW/year) to historic experience in the WPP, CA and ERCOT.

Figure 1: Projected achievement dates of WPP grid decarbonization mandates based on historic build pace in various markets

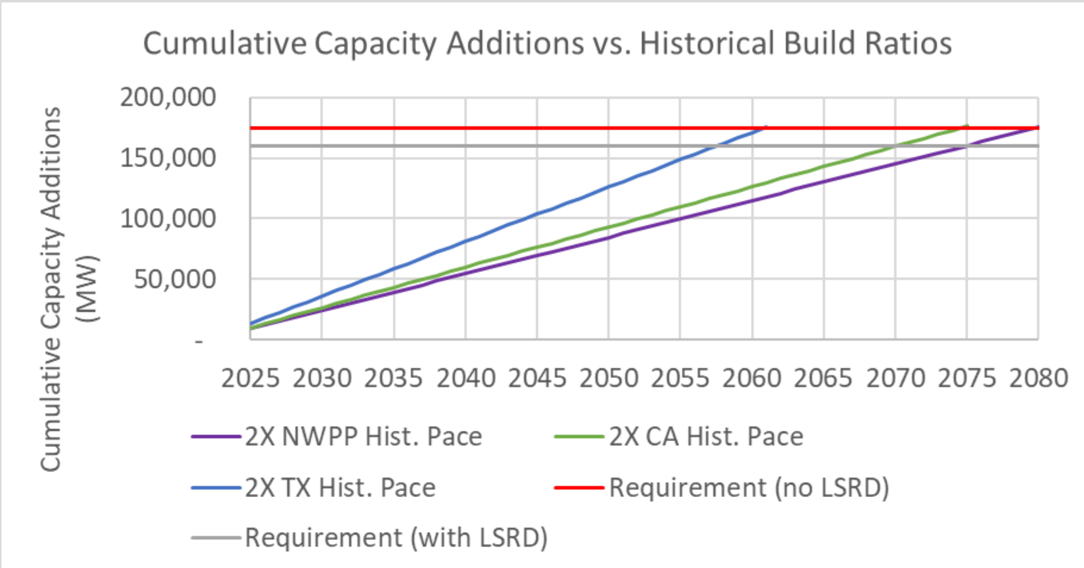


Table 2. Achievement of Study Objective under different build-out scenarios.

Annual Average Renewable Capacity Additions in WPP to meet Study Case			
	Using WPP Historic Buildout Pace	Using CA Historic Buildout Pace	Using ERCOT Historic Buildout Pace
Annual average renewable capacity additions from 2007 – 2021 (MW)	1512	1661	2326
Estimated achievement of clean energy laws if **double the historic pace** of capacity additions (Year)	2076	2071	2057
Added emissions due to delay (MMT)‡ [3]	136	114	55
Estimated achievement of clean energy laws and replacement of LSRD if double the historic capacity additions (Year)	2081	2076	2060
Added emissions due to delay for replacement of LSRD (MMT) ‡[4]	8.5	8.5	5.1

+Western Power Pool (WPP), California, and Electric Reliability Council of Texas (ERCOT)
‡Assumes average emission rate from 2030-2045 applied to each future year.

[3] We applied the average emission rate in Washington and Oregon to each future year, to calculate the added GHG emissions (past 2045) if clean energy laws are not met. These data were filtered to only Washington and Oregon to focus on Pacific Northwest impacts.

[4] To calculate the incremental emissions from breaching the LSRD, we re-ran the base case expansion plan without the LSRD, again assuming clean energy laws are not met by 2045. Emissions from the base case (with LSRD) were subtracted from the emissions from this new dispatch to estimate the incremental emissions associated from breaching the LSRD.

Parameters:

- This study did not evaluate the cost of building long-distance, high voltage transmission lines.
- This study did not evaluate risks that could further increase costs and/or delay decarbonization timing, including increased electric sector load growth due to electrification, grid reliability, land use, and permitting for new transmission and new resource builds.
- This study did not evaluate non-power related impacts of lower Snake River dam removal, such as the elimination of barging and the resultant higher CO_2 levels from a shift to trucking and rail. It also did not include financial and other considerations related to the loss of irrigation and recreational opportunities afforded by the dams.

Study Approach:

This study uses an electric industry standard Production Cost Model, best available load and resource cost estimates, and a 60-dam hourly production database to evaluate required resources additions in the Western Power Pool footprint. This study quantifies and evaluates the difference in capital costs, operating costs, and total production costs between two scenarios:

- Base Case: Meet reliability and WPP state electric grid decarbonization laws with existing lower Snake River dams,
- Study Case (Base Case without LSRD**)**: Meet reliability and WPP state electric grid decarbonization laws without existing lower Snake River dams

The model's forecast of generation additions required to replace the LSRD may be low due to the following assumptions:

- The study assumed average electric sector load growth and did not account for expected increased electric sector load due to electrification of transportation and buildings.
- The study assumed a lower capacity contribution for the LSRD relative to other regional studies.
- The study includes a limited transmission cost adder for short-distance transmission projects only. Many experts and studies recognize significant new long-distance, high voltage transmission and associated costs will required to support the new resources needed.
- The study did not put any constraints on wind and solar development and assumed sufficient land was available for new development. Other studies have indicated high land use is required and that state and local laws may limit development.
- The study assumed that adequacy and reliability were maintained under all scenarios by ensuring an industry standard planning reserve margin could be maintained. Other studies have indicated challenges in maintaining system adequacy and reliability to current standards under low or zero carbon scenarios.

Study Conclusions:

- Existing WPP state laws to decarbonize the electric system require 160,000 MW of new generation and batteries.
- An additional 14,900 MW of new generation and batteries will be required to make up for the loss of the LSRD in a zero-carbon future.
- More than 7,600 MW of renewable and battery storage additions is needed *every year* from 2023 – 2045 to meet the state laws and replace the capacity of the LSRD. This significantly

exceeds the average build of 1,500 MW per year from 2007 – 2021 in the Western Power Pool, putting achievement of state policy goals at risk.
- Even if the WPP region doubles its historic pace of renewable build, it is unlikely that state goals are met until 2076 and emissions in the region increase by 132 million metric tons.
- The additional 14,900 MW of resources needed to replace the existing carbon-free LSRD capacity puts further stress on the ability to achieve state policy goals, potentially adding an additional 5 MMT – 8.5 MMT of CO2 released into the atmosphere.

2. Background

The objective of this study is to evaluate the power supply-related financial and CO_2 impacts of breaching four dams on the lower Snake River – Lower Granite, Lower Monumental, Ice Harbor and Little Goose. The study quantifies: 1) changes in generating capacity[5], type, location, and amount required to maintain reliability standards and meet state clean energy laws[6], 2) financial costs associated with the new generating capacity mix, and 3) the CO_2 emissions implications associated with the new generating capacity mix.

To meet the study objective, the study includes the following major tasks:
1. Base Case: Quantify capacity expansion plan (new resource additions) required to meet reliability standards and state clean energy laws if the lower Snake River dams (LSRD) are in place,
2. Study Case (Base Case without LSRD): Quantify capacity expansion plan required to meet reliability standards and state clean energy laws if the LSRD are removed, and
3. Quantify difference in capital costs, operating costs, total production costs, and CO_2 emissions impacts from removing the LSRD.

3. Approach

To meet task 1, we used a Western Electricity Coordinating Council (WECC)-wide zonal production cost model (PCM) configured for long-term capacity expansion. The model was run from 2023-2045 <u>with the LSRD</u> continuing to operate. Dispatch levels, costs, and CO_2 emissions were outputted from this Base case.

To meet task 2, the PCM was run to produce a capacity expansion plan, meeting reliability and state clean energy laws <u>if the LSRD were removed</u>. Retirement dates were set to follow Representative Mike Simpson's (ID – CD2) plan, with two dams removed in 2030 and two in 2031. Dispatch and costs were outputted from this Study Case (Base case without LSRD).

To meet task 3, differences between the two simulations (with and without the LSRD) were calculated, quantifying the additional capacity (amount, type, location, and timing) required to meet state clean

[5] When this paper refers to capacity, it means nameplate capacity, unless otherwise stated. Nameplate capacity is the fully rated maximum generation a power plant can typically provide if sufficient fuel is available.
[6] This study does not directly consider the impact of current state clean energy laws on electrification of the transportation and heating resulting in additional load growth. Rather business as usual load growth is used, additional electrification of transportation or heating would lead to a greater amount of capacity and thus cost required to replace the LSRD.

energy laws and maintain reliability. Annual cost differentials and CO_2 emissions between the two runs were also calculated.

4. Methods

Production cost models are used by utilities and regulators to inform long-term planning and policy decisions. For example, the California Public Utility Commission requires production cost modeling for Integrated Resource Plans (IRP) in California. In the early planning years, utilities used spreadsheets and in-house tools for developing long-term plans. However, as the system became more complex these in-house tools have largely been replaced with commercial software. In the WECC, the key commercial software tools are the SERVM and RESOLVE tools used by CPUC[7], the ABB Capacity Expansion (CE) tool and the PLEXOS tool used by PG&E[8], and the Aurora tool used by the Northwest Power & Conservation Council[9], Portland General Electric[10], and Puget Sound Energy[11].

The production cost models solve for the least cost solution to meet forecasted load (i.e., demand for electricity) with a given set of existing or candidate generating resources subject to constraints. Constraints typically include transmission flow limits, renewable energy targets, energy efficiency and resource retirement targets.

We used the Aurora commercial production cost model for this work. Inputs for the commercial PCM were developed by EGPS and evaluated with historical data. In addition, EGPS has an hourly production database for 60 dams in the Pacific Northwest that represent most of the hydroelectric operating capacity in the region. This dataset was used to derive unit-specific hydro monthly shapes and annual capacity factors for each hydro unit, including the four LSRD studied here, based on normal hydro years and normal hydro months.[12] Unit specific hourly shaping parameters were developed using hourly generation data from 2018 to 2021. A description of the EGPS production cost model and inputs is in Appendix A.

5. Model Inputs

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[7] CPUC RA and IRP Model, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials/unified-ra-and-irp-modeling-datasets-2019

[8] SCE IRP, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M346/K291/346291781.PDF#:~:text=In%20this%20IRP%20filing%2C%20SCE%20includes%20a%20proposed,any%20energy%20storage%20used%20to%20meet%20their%20needs

[9] https://www.nwcouncil.org/2021powerplan_aurora-model/

[10] PGE IRP, https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf

[11] Puget Sound Energy IRP, https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/IRP21_Chapter%20Book%20Compressed_033021.pdf

[12] The University of Washington Climate Impact Group predicts, under likely climate change scenarios, the Pacific Northwest will see annual precipitation to remain at about historical normal, but with an earlier run-off pattern caused by warmer weather. The Energy GPS analysis did not attempt to alter historic flow river flow patterns. https://cig.uw.edu/wp-content/uploads/sites/2/2020/12/snoveretalsok2013sec5.pdf

The WECC is often broken down in to five subregions for purposes of understanding reliability. In fact, the North American Electric Reliability Corporation (NERC) currently breaks WECC into planning regions comprised of the Western Power Pool (WPP), California and Mexico (CA/MX), the Southwest Reserve Sharing Group (SRSG), Alberta (AB), and British Columbia (BC) [13]. NERC utilizes these groupings, because these sub-regions tend to have similar operating practices and demand patterns.

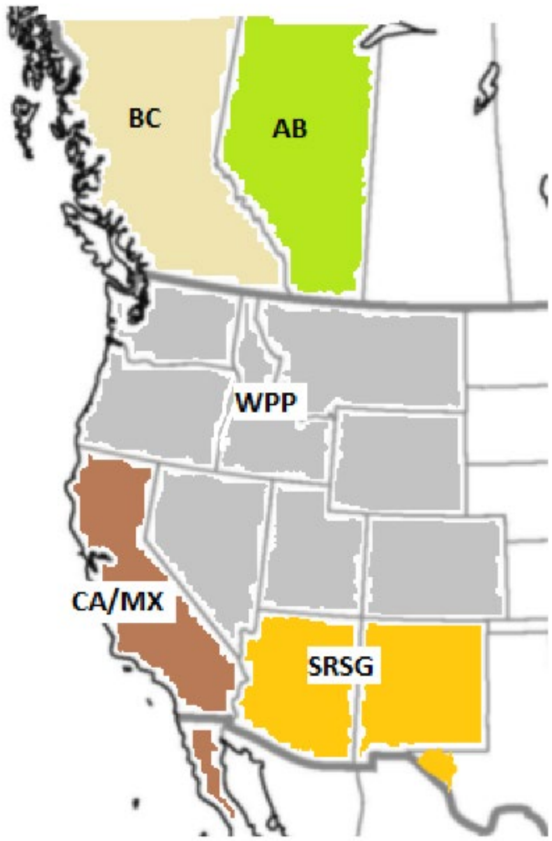


Figure 1. Reliability Regions within WECC

Note, as defined WPP includes former subregion of Rocky Mountain Reserve Group. Source: EGPS.

The WPP NERC reliability area covers the Pacific Northwest (PNW[14]) as well as Montana, Idaho, Nevada, Utah, Wyoming, and Colorado. Parts of the WPP are located in California (e.g., the Balancing Area of Northern California). The WPP has approximately 64 Gigawatts (GW) of peak load and approximately 115 GW of generating resources, primarily comprised of hydro, natural gas, coal, and wind. As with other regions, significant amounts of coal generation have been, or are planned to be, retired.

[13] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

[14] The PNW for this report is defined by the available generation and load data. It encompasses Oregon and Washington hourly load, Oregon and Washington natural gas, coal, and nuclear generation, BPA wind and solar, hydro production from the 60 largest dams in the US portion of the Columbia River Basin, plus transmission flows reported by BPA between the PNW and British Columbia, Montana/Idaho, and California.

Daily operation within the WECC is the responsibility of 38 Balancing Authorities (BA). Part of the daily operation requirements for a BA is to ensure, at a fine temporal scale, load and generation are always balanced. This is accomplished by perfectly balancing load and generation, within the balancing authority footprint, on a second-to-second basis such that system frequency is maintained at 60 hertz.

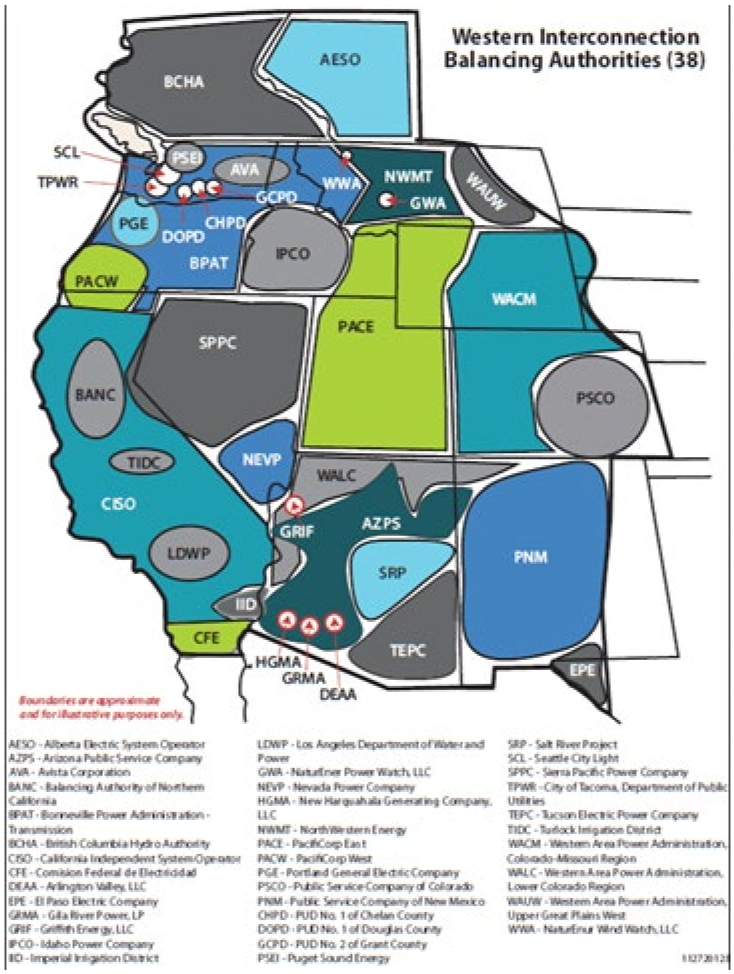


Figure 2. WECC Balancing Authorities

The California Independent System Operator (CAISO) maintains the balancing for much of California. Within the SRSG, the BAs are WAPA Lower Colorado, Arizona Public Service, Salt River Project, Tucson Electric Power, Public Service of New Mexico, and El Paso Electric. Within the WPP Rocky Mountain region (as defined by NERC), the BA's include Public Service of Colorado, WAPA Rocky Mountains, and PacifiCorp East. Within the WPP region outside of the Rocky Mountains, the BAs include WAPA Upper West, NW Montana, Idaho Power, PacifiCorp West, Bonneville Power, Avista, Portland General Electric, Seattle City Light, Tacoma Power, Puget Sound Energy, and various Public Utility Districts (PUD) including Grant County, Douglas County, and Chelan County.

A fundamental input for PCM is the definition of the transmission topology and load zones. These inputs specify where potential transmission constraints may occur as well as the load requirement for generation to serve. If BAs are aggregated and real transmission constraints not considered, the model will never capture actual system conditions. In general, our model captures the WECC BAs as individual load zones. BA loads are directly applied to each zone and disaggregated for finer granularity in some cases such as BPA Northwest, Southwest, and East. Between zones transmission constraints may exist such as the Cross Cascades Transmission Constraint, but do not exist between all BAs (e.g., Avista and BPAT East). A summary of our transmission topology for the PNW is shown in Figure 3.

From the perspective of where the LSRD are located, major constraints include the AC and DC lines to California and limits to BC to the north and ID/MT to the east.

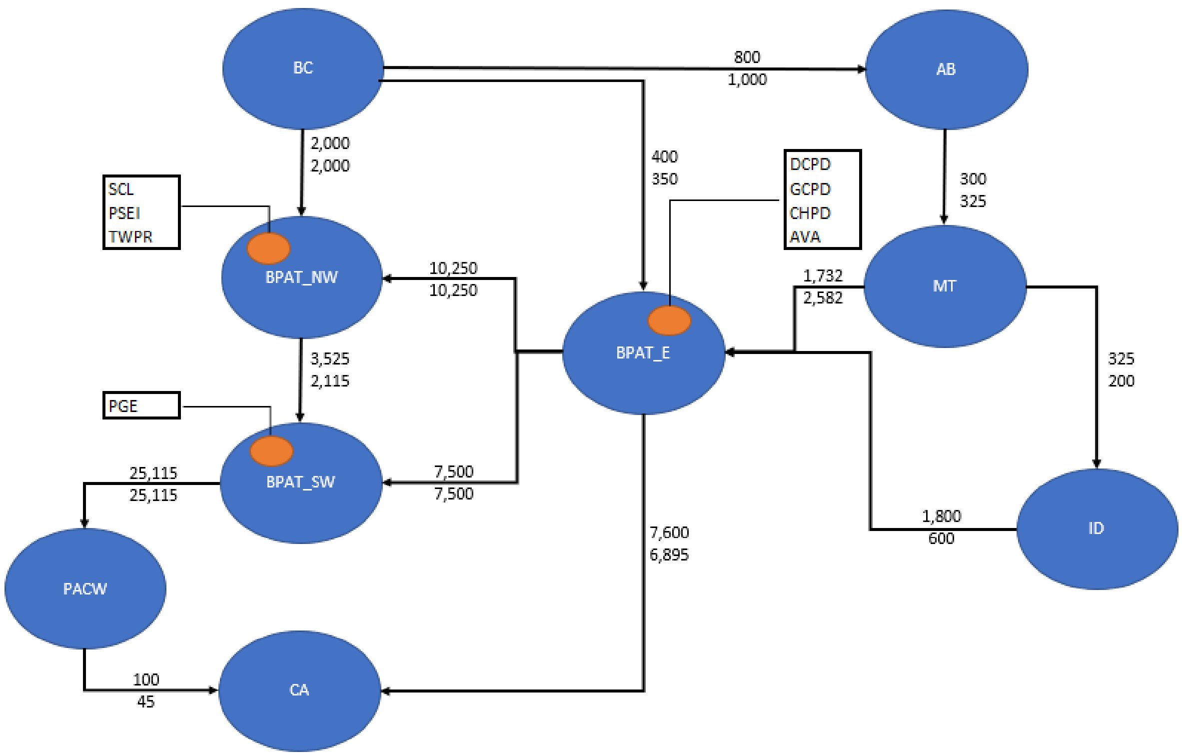


Figure 3 | Wire Bubble Diagram for PNW. Topology for the rest of WECC not shown. Note: Top value is the transfer capability in the direction indicated by the arrow and the bottom value is the transfer capability in the reverse direction. Source: EGPS, WECC.

Load is forecasted at each BA in the WECC using publicly available sources such as the FERC 714 and Utility Integrated Resource Plans (IRP). As such, the forecasted load growth represents a P50 business as usual case and does not assume aggressive electrification scenarios[15]. For the WPP, the load growth

[15] Current estimates of electrification in WA show over 1.5 times the growth in electricity demand from transportation and heating fuel switching to electricity. These were not included in the study.

is shown in Figure 4 and represents an 0.9% annual growth rate for both peak and energy. The load growth assumptions for Washington and Oregon are lower, however, at 0.5% energy average annual growth rate.

