BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-121:
Mercury Mortality Risks of Coal

Environment & Climate Health

Particulate pollution from coal associated with double the risk of mortality than PM2.5 from other sources

By **Staff Writer** • November 23, 2023

HARVARD T.H. CHAN | SCHOOL OF PUBLIC HEALTH

For immediate release: November 23, 2023

Exposure to fine particulate air pollutants from coal-fired power plants (coal PM2.5) is associated with a risk of mortality more than double that of exposure to PM2.5 from other sources, according to a new study led by George Mason University, The University of Texas at Austin, and Harvard T.H. Chan School of Public Health. Examining Medicare and emissions data in the U.S. from 1999 to 2020, the researchers also found that 460,000 deaths were attributable to coal PM2.5 during the study period—most of them occurring between 1999 and 2007, when coal PM2.5 levels were highest.

The study was published on November 23, 2023, in Science.

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much more harmful than we thought, and its mortality burden has been seriously underestimated," said lead author Lucas Henneman, assistant professor in the Sid and Reva Dewberry Department of Civil, Environmental, and Infrastructure Engineering at Mason. "These findings can help policymakers and regulators identify cost-effective solutions for cleaning up the country's air, for example, by requiring emissions controls or encouraging utilities to use other energy sources, like renewables."

Using emissions data from 480 coal power plants in the U.S. between 1999 and 2020, the researchers modeled where wind carried coal sulfur dioxide throughout the week after it was emitted and how atmospheric processes converted the sulfur dioxide into PM2.5. This model produced annual coal PM2.5 exposure fields for each power plant. They then examined individual-level Medicare records from 1999 to 2016, representing the health statuses of Americans ages 65 and older and representing a total of more than 650 million person-years. By linking the exposure fields to the Medicare records, inclusive of where enrollees lived and when they died, the researchers were able to understand individuals' exposure to coal PM2.5 and calculate the impact it had on their health.

They found that across the U.S., in 1999, the average level of coal PM2.5 was 2.34 micrograms per cubic meter of air (µg/m3). This level decreased significantly by 2020, to 0.07 µg/m3. The researchers calculated that a one µg/m3 increase in annual average coal PM2.5 was associated with a 1.12%

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The researchers were also able to quantify deaths attributable to specific power plants, producing a ranking of the coal-fired power plants studied based on their contribution to coal PM2.5's mortality burden. They found that 10 of these plants each contributed at least 5,000 deaths during the study period. They visualized the deaths from each power plant in a publicly available online tool (https://cpieatgt.github.io/cpie/).

The study also found that 390,000 of the 460,000 deaths attributable to coal-fired power plants took place between 1999 and 2007, averaging more than 43,000 deaths per year. After 2007, these deaths declined drastically, to an annual total of 1,600 by 2020.

"Beyond showing just how harmful coal pollution has been, we also show good news: Deaths from coal were highest in 1999 but by 2020 decreased by about 95%, as coal plants have installed scrubbers or shut down," Henneman said.

"I see this as a success story," added senior author Corwin Zigler, associate professor in the Department of Statistics and Data Sciences at UT Austin and founding member of the UT Center for Health & Environment: Education & Research. "Coal power plants were this major burden that U.S. policies have already significantly reduced. But we haven't completely eliminated the burden—so this study provides us a better understanding of how health will continue to improve and lives will be saved if we move further toward a clean energy future."

The researchers pointed out the study's continuing urgency and relevance, writing in the paper that coal power is still part of some U.S. states' energy

"As countries debate their energy sources—and as coal maintains a powerful, almost mythical status in American energy lore—our findings are highly valuable to policymakers and regulators as they weigh the need for cheap energy with the significant environmental and health costs," said co-author Francesca Dominici, Clarence James Gamble Professor of Biostatistics, Population, and Data Science at Harvard Chan School and director of the Harvard Data Science Initiative.

Funding for the study came from the National Institutes of Health (grants R01ES026217, R01MD012769, R01ES028033, 1R01ES030616, 1R01AG066793, 1R01MD016054-01A1, 1R01ES 034373-01, 1RF1AG080948, and 1R01ES029950); the Environmental Protection Agency (grant 835872); the EmPOWER Air Data Challenge (grant LRFH); the Alfred P. Sloan Foundation (grant G-2020-13946); and the Health Effects Institute (grants R-82811201 and 4953).

"Mortality risk from United States coal electricity generation," Lucas Henneman, Christine Choirat, Irene Dedoussi, Francesca Dominici, Jessica Roberts, Corwin Zigler, Science, online November 23, 2023, doi: 10.1126/science.adf4915.

Image: iStock/Triton_Tree

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Harvard T.H. Chan School of Public Health brings together dedicated experts from many disciplines to educate new generations of global health leaders and produce powerful ideas that improve the lives and health of people everywhere. As a community of leading scientists, educators, and students, we work together to take innovative ideas from the laboratory to people's lives—not only making scientific breakthroughs, but also working to change individual behaviors, public policies, and health care practices. Each year, more than 400 faculty members at Harvard Chan School teach 1,000-plus full-time students from around the world and train thousands more through online and executive education courses. Founded in 1913 as the Harvard-MIT School of Health Officers, the School is recognized as America's oldest professional training program in public health.

George Mason University is Virginia's largest public research university. Located near Washington, D.C., Mason enrolled over 40,000 students from 130 countries and all 50 states for the fall 2023 semester. Mason has grown rapidly over the last half-century and is recognized for its innovation and entrepreneurship, remarkable diversity, and commitment to accessibility. Also in 2023, the university launched Mason Now: Power the Possible, a $1 billion comprehensive campaign to support student success, research, innovation, community, and sustainability. Learn more at gmu.edu .

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across 19 colleges and schools. As Texas' leading research university, UT attracts more than $650 million annually for discovery. Amid the backdrop of Austin, Texas, a city recognized for its creative and entrepreneurial spirit, the university provides a place to explore countless opportunities for tomorrow's artists, scientists, athletes, doctors, entrepreneurs and engineers.

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Filed January 28, 2026

Exhibit 1-122:
Energy Reliability and Resilience

Energy Reliability and Resilience

Innovation Matters

EERE is committed to bringing the benefits of energy innovation to every American by making...

Learn More

Energy reliability is the ability of a power system to consistently deliver power to homes, buildings, and devices—even in the face of instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Energy resilience is the ability of the grid, buildings, and communities to withstand and rapidly recover from power outages and continue operating with electricity, heating, cooling, ventilation, and other energy-dependent services. Energy resilience increases energy reliability and renewable energy sources can help support a resilient, reliable energy system.

Resilient, reliable energy is critical to the well-being of every American. It keeps life-saving hospital equipment and communications systems operating, buildings at safe temperatures with good ventilation, and American workers to go about their business without interruption. Energy infrastructure—facilities or equipment used to generate, deliver, process, or produce energy—that can withstand and quickly recover from disruptions is resilient and reliable infrastructure.

A resilient and reliable power system reduces the likelihood of long-duration outages over large service areas, limits the scope and impact of outages when they do occur, and rapidly restores power after an outage.

What Makes Energy Resilient?

Power outages can be caused by extreme weather, breaches in cybersecurity, high energy demand that overloads the electric grid, failure of aging equipment, and physical interference with equipment. Grid disturbances are changes in electrical voltage and frequency on the grid that can lead to power outages.

A resilient electric grid distribution system uses local resources, such as solar panels and battery storage in homes and buildings, to quickly reconfigure power flows and recover electricity services during a disturbance. The approach to modernize the grid and increase resilience focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale.

Strong resilience measures in building energy codes can also ensure that new construction and major renovation projects minimize energy use, maximize comfort, and enhance potentially life-saving resilience benefits. Building owners and operators, communities, and local and state governments can strategically plan to increase resilience using these resources.

What Makes Energy Reliable?

When we diversify our energy mix by adding more types of energy to the grid, we increase our energy reliability. The rise of renewable power, which comes from unlimited energy resources, like wind, sunlight, water, and the Earth's natural heat, has the potential to vastly improve the reliability of the American energy system. Currently, renewable energy generates about 21% of all U.S. electricity, and that percentage is rising quickly.

A reliable electric grid distribution system can continue to deliver electricity to homes and buildings regardless of any disruptions or disturbances. The approach to modernizing the grid to increase resilience and reliability focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale. DOE efforts, like the Energy Storage Grand Challenge Roadmap, will increase resilience. DOE's Grid Modernization Initiative works with public and private partners to develop concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future.

Improving Reliability Through Energy Storage

Energy storage technologies can improve energy reliability by making surplus energy available whenever it is needed, such as during a power outage.

Pumped storage hydropower is responsible for most U.S. commercial energy storage capacity and has been used for more than 100 years. Wind energy and solar energy can be captured and stored for later use with batteries, and researchers are investigating geothermal energy storage.

Energy storage is also essential to efficient transportation. EERE invests in research and development of hydrogen storage and batteries to ensure on- and off-road vehicles can reliably move people and goods from one place to another.

The U.S. Department of Energy's Energy Storage Grand Challenge is a comprehensive program to accelerate the development, commercialization, and use of next-generation energy storage technologies. As part of this program, the Long Duration Storage Shot™ aims to, within the decade, reduce the cost of grid-scale energy storage by 90% for systems that can provide energy for at least 10 hours in duration.

Energy Reliability and Resilience News

Advanced by Americans: A Year of Energy Innovation

EERE invests in research, development, and technology-validation to help modernize the...

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Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

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Public Interest Organizations

Filed January 28, 2026

Exhibit 1-123:
EPA COBRA Health Effects Estimate

COBRA Web Edition

CO-Benefits Risk Assessment (COBRA) is a screening tool that enables state, local, and tribal government staff and others interested in the effects of air pollution to estimate the air quality and health benefits of different emissions scenarios.

You are using the web-based version of COBRA. For the COBRA desktop application, visit the COBRA download page.

Step 1: Build Scenario

Complete the sections below and click "Add to Scenario."

A. Select Location REQUIRED

Select the states or counties where the emissions changes will occur.

- [ ] Las Animas
- [ ] Lincoln
- [ ] Logan
- [ ] Mesa
- [ ] Mineral
- [x] Moffat
- [ ] Montezuma
- [ ] Montrose
- [ ] Morgan

Select All | Deselect All

B. Select Sector REQUIRED

Select the industry or sector where the emissions changes will occur.

Sector

Fuel Combustion: Electric Utility

Subsector (optional)

Coal

Subsector (optional)

All subsectors

C. Modify Emissions REQUIRED

Enter emissions changes for **at least one** of the four pollutants below.

$PM_{2.5}$ (Baseline = 93.48 tons)

reduce by | **increase by**

enter # ◉ tons ○ percent

SO_2 (Baseline = 1,824.34 tons)

reduce by | **increase by**

enter # ◉ tons ○ percent

NO_x (Baseline = 4,756.47 tons)

reduce by | **increase by**

enter # ◉ tons ○ percent

VOC (Baseline = 114.8 tons)

reduce by | **increase by**

enter # ◉ tons ○ percent

NH_3 (Baseline = 1.08 tons)

reduce by | **increase by**

enter # tons percent

ADD TO SCENARIO

Step 2: Review Scenario

Review the scenario below. To add changes to more locations or sectors, repeat Step 1 to continue building your scenario.

Location(s)	Sector	Emissions Modification(s)	
Moffat, Colorado	Fuel Combustion: Electric Utility Coal	$PM_{2.5}$ reduce by 13 tons SO_2 reduce by 335.43 tons NO_x reduce by 2,211.57 tons	✕

Discount rate:

2%

Custom: enter %

RUN SCENARIO

Step 3: View Results

BUILD NEW SCENARIO

A. Summary of Health Effects Results

Below is a table with the health effects results based on your scenario.

You are viewing results for all contiguous U.S. states. This is because changes in air quality can impact health endpoints in multiple locations due to the transportation of emissions across state and county lines.

Use the filters below to see health effects for a specific state or county.

1. Filter by state:

All contiguous U.S. states

2. Filter by county: (optional)

All counties

Results for: All Contiguous U.S. States

Export: All results | Current filter

Health Endpoint	Pollutant	Change in Incidence (cases, annual)		Monetary Value (dollars, annual)	
		Low	High	Low	High
Mortality *	$PM_{2.5}$ | O_3	3.4	4.4	$50,000,000	$64,000,000
Nonfatal Heart Attacks	$PM_{2.5}$	0.54	0.54	$46,000	$46,000
Infant Mortality	$PM_{2.5}$	0.0077	0.0077	$120,000	$120,000
Hospital Admits, All Respiratory	$PM_{2.5}$ | O_3	0.36	0.36	$7,300	$7,300
Emergency Room Visits, Respiratory	$PM_{2.5}$ | O_3	7.3	7.3	$12,000	$12,000
Asthma Onset	$PM_{2.5}$ | O_3	22	22	$1,700,000	$1,700,000
Asthma Symptoms	$PM_{2.5}$ | O_3	3,400	3,400	$1,100,000	$1,100,000
Emergency Room Visits, Asthma	O_3	0.036	0.036	$30	$30
Lung Cancer Incidence	$PM_{2.5}$	0.061	0.061	$2,700	$2,700
Hospital Admits, Cardio-Cerebro/Peripheral Vascular Disease	$PM_{2.5}$	0.1	0.1	$3,000	$3,000
Hospital Admits, Alzheimers Disease	$PM_{2.5}$	0.36	0.36	$8,200	$8,200

Hospital Admits, Parkinsons Disease	$PM_{2.5}$	0.052	0.052	$1,200	$1,200
Stroke Incidence	$PM_{2.5}$	0.053	0.053	$3,300	$3,300
Hay Fever/Rhinitis Incidence	$PM_{2.5}$ | O_3	140	140	$150,000	$150,000
Cardiac Arrest, Out of Hospital	$PM_{2.5}$	0.013	0.013	$780	$780
Emergency Room Visits, All Cardiac	$PM_{2.5}$	0.26	0.26	$550	$550
Minor Restricted Activity Days	$PM_{2.5}$	690	690	$87,000	$87,000
School Loss Days	O_3	1,800	1,800	$3,100,000	$3,100,000
Work Loss Days	$PM_{2.5}$	120	120	$37,000	$37,000
Total Health Effects from $PM_{2.5}$				**$12,000,000**	**$27,000,000**
Total Health Effects from O_3				**$44,000,000**	**$44,000,000**
Total Health Effects				**$56,000,000**	**$71,000,000**

Note: Dollar amounts shown are based on 2023 currency values. Additionally, all values have been rounded to 2 significant figures. Please export the results in order to see values prior to rounding.

* The Low and High values represent differences in the methods used to estimate some of the health impacts in COBRA. For example, high and low results for avoided premature mortality are based on two different epidemiological studies of the impacts of $PM_{2.5}$ on mortality in the United States.

B. Map of Health Effects and Air Quality Results

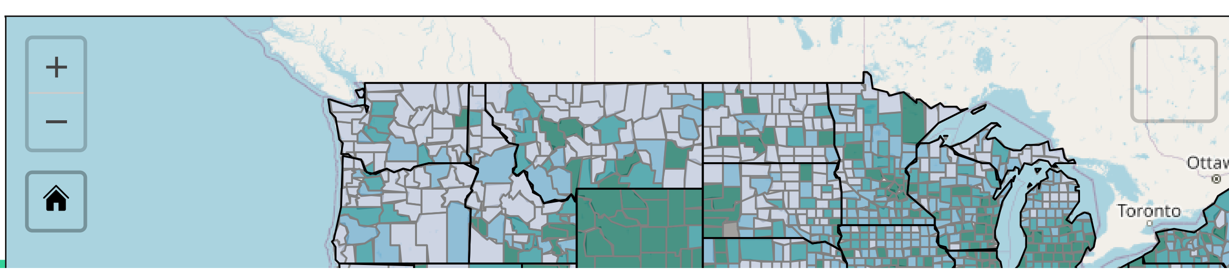
Below is a map showing health effects and air quality data based on your scenario.

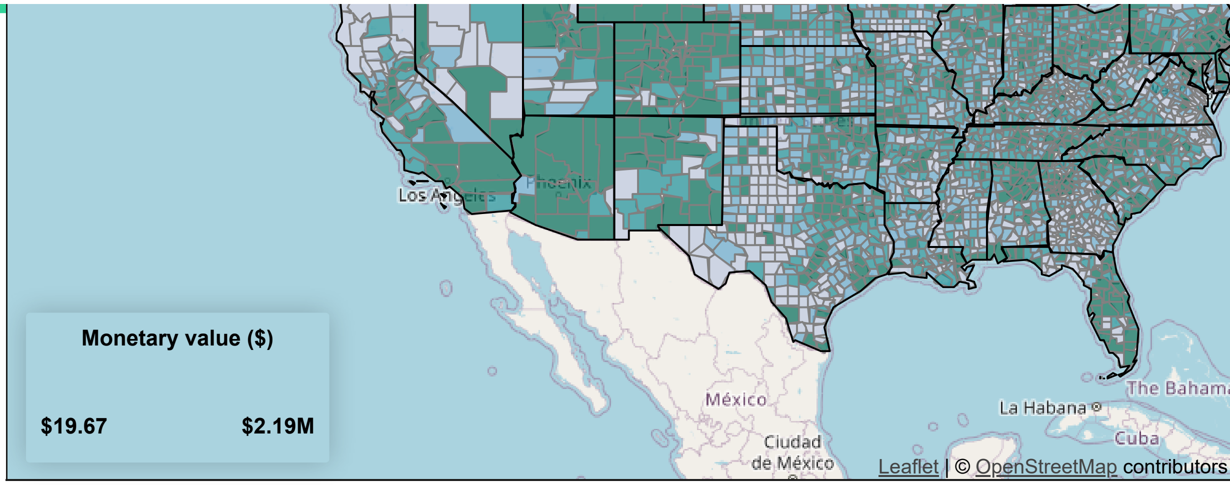
Use the filter below to change the map's data layer. Click on a county on the map to explore the data.

Select the map's data layer:

Total Health Benefits ($, low estimate)

Displaying: Total Health Benefits ($, low estimate)





LAST UPDATED ON APRIL 12, 2021

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Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

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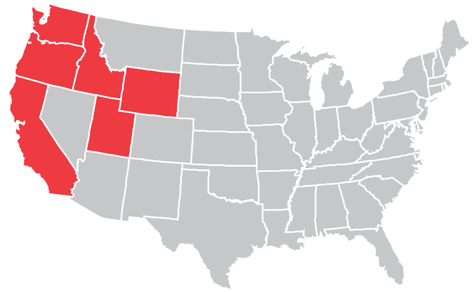
Filed January 28, 2026

Exhibit 1-124:
2025 PacifiCorp Fact Sheet

JUST THE **FACTS**

PacifiCorp

SERVICE AREA	141,500 square miles
ELECTRIC CUSTOMERS SERVED	2.1 million
NET OWNED GENERATION CAPACITY	11,700 megawatts
NET OWNED RENEWABLE AND NONCARBON CAPACITY	3,410 megawatts
RENEWABLE PROJECTS UNDER CONSTRUCTION, CAPACITY	531 megawatts
ELECTRIC TRANSMISSION LINE MILES	17,500 miles
ELECTRIC DISTRIBUTION LINE MILES	66,900 miles



- PacifiCorp owns and operates a diverse portfolio of generation resources in eight states comprised of coal, natural gas, hydroelectric, solar, geothermal and the largest owned wind fleet by a regulated utility in the Western U.S. The company also owns and operates the largest transmission system in the Western U.S., with 17,500 miles of transmission lines across 10 states. PacifiCorp serves customers through its two divisions:
  - Rocky Mountain Power is based in Salt Lake City, Utah, and serves customers in Utah, Wyoming and Idaho.
  - Pacific Power is based in Portland, Oregon, and serves customers in Oregon, Washington and California.
- PacifiCorp's Energy Gateway transmission expansion project is the largest of its kind in the U.S. The $13 billion investment totals 2,300 miles, provides access to the West's abundant and diverse energy resources, and is the foundation for a more resilient, reliable Western grid.
- As a founding partner in the Western Energy Imbalance Market in 2014, PacifiCorp has saved customers $938 million and significantly reduced emissions in the region. To further magnify the benefits of market collaboration, PacifiCorp plans to join the Extended Day-Ahead Market in 2026.
- Through investments of $1 billion through 2024 and another $2 billion planned through 2027, PacifiCorp continues to strengthen its system to reduce the risk of and prevent wildfires.
- PacifiCorp owns and manages 46,000 acres of lands reserved for wildlife habitat, forestry and recreation.

PACIFICORP®

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Public Interest Organizations

Filed January 28, 2026

Exhibit 1-125:
Service Area and Territory (Electric Power and Water) SRP

Service Territory

As a community-based not-for-profit water and energy company, SRP provides reliable, affordable water and power to more than 2 million people living in central Arizona.

Enter your address to see the SRP services available at your location

SRP delivers affordable water and power to more than 2 million customers living in and around the Valley. Our service territory is broad and covers much of central Arizona. Some addresses receive only one of our services while others are provided both water and power.

Feedback

Find address or place

Esri, TomTom, Garmin, FAO, NOAA, USGS, Bureau of Land Management, EPA, NPS, USFWS

Powered by Esri

Search for an address to learn more about the location and its surrounding area.

If you don't know the address, use one of these search methods:

Click the search box and type in an address or choose **Use current location.**

Be sure to click within the map.

Feedback

RELATED TOPICS

[About Salt River Project | SRP]

SRP is a community-based, not-for-profit organization providing affordable water and power to more than 2 million people in central Arizona. Read more here.

History of Salt River Project | SRP

Since 1903, Salt River Project has helped shape our state. Learn about our history of service to the people who call Arizona home.

Future plan for energy | SRP

Ensuring that the Valley's energy future remains reliable requires energy experts and communities working together. Learn about SRP's energy plan for the future.

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Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-126:
Xcel, List of Towns Receiving Electric Service in Colorado

COLORADO COMMUNITIES SERVED BY XCEL ENERGY

INFORMATION SHEET
COLORADO

Xcel Energy®

🔥 = Gas only   🔌 = Electricity only   🔥🔌 = Gas and Electricity

A
Alamosa 🔥🔌
Alma 🔌
Antonito 🔥🔌
Arvada 🔥🔌
Aspen Park 🔥
Atwood 🔥🔌
Ault 🔌
Aurora 🔥🔌
Avon 🔥
Avondale 🔥

B
Barnesville 🔌
Battlement Mesa 🔌
Beaver Creek 🔥
Bellvue 🔥🔌
Bergen Park 🔥🔌
Berthoud 🔥🔌
Berthoud Falls 🔌
Black Hawk 🔥🔌
Blanca 🔌
Blue River 🔌
Bonanza 🔌
Boone 🔥
Boulder 🔥🔌
Bountiful 🔌
Bow Mar 🔥🔌
Bracewell 🔌
Breckenridge 🔥🔌
Briggsdale 🔌
Brighton 🔥
Broomfield 🔥🔌
Brush 🔥🔌

C
Campion 🔥🔌
Canfield 🔥🔌
Canon 🔌
Canyon Creek 🔌
Capulin 🔥
Carbondale 🔌
Castle Pines 🔌
Centennial 🔌
Center 🔌
Central City 🔥🔌
Chama 🔌
Cherry Hills Village 🔥🔌
Clifton 🔥🔌
Climax 🔥🔌
Cody Park 🔥🔌
Columbine Valley 🔥🔌
Commerce City 🔥🔌
Conejos 🔥🔌
Conifer 🔥
Copper Mountain 🔥
Cornish 🔌
Crisman 🔌

D
De Beque 🔥🔌
Del Norte 🔥🔌
Denver 🔥🔌
Dillon 🔥🔌
Downieville 🔥🔌
Dumont 🔥🔌

E
Eastlake 🔥🔌
Eaton 🔌
Edgewater 🔥🔌
Eldora 🔌
Eldorado Springs 🔌
Empire 🔥🔌
Englewood 🔥🔌
Erie 🔥🔌
Estes Park 🔥
Evans 🔌
Evergreen 🔥🔌

F
Fairplay 🔌
Farmers Spur 🔌
Federal Heights 🔥🔌
Fort Collins 🔥🔌
Fort Garland 🔌
Fort Lupton 🔥
Fort Morgan 🔥🔌
Fosston 🔌
Foxfield 🔌
Fraser 🔥
Frisco 🔥🔌
Fruita 🔥🔌
Fruitvale 🔥🔌

G
Galeton 🔌
Garden City 🔌
Garfield 🔌
Georgetown 🔥🔌
Gilcrest 🔌
Gill 🔌
Gilman 🔌
Glendale 🔥🔌
Glenwood Springs 🔌
Gold Hill 🔌
Golden 🔥🔌
Granby 🔥
Grand Junction 🔥🔌
Grand Lake 🔥
Greeley 🔌
Greenwood Village 🔥🔌
Guadalupe 🔥🔌

H
Hideaway Park 🔥
Highlands Ranch 🔥🔌
Hillrose 🔌
Homelake 🔌
Hooper 🔌
Horca 🔌
Hot Sulphur Springs 🔥
Hygiene 🔥

I
Idaho Springs 🔥🔌
Idledale 🔥🔌
Indian Hills 🔥🔌

J
Jamestown 🔌
Johnstown 🔥🔌

K
Kelim 🔥🔌
Kersey 🔌
Keystone 🔥
Kittredge 🔥🔌
Kremmling 🔥
Kuner 🔌

COLORADO COMMUNITIES SERVED BY XCEL ENERGY

🔥 = Gas only 🔌 = Electricity only 🔥🔌 = Gas and Electricity

L
- La Jara 🔥🔌
- Laporte 🔥🔌
- La Salle 🔌
- La Valley 🔌
- Lafayette 🔥🔌
- Lakeside 🔥🔌
- Lakewood 🔥🔌
- Las Mesitas 🔌
- Lawson 🔥🔌
- Leadville 🔥🔌
- Leyden 🔌
- Littleton 🔥🔌
- Lobatos 🔌
- Lochbuie 🔥
- Log Lane Village 🔥🔌
- Lone Tree 🔌
- Longmont 🔥🔌
- Lookout Mountain 🔌
- Louisville 🔥🔌
- Louviers 🔥
- Loveland 🔥🔌
- Lucerne 🔌
- Lyons 🔥🔌

M
- Magnolia 🔌
- Malta 🔌
- Manassa 🔥🔌
- Marshall 🔌
- Marshdale 🔌
- Maysville 🔌
- Mead 🔥
- Merino 🔥🔌
- Milliken 🔥🔌
- Minturn 🔥🔌
- Moffat 🔌
- Mogote 🔌
- Monarch 🔌
- Monte Vista 🔥🔌
- Montezuma 🔌
- Morrison 🔥🔌
- Mosca 🔌
- Mountain View 🔥🔌
- Mount Vernon 🔥🔌

N
- Nederland 🔥🔌
- New Castle 🔥🔌
- Niwot 🔥🔌
- North Avondale 🔥
- Northglenn 🔥🔌
- Nunn 🔌

O
- Orchard Mesa 🔥🔌
- Ortiz 🔌

P
- Paisaje 🔌
- Palisade 🔥🔌
- Parachute 🔥🔌
- Parker 🔥
- Parshall 🔥
- Peaceful Valley 🔌
- Peckham 🔌
- Peetz 🔌
- Pierce 🔌
- Platoro 🔌
- Platteville 🔌
- Poncha Springs 🔌
- Pueblo 🔥
- Purcell 🔌

R
- Raymer 🔌
- Raymond 🔌
- Red Cliff 🔥🔌
- Redlands 🔌
- Richfield 🔥🔌
- Rifle 🔥🔌
- Riverside 🔌
- Romeo 🔥🔌
- Rulison 🔌
- Russell Gulch 🔥🔌