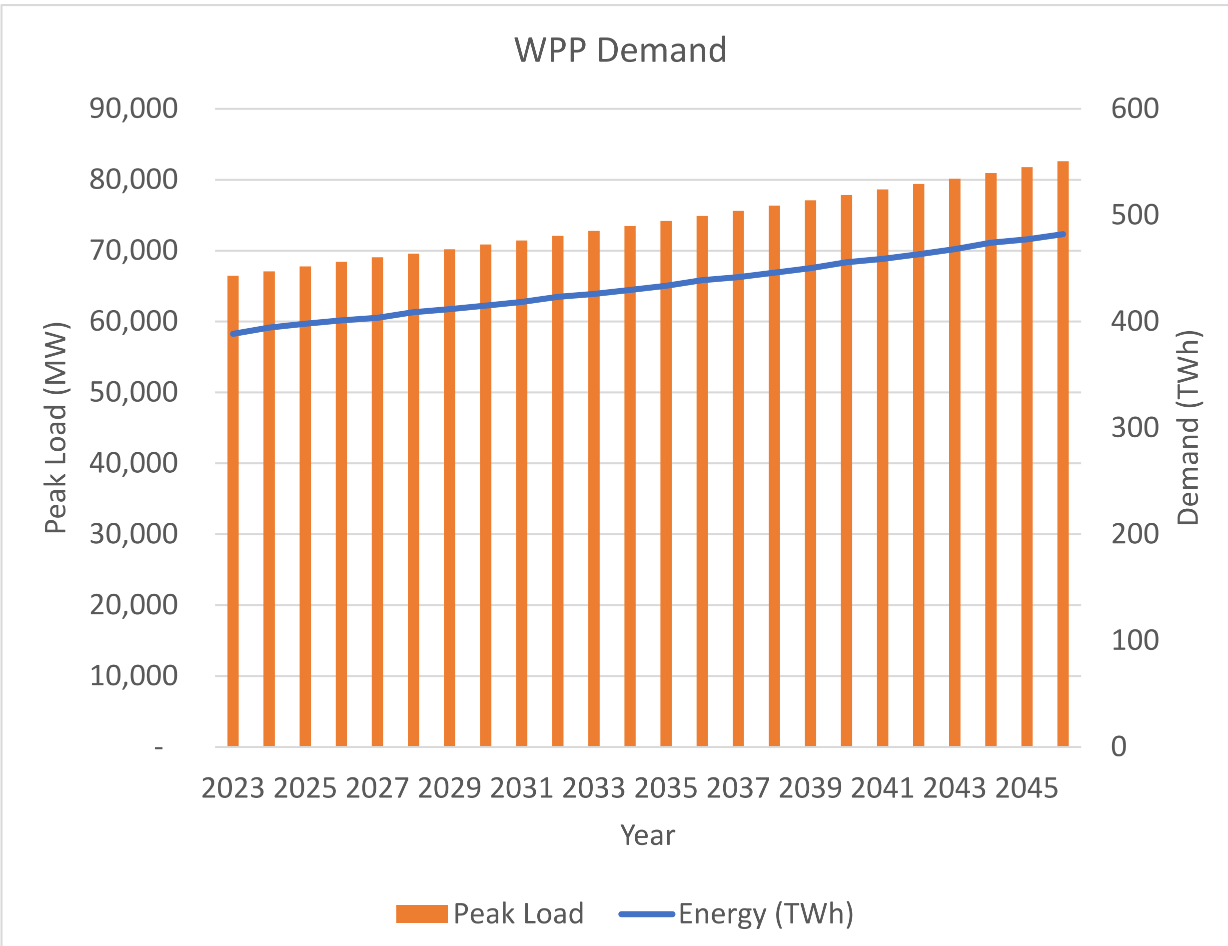


Figure 4. Peak and energy load forecast for the WPP.

Existing and planned capacity addition and retirements are inputs into the model to determine the initial capacity supply balance. We use the EGPS Power Database which relies on public information from a variety of sources such as the US Energy Information Administration (EIA) 860 and 923 reports as well as professional judgement. The WPP installed capacity in 2021 is approximately 115 GW and is comprised mostly of hydro, gas, coal, and wind as shown in Figure 5.

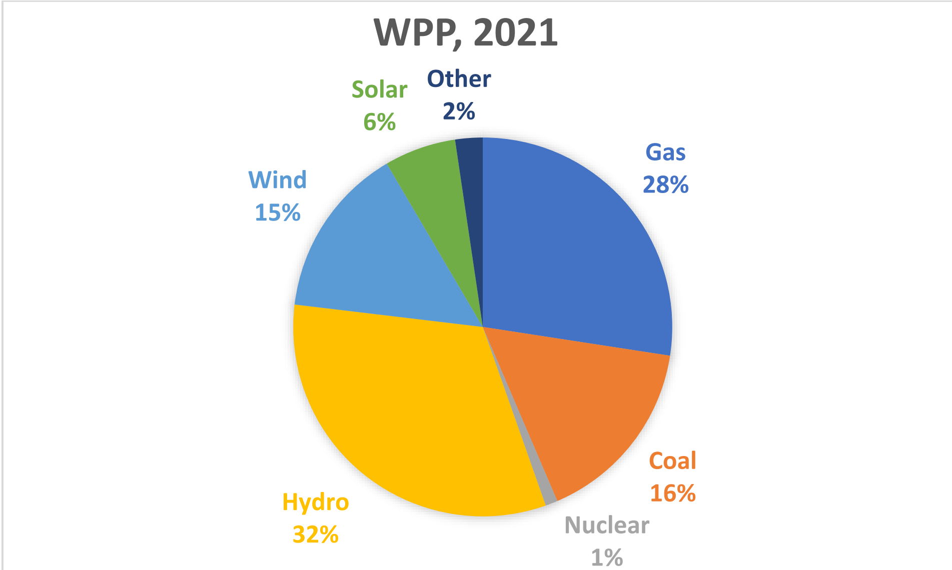


Figure 5. Installed capacity distribution in the WPP. Source: EIA, EGPS.

The largest change expected in the thermal fleet across WECC is the retirement of coal units. Our assumptions for coal retirements for all of WECC are shown in Figure 6 and total nearly 28 GW of firm capacity retirements. Individual coal plant retirement assumptions for the WPP are listed in Appendix B.

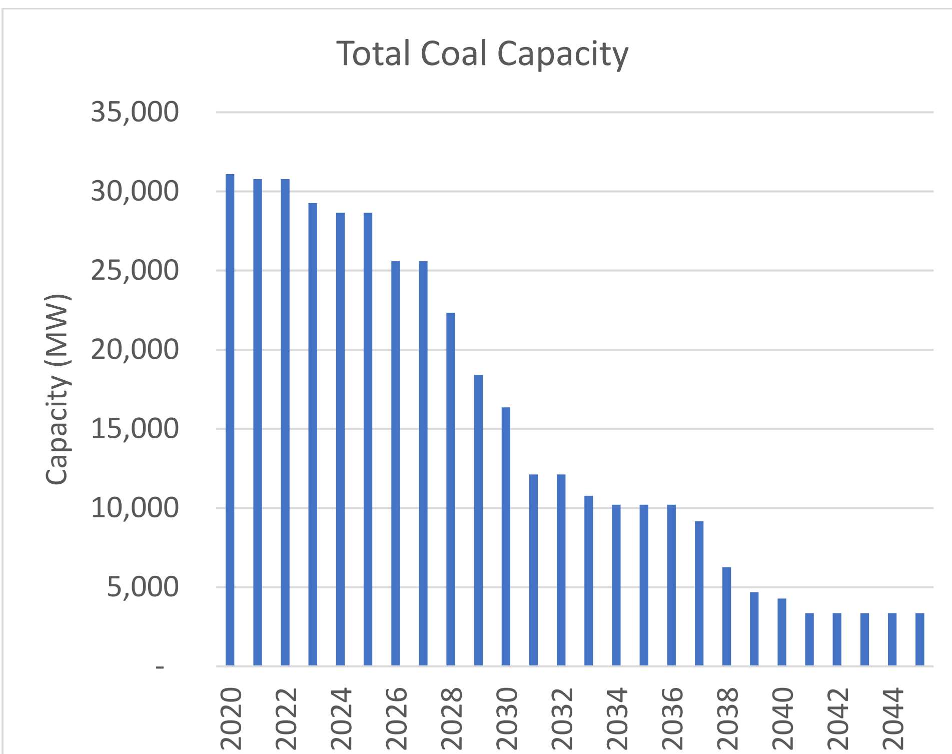


Figure 6. Total expected coal retirements in the WECC. Source: EIA, WPP, EGPS.

Candidate resources are new build options that the PCM must choose from to meet reliability, policy, and least cost energy constraints. We have included wind, solar, standalone 4-hour lithium-ion batteries and hybrid solar plus storage resources as candidate units. We have used publicly available data sources such as the NREL Advanced Technology Baseline dataset for base financial assumptions for the candidate resources. In addition to these resources, Demand Side Management (DSM) resources can be utilized by the model to reduce load in peak periods. We allowed the model to use up to 1,000 MW of DSM in each load zone.

Our capital cost assumptions (not including major transmission upgrades) decline over time as shown in Figure 7. In addition, location specific cost adders are applied based on EIA data. Candidate wind and solar resources are given locations and corresponding hourly production shapes that result in further locational granularity. Because of the tremendous amount of capacity required to meet clean energy requirements, we have also included additional transmission cost adders to the wind candidate resources to reflect additional costs of building new, short-distance transmission.

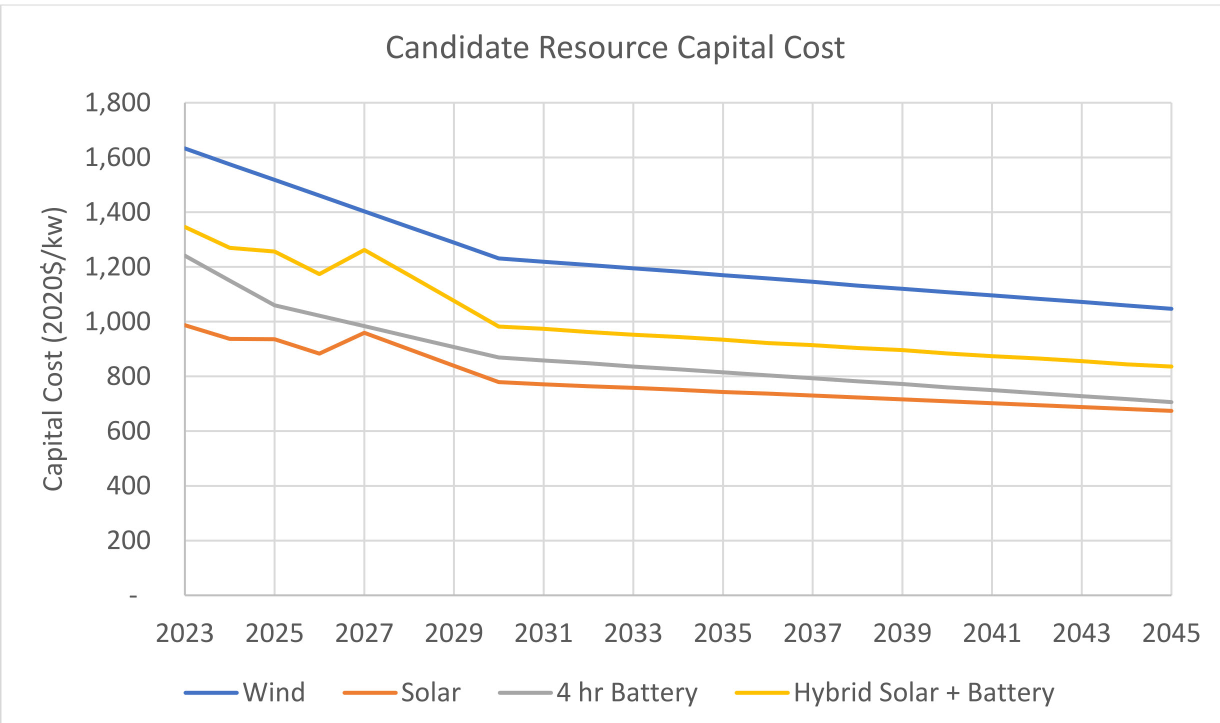


Figure 7. Capital cost assumptions for new candidate resources. Assumes declining Solar investment tax credit through 2026 applied to both standalone solar and hybrid units. Based on NREL ATB[16] and EIA AEO[17].

Existing clean energy laws are specified as a requirement in the PCM. The requirements included in this study are Washington state's 100% Clean Energy Transformation Act (CETA), Oregon House Bill 2021, as well as requirements outside of the immediate study area such as the California Senate Bill 100, and the 2019 clean energy laws in Colorado and New Mexico. The clean energy laws are inputted in two ways to ensure compliance. First, a minimum renewable generation requirement is specified, and second a maximum carbon emissions constraint is specified. The renewable generation requirement allows for

[16] NREL ATB; https://atb.nrel.gov/

[17] EIA AEO; https://www.eia.gov/outlooks/aeo/

resources to be built most economically and ensures stable model results. The emission requirement enforces in-state laws. Imports from out of state may contain carbon and thus offset the emission constraint. In this case, we ensured the emission intensity of out-of-state imports is lower than offsets allowed by losses.

Reliability is captured as a constraint to the model in the form of a required Planning Reserve Margin (PRM). The PRM minimum requirement used in the model is 16.1% as defined by the NERC Long-Term Reliability Assessment.[18]

The one-hour capacity contribution of all resources other than wind and solar are inputted. In the case of thermal, we input a capacity credit of the full capacity less forced outage rates. In the case of hydro, we applied a 67% capacity credit across each month. This capacity credit was arrived at from analysis done in California and represents a lower value than recent estimates in the WPP's Western Resource Adequacy Program (WRAP) methodology. Therefore, this assumption is less generous to the amount of peak capacity required to replace the LSRD.[19] In the case of storage, we inputted a capacity credit starting at 80% and declining over time to represent a declining Effective Load Carrying Capability (ELCC; the amount of perfect capacity that can be replaced by a given technology). In the case of wind and solar, the PCM calculates the output during the top 100 net load hours during the simulations and uses that value as the capacity credit. This approach is like an ELCC study by calculated dynamically within Aurora. The resulting capacity credit declines as a function of solar capacity on the system due to solar generation pushing the net peak load (i.e., peak demand after generation is accounted for) further in the evening.

6. Results and Discussion

Table 3. Summary of results.

Name	Type	Renewable and Storage Capacity	Total Cost (NPV)†
Base Case (with LSRD)	Base expansion case to meet reliability and state clean energy laws with the LSRD	160 GW	$142 B
Study Case (Base Case without LSRD)	Study expansion case to meet reliability and state clean energy laws without the LSRD	175 GW	$157 B
Difference	***Impact of Breaching***	***15 GW***	***$15 B***

†NPV corresponds to 2023 using 2% inflation and discount rate.

In the Base Case 160 GW of capacity is required throughout the WPP to meet state clean energy laws and maintain reliability. This capacity is comprised of wind, solar, and storage units (Figure 8). Most new additions are from wind and solar, with nearly 32 GW from battery storage units. By 2045, the one-hour Net Qualifying Capacity (NQC), or capacity that counts towards meeting the net peak load and thus

[18] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

[19] The LSRD have a combined nameplate capacity of over 3000 MW, but taking a conservative approach, the study assigns them 1844 MW of one-hour sustained peaking capacity based on the hydropower capacity credit used in the model.

planning reserve margin, drops to 20% for wind and 3% for solar at these capacity levels thus requiring significant amounts of capacity to replace the LSRD.

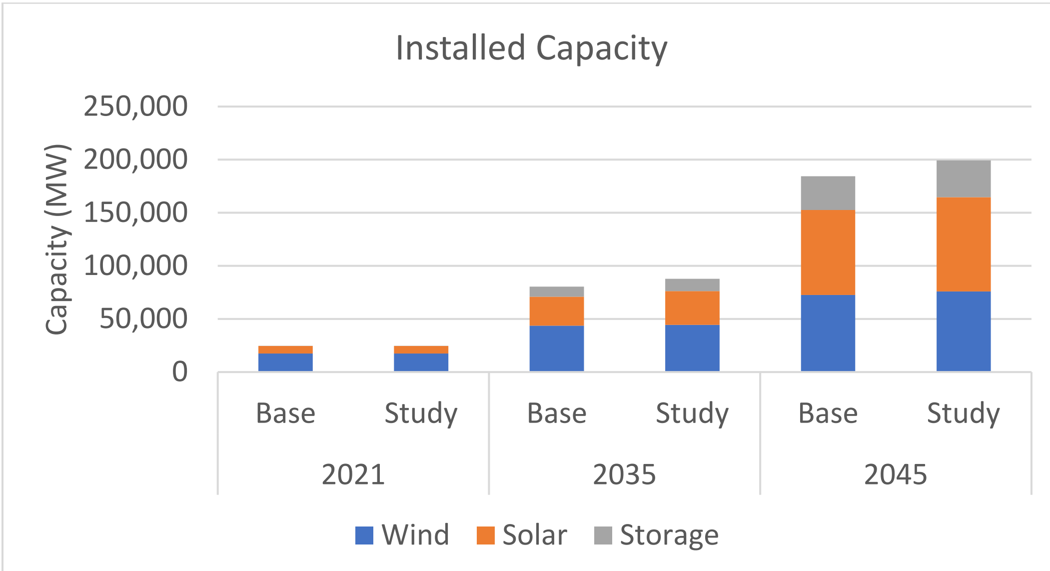


Figure 8. Installed capacity for the base and study case. Note the LSRD are breached in 2030 and 2031 corresponding to the Simpson proposal.

When the LSRD are removed, 175 GW of capacity is required in the WPP (Figure 8 and Figure 9). This is an increase of 14.9 GW comprised predominately of solar (8.7 GW), and nearly equal amounts of wind (3.3 GW) and storage (2.9 GW).

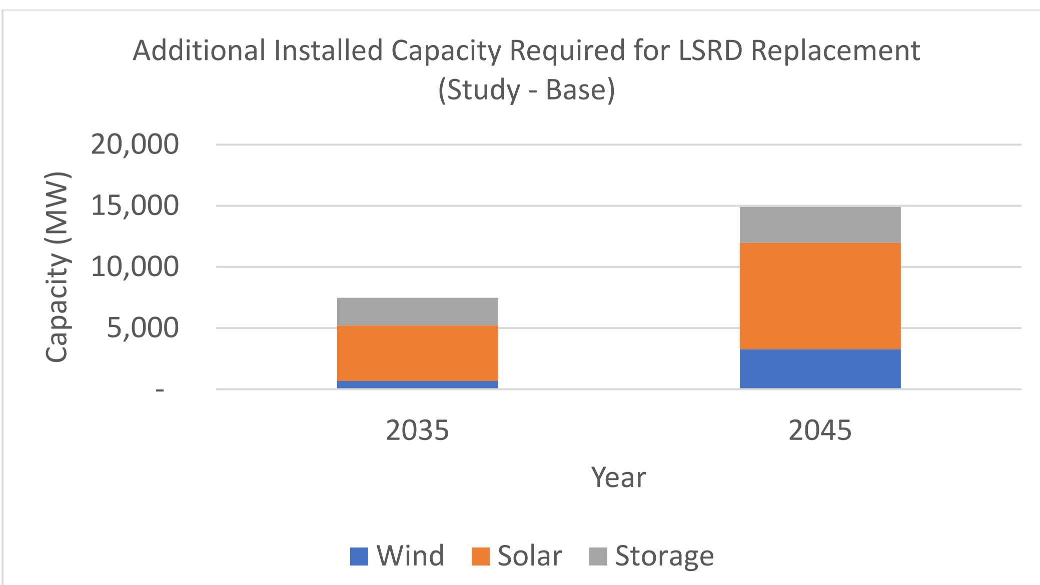


Figure 9. Renewable and storage capacity differences between the study and base case. This represents the additional capacity required to replace the LSRD.

In addition to the peak credit, energy curtailment of renewable resources plays an important role in the required capacity additions without the LRSD. Much of the renewable energy produced by these additions are in excess of load and export capabilities and curtailment rates are 35% for wind and solar resources in 2045. Given that wind and solar already have low-capacity factors due to variable generation (25 to 35%), the high curtailment rates result in overall capacity factors on the order of 9 to 12%.

The cost impacts of this replacement capacity have a Net Present Value (NPV)[20] of $15 billion from 2030-2045 (Figure 10). In 2045 the annual recurring costs are $2.5 billion. These costs are primarily driven by the new resource capital costs which are annualized. Other costs include the ongoing fixed costs for maintenance, variable operating costs, fuel costs, and emissions costs if applicable. These costs reflect the electricity replacement costs for the LSRD and do not account for major maintenance events (e.g., turbine replacement at the LSRD) or the costs related to the construction of long-distance, high voltage transmission lines to import additional renewable generation into the WPP. The study also does not consider the impacts to other sectors such as transportation or irrigation if the dams are removed.

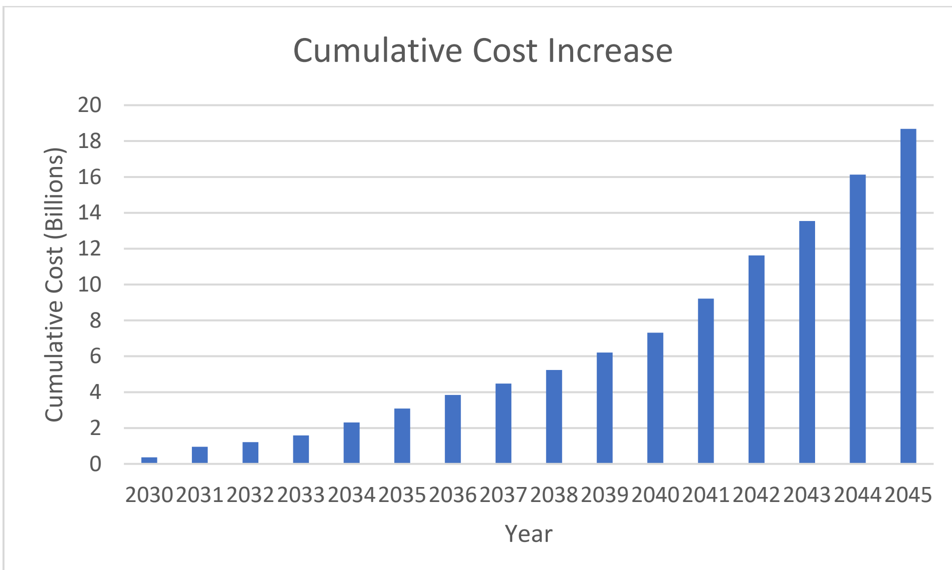


Figure 10. Increased costs from removing the LSRD. Cost represents annualized capacity costs from the added capacity as well as ongoing fixed costs, variable operating costs, and fuel costs.

With the significant capacity requirements already required for the base case and more required for LSRD replacement, it is likely that the additions of new generators will *not* keep up with the expansion plan estimated in this study. More than 7,600 MW of combined renewables, demand response, and battery storage additions are needed every year from 2023 – 2045 to meet WPP state requirements and replace the capacity of the LSRD (Figure 11). This pace of buildout significantly exceeds the average annual amount of wind, solar and storage capacity added by WPP, California or ERCOT in the last 15 years, putting achievement of state policy mandates at risk.

[20] 2% annual inflation and discount rate were used in the NPV calculation.

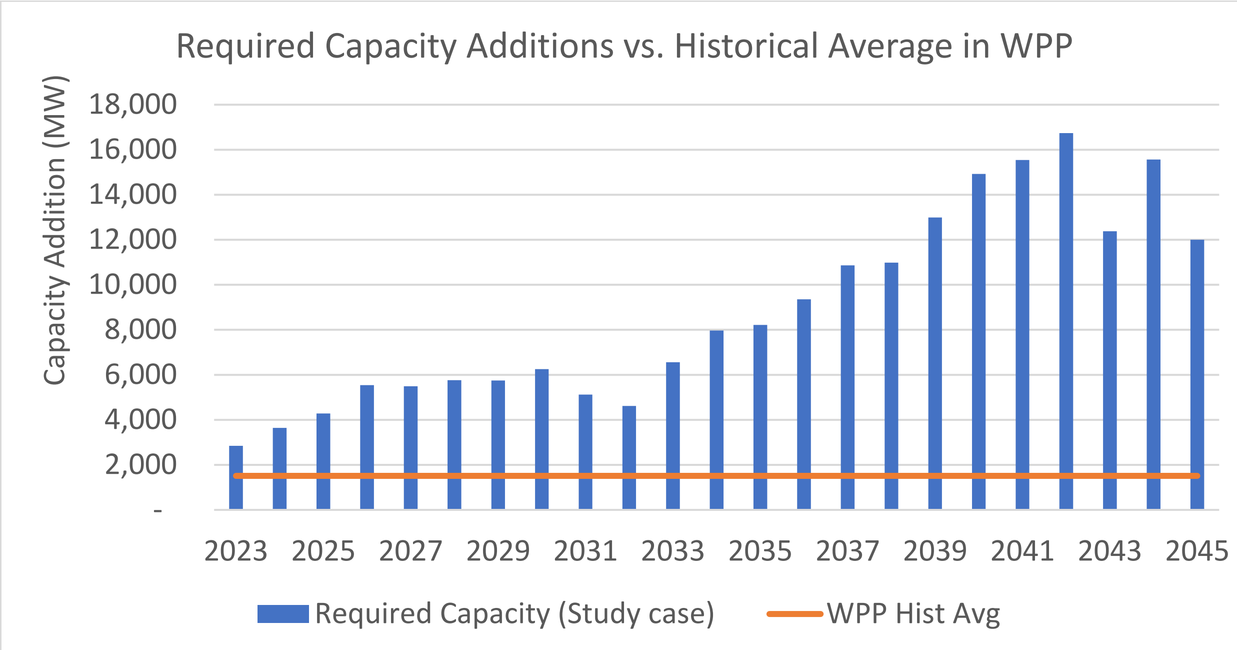


Figure 11. Required capacity additions under the Study Case to replace LSRD, meet state clean energy laws and maintain reliability compared to historical capacity additions in the WPP.

Meeting the capacity requirements laid out in this study is, therefore, unlikely. We can estimate when clean energy laws would be met using historical capacity additions and the capacity requirements from this study with and without the LSRD. If we assume the future additions in WPP, CA, and ERCOT are double that of the historical average, the amount of required capacity to achieve the Base case requirements would not be achieved until 2057 (best case assuming double ERCOT's historical pace of additions[21]) to 2076 (worst case assuming double WPP's historical pace of additions[22]) (Figure 12).

[21] Based on renewable and storage additions from 2007 to 2021 using ERCOT Capacity Trends, 2022. https://www.ercot.com/files/docs/2022/06/08/Capacity_Changes_by_Fuel_Type_Charts_May_2022_PlannedMonthly.xlsx
[22] Based on renewable and storage additions from 2007 to 2021 using EIA 860 and 923 databases, 2021.

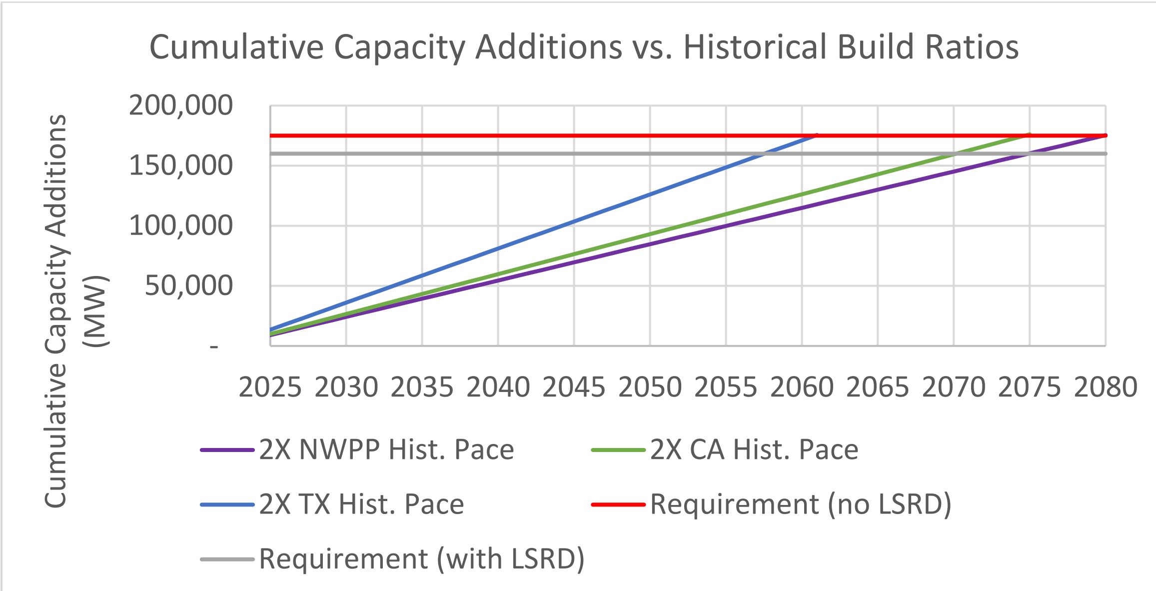


Figure 12. Range of years when the Base case (160 GW) and Study case (175 GW) WPP capacity addition requirements are met assuming double the historical pace of renewable and storage additions in various markets from 2007 to 2021.

Adding the additional 15 GW of capacity to replace the LSRD would further increase these dates by three to five years, based on double ERCOT's pace and double WPP pace, respectively.

There are also significant implications for emissions. We applied the average emission rate in Washington and Oregon to each future year, to calculate the added GHG emissions (past 2045) if clean energy laws are not met according to various dates. These data were filtered to only include Washington and Oregon to focus on Pacific Northwest impacts. The results show an incremental 136 MMT using twice the historic buildout rate for NWPP, 114 MMT using twice the historic buildout rate for California, and 55 MMT using the historic buildout rate for Texas.

Table 4. Achievement of Study Objective under different build-out scenarios.

Annual Average Renewable Capacity Additions in WPP to meet Study Case			
	Using WPP Historic Buildout Pace	Using CA Historic Buildout Pace	Using ERCOT Historic Buildout Pace
Annual average renewable capacity additions from 2007 – 2021 (MW)	1512	1661	2326
Estimated achievement of clean energy laws if **double the historic pace** of capacity additions (Year)	2076	2071	2057
Added emissions due to delay (MMT)‡	136	114	55
Estimated achievement of clean energy laws and replacement of LSRD if double the historic capacity additions (Year)	2081	2076	2060
Added emissions due to delay for replacement of LSRD (MMT) ‡	8.5	8.5	5.1

+Western Power Pool (WPP), California, and Electric Reliability Council of Texas (ERCOT)

‡Assumes average emission rate from 2030-2045 applied to each future year.

To calculate the incremental emissions from breaching the LSRD, we re-ran the base case expansion plan without the LSRD, again assuming clean energy laws are not met by 2045. Emissions from the base case (with LSRD) were subtracted from the emissions from this new dispatch to estimate the incremental emissions associated from breaching the LSRD.

The added emissions resulting from breaching the LSRD results in an additional three to five years delay in achieving a zero-carbon grid, assuming twice the historic buildout pace of WWP, CA, and ERCOT. This delay equates to 5.1 to 8.5 Million Metric Tons (MMT) of CO_2 (Table 2).

7. Conclusions and Recommended Next Steps

This study shows that to replace the LSRD and meet state clean energy laws and maintain reliability will require an additional 14.9 GW of additional capacity and cost an additional $15 billion to implement.

Clean energy laws in WPP states are aggressive and require 160 GW of renewable capacity to be added in the WPP region. At this level of capacity addition, the net qualifying capacity of renewable generators is greatly diminished thus requiring much more capacity to replace the LSRD. In addition, the renewable generation is curtailed at rates of 35% resulting in overall capacity factors on the order of 9 to 12%, requiring more than one for one capacity additions.

Even if the WPP doubled the historic average new resource builds from the WPP, CAISO, and ERCOT, the amount of required capacity to achieve the Study Case requirements could not be achieved until 2061 to 2080. A delay in meeting clean energy laws until these dates would increase emissions by 62 to 141 million metric tons.

The capacity additions estimated to replace the LSRD in this study may be low due to the following assumptions:

- **Average Load Growth**: The load growth assumptions used are P50 business as usual assumptions. If aggressive electrification load growth occurs, the load may be over 1.5 times higher than captured by this study resulting in higher amounts of capacity and cost to replace the LSRD.

- **Limited Capacity Contribution of Hydro:** The one-hour net qualifying capacity (NQC) credit of hydro used in this study was 67% based on publicly available data for summer periods. The newly formed Western Resource Adequacy Program (WRAP) may result in higher capacity credits for hydro based on max flex production and thus require more capacity and cost to replace the LSRD, all else being equal.

- **High Capacity Contribution of Batteries:** The NQC for batteries used in this study was 80% in 2023 based on the WPP WRAP (assumes net peak load is 5 hours in duration) declining to just over 50% in 2045. Many studies show a much lower NQC credit[23], starting in the 20 to 30%

[23] For example, PSEI's 2021 IRP (https://www.pse.com/IRP/Past-IRPs/2021-IRP).

range. A lower battery NQC would lower the value of storage units and thus require more capacity and higher costs to replace the LSRD.

- **Limited Transmission Cost Adder:** The availability of new transmission to support such a massive renewable build out was captured via a cost adder to incremental new wind units only. Major new transmission that is likely needed was not captured in the model and thus costs are likely to be higher when capturing these.

The capacity additions required to replace LSRD in this study may be high if new, not presently available technologies are developed and become commercially available during the study period.

Appendix A. EGPS Production Cost Model

We carefully reviewed several commercial tools and selected the Aurora tool for our production cost modeling. Aurora has been used for over 20 years by large utilities primarily in the U.S. and has well representation in the Western U.S. Aurora uses an optimization algorithm to solve for the least cost solution to meet a load forecast given a set of generating resources subject to constraints. Particularly beneficial features of Aurora for Long-Term Capacity Expansion (LTCE) that are not found in other commercial tools are an iterative approach to capacity expansion, dynamic peak credit calculations, and rigorous battery storage modelling. The iterative approach includes both an expansion plan of new generating resources followed by a commitment and dispatch run of the system. The commitment and dispatch run allows the model to see how existing and new generators operate over the study horizon. Information from this run is then fed back into the LTCE portion to inform a new expansion plan. This iteration process is done until convergence and allows for Aurora to compute expansion plans that meet a wide range of constraints such as reliability and RPS targets.

While we use a commercial tool for our studies, we have built the inputs to the tool from the ground up leveraging the existing EGPS dataset. Inputs are taken from publicly available sources, EGPS in-house tools, and EGPS staff knowledge.

The WECC is represented in our model by 40 zones including many of the 38 balancing authorities shown in Figure 2 with increased granularity for BPAT to separate the NW, SW, and Eastern zones of BPAT. This breakout allows us to capture the Cross Cascades and South of Allston transmission constraints. Transmission limits between zones are derived from historical flow limits, the CPUC RA and IRP Model[24], and the WECC Power Supply Assessment[25]. Load forecasts for each zone are derived from the FERC 714 for zones in the U.S, the NERC ES&D for zones in Canada, and the PRODESEN for Mexico Baja California. Hourly load shapes are derived from the WECC Anchor Data Set (ADS).

[24] CPUC RA and IRP Model, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials/unified-ra-and-irp-modeling-datasets-2019

[25] WECC Power Supply Assessment, https://www.wecc.org/Reliability/2016PSA_Final.pdf

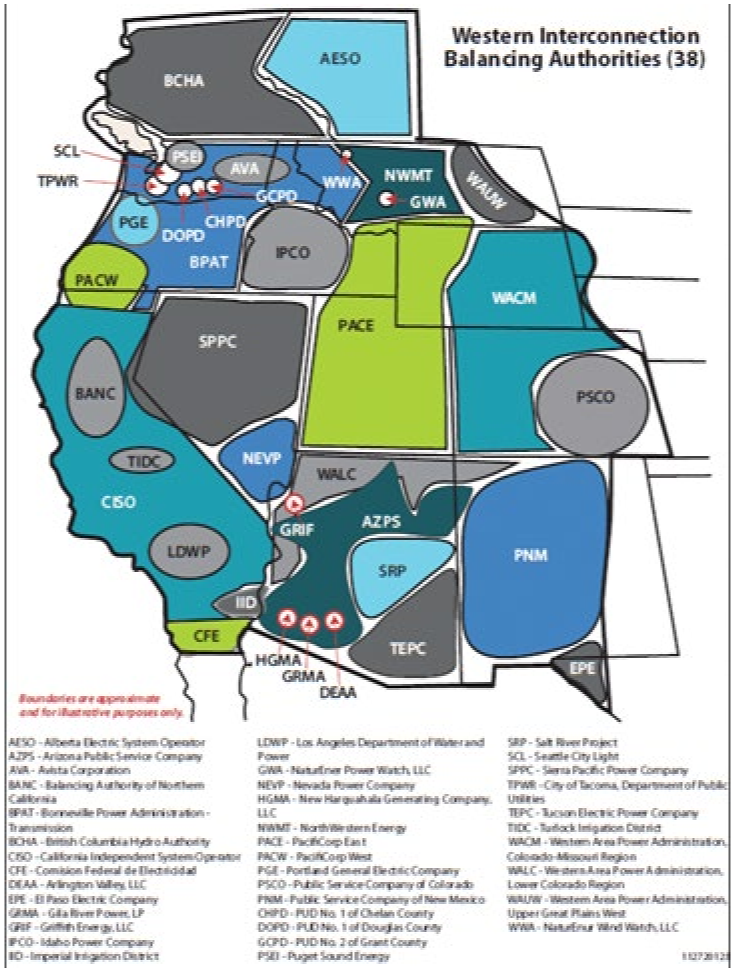


Figure 13. Balancing Authorities in the WECC.

The EGPS Power Database is used to determine the existing supply stack within WECC and is built off a variety of sources including the EIA 860 and 923. Future generator candidates are derived from the EIA and NREL. Generator operational and financial properties are derived from the WECC ADS, the CPUC RA and IRP model, and general rules of thumb from the EPA and NREL. Fuel forecasts for thermal generators are derived from the EIA and forward trading curves. The model contains seven natural gas hubs in the west and unit-level gas transportation cost adders.

Our production cost model has been carefully benchmarked to the last three full years of energy data in terms of installed capacity, generation by fuel type, unit-level hourly hydro generation, transmission flows on major paths, and power prices. Our long-term capacity expansion has been evaluated against publicly available expansion plans including the 2021 NW Power Plan[26].

Our model has several differentiators including

- Separate zones for BPAT into NW, SW, and E with current transmission limits between,

[26] 2021 NW Power Plan, https://www.nwcouncil.org/sites/default/files/2021powerplan_2021-5.pdf

- Hydro model in PNW integrated in PCM,
- Tethered to reality with benchmarking three years, and
- Iterate approach to capacity expansion.

Appendix B. Coal Retirement Assumptions

Table 5. Coal retirement assumptions for the WPP. Source: EIA, WPP, EGPS.

Name	Nameplate Capacity	Retirement Date	Generator	State
Comanche (CO)	383	12/1/2022	1	CO
Martin Drake	75	12/1/2022	6	CO
Martin Drake	132	12/1/2022	7	CO
Jim Bridger	608	12/31/2023	1	WY
North Valmy	290	12/1/2025	2	NV
North Valmy	277	12/1/2025	1	NV
Centralia	730	12/1/2025	2	WA
Comanche (CO)	396	12/1/2025	2	CO
Craig (CO)	446	12/1/2025	1	CO
Naughton	256	12/31/2025	2	WY
Naughton	384	12/31/2025	3	WY
Naughton	192	12/31/2025	1	WY
Neil Simpson II	90	12/31/2025	2	WY
Dave Johnston	255	1/1/2027	3	WY
Hayden	275	12/1/2027	2	CO
Dave Johnston	134	12/31/2027	2	WY
Dave Johnston	400	12/31/2027	4	WY
Dave Johnston	134	12/31/2027	1	WY
Craig (CO)	446	9/1/2028	2	CO
Hayden	190	12/1/2028	1	CO
Jim Bridger	617	12/31/2028	2	WY
Pawnee	552	12/31/2028	1	CO
Rawhide	294	12/1/2029	1	CO
Craig (CO)	535	12/1/2029	3	CO
Ray D Nixon	207	12/1/2029	1	CO
Bonanza	500	12/1/2030	1	UT
Wygen 1	90	12/31/2032	1	WY
Laramie River Station	570	12/31/2033	3	WY
Huntington	496	12/31/2036	2	UT
Huntington	541	12/31/2036	1	UT
Jim Bridger	608	12/31/2037	3	WY
Jim Bridger	608	12/31/2037	4	WY
Colstrip	824	12/31/2037	4	MT
Colstrip	824	12/31/2037	3	MT
Colstrip Energy LP	46	12/31/2037	GEN1	MT

Hunter	525	12/31/2038	1	UT
Hunter	525	12/31/2038	2	UT
Hunter	527	12/31/2038	3	UT
Wyodak	402	12/31/2039	1	WY

Lower Snake River Dams Power Supply Replacement Analysis

Study performed by Energy GPS Consulting

Study commissioned by Northwest RiverPartners

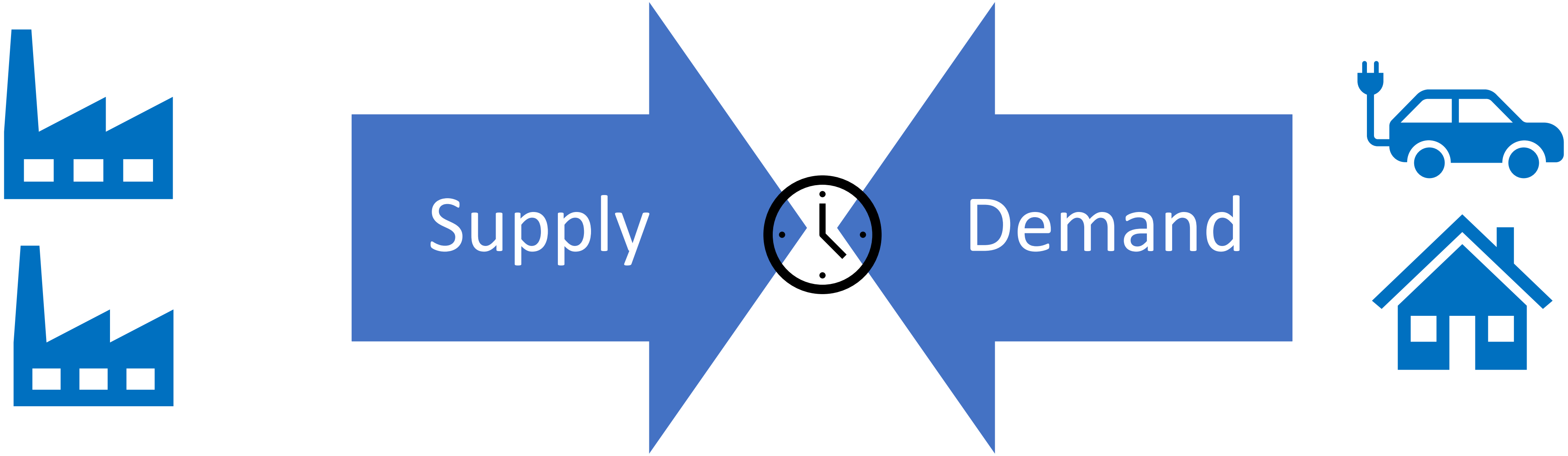
6/29/2022 Presentation

Northwest RIVERPARTNERS™

Challenge

"Lead the charge for the Northwest to realize its clean energy potential using hydroelectricity as the cornerstone."