S
- Saguache 🔥🔌
- Salida 🔌
- Salina 🔌
- San Antonio 🔌
- San Francisco 🔌
- San Luis 🔌
- San Pablo 🔌
- San Pedro 🔌
- Sanford 🔥🔌
- Sargent 🔥🔌
- Sedalia 🔥
- Severance 🔥🔌
- Sheridan 🔥🔌
- Silt 🔥🔌
- Silver Plume 🔌
- Silverthorne 🔥🔌
- Smeltertown 🔌
- Snyder 🔌
- Springdale 🔌
- Sprucedale 🔌
- Sterling 🔥🔌
- Sterling Ranch 🔥🔌
- Stoneham 🔌
- Stringtown 🔌
- Sugarloaf 🔌
- Summitville 🔥🔌
- Sunshine 🔌
- Superior 🔥🔌

T
- Tabernash 🔥
- Thornton 🔥🔌
- Timnath 🔥🔌
- Tiny Town 🔌

V
- Vail 🔥
- Valmont 🔌
- Vineland 🔥

W
- Wah Keeney Park 🔥🔌
- Wallstreet 🔌
- Ward 🔌
- Watkins 🔌
- Weldona 🔥🔌
- Wellington 🔌
- West Vail 🔥
- Westminster 🔥🔌
- Wheat Ridge 🔥🔌
- Wiggins 🔥
- Willard 🔌
- Windsor 🔥🔌
- Winter Park 🔥

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

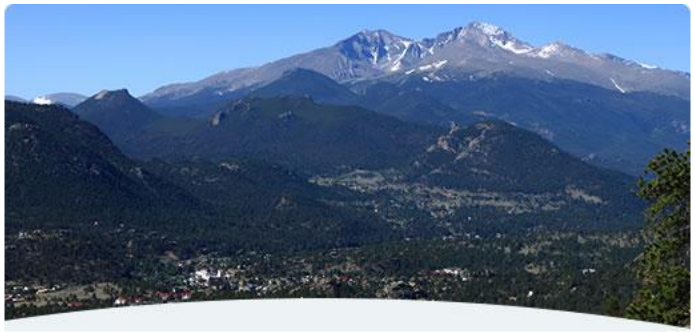
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-127:
Who we serve - Platte River Power Authority

Our communities

Platte River Power Authority is a Colorado political subdivision established to provide wholesale electric generation and transmission to the utilities of its owner communities – Estes Park, Fort Collins, Longmont and Loveland.



Town of Estes Park

Estimated population*: 6,426
Utility: Estes Park Power and Communications, established in 1945
[Source to Switch]

City of Fort Collins

Estimated population*: 170,243
Utility: Fort Collins Utilities, established in 1938
[Source to Switch]

EN

City of Longmont

Estimated population*: 97,261
Utility: Longmont Power & Communications, established in 1912
Source to Switch

City of Loveland

Estimated population*: 78,877
Utility: Loveland Water and Power, established in 1925
Source to Switch

*Based on the U.S. Census Bureau

Accessibility Notice:
Per the Americans with Disabilities Act (ADA), Platte River Power Authority will provide reasonable accommodation to qualified individuals with a disability who need assistance. Please email us at communications@prpa.org or call 970-226-4000. "Walk-in" requests for auxiliary aids and services may be honored to the extent possible but can be unavailable if advance notice is not provided.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-128:
Order No. 24-073 OR PUC on Pac 2023 IRP

ORDER NO. 24-073

ENTERED Mar 19 2024

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED.

In this order, we adopt the recommendations made by Staff of the Oregon Public Utility Commission to acknowledge in part and not acknowledge in part PacifiCorp, dba Pacific Power's Integrated Resource Plan (IRP). We do not acknowledge PacifiCorp's Clean Energy Plan (CEP). We also adopt Staff's 21 recommendations, which set firm direction for what we require to be provided with PacifiCorp's 2025 IRP.

While we understand that development of PacifiCorp's 2025 IRP is a multi-stakeholder, multi-state process in which the company might reasonably seek our flexibility in setting requirements for the analysis, we are reacting to the rigidity PacifiCorp has displayed in responding to Oregon Staff and stakeholders' reasonable requests for adjustments and additional analysis during our review of its filed IRP and CEP, and even in its forthcoming IRP Update. We expect PacifiCorp to embrace the letter and spirit of the Staff recommendations that we adopt here, to follow them assiduously in developing its 2025 IRP, and to return to us for clarification if there is any doubt about what we require. With the urgency of reliability, cost control, and House Bill (HB) 2021 compliance challenges upon us, we would rather review any emerging questions or uncertainty about our direction before an IRP is locked down rather than find the IRP deficient and the company unwilling to adjust until the next cycle.

I. INTRODUCTION

The purpose of the IRP review process is to provide the utility with the input of the Commission, Commission Staff, and stakeholders on the reasonableness of the plan presented. Our acknowledgment decision provides PacifiCorp with guidance to consider in taking resource actions that, ultimately, rest with the company.[1]

We take seriously our role in informing PacifiCorp's direction, but also reinforce that we do not control PacifiCorp's resource decisions and that any risks associated with carrying out even acknowledged actions rest with the company.

Our goal in an IRP proceeding is to acknowledge that a utility's action plan and preferred portfolio represent the least-cost, least-risk strategy for meeting customer needs, based on the best data available at the time and using the best available tools to analyze and review that data. In this particular IRP proceeding, we are asked to review a plan and portfolio that PacifiCorp had already abandoned by suspending the 2022 All-Source RFP, and that was further impacted by the stay of the federal Ozone Transport Rule. We are left without a plan that reflects PacifiCorp's reality, and without any willingness by PacifiCorp to adjust its action plan to reflect that reality. Therefore, we have no basis on which to acknowledge the majority of PacifiCorp's IRP, nor can we acknowledge its CEP without the foundation of a viable IRP action plan. We expect that, in 2025, we will be given a plan that follows Staff's recommendations and reflects both updated operating circumstances and an action plan that the company can stand behind. Recognizing that circumstances are rapidly evolving, that plan may describe action items and the key factors that would instigate a change in course. We also invite the company to present an IRP Update with revised actions that can serve as the foundation for a refiled CEP, which we will consider for acknowledgment and as a demonstration of continual progress.

II. IRP AND CEP PROCESS

A. Overall Purpose of the IRP

The IRP is a road map for providing reliable and least-cost, least-risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing and planning for uncertainties.[2] The primary outcome of the process is the "selection of a

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[1] *See In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon,* Docket No. UM 180, Order No. 89-507 at 6 (Apr. 20, 1989) (explaining, "The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission* * *.").

[2] *In the Matter of Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at Appendix A, Guidelines 1-13 (Jan. 8, 2007) corrected by Order No. 07-047 (Feb. 9, 2007); *In the Matter of Investigation into* the *Treatment of CO_2 Risk in the Integrated Resource Planning Process*, Docket No. UM 1302, Order No. 08-339 (June 30, 2008) (refining Guideline 8 addressing environmental costs.).

portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[3]

Our IRP guidelines provide procedural and substantive requirements for utilities to meet in developing their IRPs.[4] Consistent with our guidelines, which require modeling of at least a 20-year time horizon, a utility's IRP must include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources;
- Identification and estimated costs of all supply-side and demand-side resource options;
- Construction of a representative set of resource portfolios;
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;
- Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; and
- Creation of a two- to four-year Action Plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.

In reviewing an IRP, we assess reasonableness based on the information available at the time. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our examination of whether the costs associated with a utility's resource investment should be recovered in customer rates. The question of whether a specific utility investment or procurement decision was prudent and reasonable will be examined in the subsequent rate proceeding.

B. Overall Purpose of the CEP

The Commission is tasked with ensuring progress towards, and evaluating compliance with, the emissions reductions targets required by HB 2021. Oregon electric companies subject to HB 2021 must file clean energy plans (CEPs), which we are charged with evaluating for acknowledgment pursuant to ORS 469A.415(6).[5] CEPs must meet statutory requirements set forth in ORS 469A.415, and also must demonstrate continual

[3] Order No. 07-002 at Appendix A, Guideline 1.
[4] Order No. 07-002 and Order No. 07-047 (adopting 13 IRP Guidelines); Order No. 08-339 (June 30, 2008) (refming Guideline 8 addressing environmental costs).
[5] ORS 469A.410(1) lists the required greenhouse gas emission reductions; the Commission's required evaluation is described in ORS 469A.415(4)(e) and (6).

progress towards meeting the HB 2021 targets in a way that results in "an affordable, reliable and clean electric system."[6]

Oregon electric companies subject to HB 2021's requirements must submit a CEP to the Commission concurrent with the development of each IRP.[7] CEPs "must be based on or included in an [IRP] filing," and must be filed concurrently with the IRP.[8]

Each CEP must:

(1) incorporate the clean energy targets articulated in ORS 469A.410;

(2) "[i]nclude annual goals set by the electric company for actions that make progress towards meeting the clean energy targets * * * including acquisition of nonemitting generation resources, energy efficiency measures and acquisition and use of demand response resources;"

(3) "[i]nclude a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards;"

(4) "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy;"

(5) "[d]emonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets * * * including demonstrating a projected reduction of annual greenhouse gas emissions;" and

(6) "[r]esult in an affordable, reliable[,] and clean electric system."[9]

The actions and investments proposed in a CEP can include "the development or acquisition of clean energy resources, acquisition of energy efficiency and demand response * * * development of new transmission * * * retirement of existing generating facilities, changes in system operation and any other necessary action."[10]

The CEP must also "present annual goals for actions that balance expected costs and associated risks and uncertainties for the utility and its customers, including a demonstration of making continual progress towards meeting the clean energy targets, the

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[6] ORS 469A.415(4)(f).
[7] ORS 469A.415(1).
[8] ORS 469A.415(3).
[9] ORS 469A.415(4)(a) - (f).
[10] ORS 469A.415(5).

pace of greenhouse gas emissions reductions, and community impacts and benefits."[11] The CEP must be "written in language that is as clear and simple as possible, with the goal that it may be understood by non-expert members of the public."[12]

III. PACIFICORP'S 2023 IRP AND CEP

After PacifiCorp filed its amended IRP and CEP in May 2023, we adopted a procedural schedule. This schedule allowed numerous opportunities for submission of written comments from Staff and intervenors, as well as opportunities to obtain feedback from PacifiCorp. On January 24, 2024, Staff filed its Round 2 Comments and Recommendations, in which it recommended truncating the schedule and bringing PacifiCorp's IRP to the February 20 regular public meeting for decision. Due to changed circumstances, including suspension of PacifiCorp's 2022 All-Source RFP and stay of the federal Ozone Transport Rule, Staff recommended only partial acknowledgment of the IRP and that instead of finishing the established procedural schedule, stakeholder and Staff attention should instead turn to the IRP update, to be filed in April 2024. On January 30, 2024, Staff filed a motion to modify the procedural schedule consistent with that recommendation, which was granted. After engagement with parties and Commissioner deliberation on February 20, we adopted the decision memorialized in this order at our March 5 regular public meeting.

C. PacifiCorp's Preferred Portfolio and Action Items

PacifiCorp states its preferred portfolio includes "substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources."[13] Among other things, PacifiCorp states that it plans 1,792 MW of wind, and 495 MW of solar additions with 200 MW of battery storage capacity from the 2020 All-Source RFP, as well as resource selections from the 2022 All-Source RFP. It also includes 1500 MW of advanced nuclear resources, including the 500 MW Natrium demonstration project. PacifiCorp asks for acknowledgment of the preferred portfolio, as well as a variety of actions, specifically:

- Existing Resource Actions – PacifiCorp seeks to exit Colstrip Units 3 and 4, and Craig Unit 1. It seeks to convert Naughton Units 1 and 2 and Jim Bridger Units 1 and 2 to gas. Finally, it seeks acknowledgment of its compliance plans for Wyoming House Bill 200 (Carbon Capture, Utilization, and Storage); regional haze; and the Ozone Transport Rule.

[11] OAR 860-027-0400(5).
[12] *Id*.
[13] Amended IRP at 10 (May 31, 2023).

- New Resource Actions – PacifiCorp seeks acknowledgment of its customer preference RFP; its 2024 All-Source RFP; and its 2022 All-Source RFP (now suspended).
- Transmission Action Items – PacifiCorp seeks acknowledgment for three long transmission segments – Energy Gateway South, Segment F; Energy Gateway West, Segment D.1; and Boardway-to-Hemingway – and for local reinforcement projects. It also seeks acknowledgment of continued permitting activities for Gateway West Segments D.3 and E.
- Demand-Side Management (DSM) Actions – PacifiCorp seeks acknowledgment of its energy efficiency targets.
- Market Purchases – PacifiCorp seeks acknowledgment of its intent to acquire short-term firm market purchases for on-peak delivery from 2023-2025.
- Renewable Energy Credit (REC) Actions – PacifiCorp seeks acknowledgment of its intent to pursue unbundled REC RFPs and purchases to meet state compliance obligations and to sell RECs that are not required to meet state RPS obligations.

D. PacifiCorp's CEP

PacifiCorp's CEP first discusses its community engagement strategy, community benefit indicators and metrics, local resiliency, and community-based renewable energy. It then discusses the company's procurement strategy and the IRP's projection that the company will need to acquire over 30 GWs of new resources, including over 800 MW of small-scale renewables. PacifiCorp's CEP finally lays out two pathways for complying with HB 2021: Pathway 1 achieves compliance by allocating the company's gas resources in such a way that the amount allocated to Oregon is capped; Pathway 2 achieves compliance by assuming that new large commercial load is 100 percent served with non-emitting generation through voluntary renewable options.