Maintaining a Reliable, Affordable, Clean



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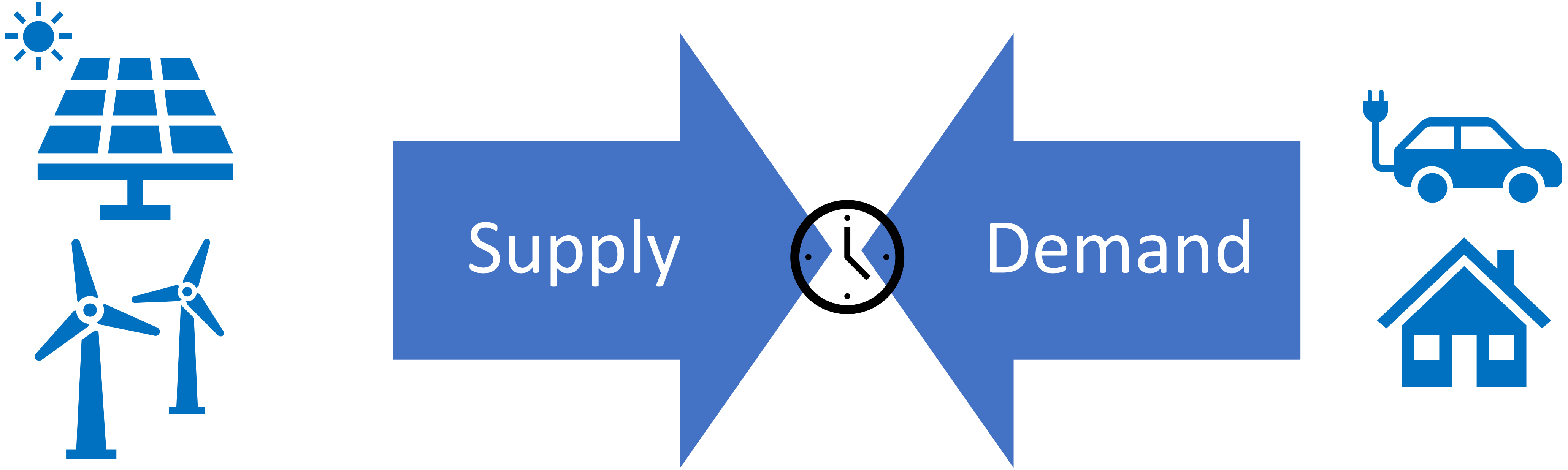

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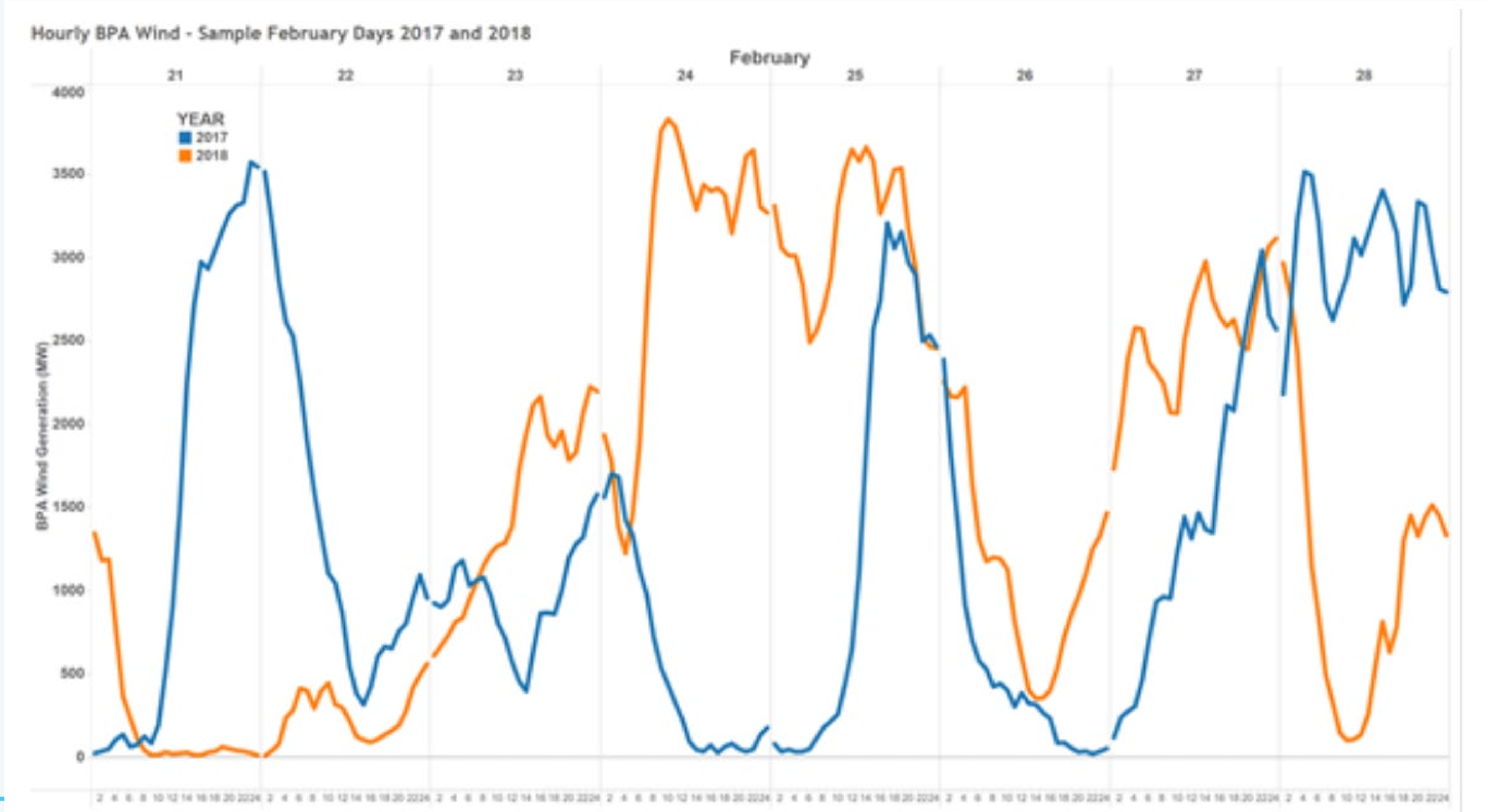
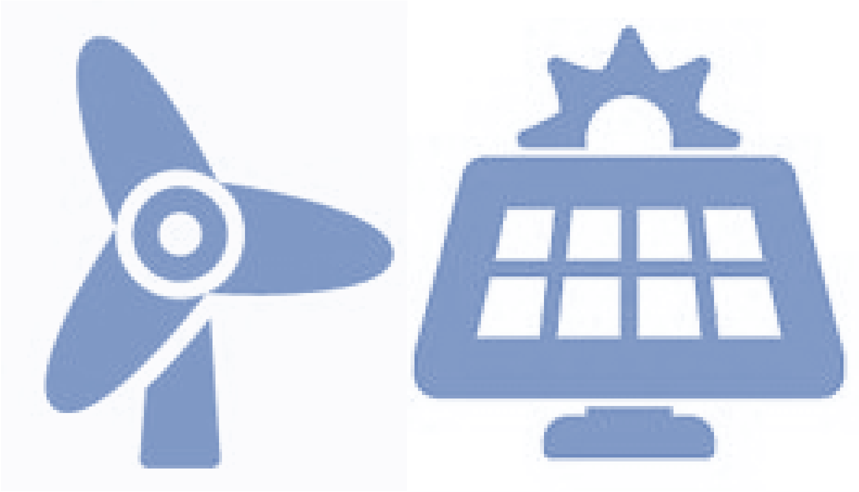
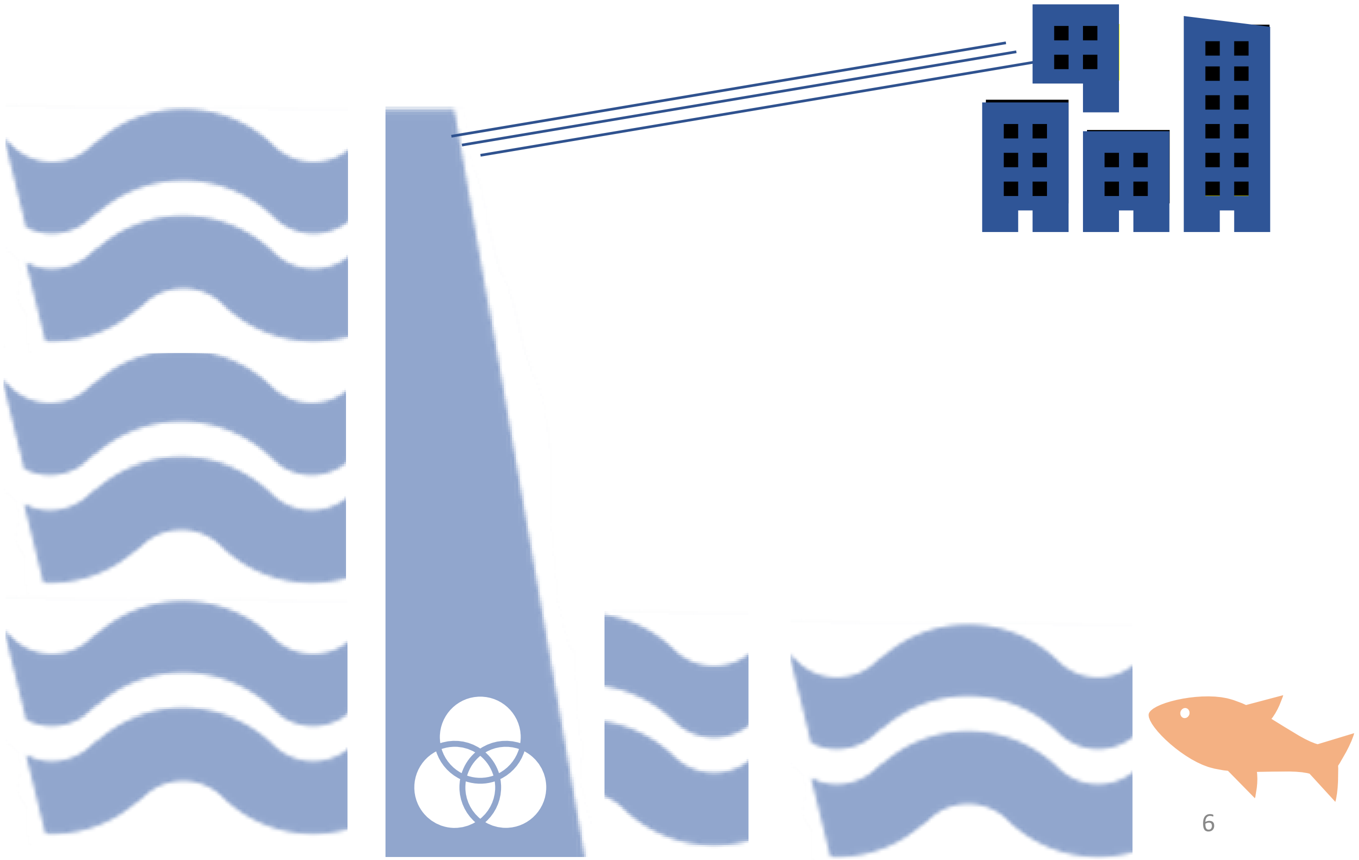
Intermittency



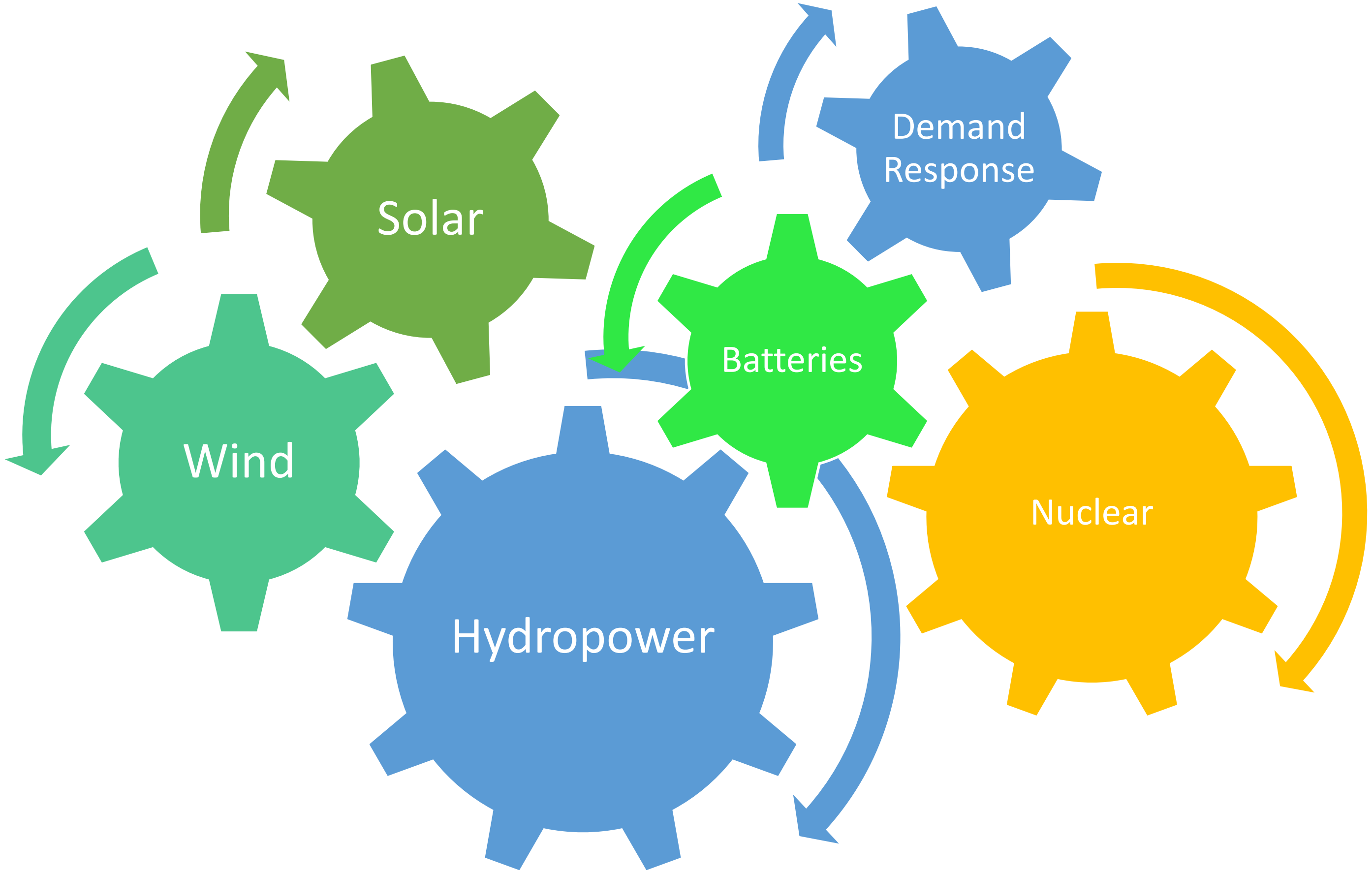
"Lead the charge for the Northwest to realize its clean energy potential with hydroelectricity as the cornerstone."

Losing the Lower Snake River Dams?





Use Aurora-Based Model to Optimize Buildouts & Compare



Production cost models are used by utilities and regulators to inform long-term planning and policy decisions. Aurora has been used for over 20 years by large utilities primarily in the U.S. and has well representation in the Western U.S. Aurora uses an optimization algorithm to solve for the least cost solution to meet a load forecast given a set of generating resources subject to constraints. Particularly beneficial features of Aurora for Long-Term Capacity Expansion (LTCE) that are not found in other commercial tools are an iterative approach to capacity expansion, dynamic peak credit calculations, and rigorous battery storage modelling. The Aurora tool is used by the Northwest Power & Conservation Council , Portland General Electric , and Puget Sound Energy.

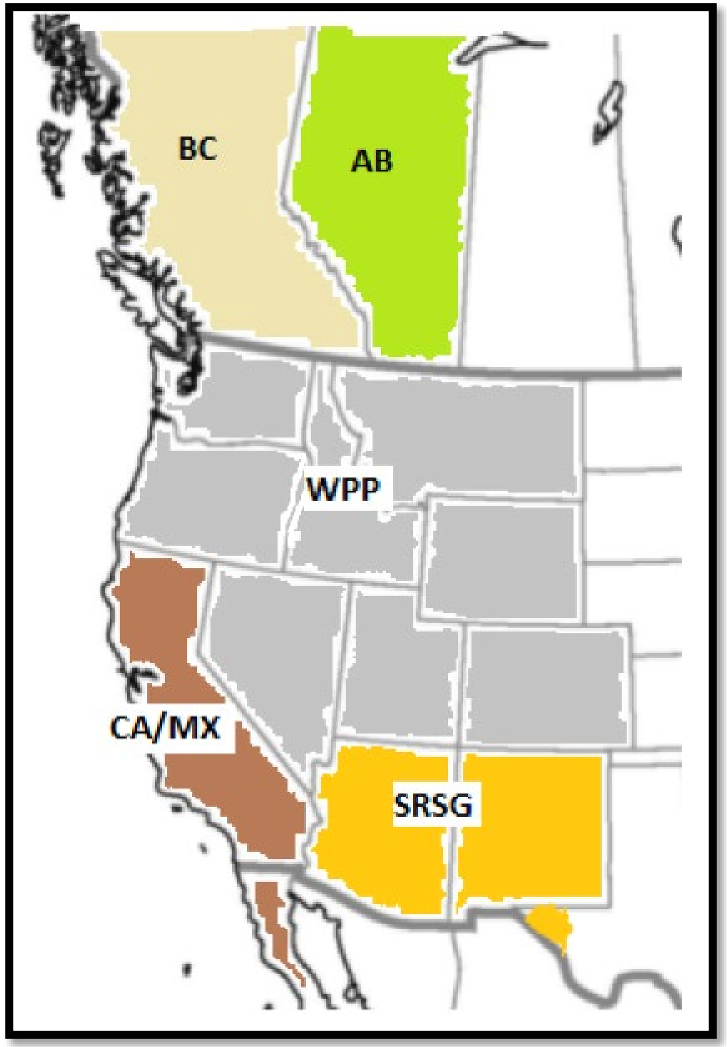
Parameters

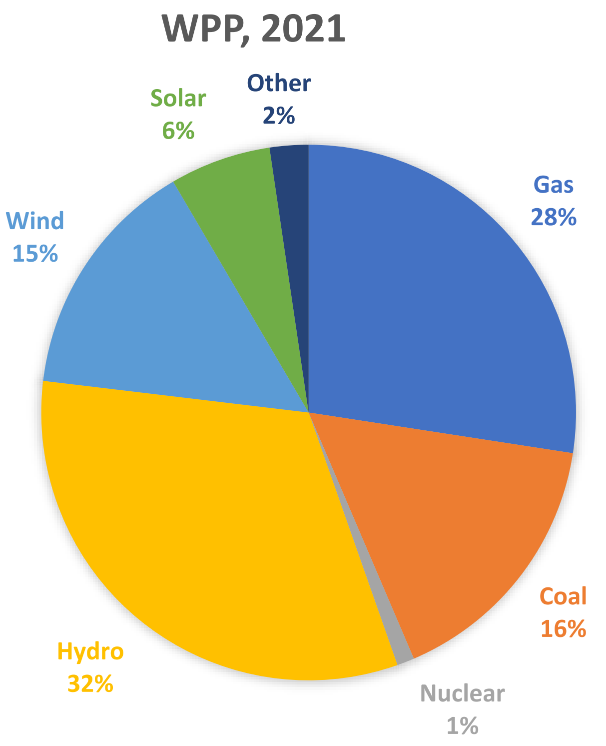
“Lead the charge for the Northwest to realize its clean energy potential using hydroelectricity as the cornerstone.”

Western Interconnect Clean Energy Mandates

State	Zero Carbon Grid Law	Zero-Carbon Grid Law Deadline
Washington	2019	2045
Oregon	2021	2040
California	2018	2045
Colorado	2019	2045
Nevada	2019	2050

Modeling Focus: Western Power Pool

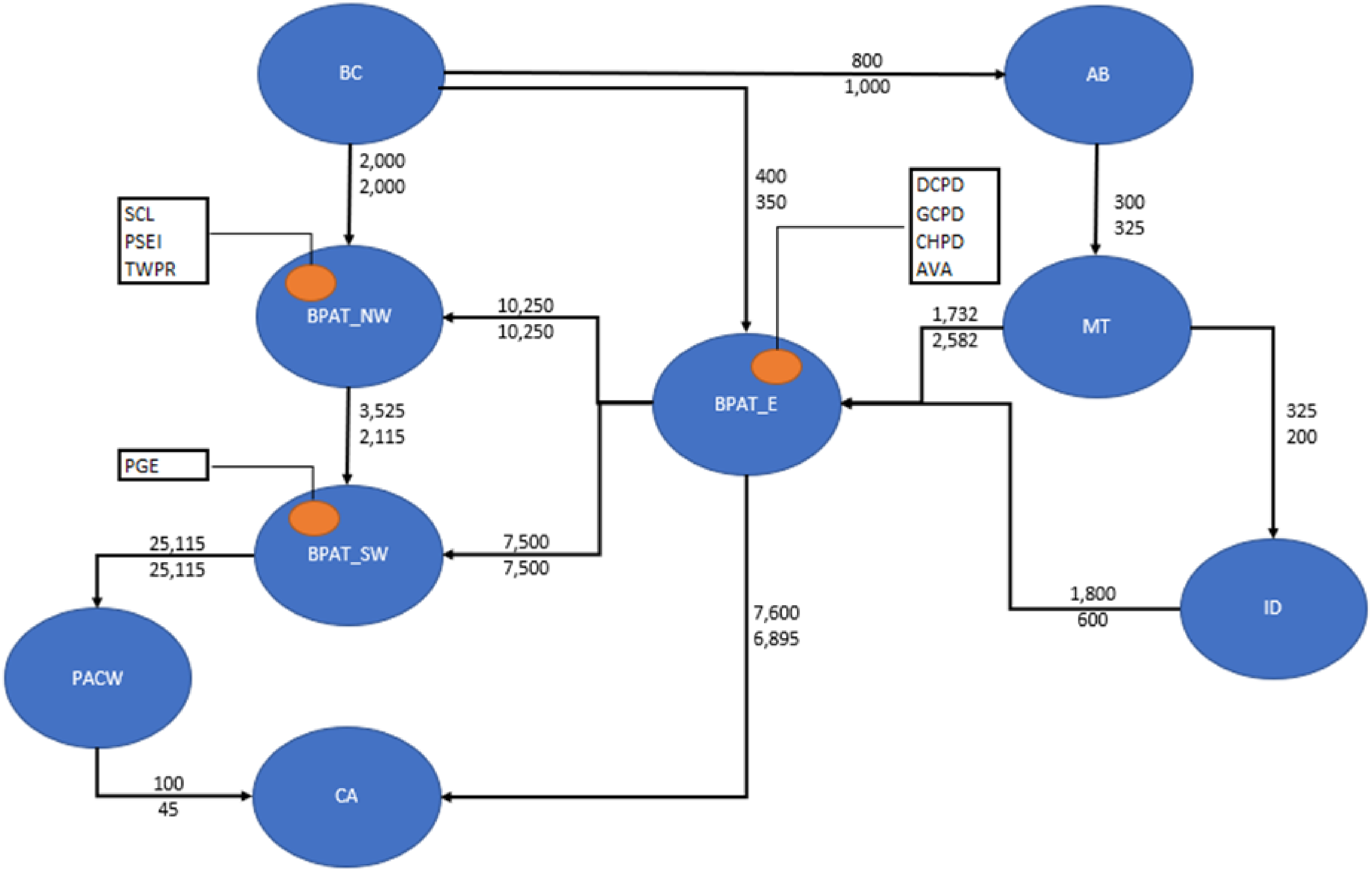




- 64 GW of Peak Load
- 115 GW of Generating Resources
- NERC-defined planning region that includes the Pacific Northwest

Key Modeling Requirements

- Observe Transmission Path Limits
- Maintain 16.1% Planning Reserve Margin (as defined by NERC Long-Term Reliability assessment)
- Meet Decarbonization Laws by Required Dates



Key Model Assumptions

One-Hour Capacity Contribution

- Thermal: Fully capacity - historical forced outage rates
- Hydro: 67% (based on CA study)
- Battery Storage: 80%, but declines over time
- Wind and Solar: Calculated value based on 100 top net load hours

Load

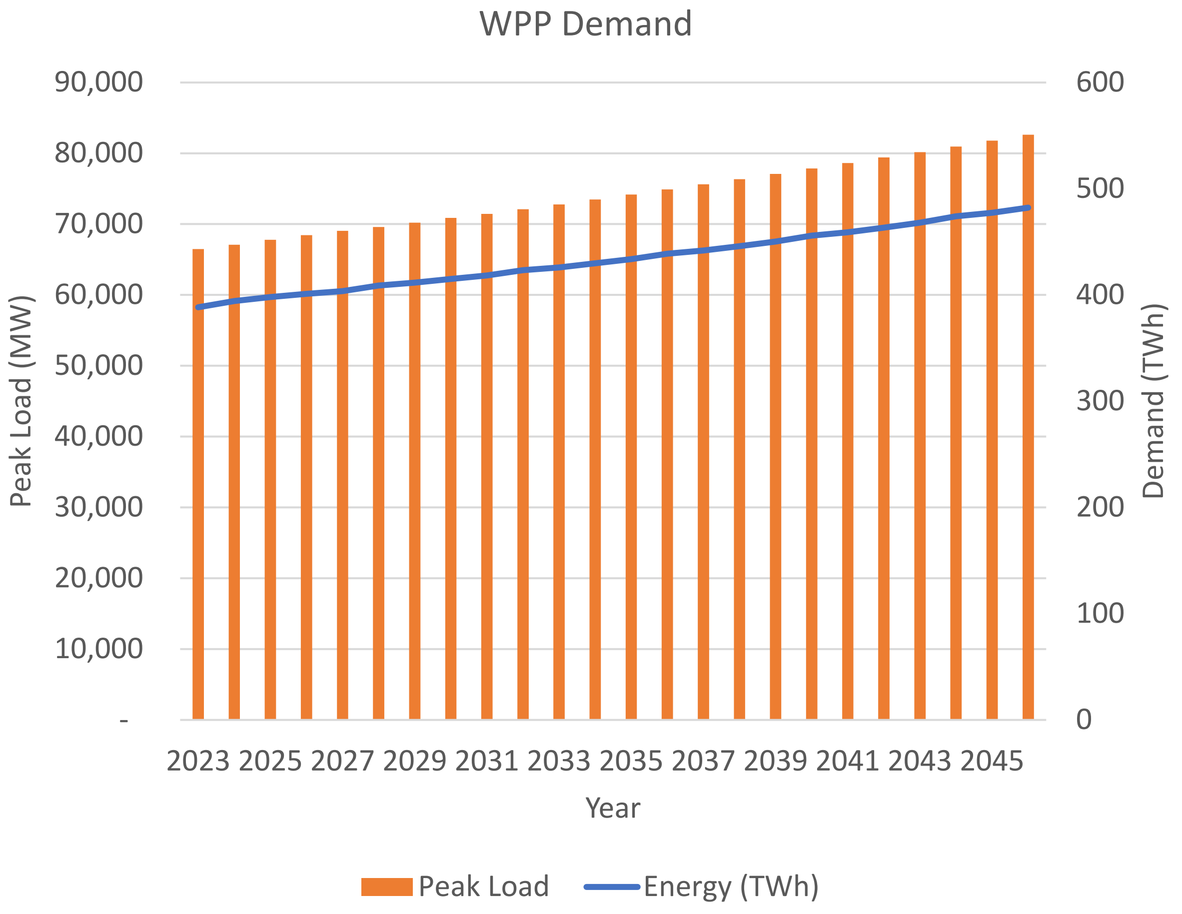
- Load growth assumed at 0.9% for WPP and 0.5% for WA & OR
- Load growth does not incorporate aggressive electrification scenarios

Siting

- Model assumes siting of new generation resources is not an issue

Transmission

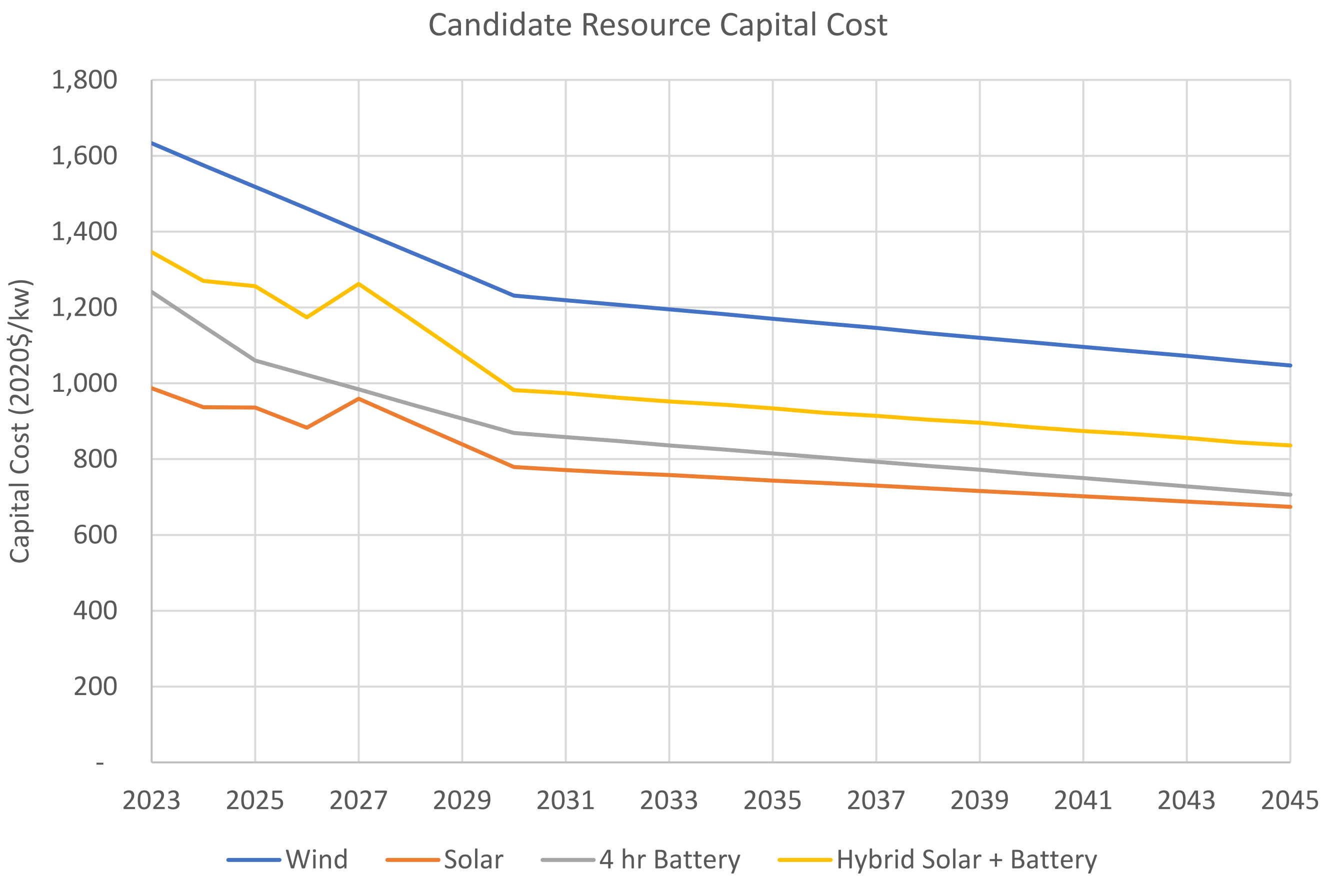
- Model does not build new transmission lines and does not incorporate the costs of building long-distance transmission lines
- Incorporates a limited transmission cost adder for short-distance transmission to connect to the grid



Key Model Assumptions (continued)

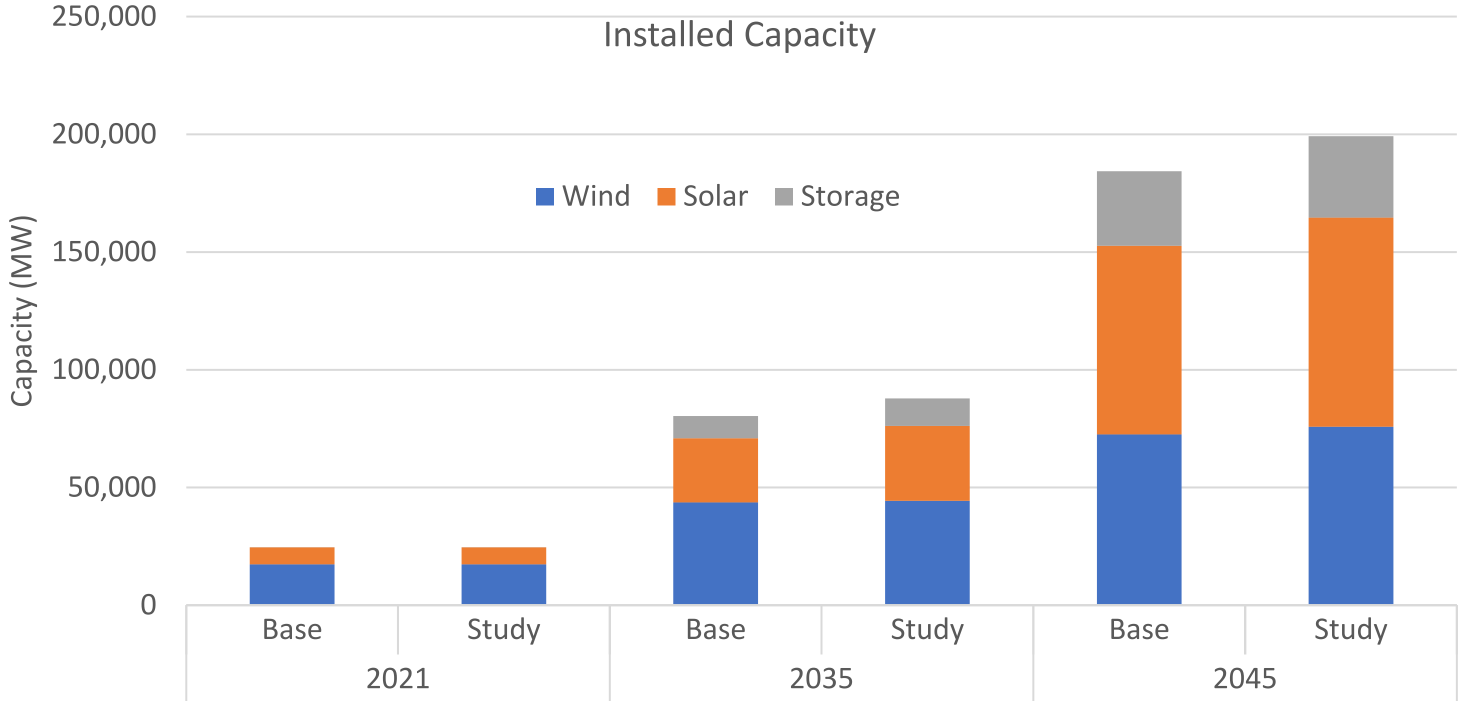
Capital Costs

- capital costs of wind/solar/batteries is assumed to continued to decline



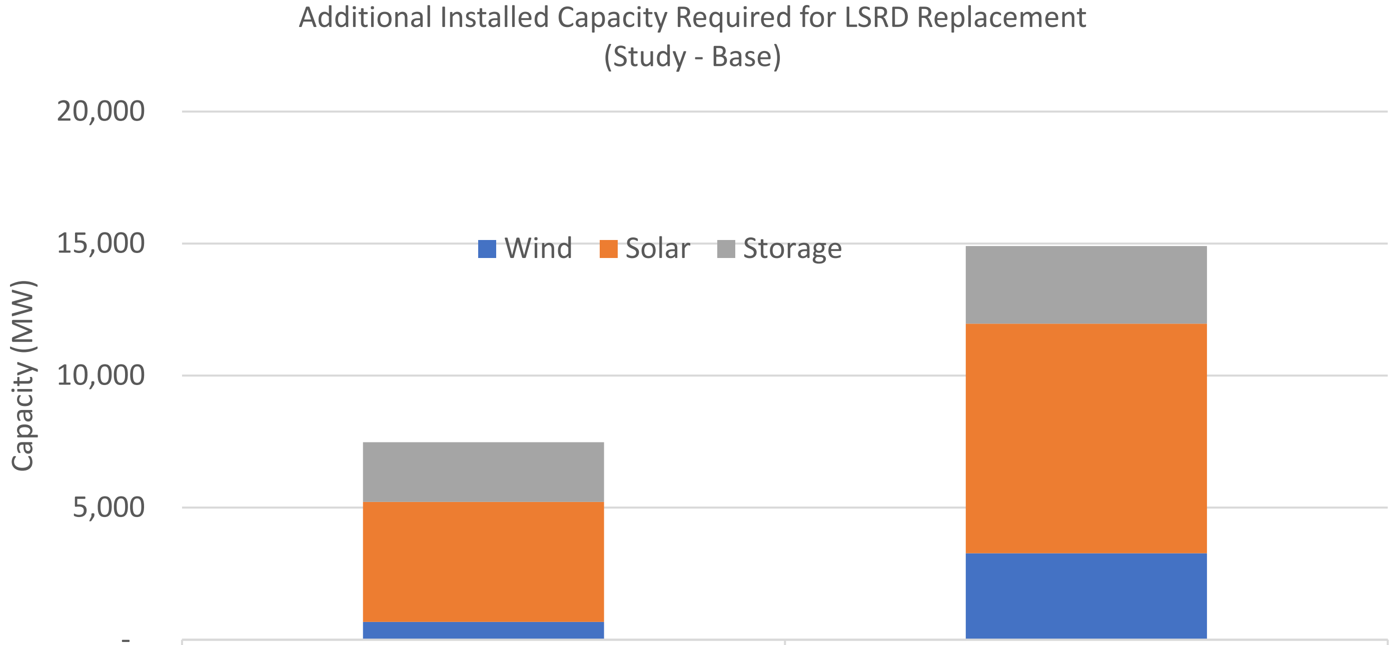
Results

WPP Renewable Build-Out



	2021 Base	2021 Study	2035 Base	2035 Study	2045 Base	2045 Study
Storage	48	48	9,428	11,684	31,658	34,598
Solar	7179	7179	27,248	31,797	80,104	88,796
Wind	17388	17388	43,695	44,366	72,573	75,844

Incremental WPP Renewable Build-Out for LSRD Replacement

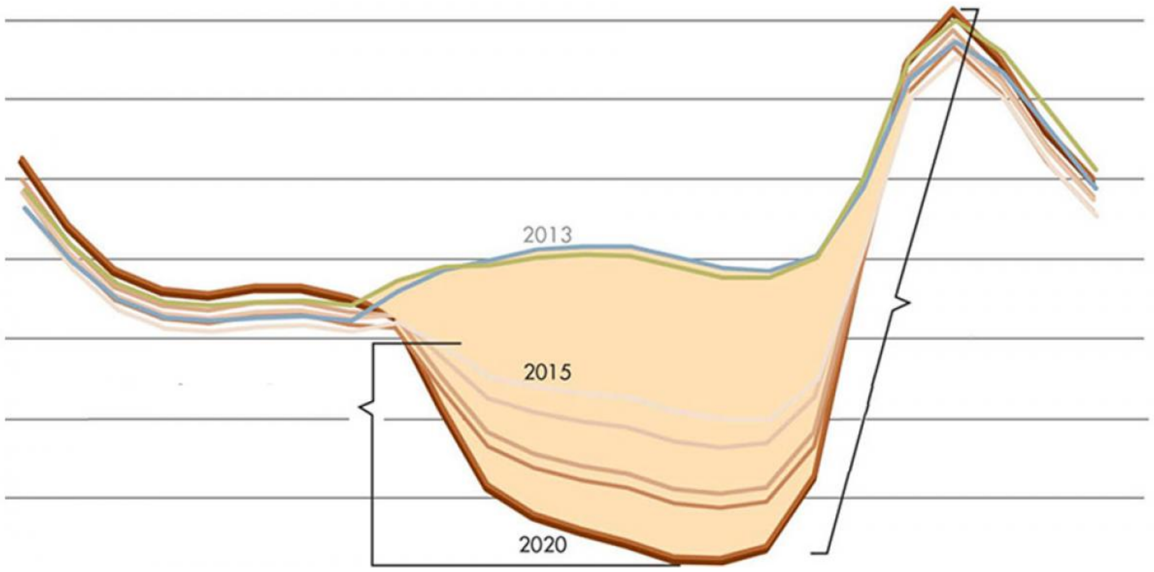


	2035	2045
Storage	2,257	2,940
Solar	4,548	8,692
Wind	671	3,271

Incremental WPP Renewable Build-Out for LSRD Replacement

Name	Type	Renewable and Storage Capacity	Total Cost (NPV)†
Base Case (with LSRD)	Base expansion case to meet reliability and state clean energy laws with the LSRD	160 GW	$142 B
Study Case (Base Case without LSRD)	Study expansion case to meet reliability and state clean energy laws without the LSRD	175 GW	$157 B
Difference	***Impact of Breaching***	***15 GW***	***$15 B***

Why So Much Additional Generation?