E. Stakeholder Engagement

Numerous stakeholders filed comments and otherwise participated in this proceeding. Some of their recommendations were incorporated by Staff into their initial and supplemental Staff Reports. Participating stakeholders were: the Oregon Citizens' Utility Board; Energy Advocates; Columbia River Inter-Tribal Fish Commission; NewSun Energy LLC; Renewable Northwest; Swan Lake North Hydro, LLC and FFP Project 101, LLC; Alliance of Western Energy Consumers; Fervo Energy; Sierra Club; Cascade Policy Institute; and Community Advocates.

F. Staff Report

On February 7, 2024, Staff submitted an extensive Staff Report, in which it reiterated its recommendation for partial acknowledgment. That Staff Report is attached as Appendix A. In it, Staff recommends acknowledging eleven action plan items and the company's load forecast. It recommends not acknowledging nine action plan items, the preferred portfolio, and the company's long-term IRP/CEP strategy. It also makes thirteen recommendations that it asks the Commission to adopt and lists over 50 expectations that it intends to work with the company on for the IRP Update or 2025 IRP; it states that it does not seek the Commission impose those expectations.

Staff recommends this course of action because "the 2023 IRP/CEP would not be revised to reflect major events—like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027"—and therefore "Staff and stakeholders lack the shared analytic foundation from which most of the important acknowledgment decisions could be made."[14] Staff's recommendations are also premised on the fact that "the IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner."[15]

On March 1, 2024, Staff filed a report containing an updated set of recommendations, responding to Commissioner deliberation in the February 20 public meeting, including some edited recommendations and a number of new ones. This report is attached as Appendix B and stands as Staff's final recommendations in this proceeding. It did not change Staff's acknowledgment recommendations but did provide specific expectations for PacifiCorp's 2025 IRP and the analyses that PacifiCorp is to provide with that document.

IV. DISCUSSION

We adopt the recommendations set forth in Staff's March 1 report. We acknowledge certain elements and action items in the IRP, but do not acknowledge many other action items. Moreover, we do not acknowledge PacifiCorp's preferred portfolio or the CEP. The plans and many of the action items simply no longer reflect PacifiCorp's reality; most significantly, when PacifiCorp suspended the 2022 All-Source RFP and declined to update its analysis or the further procurement actions set forth in its action plan, we were left with few reality-based actions to acknowledge. Also, when the decision not to take those actions fundamentally undermines a preferred portfolio that was already substantially altered by the federal Ozone Transport Rule, we find it curious that PacifiCorp continues to assert that we should acknowledge its IRP and CEP. In short,

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[14] Staff Report at 4.
[15] *Id.*

when the IRP and CEP are superseded by events, and the company makes no effort or space to adjust and provide visibility into what actions it is actually planning to take, acknowledgment is not appropriate. Much in the way we would not acknowledge actions that PacifiCorp has already taken, we do not see a point in acknowledging actions that PacifiCorp has already abandoned.

In saying this, we recognize that not all of these changed circumstances are in the company's control—there are real changes in federal regulations, real operating circumstances and pressures affecting the company, and some inflexibility in PacifiCorp's six-state IRP structure. Nonetheless, we expect PacifiCorp to design its IRP process so that Oregon-specific analysis is upfront and visible to us in our review. If IRP timelines in other states do not allow for testing assumptions and making adjustments during review of the filed IRP and CEP, we expect the company to make an extra effort to ensure a full exploration of alternatives for Oregon.

As to the CEP specifically, the elements that made up the basic actions that would move the company toward the HB 2021 targets were removed at the company's discretion and there has been no engagement around how those can be revised. PacifiCorp chose to pull back on the actions on which the CEP relied as the foundation for movement toward the clean energy targets—movement toward resource acquisitions that would reduce emissions but also, importantly, reduce customers' exposure to electricity market price volatility, for instance.

Beyond the changed circumstances, we are concerned that the CEP was treated as a manual or outboard adjustment to the preferred portfolio development and analysis in the IRP. Without alternative portfolio testing that incorporates state policy requirements, we are unable to see alternatives to the company's allocation-only approach. Had PacifiCorp's plans stayed on track, this approach may have been acceptable for a first iteration given PacifiCorp's persuasive assertion that the IRP preferred portfolio with reallocation was least cost for HB 2021 compliance, and we are not concluding that an allocation approach is legally invalid. It may well be a viable pathway, but going forward, we expect the company to integrate the requirements of state policies into the IRP itself. We need modeling of state policy in order to be able to see, among other things, achievement of the small-scale resource requirement in context of other resources and as a relative cost driver. As we understand it, a key element of HB 2021 is to be able to use the planning process to see tradeoffs and alternative paradigms, and we conclude that adopting requirements for 2025 is necessary to be able to understand PacifiCorp's alternatives for progress to HB 2021 compliance.

To that end, we are approving Staff's clear recommendations laying out a roadmap for the company's next IRP and we emphasize the importance of the company following these recommendations in its 2025 IRP. At the same time, we invite the company to find a way to include in its 2024 IRP update some of the items that Staff is looking for and to update the CEP. We also voice our support for Staff continuing to pursue its non-binding "expectations;" it is not our intention to only support the items that have been formed into recommendations for our adoption.

We particularly want to call out Recommendations 15, 16, and 17 as difficult but important analyses. Stakeholders have worked with the company over successive IRP cycles to effectively model the comparative economics and flexibility of the many resource options, including careful analysis of when it is cost effective to retire a thermal facility. This rigor must continue as cost pressures mount. Recommendation 16, derived from CUB's comments, is a sound recommendation to incorporate actual carbon prices from California and Washington as PacifiCorp is modeling the cost of resources and the resulting dispatch. PacifiCorp has historically put a long-term price on carbon as a proxy for future regulatory requirements. HB 2021 requires a specific carbon budget and a carbon price, and without it, the CEP is not precise enough to establish compliance. Remedying this is especially important so that the CEP can test how much the portfolio as a whole will meet the Oregon requirements, how much will need to be solved with allocation, and what the cost will be. It will also help us determine whether the company is on a least-cost path to compliance. We also note that analysis of the federal loan program is a critical, near-term priority given capital constraints and rate pressure.

In general, we expect to see more cost information in the course of PacifiCorp's planning, both due to affordability concerns and because we need the company to be clearer about constraints that may be impacting their progress and how they are allocating their resources among their many priorities. The company should be transparent with stakeholders if the IRP Update or the 2025 IRP action plan are being driven by constraints that are not visible in the modeling The company needs to do more to communicating the many moving parts in the company's planning and procurement landscape.

We recognize that we committed in our order in docket UM 2273 to consider, alongside IRP and CEP review processes, whether utilities have demonstrated continual progress.[16] We are not doing so here simply because we expect, in a matter of weeks, to have a more realistic view of PacifiCorp's status with the IRP/CEP Update that are to be filed in April 2024. We will assess continual progress in connection with our review of the update. If we do not find that PacifiCorp has demonstrated "continual progress [toward the HB 2021 targets] and [that it] is taking actions as soon as practicable that facilitate

[16] *In the Matter of Public Utility Commission of Oregon, Investigation of House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 23-465 (Dec. 4, 203).

rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers," we will consider in a holistic manner whether we need to take actions to fulfill our responsibility to ensure this progress.

V. ORDER

IT IS ORDERED that the Integrated Resource Plan filed by PacifiCorp, dba Pacific Power, is acknowledged in part to the extent and with the conditions contained in Staff's February 7, 2024, and March 1, 2024 reports attached as Appendix A and Appendix B.

Made, entered, and effective Mar 19 2024.

Megan W. Decker Chair	**Letha Tawney** Commissioner

ITEM NO. RA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: FEBRUARY 20, 2024

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** ____N/A____

DATE: February 7, 2024

TO: Public Utility Commission

FROM: JP Batmale

THROUGH: Kim Herb **SIGNED**

SUBJECT: PACIFICORP:
Docket No. LC 82
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PGE's CEP or decline to acknowledge the CEP and direct the Company to revise and resubmit certain portions of the plan. Whether the Commission should direct PGE to take any additional actions prior to filing its next IRP or IRP Update or CEP.

Applicable Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), and 08-339 clarify the procedural steps and substantive analysis required of Oregon's regulated utilities before the Commission considers acknowledgement of a utility's resource plan.[2] These orders are incorporated in OAR 860-027-0400(2), which requires any IRP to satisfy their requirements.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years.[4] The utility's IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[5] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonably based on the information available at the time.[6] However, the Commission explains: "We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers."[7] The Commission may also provide direction on additional analysis or actions for the next IRP or IRP Update.[8]

[1] Order No. 89-507.
[2] Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: See Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[3] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[4] Order No. 14-415 at 3.
[5] Order No. 07-002 at 1-2.
[6] *Id.* at 1.
[7] *Id.*
[8] OAR 860-027-0400(7), (10).

In 2021, the legislature passed Oregon House Bill (HB) 2021, codified as ORS 469A.400 to 469A.475, which requires the state's large investor-owned electric utilities (IOUs) and electricity service suppliers (ESSs) to decarbonize their retail electricity sales with consideration for direct benefits to local communities.

ORS 469A.415 requires large electric IOUs to, "develop a clean energy plan for meeting the clean energy targets set forth in ORS 469A.410 concurrent with the development of each integrated resource plan," and file the plan with the Commission and Oregon Department of Environmental Quality (DEQ).

ORS 469A.420 outlines the requirements and considerations for the Commission to acknowledge the CEP "…if the commission finds the plan to be in the public interest and consistent with the clean energy targets...."

In addition, ORS 469A.415(6) requires the Commission to ensure that the utilities demonstrate continual progress within the CEP planning period toward meeting the clean energy targets and are taking actions as soon as practicable to reduce emissions at reasonable cost to retail electricity consumers.

Additional requirements for the filing, review, and update of IRPs and CEPs are provided in OAR 860-027-0400.

Finally, PacifiCorp's previous IRP, LC 77, resulted in Order No. 22-178, which provided specific direction to the Company on analytic matters for this IRP.

Analysis

Background
PacifiCorp filed its 2023 Integrated Resource Plan and Clean Energy Plan (IRP/CEP or Plans) with PUC on May 31, 2023. PacifiCorp's filing shortly followed PGE's filing of the first IRP/CEP on March 31, 2023, both of which followed from the passage of HB 2021 and direction from Docket UM 2225.

Originally three rounds of comments had been planned in the lead up to a final Staff memo for an April 2024 Special Public Meeting to acknowledge PacifiCorp's 2023 IRP/CEP. Round 0 comments provided preliminary notes about improvements PacifiCorp could make in advance of participants' in-depth review of the IRP/CEP. Round 1 comments evaluated the reasonableness of the plan and explored acknowledgement considerations. Round 2 comments were meant to focus on Staff's draft recommendations for Commission acknowledgement of the IRP/CEP. The Company would respond with a final set of comments, typically including a final set of revisions to the IRP. Then in March a public meeting memo from Staff with final acknowledgement recommendations was to be published, giving stakeholders and the Company a final opportunity to make written comments to the Commission.

Round 1 comments by Staff and stakeholders reflected the fact that there had been material changes impacting the IRP/CEP analysis since the documents were filed in May 2023. These changes rendered moot most of the IRP's Action Plan and Preferred Portfolio. The changes also undermined PacifiCorp's CEP and plan to meet the HB 2021 targets. Of particular concern, PacifiCorp confirmed in response to an information request that the Company will not be able to procure the clean energy additions included in the Preferred Portfolio through 2028 given the suspension of the 2022 All-Source RFP.[9]

In PacifiCorp's December 2023 LC 82 Round 1 reply comments, PacifiCorp made it plain that changes would not be made to the 2023 IRP/CEP, despite Staff and stakeholders' requests. Instead, the Company pointed toward the IRP Update – planned for April 2024 – for any revisions of the Company's now obsolete IRP analysis. PacifiCorp reinforced this position several information request responses.

As the 2023 IRP/CEP would not be revised to reflect major events – like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027 – Staff and stakeholders lacked the shared analytic foundation from which most of the important acknowledgement determinations could be made. Given this threshold issue, Staff saw little value in continuing multiple rounds of comments on the plan as filed. Staff's Round 2 comments included proposed ***final*** recommendations, rather than ***draft*** recommendations, and a request to shorten the procedural schedule and end LC 82 in February, rather than April.[10] A revised schedule consistent with Staff's request was adopted by the ALJ in a ruling on February 5, 2024.

Staff sees benefits to an abbreviated schedule, and non-acknowledgment as proposed by Staff followed by revision and resubmission of the CEP and additional actions for the IRP Update. The first, the Company's planned IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner. Second, by directing a revised and resubmitted CEP in mid-2024, the Commission can avoid an extensive delay in the acknowledgment of a CEP the Company to implement, given the looming emissions reductions targets in HB 2021, rather than stalling consideration of the CEP to 2025. Finally, the Commission could consider providing

[9] PacifiCorp response to OPUC Staff Information Request No. 243.
[10] LC 82, OPUC Staff Second Round Comments, January 24, 2024, pg. 4 and Staff procedural motion on January 30, 2024 to change the schedule.

direction to shape PacifiCorp's quickly moving small-scale renewable request for proposal (SSR RFP).

Staff's redacted Round 2 comments are included with this memo as Attachment A. The Round 2 comments provide more details to Staff's recommendations. The Round 2 comments also include more background information on the IRP itself and stakeholder comments than is contained in this memo. This public meeting memo includes no new analyses. It does, however, seek to reemphasize and clarify the positions taken by Staff in the Round 2 comments and address potential shortcomings in the SSR RFP currently under development.

Acknowledgement Recommendations for the IRP and CEP

Staff made thirteen acknowledgement recommendations in our Round 2 comments.[11] They spanned the IRP and CEP. Staff also listed over fifty expectations for the IRP Update or the 2025 IRP. These expectations amounted to issues that did not require Commissioner deliberation and would not require an order. Instead, Staff plans to work with PacifiCorp and stakeholders to meet these expectations.

The table below summarizes the recommendations from Staff's comments regarding the IRP.[12]

Table 1

	Acknowledge	Not Acknowledge
IRP	• Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) • Load Forecast	• Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) • Preferred Portfolio • Long-Term IRP/CEP Strategy

With regard to the CEP, Staff believes that the necessary changes to the Preferred Portfolio in the IRP Update will significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies needed for PacifiCorp to comply with HB 2021. Staff does not believe the CEP is consistent with the emissions reduction targets of HB 2021, given the present circumstances. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

With regard to PacifiCorp's allocation approach to CEP compliance pathways, Staff stated previously that we find the approach of testing hypothetical allocations to be a reasonable approach to forecasting future Oregon-allocated emissions in years beyond

[11] LC 82, OPUC Staff Second Round Comments, January 24, 2024, Appendix A, pgs. 55-56.
[12] *Id.*, pg. 4.

the current allocation agreement. It would, however, generate more insight if PacifiCorp tested more options and was more transparent about those options and their tradeoffs. Additionally, Staff is clear in our Round 2 comments that the Company is not expected to make significant revisions in community-focused areas of the CEP as part of a revised filing; only the CEP Compliance pathways and demonstration of continual progress on emission reductions. With that said, Staff did include four CEP, community-focused recommendations:

> **Staff Recommendation 5.** Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.
>
> **Staff Recommendation 6.** Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.
>
> **Staff Recommendation 7.** Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.
>
> **Staff Recommendation 8.** Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Beyond these recommendations, to the extent that the CEP's community-based activities or strategies have changed since it was filed in May 2023, the Company should provide new information in the revised CEP filing. Otherwise, Staff expects PacifiCorp to leverage the CBIAG and 2025 IRP process to continue to improve the community-based elements of the CEP.

Minimum Changes Sought by Staff in the IRP Update and Revised CEP

Staff's Round 2 comments identified four analytic threshold issues that would need to be addressed in the IRP Update and reflected in the revised and resubmitted CEP for

Staff to consider recommending acknowledgment of the revised and resubmitted CEP.[13] These were in addition to the thirteen acknowledgement recommendations.

1. Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
2. Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
3. Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
4. Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

On January 31, 2024, PacifiCorp released a draft of the IRP Update. This draft outlined eight areas that PacifiCorp planned to revise with new information in the IRP Update. They are:

- System coincident peak load forecast,
- Natural gas and power market price updates,
- Stay of the ozone transport rule,
- Suspension of the 2022 all-source RFP,
- Natural gas generation and the use of either green hydrogen or green ammonia,
- Preference for peaking type resources,
- Demand-side management,
- Front office transactions,
- Contracted resources, and
- Transmission option updates.

It appears that PacifiCorp plans to update the Preferred Portfolio and Action Plan in the IRP Update, though these updates were not completed and included in the draft document. PacifiCorp makes no mention of Staff's other three recommendations. Further, the draft IRP Update outline included no mention of seeking acknowledgement of a revised Preferred Portfolio and Action Plan as part of the IRP Update. All of these things are crucial.

If Staff's additional analyses are not addressed as part of the April 2024 IRP Update, Staff is concerned that the basis from which to assess the acknowledgability of a revised and resubmitted CEP will be compromised and more time wasted. Thus, Staff

[13] *Id.,* pg. 3.

requests that the Commission order PacifiCorp to conduct Staff's recommended analyses within the IRP Update, in addition to all thirteen recommendations from Staff's Round 2 comments.

Timing of Resubmission of Revised CEP
Due to the circumstances surrounding this IRP and CEP, Staff finds that PacifiCorp should seek to resubmit its revised CEP with the IRP update. However, given that April is less than two months away, Staff is open to PacifiCorp filing a request in its reply comments for an extended CEP filing date of four to eight weeks.[14] Regardless of the timing, Staff plans to work quickly to review the CEP once it is filed.

SSR RFP
The 2023 IRP/CEP forecasted a need of approximately 490 MW of new, renewable capacity – all less than 20 MW in size – to meet HB 2021's 2030 SSR requirement. Because the Company believes acquiring this volume and type of capacity by 2030 may be difficult, PacifiCorp plans to move rapidly. On January 24, 2024, PacifiCorp held a bidders workshop for its SSR RFP. The workshop outlined the Company's initial approach to acquiring the SSR resources necessary to meet a key component of HB 2021. Per the bidders conference presentation, the RFP will be finalized and issued by March 29, 2024. Staff appreciates the Company's sense of urgency on this topic.

However, Staff is concerned about the strategic choices made by PacifiCorp in designing this RFP. First, the timing was such that the bidders conference was the same day as Staff's comments were due. Staff did include two SSR RFP recommendations that were not part of the RFP. They were:

> **Staff Recommendation 5.** Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.
>
> **Staff Recommendation 9.** The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Should the Commission choose to accept Staff recommendation we would hope to see the SSR RFP be updated accordingly.

[14] OAR 860-027-0400(9)(c).

Beyond this, the Company also appears to be establishing RFP parameters that limits the pool of potential resources, drives up SSR project costs borne by Oregon ratepayers, and/or limits insights into the community benefits of projects. Specifically:

- The RFP bars energy storage from being paired with eligible renewable systems.
- No RFP mechanism like non-price scoring or sensitivities to identify, track, and/or allow for project selection that accounts for community benefits.
- Premium peak hour pricing, like what was approved for Oregon PURPA projects, is not allowed. Only flat pricing and on-peak/off-peak.
- Requiring ODOE RPS certification, which includes WREGIS certification and metering.
- Requiring CAISO EIM visibility and dispatchability.

Staff has included two attachments associated with the SSR RFP. Attachment B is the bidders conference presentation and Attachment C Staff's response.

Time permitting at the Public Meeting, Staff suggests that it may be productive to discuss with PacifiCorp their SSR acquisition strategy. The SSR RFP represents one of the first actions by PacifiCorp to meet the HB 2021 targets. As such, a better understanding of PacifiCorp's strategy and approach to SSR acquisition could help all parties learn more about balancing tradeoffs around the economic and technical feasibility of HB 2021 actions.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

LC 82

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

Docket No. LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.	OPUC STAFF ROUND 2 COMMENTS AND RECOMMENDATIONS

Table of Contents

Executive Summary

In this second round of comments on the PacifiCorp (PAC or Company) Integrated Resource Plan (IRP) and Clean Energy Plan (CEP), the Oregon Public Utilities Commission (OPUC) Staff puts forth draft recommendations for acknowledgment and future expectations. Our recommendations and expectations cover this IRP, the planned IRP Update (April 2024), and the next IRP (April 2025). As detailed below – and throughout this document – Staff also puts forth a plan and rationale to revise the current IRP/CEP process to enable the Commission to consider the significant changes to the Preferred Portfolio and Action Plan that PacifiCorp plans to include in the IRP Update to be filed in April 2024.

Staff finds the 2023 IRP was an insightful first attempt at putting forth a comprehensive resource plan to meet HB 2021's decarbonization targets and community benefit goals while accomplishing traditional IRP analysis. PacifiCorp staff conducted more complex modeling than in any previous IRP and demonstrated a commendable level of engagement and candor with Staff and stakeholders. However, Staff has determined that a change of course in this IRP is necessary. This is spurred by two developments.

First, events outside the LC 82 process profoundly changed the relationship between this IRP/CEP's conclusions, action plan, and the market and policy realities faced by PacifiCorp. The two most notable of these events were the judgment against PacifiCorp in the wildfire lawsuits in August 2023 and the Tenth Circuit Court of Appeals' stay of the Ozone Transport Rule in July 2023. The combination of these two events, along with other events, led PacifiCorp to suspend its 2022 AS RFP in September 2023. As noted by many stakeholders in the first round of comments, the RFP suspension, which removed approximately 1.5 GW of new, non-emitting capacity by 2027 from the Preferred Portfolio, cast into doubt several important elements of the IRP/CEP. These included the Preferred Portfolio itself, many action plan items, and any understanding of the potential of forecasted emissions reductions to achieve CEP compliance. In short, the IRP/CEP map no longer matches the territory of operational and market realities. Thus, Staff and stakeholders argued in the first round of comments that additional analysis within this IRP/CEP was necessary in order for several elements to be acknowledged. Independent of these outside events, Staff and stakeholders also noted in Round 1 comments the need for improvements to the IRP/CEP to consider acknowledgement. These included:

- Including Oregon's Small Scale Renewable (SSR) requirement in the Preferred Portfolio in 2030 to capture the portfolio benefits of SSRs.
- Adding more energy efficiency (EE) in Oregon to reflect the higher value that EE brings to Oregon in the context of HB 2021.
- Utilizing more reasonable resource cost estimates.
- Addressing any identified errors with the granularity adjustments that PacifiCorp applied within its PLEXOS modeling.
- Analyzing the sufficiency of the Preferred Portfolio to enable simultaneous compliance with clean energy and GHG policies in Oregon, Washington, and California.
- Reoptimizing select portfolios for a clearer understanding of portfolio NPVRR and the ability to compare actions.

- Articulating more clearly the Oregon implication of coal-to-gas conversions vis-à-vis emissions, decarbonization efforts, and future MSP allocations.

While PacifiCorp has signaled an openness to eventually considering the improvements listed above, the Company was also clear that it would not conduct additional analysis to revise its filed IRP/CEP.[1] The Company has pushed all additional analysis or changes to this IRP/CEP to either the IRP Update or the next IRP.

While it would be unwieldy to constantly revise a filed IRP/CEP, additional analysis has been done in the past when staff or stakeholders indicate they cannot support acknowledgement without material revisions. Conducting additional analysis within the IRP/CEP timeframe to adjust to large-scale and material events impacting the Preferred Portfolio – or in response to stakeholder insights and requests – is reasonable. The IRP process is designed for rounds of comments to consider, discuss, and debate changes to achieve acknowledgement. Accordingly, the IRP/CEP is deemed reasonable to acknowledge at the end of the process, not upon filing.

Because PacifiCorp will not voluntarily make changes to this IRP/CEP, some of the most important issues before us lack a shared analytic foundation from which an acknowledgement determination can be made. As such, Staff does not see a path to recommending acknowledgment of PacifiCorp's current IRP/CEP. At the same time, Staff is concerned that non-acknowledgement and reconsideration at an undetermined future date could delay important activities that the Company must or should undertake to comply with HB 2021. Time is limited for the utility to adopt a CEP that can be acknowledged and successfully implemented before the first emissions reduction target in 2030. Given this tension and the indications from PacifiCorp that there will be significant changes to the Preferred Portfolio and Action Plan in the IRP Update to be filed in April 2024, Staff recommends that the schedule be updated to allow the Commission to consider the information in the forthcoming IRP Update. Staff also recommends that PacifiCorp be directed to address, within the IRP Update, a limited number of threshold issues that have been raised within this docket.

Specifically, Staff recommends that PacifiCorp be directed to, at a minimum:

- Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
- Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
- Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
- Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

With regard to the CEP, Staff believes that the changes to the Preferred Portfolio in the IRP Update may significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies

[1] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 96. "Pertaining to the 2022 AS RFP, PacifiCorp has no revised plan or substantive updates available at this time and is actively working to incorporate a number of updated assumptions as part of portfolio development for its 2023 IRP Update, anticipated to be filed April 1, 2024. The result will be comprehensive changes to the portfolio, and not just specific line items that could be modified in a few figures in the filed 2023 IRP."

needed for PacifiCorp to comply with HB 2021. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

Staff also describes in these comments a number of issues regarding PacifiCorp's efforts to incorporate community impacts into planning decisions and presents a number of expectations regarding community engagement, community benefit indicators (CBIs), community-based renewable energy (CBREs), and resiliency. Staff views PacifiCorp's efforts on these fronts as important first steps upon which to build in future planning cycles. Staff does not expect the Company would make significant revisions in these areas prior to filing a revised CEP, but does expect the Company would update information in a revised CEP filing to the extent that their plans have changed.

To accommodate the timing of PacifiCorp's planned IRP Update filing, Staff proposes that the Commission take up these recommendations at the February 20, 2024, Public Meeting. This will allow Staff and stakeholders to focus the remaining efforts for this IRP/CEP on reviewing the April 2024 IRP Update and a revised and resubmitted CEP. Staff believes a revised CEP should be submitted with the IRP Update.

The table below summarizes those IRP items that Staff plans to recommend and not recommend for acknowledgement in LC 82:

Table 1: IRP Elements Recommended for Acknowledgement

	Acknowledge	Not Acknowledge
IRP	Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) Load Forecast	Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) Preferred Portfolio Long-Term IRP/CEP Strategy

Finally, Staff is incredibly grateful to the following stakeholders for their work in LC 82: Alliance of Western Energy Consumers (AWEC); Community Advocates; Columbia River Inter-Tribal Fish Commission (CRITFC); Oregon Citizens' Utility Board (CUB); Energy Advocates; Fervo; NewSun Energy LLC (NewSun); Renewable Northwest (RNW); Sierra Club; and Swan Lake and FFP Project 101. The comments and overall engagement throughout this IRP have deepened Staff's understanding of the issues surrounding HB 2021. They have also improved this IRP/CEP and future filings by PacifiCorp as they chart a pathway to a reliable, affordable, equitable and decarbonized system.

Key Challenges & Vulnerabilities

In Round 1 comments, Staff identified key challenges and key vulnerabilities to LC 82. The challenges represented issues within IRP and CEP that would require more explanation of the near-term resource strategy and general implementation. Staff's identified vulnerabilities represented more critical issues that called into question the ability to acknowledge a particular aspect of LC 82. While all of the identified topics from Round 1 are covered in these comments, we revisit the most pressing or unresolved items below.

Composition and Costs of Small-Scale Renewables and Community-Based Renewable Energy (Challenge)

In Reply comments, PacifiCorp addressed questions around costs and composition of SSRs. While the Company reasserted that SSRs remain uneconomic, the Company is clearly committed to trying to meet the 2030 SSR target in HB 2021.[2] Staff appreciates PacifiCorp's approach of letting the RFP run its course and then pivot to other methods of acquiring SSRs based on the RFP results.[3] Staff also appreciates PacifiCorp's thorough response on the potential barriers in Oregon rule to SSR procurement.[4] The Company's four suggestions provide a solid basis for fruitful public dialogue. Staff will not address each of the Company's suggestions in its comments, but would be open to participating or leading an informal public discussion on PacifiCorp's suggestions.