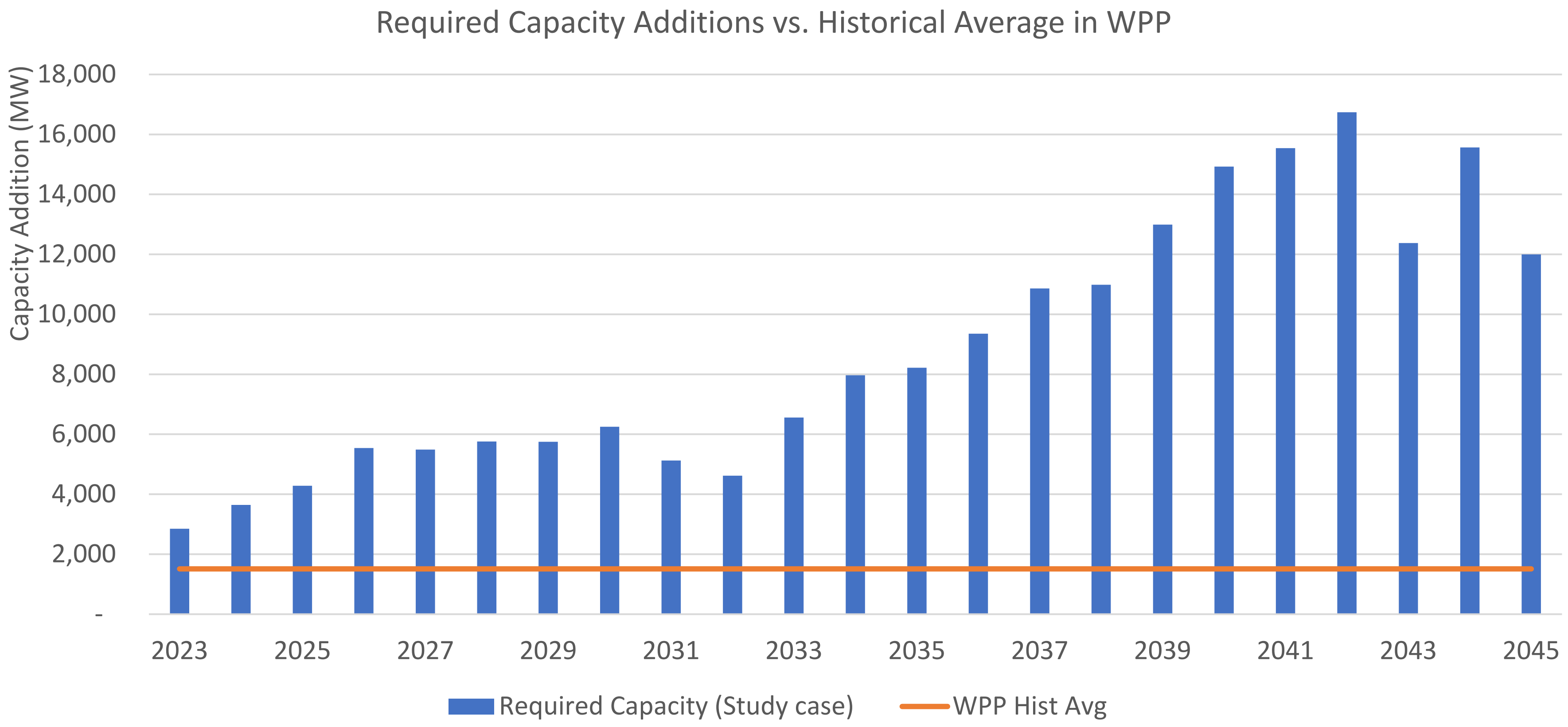


- Observe Transmission Path Limits
- Maintain 16.1% Planning Reserve Margin
- Meet Zero Decarbonization Laws by Required Dates
- + Duck Curve magnified
  - Intermittent generation
  - Huge buildout shifts “net” peak needs
  - 35% is curtailed
  - Only 9-12% of nameplate is useable

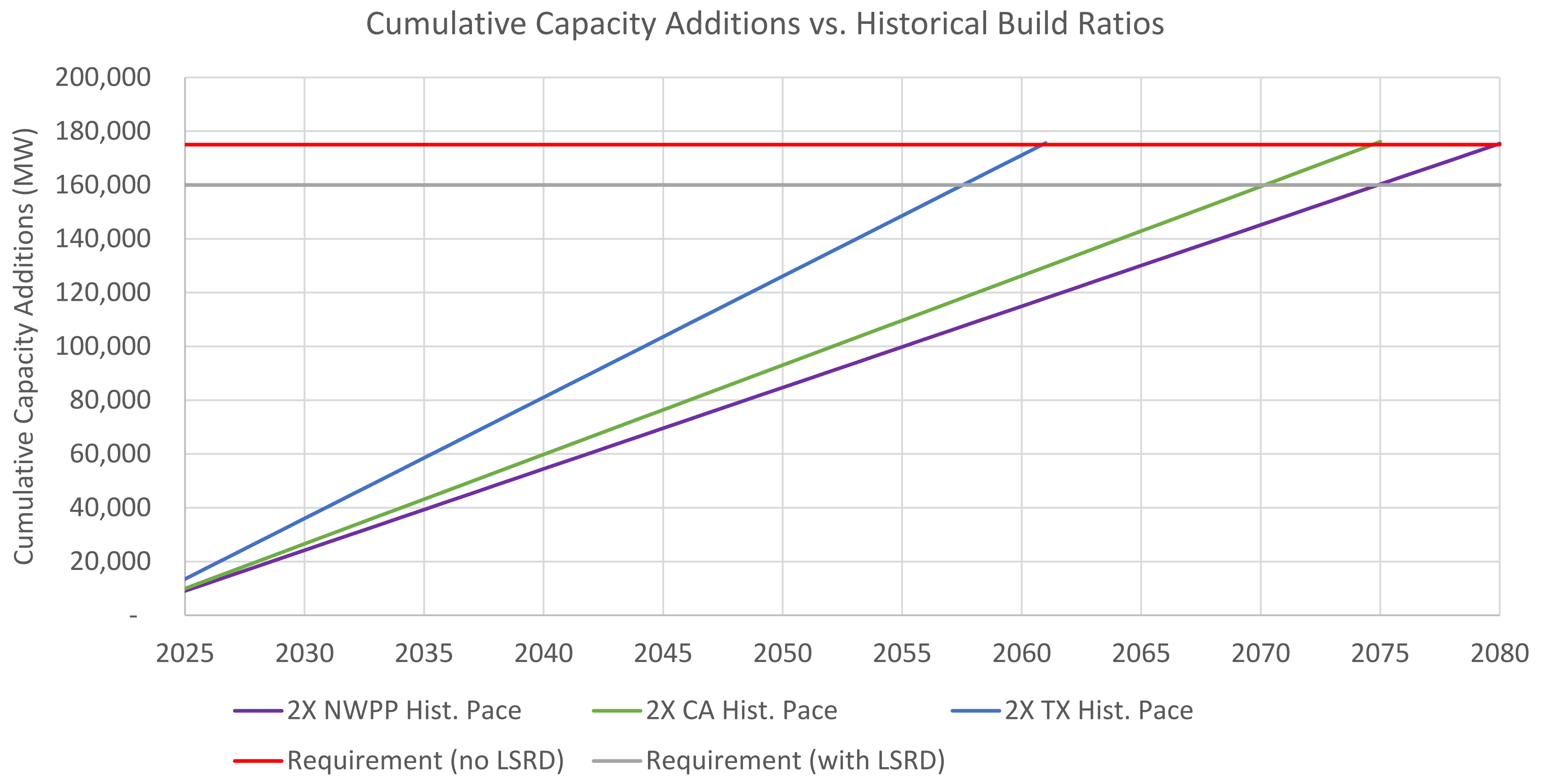
CO_2 Implications

"Lead the charge for the Northwest to realize its clean energy potential using hydroelectricity as the cornerstone."

Historic Buildout Pace Does Not Get Us to Emissions-free by 2045



Doubling the Historic Pace Doesn't Get Us There Either



Removing LSRD Pushes the Decarbonization Effort Back by Years

Annual Average Renewable Capacity Additions in WPP to meet Study Case			
	Using WPP Historic Buildout Pace	Using CA Historic Buildout Pace	Using ERCOT Historic Buildout Pace
Annual average renewable capacity additions from 2007 – 2021 (MW)	1512	1661	2326
Estimated achievement of clean energy laws if **double the historic pace** of capacity additions (Year)	2076	2071	2057
Added emissions due to delay (MMT)‡	136	114	55
Estimated achievement of clean energy laws and replacement of LSRD if double the historic capacity additions (Year)	2081	2076	2060
Added emissions due to delay for replacement of LSRD (MMT) ‡	8.5	8.5	5.1

Final Thoughts

"Lead the charge for the Northwest to realize its clean energy potential using hydroelectricity as the cornerstone."

Summary

- 160,000 MW of new resources required in WPP by 2045 to meet clean energy laws
- LSRD replacement requires incremental 15,000 MW at cost of $15 billion (Net Present Value).
- Removing LSRD capacity puts further stress on the ability to achieve state policy mandates, likely adding an additional 5 MMT – 8.5 MMT of CO_2 released into the atmosphere.

nwriverpartners.org

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/12/2022

Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Discussion Refresh on Energy Storage and Demand Response Opportunities (15 minutes - Felton)

Department:
Energy Services

Recommended Motion:

Summary:
UAC Member Larry Felton will share some historical studies that could be helpful for the City on energy storage and demand response opportunities. This is an informational discussion only at this point as some parameters or markets may have changed. Attached are a June 2012 BPA presentation and an August 2014 BPA article on these topics. UAC Member Larry Felton will review the presentation with members during the meeting.

Fiscal Impact:

Attachments:
1. Smart End-Use Energy Storage
2. Milton-Freewater_Demand Response System Info_Aug 2014

Smart End-Use Energy Storage and Integration of Renewable Energy

(A BPA Sponsored Pilot)

Pilot Overview

June 2012

BPA is working with Utilities Across the Region to Test Demand Response Strategies

Current DR Pilots — Utility	Residential	Commercial	Irrigation	Industrial	Building management	Storage-battery	HVAC thermostat	In-home display	Process adjustment	Refrigeration/ cold storage	Thermal storage space heating	Thermal storage water hearting	Water heater controller	Water pumping
	Sector/Expected MW				**Technology/Planned Installs**									
Central Electric	0.2												403	
City of Forest Grove				0.1						1				
City of Port Angeles	0.4						90	90			30	20	500	
		1.8			1	1	2		4				4	2
				18.0-40.0					2					
City of Richland				0.2						1				
Clark Public Utilities		0.1			1									
Columbia REA			3.0-5.0						1					2
Consumers Power				0.3						2				
Cowlitz County PUD	0.1 - 0.2											70		
Emerald PUD	0.3						200				10	10	200	
EWEB	0.1			.0.2								50		
Kootenai Electric	0.1-0.2						78						95	
Lower Valley	0.1-0.2										6			
		0.1-0.2									3			
Mason County PUD #3	0.1-0.2					2							100	
Orcas Power & Light	0.4												410	
United Electric Co-op			1.8											4

✓ **_Testing in Residential and Commercial / Industrial sectors_**

✓ **_Testing Technical Feasibility_**

✓ **_Testing Approaches to Signal Events_**

The End-Use Energy Storage and Demand Response Pilot is part of this Portfolio

Objectives:

- Use controllable loads to help integrate variable renewables - testing control and dispatch
- Demonstrate that these loads can provide balancing services and benefit end-use customers
- Scope: 1 to 3 megawatts of DR storage
- Develop a demand response business case and marketing materials to support utilities
- Two year project; active since Sept. 2010

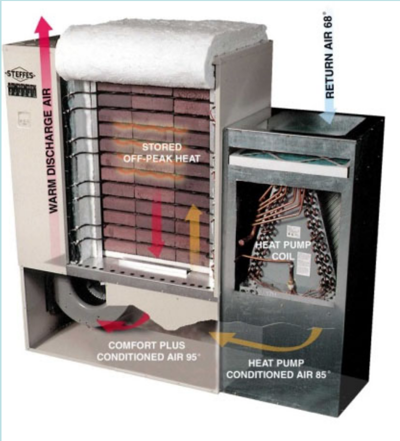
Commercial and Industrial

Commercial HVAC Controls

Cold storage

6 Sites – Washington/Oregon

Residential



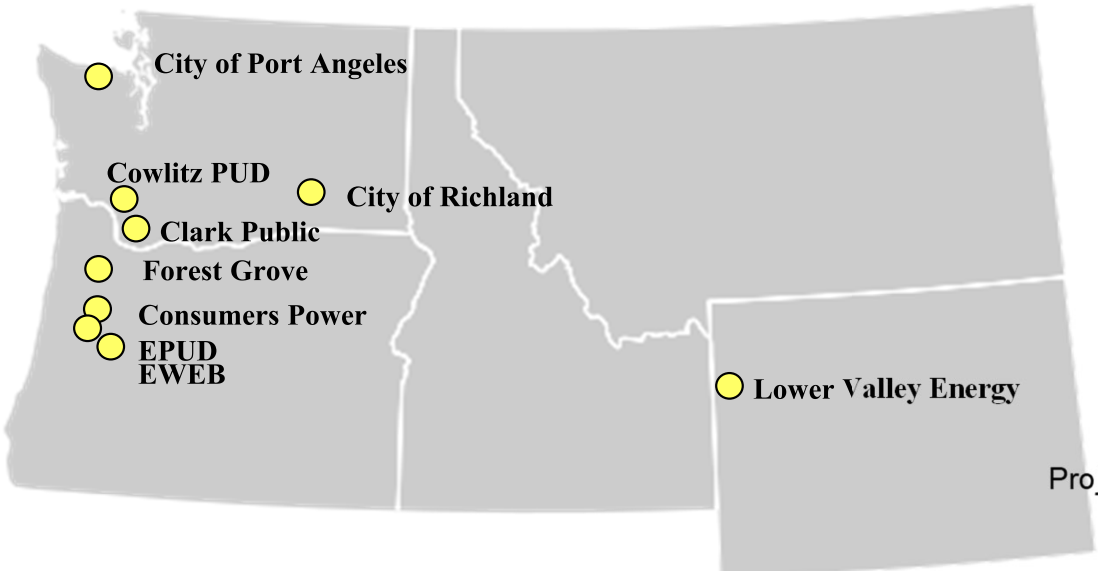
Thermal Brick Furnaces

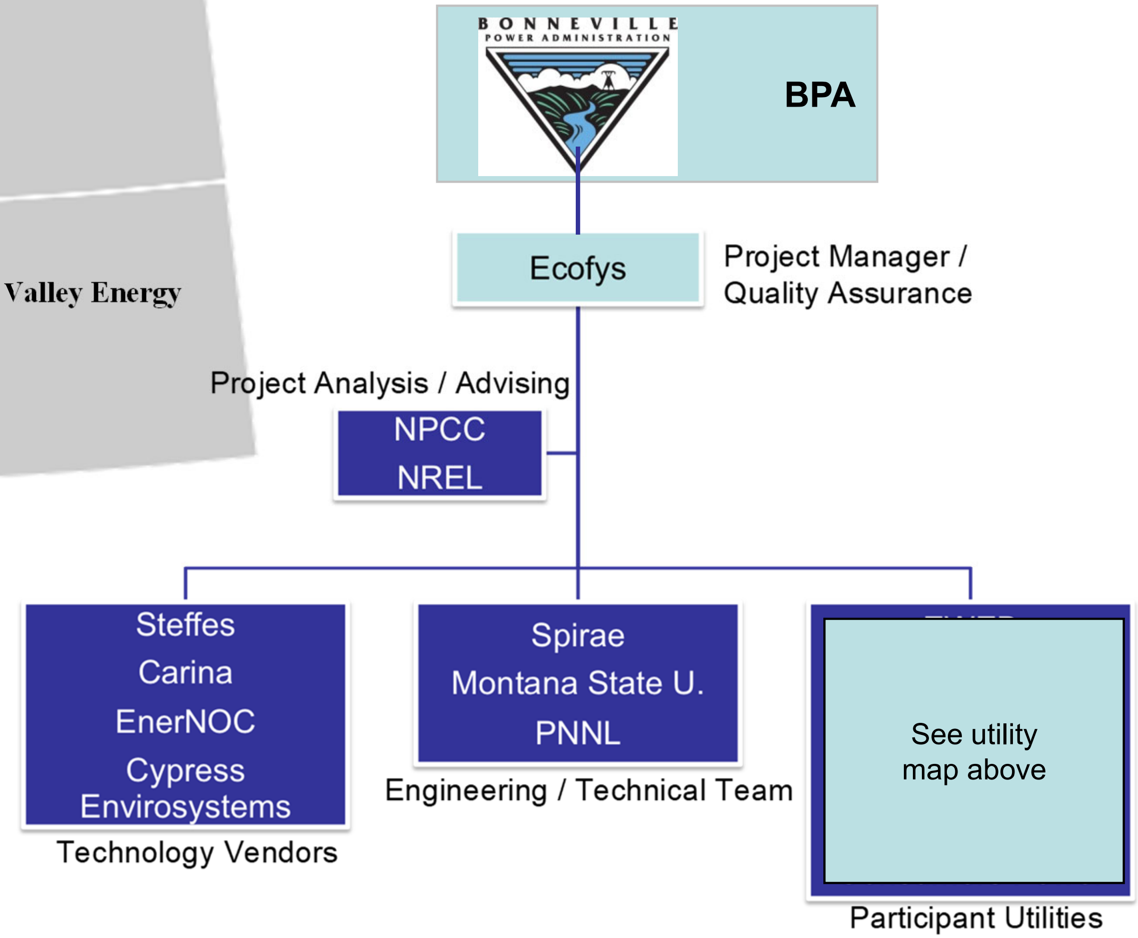
7 units -Wyoming

Residential Water Heaters

200 units - Washington/Oregon

The Pilot includes Participants from across the Region





Testing Multiple Demand Response strategies that have potential benefit for utilities and BPA

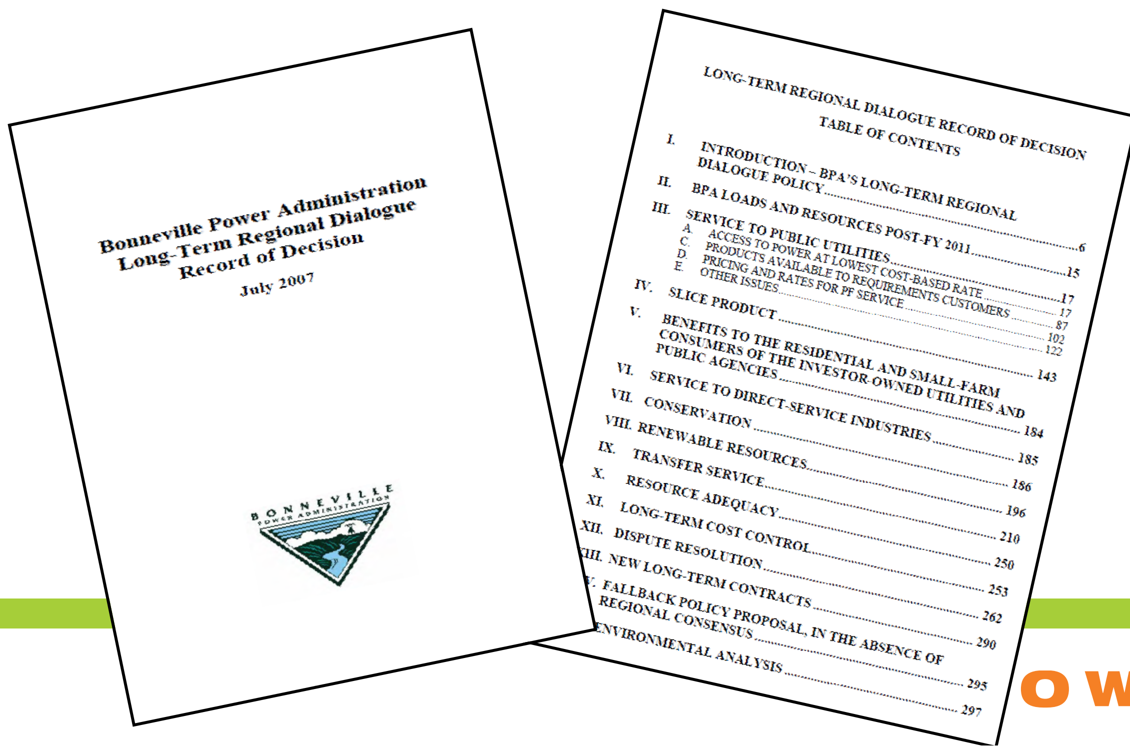
Joint benefits to BPA and utilities to use demand response

- ***load shifting***
- ***peak avoidance***
- ***balancing***
- ***reliability***
- ***congestion management***

Potential DR Use	Constraint Example	Notification Period	Duration	Dispatch	Frequency
Load shifting (HLH to LLH)	Heavy spring run-off Dry April I or August II	Pre-planned, day-ahead or longer	Up to 3 months	BPA	Seasonal, not deployed every year
Utility peak load avoidance	Tier 1 demand charge avoidance by utility	Pre-planned, based on utility algorithm	Up to ~4 hours	Utility	Monthly (e.g., up to 4x per month)
DEC (load up)	Wind integration	< 10 minutes	< 90 minutes	BPA	Up to multiple times per day, multiple frequencies possible
INC (load down)	Wind integration	< 10 minutes	< 90 minutes	BPA	Up to multiple times per day, multiple frequencies possible
Capacity	Winter cold spell, summer heat wave	Day-ahead	Up to ~4 hours	BPA or Utility	As needed, locational, multiple frequencies possible
Reliability / emergency	Large generation unit outage or unit fails to start	< 10 minutes	< 90 minutes	BPA	As needed, BA-wide multiple frequencies possible
Congestion management - transmission	Defer or avoid transmission construction	< 10 minutes	Multi-hour	BPA	As needed, location-specific
Congestion management - distribution	Defer or avoid distribution construction	< 10 minutes	Multi-hour	Utility	As needed, feeder/substation-specific

New BPA Rate Structure sends a Demand Price Signal for Utilities

- BPA recently signed 17-year contracts with all preference customers- the agency has requirements to serve this load
- New rates include a higher demand charge rate (about 4x of previous) for the peak load hour….presents an opportunity for utilities to use Demand Response to reduce this peak


Bonneville Power Administration
Long-Term Regional Dialogue
Record of Decision
July 2007