Both Staff and the Company see some overlap between CBRE and SSR projects.[5] However, PacifiCorp has modeled CBRE Projects and SSR projects separately, most notably with CBRE projects having a higher cost per MWh. PacifiCorp plans to acquire CBRE projects through a grant pilot program rather than an RFP.[6]

Staff would note the initial SSR RFP filing limits the range of projects from 3 MW to 20 MW. We think the bound at the low-end of the range may unnecessarily exclude potential CBRE projects that are smaller in nature. Staff will work to expand this range in the SSR RFP so that it can potentially capture these projects and establish two channels for acquiring this resource.

State Policy Compliance in IRP Portfolios (Vulnerability)

In Round 1 Comments, Staff raised a central concern to PacifiCorp's CEP compliance allocation methodology: would the Preferred Portfolio contain a sufficient amount of non-emitting resources in 2030 to simultaneously comply with the clean energy and GHG policies of Oregon, Washington, and California? Staff is concerned that if PacifiCorp continues to evaluate compliance with each state-level policy in separate analyses outside of the IRP, resources could be erroneously double-counted toward policy compliance in multiple states.

Staff requested that PacifiCorp demonstrate in this IRP that the Preferred Portfolio could simultaneously comply with clean energy and GHG policies in Oregon, Washington, and California and that, in future IRPs, the Company to constrain the Preferred Portfolio to ensure that simultaneous policy compliance is feasible.

PacifiCorp's Response Comments noted that, "there is no feasible single-pass modeling solution that guarantees Oregon compliance while simultaneously meeting all other portfolio requirements."[7] PacifiCorp also suggested that Staff's request to demonstrate simultaneous compliance of state-level policies would not be possible due to limitations of PLEXOS and the fact that resource allocations have not yet been determined.[8]

[2] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 53.
[3] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 52.
[4] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 85.
[5] LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 36.
[6] LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 54.
[7] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 24.
[8] *Ibid*.

Yet elsewhere in PacifiCorp comments, the Company expresses openness to developing a more "unified" portfolio that integrates systemwide and state-level constraints.[9]

From Staff's perspective, ensuring that PacifiCorp can simultaneously comply with all state-level policies to which it is bound should be foundational to the Company's IRP process. Staff appreciates PacifiCorp's concern that a "single pass" modeling solution to this problem may not be available through the PLEXOS model. However, this limitation does not prevent PacifiCorp from demonstrating that simultaneous state-level policy compliance is feasible or ensuring that portfolios meet this requirement. PacifiCorp already uses multiple modeling passes to make adjustments to portfolios to respect other complicated constraints (e.g. the reliability and granularity adjustments). PacifiCorp could similarly adopt an iterative process within the IRP in the event that a portfolio was found not to comply with one or more state-level policies simultaneously.

Staff also appreciates PacifiCorp's concern that evaluating state-level policy compliance may require the Company to make assumptions regarding future allocation. However, Staff does not see this as an impediment to testing the <u>feasibility</u> of simultaneous policy compliance. PacifiCorp could, for example, demonstrate that there is <u>some</u> feasible allocation (i.e. all allocation factors fall between 0 and 1 and sum to 1) that achieves simultaneous policy compliance, without adopting that allocation strategy. Such an exercise could be used to test the limitations of what can be achieved through allocation and to identify if there are high-level constraints that could inform allocation discussions in MSP.

Because PacifiCorp would not or could not conduct this analysis – and given its centrality to the IRP and CEP – Staff conducted a high level and approximate exercise to make a "back of the envelope" determination of the non-emitting sufficiency of the Preferred Portfolio in 2030. Staff's simple analysis, which was based on public information from PacifiCorp's IRP and CEP workpapers, identified multiple energy allocation strategies for the Preferred Portfolio that would likely result in simultaneous policy compliance in Oregon, Washington, and California in 2030.

Further, the policy-feasible allocations that Staff tested also resulted in the majority of the load in Idaho, Utah, and Wyoming being met with non-emitting generation by 2030 under the Preferred Portfolio.

Staff's findings are in fact consistent with PacifiCorp's assertion that the proposed renewable additions originally proposed in this IRP are primarily being driven by economics, rather than policy compliance. Staff's analysis also bolstered Staff's view that it is reasonable for PacifiCorp to incorporate this type of analysis into future IRPs and IRP Updates.

Staff Expectations:

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

[9] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 54.

CEP Compliance Pathways (Vulnerability)

Staff finds that considering the effect of allocation pathways in the CEP on HB 2021 compliance is an acceptable, flexible approach to beginning a conversation about HB 2021 compliance that reflects how DEQ conducts annual emissions compliance evaluation. However, Staff also recognizes that it represents a complete departure from the allocation methodology approved in the 2020 MSP. Staff agrees with CUB that this was done with limited discussion outside of MSP. CUB observed that, beyond comparing compliance costs across portfolios, PacifiCorp's approach to developing CEP pathways – along with changes in coal retirements and this IRP's quick pivot to coal-to-gas conversions – represent a fundamental break from the approach of the 2020 Multi-State Protocol (MSP) with no transparent discussion or analytic demonstration of how these changes to the allocation methodology are in the best interest of Oregon.[10] Further, AWEC speculated that PacifiCorp's proposed pathways most likely exceeded HB 2021's incremental cost cap, that neither pathway can be enforced or guaranteed, and that because both pathways do not reflect the current MSP allocation they should be prohibited.[11] Both RNW and the Energy Advocates generally objected to PacifiCorp's approach as just an allocation exercise with no meaningful emission reductions and little chance of being accomplished within the MSP framework.

The Company's response points out that CEP pathways are compliant with the 2020 MSP prior to its expiration at the end of 2024, and that no MSP has been agreed upon for the time period after 2024 when most CEP cost will be incurred. Further, PacifiCorp counters CUB that the CEP does include cost analysis. The CEP pathways also represent issues to be considered in the current MSP negotiations, not actual positions that must be taken. To this end, PacifiCorp notes that the pathways were not the primary means to achieve CEP compliance. Rather, the IRP's proposed system-wide, Preferred Portfolio would in fact achieve 98 percent of the Oregon CEP emission reduction targets by 2030.[12] Finally, PacifiCorp argues for a narrow interpretation of HB 2021's cost cap that should be applied once costs are incurred and to conduct such an analysis in a rate case.[13]

Staff agrees with PacifiCorp that the expiration of the 2020 MSP provides a level of flexibility in proposing CEP compliance pathways. Yet the analysis in this CEP – while instructive and insightful –falls short of providing actionable insights *and* a forum to discuss the tradeoffs for Oregonians around MSP allocation methodologies capable of meeting HB 2021's goals. In this sense Staff agrees with CUB: by limiting the CEP pathways to only "illustrate" what could eventually occur in MSP, the IRP/CEP falls short of providing an actionable "plan" around which to debate the costs and risks of various CEP Compliance Pathways. Finally, Staff agrees with the Company's assertion that UM 2273 will be the best place to address policy issues around HB 2021's cost cap, not this IRP/CEP.

Staff Expectations:

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP "actions," Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.

[10] LC 82, CUB Round 1 Comments, October 25, 2023, page 5.
[11] LC 82, AWEC Round 1 Comments, October 25, 2023, page 3-5.
[12] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 23.
[13] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 26.

- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions (Vulnerability)

In Opening Comments (Round 1), Staff recognized that PacifiCorp's 2023 IRP makes a significant departure from its 2021 IRP in its plans to retire coal-fired generation resources. Specifically, while the 2021 IRP only included gas conversions of Jim Bridger Units 1 and 2, the current plan adds Jim Bridger Units 3 and 4 and Naughton Units 1 and 2 to the list.

PacifiCorp's analysis shows that the conversions are selected by its optimization model based on economics. Staff appreciated this analysis and sought more information from the Company to better understand the cost and risks associated with these conversions for Oregon customers as well as the consistency of these actions with HB 2021 emissions reduction targets. Staff appreciates PacifiCorp's responses to some of the questions posed by Staff, however, expresses disappointment that the Company did not answer most of the questions posed by Staff.

In response to Staff's question regarding the prominence of gas conversions in this plan compared to the 2021 IRP, PacifiCorp explains that the previously realized benefits from Bridger 1 and 2 conversions in the 2021 IRP portfolio analysis prompted the Company to explore this option for the other coal plants, and the conversions were endogenously selected within its optimization model. The Company also points out that gas conversions identified in the 2021 and 2023 IRP are a better outcome compared to a new gas plant selected in its 2019 IRP. Further, the Ozone Transport Rule limiting nitrous oxide emissions also favors gas conversions over coal. PacifiCorp also sees benefits in using the converted plants as a backup resource to be used in "limited circumstances" as it integrates clean energy resources into its system. The delay in the Natrium demonstration project has further necessitated the conversion of the Naughton Units 1 and 2.

PacifiCorp did not provide explanations in its Reply Comments to Staff's other requests in which Staff sought to understand if the Company has evaluated the risks of these converted units becoming stranded assets, or what factors could alter the decisions around future coal plant retirement and conversions. Staff had also asked for an analysis with a portfolio variant that does not allow any conversion beyond Jim Bridger 1 and 2, and to test this variant across various gas and CO_2 price options. Staff expected PacifiCorp to either include this portfolio in its CEP alongside other high-performing portfolio variants or introduce constraints related to HB 2021 in its IRP analysis. PacifiCorp indicated that more detailed analysis around coal retirement and conversion options will be provided in its 2023 IRP Update due to be filed in April 2023. Staff looks forward to receiving the updated analysis and expects PacifiCorp to include a detailed analysis of risk of regrets, potential changes in future retirement and conversion plan and the portfolio variant that Staff suggested.

CUB pointed out that coal to gas conversions nullify the agreement reached in the 2020 Multi-State Protocol regarding Oregon's exit from these coal plants, which was key to the determination of the 2020 MSP agreement. CUB had also expressed concerns with the implications of coal to gas conversion for decommissioning and cost allocation to Oregon customers. PAC is inclined to address MSP issues in the MSP process. PacifiCorp indicated that the main component of gas conversion costs is the cost of natural gas pipeline transport and therefore there is no significant impact on depreciation and decommissioning costs.

Energy Advocates commented that coal to gas conversion is not shown to be least cost least risk in the presence of HB 2021. PacifiCorp indicated that they provided economic analysis showing system benefits from conversion of all Bridger units and Naughton units (in both 2021 (JB1 and 2) and 2023 IRPs). Conversion should be consistent with HB 2021, since these plants would have lower emissions compared to before and will be operated with low-capacity factor but meet peak and reliability needs. In response to Energy Advocates' comments on whether the benefits from these conversions and costs will only be limited to Oregon customers, PacifiCorp replied that these plants will retire in 2037, before HB 2021's 2040 timeline, hence Oregon is not the only one sharing costs. Moreover, conversion costs are much lower than cost of new renewables.

Sierra Club had expressed concern around availability of firm gas capacity for the converted units. PacifiCorp did not disclose the pipeline information in its Reply Comments due to confidentiality agreements with third parties.

Staff believes that the Company's decision to continue to operate coal generation units as natural gas plants must be evaluated in the light of HB 2021. Staff understands that inter-state protocol and cost allocation concerns raised by CUB are vital and expects the Company to respond to those in the appropriate docket. Further, Staff understands that the conversions of Jim Bridger 1 and 2 was acknowledged in the 2021 IRP and the conversion plan for Naughton 1 and 2 is also well under way, and therefore these items are not appropriate action items for acknowledgement in this IRP.[14]

Staff Expectations:

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the Action Plan because the Company has already taken these actions.

RFP Suspension

As previously noted in Staff's Round 1 comments, PacifiCorp recently suspended its 2022 All Source Request for Proposals (2022 AS RFP), which sought bids from resources capable of coming online by the end of 2026. The suspension raises concerns around the Company's ability to execute certain Action Plan items in the 2023 IRP and procure sufficient near-term resources to meet Oregon's HB 2021. RNW's Round 1 comment similarly noted the risk from this suspension and encouraged PacifiCorp to resume the RFP as soon possible or have the Commission to direct the Company to do so.[15]

PacifiCorp's Round 1 Response Comments did not provide much information to assuage 2022 AS RFP suspension concerns. The Company failed to address many of the questions raised by Staff and stakeholders. Despite stating previously in LC 82 that the greatest risk to the IRP was under procurement of resources, the Company now stated that it did not have any revised plan or substantive updates available that reflected the impacts of the RFP suspension.[16] However, the Company did state that it had

[14] PacifiCorp Response to Staff DR Nos. 222 and 223.
[15] LC 82, Renewable Northwest, Round 1 Comments, October 25, 2023, page 7.
[16] LC 82, PacifiCorp Reply Comments, page 96.

engaged in a bilateral effort to procure battery storage technology by June 1, 2026, and that in the IRP Update a new RFP may be put forth.

Given that the Preferred Portfolio included 2,531 MW of wind, 6,383 MW of solar, and 6,411 MW of battery capacity on the system by 2028, the impact of suspending a near-term RFP puts these builds at risk. In response to discovery, PacifiCorp confirmed that it is unable to procure the amount of wind and solar included in the Preferred Portfolio in years leading up to 2028.[17] Table 2 summarizes the difference in installed capacity between the Preferred Portfolio and the additions that may actually occur if PacifiCorp is unable to procure any additional new renewables, other than the bilateral storage mentioned above.

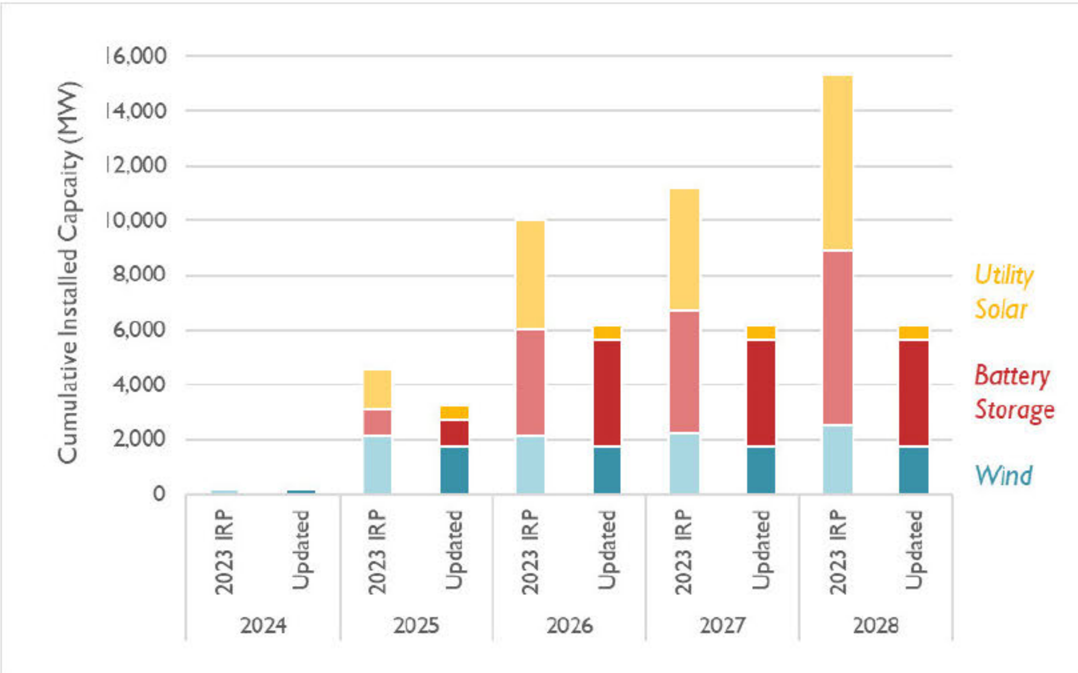
Table 2: Difference in Installed Capacity Between 2023 IRP Preferred Portfolio and Current Reality

Cumulative Installed Capacity Delta (MW)	2024	2025	2026	2027	2028
Renewable- Utility Solar	0	-974	-3,498	-3,981	-5,888
Renewable- Battery	0	0	0	-628	-2,528
Renewable- Wind	0	-339	-339	-439	-739
Total	**0**	**-1,313**	**-3,837**	**-5,048**	**-9,155**

The figure below demonstrates the impact that this delayed procurement could have on renewable resource builds over the next five years. The "2023 IRP" chart series on the left represents the data as presented in the Preferred Portfolio. The "Updated" chart series on the right represents capacity that PacifiCorp has currently indicated it can procure based on the 2020AS RFP and bilateral storage contracts. Solar is the resource that is most at risk due to the 2022AS RFP suspension, as the 2020AS RFP did not result in a large number of solar additions and PacifiCorp has not indicated any alternative procurement processes for solar.

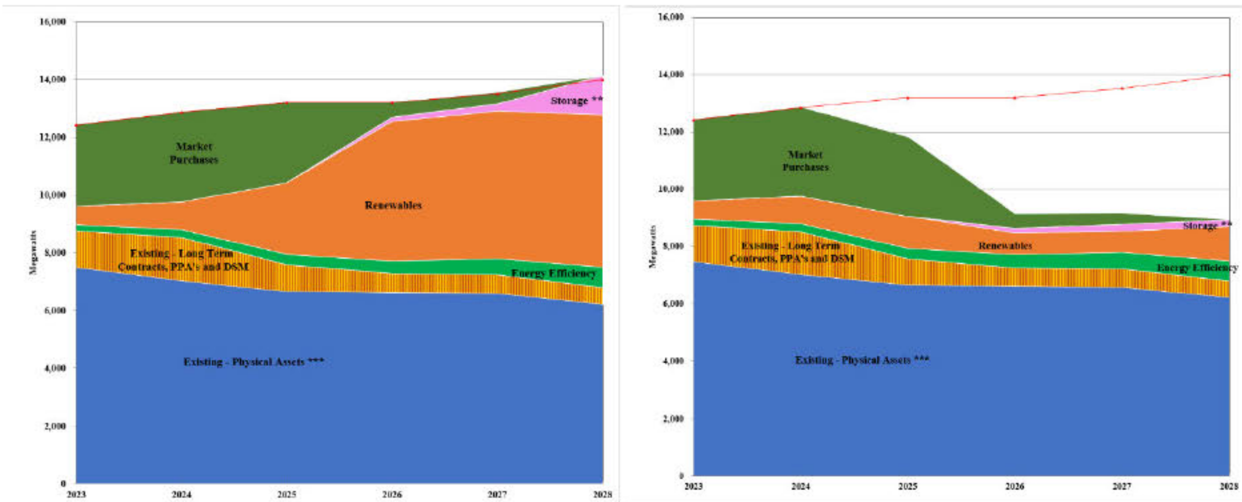
[17] PacifiCorp Response to Staff DR No. 243.

Figure 1. Difference in Installed Cumulative Capacity Between 2023 IRP Preferred Portfolio and Current Reality



This delay will also have a significant impact on the generation mix of the system. Figure 9.60 in the IRP shows the projected generation by resource type for the Preferred Portfolio. Over the next five years, PacifiCorp's Preferred Portfolio relied heavily on market purchases (also referred to as front office transactions or FOTs) and existing resources in the near-term while transitioning to rely more and more on new renewable resources. The left side of the figure below is a reproduction of Figure 9.60 as published in the IRP for years through 2028. The right side of the figure below demonstrates what the generation mix could look like if PacifiCorp does not procure new renewables and instead has a capacity mix that resembles the "Updated" chart series in Figure 9 above.

Figure 2. Reproduction of Figure 9.60 in IRP, with and without 2022AS RFP Suspension Impacts



Without the guarantee of additional solar, storage, and wind resources coming online over the next few years, PacifiCorp may end up relying more heavily on FOTs or delaying thermal resource retirements relative to the Preferred Portfolio. This could lead to decarbonization risks, which the Company has not adequately addressed in the current IRP.

As PacifiCorp will not remove the Action Plan items related to the 2022 <u>and</u> the proposed 2024 AS RFP from the filed IRP, nor update any analysis in this IRP/CEP to reflect the indefinite suspension of these procurements, the filed plans do not appear feasible. Staff finds little value in continuing to review this IRP/CEP. Too much is indeterminate and unknown. Further, as the CEP compliance pathways, and thus any determination of continual progress of emission reductions and compliance with the reduction targets, rests so squarely upon the IRP's Preferred Portfolio, without a revised analysis and procurement plan by PacifiCorp, Staff cannot determine the extent to which the CEP demonstrates compliance with the emissions reduction targets or can be substantiated to meet most if not all of the public interest factors detailed in HB 2021.[18]

Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

Action Plan Changes

PacifiCorp reply comments did not offer alternatives or revisions to the following Action Plan items that were impacted by events external to the IRP/CEP.

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[18] See ORS 469A.420(2).

- Action Plan Item 1h: Per the non-confidential response to Sierra Club Information Request (IR) No. 37, the very near-term installation of the proposed selective, non-catalytic reduction (SNCR) installations at several coal plants is being paused and reevaluated due to the Federal Court stay of the Ozone Transport Rule.
- As noted previously all Action Plan Items Under Category 2 involve the acquisition of new resources either through the suspended 2022 AS RFP or through a proposed, new 2024 AS RFP. No alternatives or revisions to these activities were offered by the Company. Instead, PacifiCorp points to the potential for new procurements to be proposed with the April 2024 IRP Update.

Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments

CEP acknowledgement hinges upon a finding that the CEP is, "in the public interest and consistent with the clean energy targets…" of HB 2021.[19] The recent order in UM 2273 provides an excellent overview of the public interest factors for valuating a CEP.[20] As noted above, given the Company's unwillingness to revise its analysis, Staff recommends not acknowledging the CEP. In the sections below, Staff details its determination that the community-focused elements of the LC 82 CEP appear reasonable with certain recommended changes, while the GHG emission reduction related portion of the CEP is not consistent with the clean energy targets nor does it appear to meet most if not all of the public interest factors detailed in HB 2021. For this reason, Staff does not recommend acknowledgement, but identifies portions of the CEP that may be included and/or improved in the revised and resubmitted CEP.

Community Benefits Indicators (CBI)

In Round 1 Comments Staff expressed concern that the interim CBIs provided no incremental information for evaluating the Company's IRP or CEP portfolios and did not materially affect its plans.[21] Staff requested that for the next IRP, the Company adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.[22]

The Energy Advocates recommend greater granularity for the Company's CBIs.[23] They also encourage the Company to include better measures of distributional justice when creating CBIs.[24] The Energy Advocates then state that the Company's CBIs do not offer any sense of how PacifiCorp brings economic benefits to communities,[25] a sentiment that is echoed by NewSun Energy.[26] The Community Advocates Cohort is discouraged by the lack of details in the Company's proposed CBIs and believes the Company's CO2 emissions CBI is not an indicator of community benefits.[27] Renewable Northwest (RNW) would like more detail about how the Company chose the 17 metrics that were included in the CEP.[28] RNW also recommends that the Company adopt additional environmental CBIs and believes that the language the Company uses when describing its resiliency CBIs expresses a hope instead of indicating that it is strongly committed to improvements or has any planned actions.[29] CRITFC supports past recommendations by the Energy Advocates to improve CBIs and wants better accounting for tribal needs in the Company's CEP.[30] In particular, CRITFC wants the CBI to incorporate tribal energy metrics and create metrics that target reducing peak loads, maximizing energy efficiency, strategically siting renewable resources, reducing reliance on Federal hydro resources, and minimizing the transmission and distribution system.[31]

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[19] ORS 469A.420(2).
[20] UM 2273, Investigation into HB 2021 Implementation Issues, Order No. 24-002, Jan. 5, 2024, starting on page 17.
[21] Staff's Round 1 Comments, page 19.
[22] Staff's Round 1 Comments, page 21.
[23] Energy Advocates' Round 1 Comments, page 7-8.
[24] Energy Advocates' Round 1 Comments, page 11.
[25] Energy Advocates' Round 1 Comments, page 12.
[26] NewSun Energy's Round 1 Comments, page 6.
[27] Community Advocates Cohort's Round 1 Comments.
[28] RNW's Round 1 Comments, page 65.
[29] RNW's Round 1 Comments, page 65.
[30] CRITFC's Round 1 Comments, page 4.
[31] CRITFC's Round 1 Comments, page 7.

PacifiCorp stated in Round 1 Response Comments that it intends its CBIs to be a holistic representation of all the Company's activities to increase community benefits and highlights that it has added two new draft CBIs through its stakeholder process.[32] The Company states that it intends to refine its approach to resiliency and that there is additional work necessary to develop its CBIs.[33] In response to Staff's suggestion to frame CBIs as a metric rather than a goal, the Company states that it would consider it, but anticipates that it may cause confusion.[34] The Company did not appear to directly respond to any other concerns raised by Staff or stakeholders regarding CBIs.

Staff finds that the Company failed to fully respond to Round 1 comments by both Staff and stakeholders. In particular, the Company failed to:

- Provide any timeline to refine CBIs or provide any detail about how they could be refined.
- Discuss how it is attempting to implement tribal concerns brought up by CRITFC or greater CBI granularity brought up by Energy Advocates and Staff into CBIs.
- Discuss whether or how it would incorporate additional environmental CBIs into its next CEP.
- Provide any explanation about how the 17 metrics were chosen, as requested by RNW.

Staff agrees with the Company that developing CBIs is an iterative process that should be done in consultation with local communities and tribal governments. Staff is worried by the Company's apparent lack of response to published concerns by stakeholders, lack of record keeping, and lack of target timeline to improve CBIs. Staff would note the importance of maximizing to the extent possible Oregon community benefits across such planning activities such as portfolio development[35] and resource selection.[36] As such, relying solely on measures of systemwide impacts provides very little value when evaluating whether the Company's IRP and CEP provide tangible benefits to Oregon communities. Staff's Round 1 comments to recommended that CBIs better addressing energy efficiency, local emissions, and CBRE impacts were meant to bridge this gap.

With the following draft recommendations and expectations, Staff recognizes that the CBIs in this CEP are interim, but also seeks to stress the importance of using CBIs to meaningfully inform utility decisions and to track progress over time. Staff expects that the further development of CBIs be done in coordination with local communities and tribal governments and describes additional recommendations and expectations regarding this coordination in the Community Engagement section.[37]

Staff believes that in order to have an effective set of CBIs, it is critical to provide baseline measures of community impact prior to the next IRP/CEP update, and to develop more CBIs that address local non-GHG emissions, energy efficiency, and CBRE actions.

Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

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[32] LC 82, PacifiCorp Reply Comments, page 13.
[33] LC 82, PacifiCorp Reply Comments, page 16-17.
[34] LC 82, PacifiCorp Reply Comments, page 18.
[35] UM 2225, Order No. 23-060, February 23, 2023, Appendix A, page 5.
[36] UM 2273, Order No. 24-002, January 3, 2024, page 23.
[37] UM LC 80, Staff's Round 2 Comments, page 31.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

Staff Expectations:
In the next IRP/CEP, Staff expects PacifiCorp to:

- Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
- Better inform CBIs and methods with input from stakeholders and community.
- Enhance tribal-focused CBIs.
- Use CBIs to better reflect the health impacts of EE.
- Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
- Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
- Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

Community Based Renewable Energy (CBRE)

Staff found PacifiCorp's identified CBRE resources a reasonable starting point, but questioned whether more should be available based on a forecast of market activities not just existing programs. Staff also questioned whether net benefits were appropriately considered. Staff encouraged PacifiCorp to not limit CBRE potential to the activities and resources identified in the CEP and consider energy efficiency and flexible loads as potential valuable contributors. Lastly, Staff drew the connection between CBRE and SSR, and encouraged PacifiCorp to more aggressively pursue CBREs. Further, Staff encouraged PacifiCorp to pursue a CBRE strategy targeted at Oregon load pockets to avoid significant local transmission and distributions system upgrades.