LONG-TERM REGIONAL DIALOGUE RECORD OF DECISION
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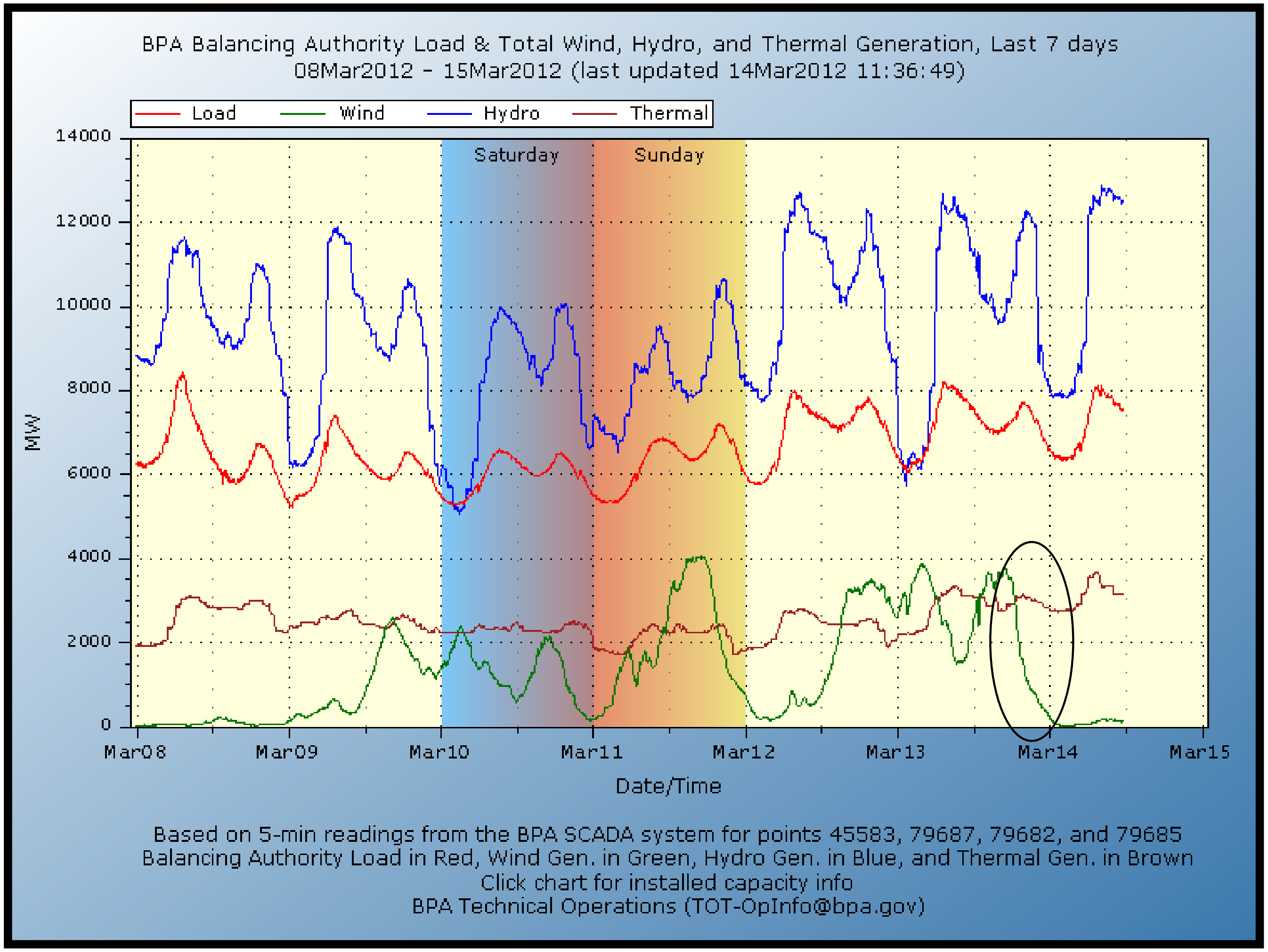
Regional Dialogue Record of Decision Cover page and TOC

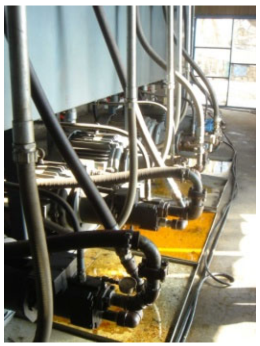
…and Demand Response Acquired via Utilities May be Potential Balancing Reserve



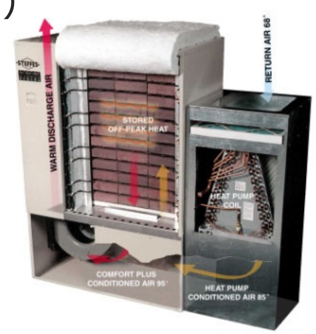
The limits of the federal hydro system are being pushed to support balancing, particularly with the wind buildout

Additional strategies needed for balancing, including Demand Response

Each Asset is Being Tested to Evaluate Storage capability to Shift, Reduce or Take Load without Negatively Impacting the End-User



Commercial Efficient Equipment (Cold Storage)



Thermal Brick Furnaces, Residential & Commercial

Coordinated Control Strategies between Utility and BPA

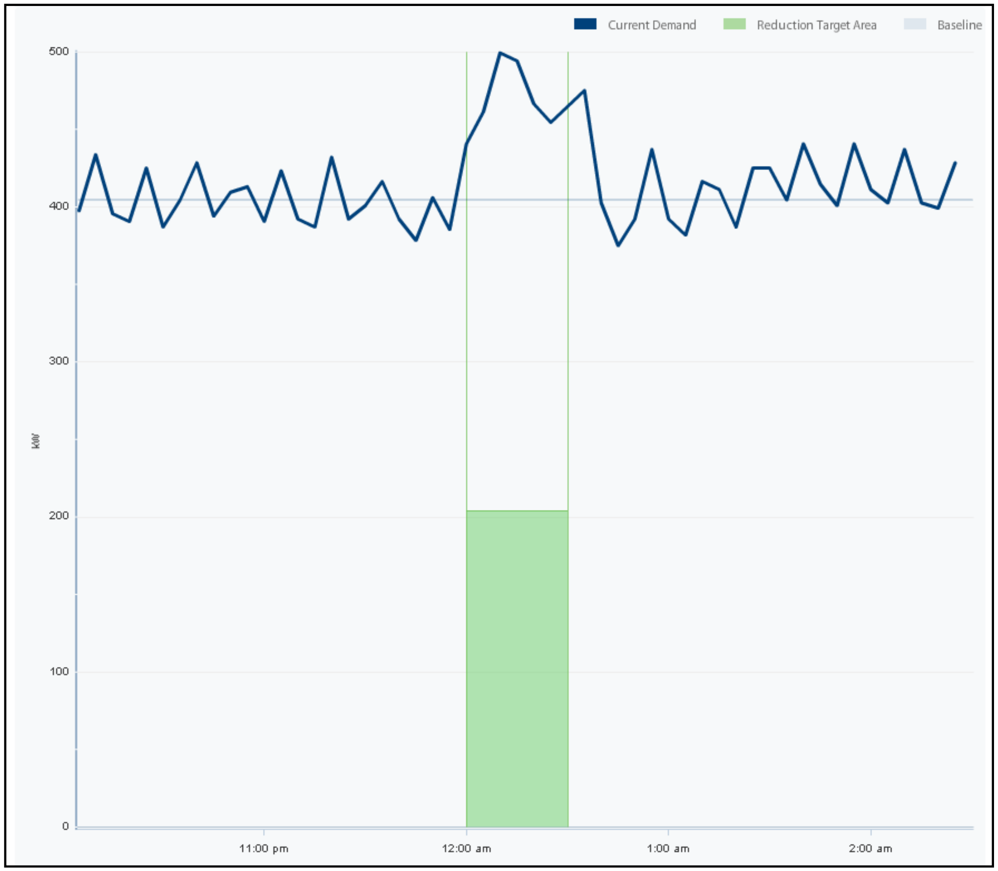
Residential Water Heaters (Steffes & Carina controllers)

Commercial HVAC Controls

C&I Demand Response Includes Testing Cold Storage Warehouses with Four Utilities

Response Types	Fully automated load decreases (INCs) and increases (DECs)
Portfolio	Currently five refrigerated warehouse sites with four utilities– City of Richland, Consumers Power (2), EWEB, and Forest Grove
Capacity	Pilot budget compensates participants for up to 200kW of load control per site, structured as a $/kW capacity or availability payment
Response Time	Capacity dispatched upon 10 minutes notice.
Availability	24 hours per day, year round
Event Duration / Limitations	Maximum event duration of 30 minutes (Phase I events) Maximum of 2 events per day, 10 events per week Minimum of 3 hours between events
Technology	1-minute interval metering
Baseline	Average of ten 1-minute readings prior to event start
Performance	For each interval, difference between baseline and facility usage

The C&I Cold Storage Testing Across Sites Began in 2011



32 Defined Events across all participants:

- 10 min. notice
- 30 min. duration
- 2 events/day
- INC or DEC calls (curtail load or increase load)

Facilities are now proceeding to longer & more frequent events, and fine-tuning of response, with no DEC testing during peak hours

Henningsen Pilot in Richland

Objective: Estimate the potential for and performance characteristics of a C&I load following resource for the City of Richland (Henningsen facility) through testing of the C&I cold storage facility. Identify potential roadblocks to widespread adoption and potential solutions.

Background: This portion of project being coordinated with EnerNOC, a national demand response aggregator (manages a total of 8GW of Demand Response). The tests are being conducted per an agreed upon protocol with Henningsen, the City of Richland, Ecofys and BPA. Enernoc initiates the event and is working with Ecofys to gather/analyze data.

ENERNOC

Henningsen receives a participation fee of $1.67/kW-month to participate in the pilot for opportunity cost and allowing 3rd party control.

Henningsen Pilot in Richland – Testing Plan

Phase 1 Events: August – December 2011

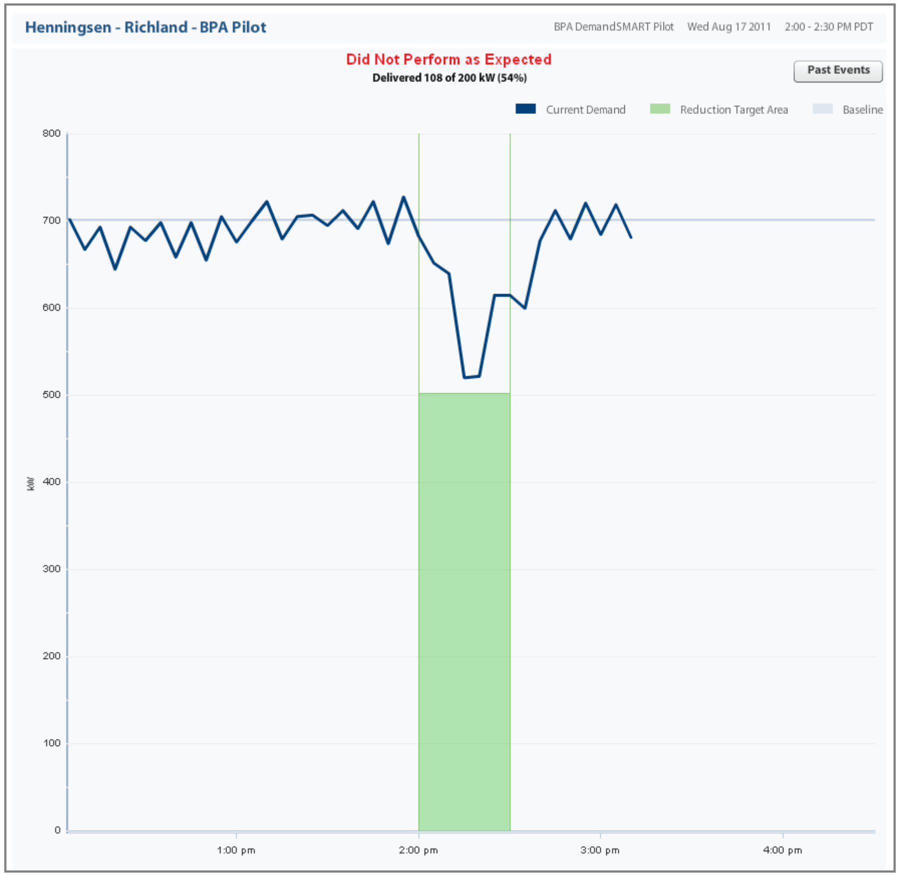
- 15 Tests conducted.
- Result:
  - Goal was to have enablement, identify capabilities of the resource, and understand which portion of 200K available. In this testing, 0-108KW for load down (15% of target) and 0 -125KW (77%) for load up. See next page example.

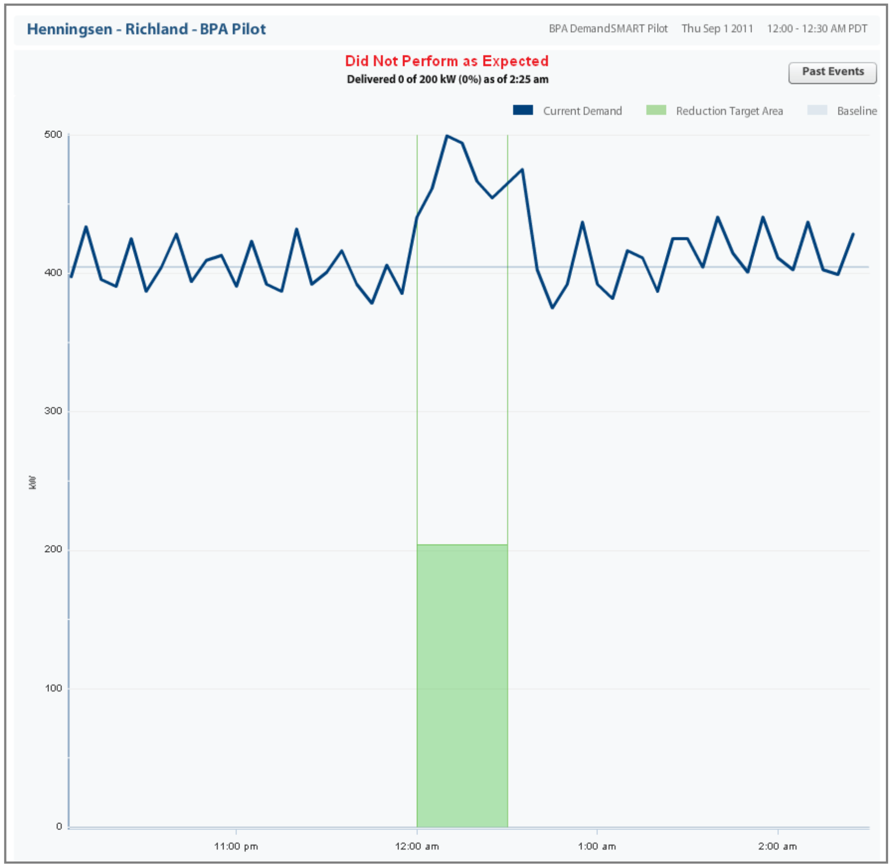
Phase 2 Event Plan - longer and more frequent events

- **Load increase (DEC) events**
  - Duration: 30, (45 and 90 minutes – being discussed)
  - Notification: 10 minutes
  - Event window: between 11 pm – 4 am (this will avoid coinciding with a morning/afternoon peak, and be during light load hours)
  - Target # of events: 28
- **Load decrease (INC) events**
  - Duration: 30, (45 and 90 minutes – being discussed
  - Notification: 10 minutes
  - Event window: between 10 am – 6 pm
  - Target # of events: 14
- **Event summaries to be shared monthly, analysis completed Sept. 2012**

May to August 2012

Example Cold Storage – INC and DEC Dispatches



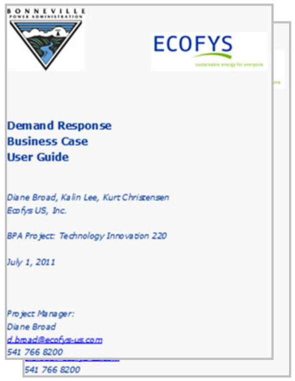


- INC dispatch (load decrease)
- August 17, 2011, 2pm to 2:30pm
- Delivered 108kW of 200kW target

- DEC dispatch (load increase)
- September 1, 2011, 12am to 12:30am
- Delivered 80kW of 100kW target

Confidential & Proprietary

Tailored Business Cases are Being Built with Participating Utilities so Utilities can Assess Benefits of Demand Response



Business Case Example –
The Model produces various Return on Investment Views

Revenues per load mgt. strategy (x 1,000)	2013	2014	2015
1. Load shaping	$ 0.92	$ 1.14	$ 1.57
2. Peak shavings	$ 29.63	$ 41.59	$ 54.57
3.a HQ INC load balancing service	$ 0.45	$ 0.55	$ 0.72
3.b HQ DEC load balancing service	$ 0.18	$ 0.22	$ 0.29
4. Energy losses	$ -0.81	$ -1.18	$ -1.56
Total cash in (x 1,000)	$ 30	$ 42	$ 56

Revenue by Utility Strategy Employed

Payback Period

1.2 Devices procured & installed in 2013

Financial results per device (incl. costs for comm. & data kit)	Additional investment	Add. annual maintenance	Annual revenues	Payback time [years]
Steffes IWHC with 50 gallon tank	$ 738	$ 7	$ 221	3.5
Steffes IWHC with 105 gallon tank	$ 1,385	$ 14	$ 250	5.9
Steffes ETS furnace (Forced air) (Incl. Air source Heat Pump)	$ 3,844	$ 65	$ 667	6.4
Steffes ETS furnace (Hydronic) (Incl. Air source Heat Pump)	$ 5,904	$ 86	$ 716	9.4
Carina WISE controller 50 gallon retrofit	$ 400	$ 4	$ 204	2.0
One-Way WH Controller Switch	$ 300	$ 3	$ 93	3.3

Pacific Northwest Smart Grid Demonstration Project
SUCCESS STORIES
AUGUST 27, 2014

MILTON-FREEWATER

Milton-Freewater: A frontier for new technology

Oregon's oldest city-owned utility is far from old-fashioned. In fact, it's a power pioneer in the Pacific Northwest. Since 1985, Milton-Freewater City Light and Power has reduced peak energy use with a technique called demand response. Demand response may not be the talk of the town, but it's still a big deal to this homegrown utility. And it's one of the many technologies the Pacific Northwest Smart Grid Demonstration Project intends to advance.

Milton-Freewater is the only public utility in Oregon chosen to take part in the nation's largest smart grid test. The project spans five states and includes 60,000 metered customers. Eleven utilities, five technical firms and two universities are participating. The $178 million project is funded by the utility participants, with matching funds from the Department of Energy. The Bonneville Power Administration is contributing $10 million, also matched by DOE.

With Milton-Freewater's $1.8 million investment and DOE's matching funds, the rural utility upgraded its historic demand response program and tested some newer technologies, such as voltage reduction and voltage-sensing water heaters.

Of the 60,000 metered-customers involved in the regionwide project, Milton-Freewater City Light and Power is the smallest participant with only 4,550 customers. The utility did not hire any additional staff except for a contractor to perform installations, because the utility's only electrician had retired.

Blazing the trail for demand response

When not at his cherry orchard, retired city electrician Bill Saager enjoys the cowboy shooting range just outside of

MILTON-FREEWATER CITY LIGHT & POWER
Milton-Freewater, Oregon

- Locally-owned and operated since 1889
- Average annual sales: 118,000,000 kilowatt hours
- 4,550 customers

INVESTMENT IN PNWSGDP:

- $1.8 million

HIGHLIGHTS:

- Completed AMI rollout
- Direct load control/DR
- 5 megawatt reduction
- CVR

FOR MORE INFORMATION:

Tina Kain 541-938-8238
www.mfcity.com/electric

DRAFT
8.29.14

town. The 75-year-old bandana-wearing quick-draw installed the city's original demand response units – all 500 of them.

But getting and using a contractor's license wasn't easy. Saager convinced the State of Oregon Construction Contractors Board to forgo the insurance and bonding requirement because he was only doing work for the utility, not the customer. Cleary, Saager is a fan of smart technology.

"I think that utilities are really missing the target if they don't pursue some type of DR in the future," said Saager. "You can really extend the capabilities of your system."

Milton-Freewater's original demand response program used a radio energy management system, or REMS, to control electric water heaters and electric heating and air conditioning systems. A centralized computer system monitored the power demand and sent a radio signal to the REMS units to cycle off connected loads to reduce energy when the peak demand set-point was reached.

The city's goal of the Pacific Northwest Smart Grid Demonstration Project has been to enhance its already highly successful demand response program.

Listen. Respond. Repeat.

To do that, the newer technology must go one step further, by listening and responding from both sides of the communication. With a smart meter system that uses two-way communications, the utility confirms that the demand response units receive the signal and controls the amount of time the electricity is shut off. The goal is for the entire demand response process to go unnoticed.

Water heaters, electric heaters and air conditioners are connected to the demand response system to trim energy use when a certain set-point is reached. Up to three megawatts can be reduced by shaving the energy used in 754 customers' homes, businesses and even churches.

Replacing the old units with the newer models spurred a lot of questions. Many customers didn't know the units existed. A few were suspicious of the utility installing new, more intelligent units. But only a few opted out.

"We found that many homes had changed tenants," said Tina Kain, engineering technician for the city. "New residents were unaware of the DR units, which is a great sign. The undisruptive units helped residents save money without even knowing it."