RNW encouraged PacifiCorp to better quantify the benefits of CBRE and identify above market costs. Energy Advocates similarly encouraged PacifiCorp to consider broad benefits of CBRE, beyond a levelized cost of electricity analysis. RNW and Energy Advocates highlighted that PacifiCorp's CBRE potential relied on tallying existing programs which could be counted as CBRE. Both entities encouraged PacifiCorp to take initiative to identify additional CBRE resources. Energy Advocates highlighted that costs are likely inflated due to modeling not considering the IIJA and IRA. CUB raised government funding and questioned how funds may support CBRE development.

In response to Round 1 comments, PacifiCorp emphasized the Company's commitment to launching the CBRE Pilot proposal to external parties in the first quarter of 2024. The Company highlighted some of the ways in which the landscape of CBRE is quickly developing since the initial CEP filing. Of note, PacifiCorp anticipates a larger CBRE potential in Group B, siting 20 new projects in the pipeline. Initially, Group B included 3.5 MW of small-scale and community-focused renewable projects, primarily solar plus storage.

PacifiCorp commented on features of the Company's modeling that were raised by Staff and stakeholders. PacifiCorp clarified that the 10 percent adder was used to treat CBRE resources commensurately with energy efficiency. For the CBRE scenario, PacifiCorp clarified that the Company had to force the model to acquire CBRE resources as the model would not have otherwise done so for cost reasons. Finally, PacifiCorp emphasized the dynamic nature of the planning environment for CBRE and committed to ongoing refinement of CBRE Pilot Approach. In particular, the Company resolved to support projects that are "in-flight" via other co-funding mechanisms and programs. PacifiCorp contends that despite commitment to ongoing improvement, costs were not inflated in this first round of analysis even though large federal legislation, namely the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA), were not included in initial analysis.

CBRE Resource Potential

Staff recommends that PacifiCorp consider more ambitious CBRE potential than the 95 MW identified, including 92 MW of which are in existing programs. The initial potential study tallied pending projects, and did not rely on forecasting sophistication of consumer adoption curves, historical cost declines, or enabling funding and programs. Staff appreciates PacifiCorp's acknowledgement that the 3.5 MW, Group B, potential is likely much greater due to new funding and programs. Due to rapid increases in renewable energy acquisition, Staff finds that 95 MW could significantly undercount the CBRE potential if effective program designs are deployed that recognize the benefits of CBRE, especially in the preferred portfolio.

Due to the magnitude of the 490 MW SSR requirement and the potential of CBRE resources to grow, Staff would like PacifiCorp to take a more aggressive approach than the "measured and incremental approach to investigating CBREs".[38] Staff encourages a sense of urgency and recommends PacifiCorp immediately publish the CBRE Grant Pilot Proposal to the CBIAG. Feedback should be solicited and processed quickly, such that PacifiCorp files the first round of the CBRE Grant Pilot for Staff approval by the end of Q2 2024. A quick feedback cycle is essential such that PacifiCorp may consider amending its CBRE potential based on feedback and results of an initial CBRE Grant Pilot.

Staff Recommendation 7. Direct PacifiCorp to pursue the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

CBRE Activities

In the upcoming 2024 CEP update, Staff recommends PacifiCorp include an acquisition target of CBRE in its Action Plan. PacifiCorp's Round 1 comments identified a growing pool of known CBRE resources suggesting that 95 MW is likely a floor for a 2030 acquisition goal.[39] Many of PacifiCorp's CBRE actions are positive steps, but the current Action Plan, with no firm acquisition target, falls short of Staff's expectations. Staff appreciates that PacifiCorp continues to develop the CBRE Grant Pilot with stakeholders and is prioritizing "in-flight projects", such that the Company can accelerate how quickly those come online. Further, Staff expects PacifiCorp to be proactive beyond publishing a CBRE Grant Pilot. PacifiCorp should report regularly to the CBIAG on development activities, including on concrete actions PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

Staff Expectation:

- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

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[38] LC 82, PacifiCorp Reply Comments, page 4.
[39] LC 82, PacifiCorp Reply Comments, page 92.

CBRE Inclusion in Preferred Portfolio

In Portland General Electric's (PGE) 2023 IRP/CEP, PGE clearly communicated the fixed cost minus the benefit streams of CBRE resources. PGE's modeling selected the entire 155 MW of CBRE potential for the resource's value within the balancing authority.[40] Acknowledging that PGE and PacifiCorp have different geographic and resource characteristics, PacifiCorp's load pockets are an example where prioritization for CBRE resources would maximize benefits to both individual communities and to all ratepayers.

Staff disagrees with PacifiCorp's blanket characterization that a commitment to pursuing CBRE resources would break from historical least-cost, least-risk paradigm. Much of the CBRE resources identified have complementary, non-ratepayer sources of funding to reduce costs and avoid separate SSR procurement. As PacifiCorp acknowledged, the IRA and IIJA incentives were not accounted for in CBRE analysis which both reduces the potential and inflates the cost. Further, as was raised by Energy Advocates and RNW, PacifiCorp did not provide a transparent accounting of the benefits of CBRE resources to the system, particularly with respect to investments that can be avoided as a result. Without this clear articulation of value and despite PacifiCorp's claims of "considerable favor to SSRs" in PLEXOS modeling, Staff is not persuaded that all CBRE resources are as uneconomic as the Company portrays.[41]

Also undermining PacifiCorp's argument that pursuing CBRE breaks from the least-cost, least-risk paradigm is the fact that the Company's potential study found 92 MW of CBRE in existing programs. Proper cost consideration should have included these resources in the IRP preferred portfolio. Staff expects PacifiCorp to include these CBRE resources in the 2024 IRP update preferred portfolio and to update the CBRE potential in the 2024 CEP update.

Staff requested PacifiCorp address CBRE's role in minimizing costs in Oregon's load pockets.[42] PacifiCorp acknowledged the request but failed to respond in a quantitative manner. Staff highlights that PacifiCorp is versed in the dynamics of storage as a tool to manage transmission constraints, as section 6 in Round 1 comments includes robust discussion of specific examples (storage in lieu of B2H) and general agreement that less transmission expense is a "chief advantage of SSR".[43] However, it is unclear whether the Company applied a commensurate benefit to small scale and customer sited renewables and storage.

Staff Expectations:

In the IRP/CEP update:

- Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

By the next IRP/CEP:

- Highlight and communicate the relative benefits of CBRE in load pockets.

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[40] See Docket No. LC 80, *Portland General Electric 2023 Integrated Resource Plan and Clean Energy Plan,* Figure 77. Net cost of a microgrid CBRE, page 251, https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf.

[41] Id., page 84.

[42] Staff Round 1 Comments, DR No. 16, page 25, https://edocs.puc.state.or.us/efdocs/HAC/lc82hac144131.pdf.

[43] LC 82, PacifiCorp Reply Comments, page 53, https://edocs.puc.state.or.us/efdocs/HAC/lc82hac1546.pdf.

- Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[44]
- Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

Staff encourages PacifiCorp to consider CBRE program designs that scale quickly and provide meaningful capacity distributed across the geographically diverse territory and specifically to load pockets. Staff highlights Green Mountain Power's (GMP) residential storage programs that have 1.1 percent of customers enrolled today and are poised to double annual customer acquisition rates.[45] A similar program growing at the same, per capita rate as GMP's could add 200 MW of distributed storage capacity to PacifiCorp's Oregon territory by 2030.[46] GMP's rate-based cost to operate the programs is reduced by the benefit of a 30 percent federal tax credit, monthly customer participation fees, and GMP's ongoing economic dispatch of the aggregated capacity. Over the system's lifetime, GMP identifies a positive lifetime net-present value of $2,749, despite the upfront, fixed cost of $22,000.[47]

Staff highlights Green Mountain Power as an example of a program design that delivers resilience, helps increase renewables adoptions, and scales quickly. Staff encourages PacifiCorp to be more expansive in its consideration of CBRE resources and consider additional energy efficiency and demand response capacity. For example, many buildings and communities across the state lack basic weatherization and existing programs are not scaled up to meet the need. In one example, the Northwest Energy Efficiency Alliance's 2016-2017 Residential Building Stock Analysis showed that 11 percent of Oregon's single family homes have uninsulated walls.[48] Efficient buildings that can maintain comfort during severe heat and cold events deliver not just energy savings but are better able to participate in demand response programs and deliver capacity savings.

Staff Expectation:

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

In Order No. 22-390, the Commission adopted expectations for PacifiCorp and PGE to furnish details on community engagement.[49] PacifiCorp used its existing IRP public input process, DSP efforts, and CETA Washington Equity Advisory Group as the basis of its CEP engagement efforts. The Company's

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[44] ORS 469A.415(4)(d).

[45] Howland, Ethan, *Vermont PUC lifts caps on Green Mountain Power battery storage programs with Tesla, others,* Utility Dive, Aug. 29, 2023, https://www.utilitydive.com/news/vermont-puc-green-mountain-power-gmp-battery-storage-programs-tesla/692052/.

[46] Ibid. GMP anticipates growth of 474 residential battery installs per 100,000 customers. At 10 kW capacity per install, PacifiCorp's 610,000 customers could accumulate 200 MW of capacity by 2030.

[47] Ibid.

[48] *Residential Building Stock Assessment II Single Family Report,* Northwest Energy Efficiency Alliance, April 2019, neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf.

[49] *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (October 25, 2022) *corrected,* Order No. 22-470 (December 5, 2022).

engagement efforts consist of customer surveys, sharing the Company's planning decisions at public "stakeholder engagement venue" meetings, and a Feedback Tracker to document the Company's response meeting questions and comments. The engagement venues include, among others, a CEP Engagement Series, the Community Benefits and Impacts Advisory Group (CBIAG), and the Oregon Tribal Nations Clean Energy Engagement Series.

Staff Round 1 Comments asserted that PacifiCorp had not successfully articulated the Company's path from engagement and input to planning and action. While the CEP discussed tribal engagement opportunities, Staff found the CEP lacked detail on whether the Company had successfully incorporated Tribal perspectives into the Company's decision making and engagement strategy. Additionally, it was not clear that the Company's plan included the perspectives of environmental justice communities. To this extent, Staff suggested improvements including reevaluating the Feedback Tracker to include a clear description of why feedback was or was not included in IRP/CEP.[50] Going forward, Staff also recommended a dedicated stakeholder and cross-utility community engagement working group similar to that put forward in LC 80.[51]

In Opening Comments, the consensus among CUB, RNW, Energy Advocates, and Community Advocates, was that PacifiCorp had not meaningfully considered input from environmental justice communities. Energy Advocates and Community Advocates further noted that PacifiCorp had not measured the effectiveness of their engagement strategy. CRITFC advanced that there is no indication from the CEP or IRP that PacifiCorp has consulted with affected Tribes prior to making decisions, particularly around hydropower reliance.

In Reply Comments, PacifiCorp did not oppose working with PGE to create a common community engagement strategy group along the lines of Staff's suggestion.[52] PacifiCorp committed to timely updating the Feedback Tracker following public workshops,[53] but did not address Staff's additional suggestions to improve the Feedback Tracker. PacifiCorp stated the Company continues to pursue a dialogue with its sovereign tribal partners across its six-state service area and intends to hire a tribal-affairs representative. The Company further commented that it was developing a Tribal CBI focused on TE. PacifiCorp linked components of its DSP/Clean Energy survey to outreach and accessibility practices. Regarding environmental justice, the Company referenced an educational component at CBIAG meetings.

On December 19, 2023, following Round 1 Reply Comments, PacifiCorp met with Staff informally to explain how the Company had used the community engagement process to develop its Interim CBIs. PacifiCorp explained that, due to time constraints, the Interim CBIs presented in the CEP did not originate with the CBIAG. Instead, PacifiCorp selected CBIs previously developed through Washingtons' Clean Energy Transformation Act (CETA) engagement process. According to PacifiCorp, CBIAG members had approved of the Washington CBIs and also suggested additional CBIs; however, PacifiCorp stated at the meeting with Staff that it could not provide Staff with documentation of this approval or the

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[50] *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (Oct. 25, 2022) *corrected,* Order No. 22-470 (Dec. 5, 2022).

[51] *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Round 2 Comments and Recommendations at pages 29-30 (October 24, 2023).

[52] LC 82, PacifiCorp Reply Comments, December 1, 2023, pages 10, 11.

[53] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 11.

proposed CBIs from CBIAG members[54] beyond the map showing the Company had opposed CBIs proposed by Joint Advocates that were not in line with the Washington CBIs.[55] Going forward, Company representatives committed to:

- Working with the CBIAG to evolve CBIs to be Oregon specific and reflective of CBIAG member feedback;
- Leveraging other efforts to inform and bolster CBIs, including through a 2023 survey and by developing channels to streamline community input from adjacent initiatives to CBIAG members; and
- Making changes to how the Company received and documented input to ensure CBIAG member feedback and knowledge was captured and could be referenced at a later date.[56]

After review of Stakeholder and PacifiCorp comments, Staff has identified the following key adjustments to the Company's platforms and methods that can improve community engagement in future CEP/ IRP processes.

Accountability and Transparency

PacifiCorp's CEP includes available venues for public input, yet the Company's community engagement strategy could be improved and ultimately more effective through better documentation of stakeholder input. This CEP did not provide a clear roadmap of how or why PacifiCorp used stakeholder input to inform the Company's IRP and CEP. Going forward, this documentation can help close the gaps between the Company's interpretation of effective engagement and stakeholders' priorities and expectations. Accordingly, Staff reiterates the need for Feedback Tracker improvements and looks forward to working with PacifiCorp and stakeholders to implement these improvements. Staff also recommends the utility conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts. Additionally, Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document how Environmental Justice community priorities