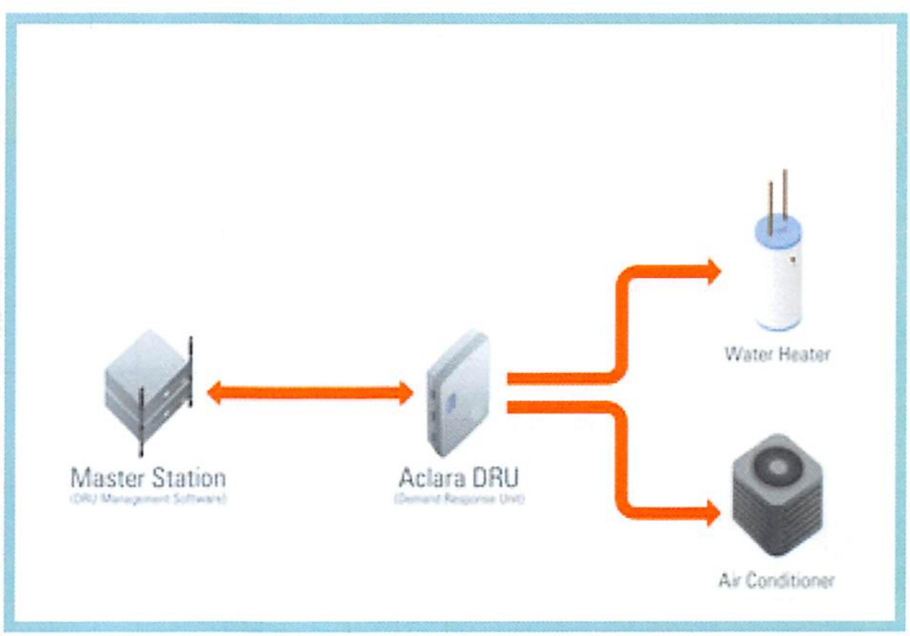
To entice participation, a rate discount was offered to customers:

- 2.5 percent for water heaters
- 2.5 percent on electric heating
- 1 percent for air conditioning

DR is used as a last resort in the peak shaving process. When the system begins to approach its peak energy use, the first step is to reduce voltage by 4.5 percent. Next, the city shuts off the wells that are connected to the centralized computer system. Finally, DR units are employed. Reverse order restores the system to its original state.

The incredible value of the smart meter

Every customer of Milton-Freewater City Power and Light is now set up with a smart meter that uses two-way communication over the power line. With these more advanced meters, energy use is monitored every fifteen minutes. That means better customer service, such as



> "You can see from our history that Milton-Freewater's City Light and Power is innovative and forward thinking. It's about planning ahead. We all know that electric rates probably aren't going to be going down any time soon, so if a new technology pencils out now, it's going to be more beneficial in years to come."

– RICK RAMBO, THE CITY OF MILTON-FREEWATER ELECTRIC SUPERINTENDENT

helping homeowners troubleshoot high bill complaints and remote meter reading. On selected meters, a device called a disconnect collar, which allows for a remote disconnect or reconnect, was installed.

One of the biggest benefits is a smart meter's ability to quickly detect an outage. Previously, the utility wasn't aware of an outage until a customer called it in. A crew was then dispatched to investigate and do the repairs. Often, the process could take hours. Now, many outages are fixed in minutes, saving the utility both labor and transportation expenses as well as providing better service to the customers.

Conservation voltage reduction

Conservation voltage reduction is Milton-Freewater's first step to address a peak on the system. Substation voltage regulators lower the system voltage by 1.5 volts on four feeder lines out of the Milton Substation. This reduces the megawatts used on the entire system while still maintaining adequate distribution voltage.

To test the theory that every 1 percent in voltage reduction leads to a 1 percent reduction in kilowatt-hours used, Milton-Freewater reduces voltage one week, and then returns it to the status quo the next. By alternating weeks, the utility will be able to compare the two datasets and calculate the benefits once the demonstration is complete.

Specialized water heaters

To further test possibilities with conservation voltage reduction, Milton-Freewater installed 100 demand response units on water heaters that operate when the city's voltage reduction occurs. The demand response units are programmed to sense voltage and turn off connected load.

Although the water heaters worked well with the voltage reduction system, they didn't work so well with another part of the project – the transactive control signal. This signal is being tested as part of the demonstration across a multiple utility footprint to assess the feasibility of automating the trade of energy based on many conditions, such as the availability of wind or solar power, for a regional benefit.

When the transactive control signal activated a voltage reduction, the demand response units turned off the connected water heaters, and they stayed off until the voltage reduction ended. When the signal lasts longer than five or six hours, the customer may run out of hot water, resulting in customer complaints and countering the city's goal of ensuring demand response goes unnoticed.

Sizing up the study

Even though the city has been doing demand response for three decades, testing new technologies presented challenges.

First, differences between the original and new demand response systems were disappointing. The old REMS units operated 20 minutes on, 15 minutes off, so Milton-Freewater could reassure customers that their water heaters would be turned off no longer than 15 minutes. But the new units turn on and off in an inconsistent, unpredictable pattern, which is a little more difficult for customers to accept.

And that wasn't the only challenge with the units. They all cycled on or off at the same time, creating their own peaks and valleys. Innovative solutions were needed to stagger the units.

Data storage is also a problem. Unless the data is manually extracted from the unit before its next operation, the data is lost. That means the utility cannot determine how well the unit worked for

that cycle. To work around this issue, the research laboratory will analyze meter data to determine load fluctuations from the demand response units.

Overall, lack of resources has been one of the largest challenges for the small rural utility – the employees had to learn a whole new system while doing their regular jobs. But that also demonstrates the city's dedication to keeping rates low.

"Every little bit counts," said Bill Saager, the retired electrician-turned cowboy.

WHAT'S NEXT

for Milton-Freewater?

As a result of the lessons learned from the project, the city plans to discontinue conservation voltage reduction. Even though it has provided some benefits, operating more than one voltage reduction system at the same time on different feeders was confusing for work crews.

Furthermore, once the project is concluded, the city will explore transactive control opportunities based on the needs of the city and the potential benefits.

Other ideas for the future include a customer pre-pay system so that energy use can be managed based on an individual family budget.

"We're at the point of trying to learn what we can do with the system." said Rick Rambo, the electric utility's superintendent. "I know we're not using it to its full potential."

Still, the tried and true prevails. Demand response will continue as it has since 1985 across the city's entire electrical system, with fine-tuning of the operation as needed and with very little impact on the customer.

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Richland Washington

Meeting Date: 7/12/2022

Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
RES Capital Work Plan Status Report - May 2022

Department:
Energy Services

Recommended Motion:
This item is information only.

Summary:
The Capital Work Plan for Energy Services through May 2022 is attached.

Fiscal Impact:

Attachments:
1. RES CWP REPORT-May 2022

CITY OF RICHLAND
WASHINGTON

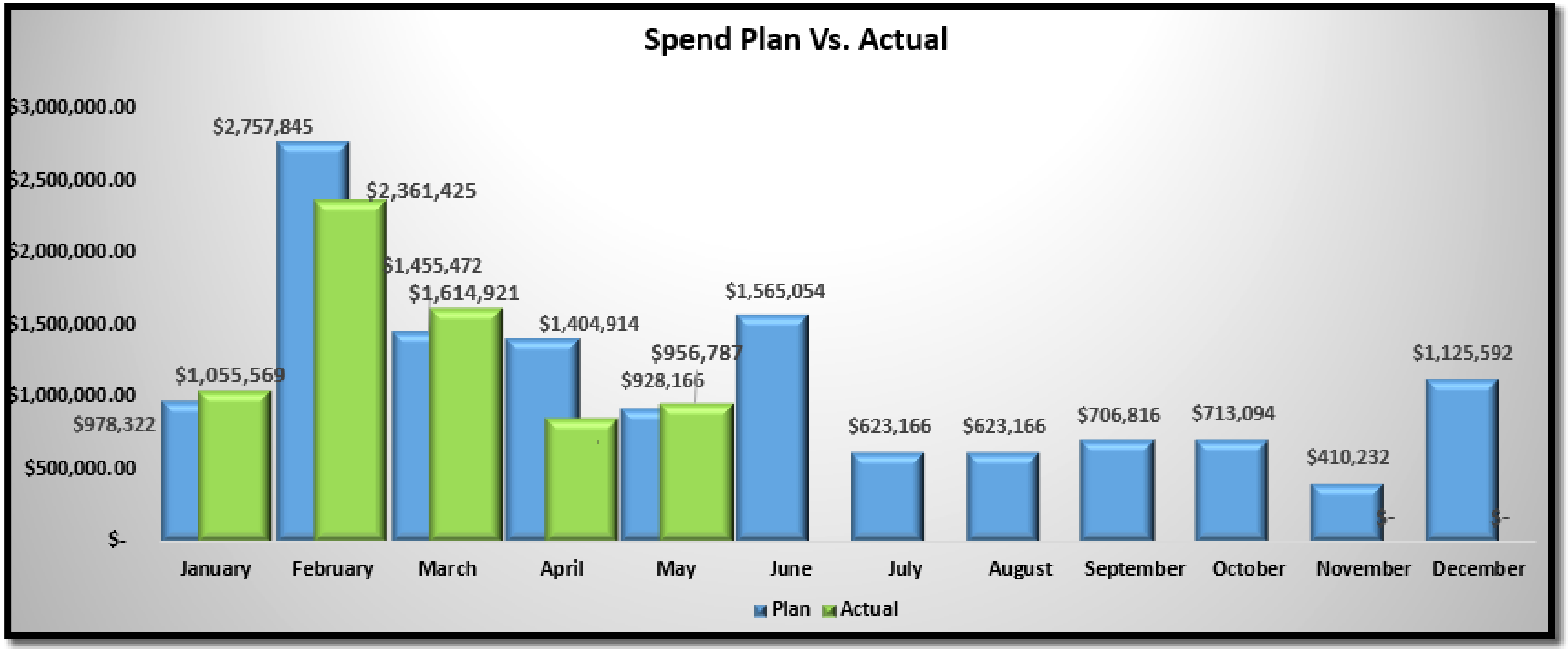
Richland Energy Services
Capital Work Plan
May 2022

CWP Costs for May

	Approved 2022 Budget	Carry Over from 2021	2022 Estimated Costs	Actual	Remaining	May
⊞ Line Extensions	$1,580,000	$ -	$ 1,580,000	$ 106,831	$ 1,473,169	$ 26,248
⊞ Smart Grid - Advanced Metering Infrastructure	$3,186,000	$ 2,420,708	$ 4,291,900	$ 2,529,230	$ 1,762,670	$ 354,608
⊞ System Improvements	$2,067,000	$ -	$ 2,165,994	$ 1,695,854	$ 470,140	$ 306,968
⊟ Renewal and Replacement	$1,996,000	$ 80,033	$ 1,664,564	$ 1,225,336	$ 439,228	$ 249,544
⊞ Substation Improvements	$1,957,000	$ 1,368,652	$ 3,589,381	$ 1,294,346	$ 2,295,035	$ 19,346
Grand Total	$10,786,000	$ 3,869,393	$ 13,291,839	$ 6,852,042	$ 6,439,797	$956,787

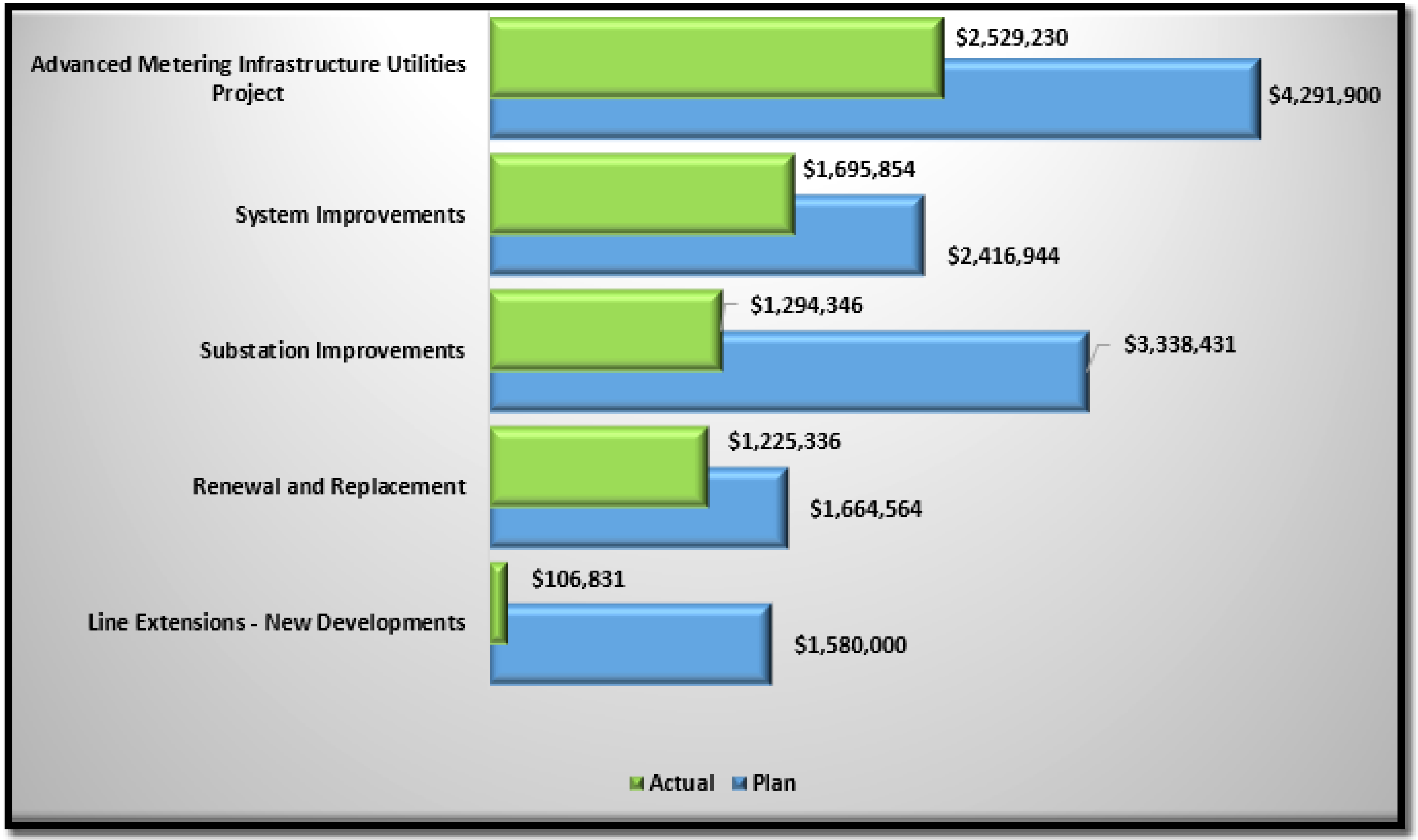
Cost Performance YTD:	**$6,852,042**
Cost Performance remaining:	**$6,439,797**
YTD % Complete	**52%**

CWP Monthly Spend Vs. Actuals

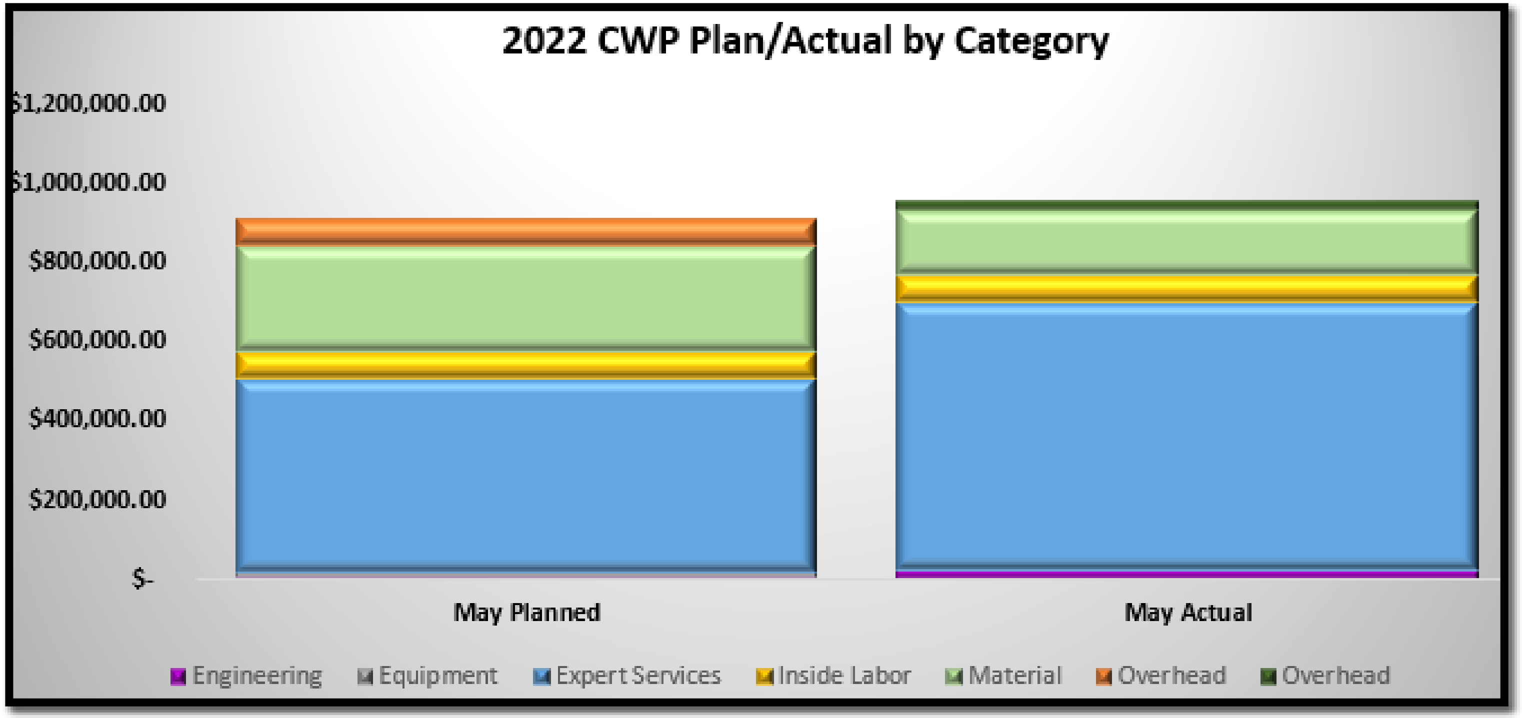


% Complete of Overall		
To-Date Pro	$ 7,524,719	
Actual	$ 6,852,042	
Variance	($672,677)	91%

Costs by Category



CWP Cost Types



Cost Type	May Planned	May Actual
Engineering	$ 4,250	$ 20,209
Equipment	$ 9,920	$ -
Expert Services	$ 489,404	$ 678,790
Inside Labor	$ 67,098	$ 68,763
Material	$ 269,087	$ 160,798
Overhead	$ 70,208	$ 28,209
Total	$ 909,966	$ 956,769

CITY OF RICHLAND WASHINGTON

CWP Project Costs for May

	Approved 2022 Budget	Carry Over from 2021	2022 Estimated Costs	Actual	Remaining	May
Line Extensions	**$1,580,000**	**$ -**	**$ 1,580,000**	**$ 106,831**	**$ 1,473,169**	**$ 26,248**
Smart Grid - Advanced Metering Infrastructure	**$3,186,000**	**$ 2,420,708**	**$ 4,291,900**	**$ 2,529,230**	**$ 1,762,670**	**$ 354,608**
System Improvements	**$2,067,000**	**$ -**	**$ 2,165,994**	**$ 1,695,854**	**$ 470,140**	**$ 306,968**
System Improvements						
Renewal and Replacement						
1434 GENEVA ST; POLE UPGRADE	$0	$ -	$ -	$ 148,765	$ (148,765)	$0.00
CANYON TERRACE 2, UG R&R	$0	$ -	$ -	$ 1,381	$ (1,381)	$0.00
1403 Keller; Renew Replace #6BC with 1/0ACS	$0	$ -	$ -	$ 180	$ (180)	$0.00
INDIAN VALLEY; NEW PRIMARY AND SECONDA	$0	$ -	$ -	$ 85,726	$ (85,726)	$46,605.71
First Street Re-Gasket	$80,000	$ -	$ 80,000	$ -	$ 80,000	$0.00
Overhead Dock Crew	$0	$ 80,033	$ 80,033	$ 103,768	$ (23,735)	$0.00
2021 Boring Project, Westview Acres	$1,916,000	$ -	$ 1,504,531	$ 883,591	$ 620,940	$202,938.23
Substation Improvements	**$1,957,000**	**$ 1,368,652**	**$ 3,589,381**	**$ 1,294,346**	**$ 2,295,035**	**$ 19,346**
Relay Replacement						
City View Sub: Relay Replacement	$69,000	$ -	$ 83,650	$ -	$ 83,650	$0.00
Sandhill Crane Sub Bank 1: Relay Replacemen	$69,000	$ -	$ 83,650	$ 61	$ 83,589	$0.00
Sandhill Crane Sub Bank 2: Relay Replacemen	$69,000	$ -	$ 83,650	$ -	$ 83,650	$0.00
Substation Improvements						
Gateway Substation 2021 Project	$0	$ 1,368,652	$ 1,588,431	$ 1,279,846	$ 308,585	$16,832.69
City View Bank 2 Addition	$1,325,000	$ -	$ 1,325,000	$ 12,214	$ 1,312,786	$2,307.22
Gateway Substation Feeder 151	$425,000	$ -	$ 425,000	$ -	$ 425,000	$0.00
Grand Total	**$10,786,000**	**$ 3,869,393**	**$ 13,291,839**	**$ 6,852,042**	**$ 6,439,797**	**$956,787**

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/12/2022

Agenda Category: Other Informational Items

Prepared By:

Subject:
Forward Agenda Planning

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:

September
- Sewage Treatment Plant
- Energy Conservation Update (RES)

November
- Cost of Service Analysis (COSA) (RES)
- Resource Adequacy (RES)

Ongoing
- Cybersecurity (RES)
- Heat Dome Communication Plans (RES)
- Supply Chain Status (RES)

Fiscal Impact:

Attachments: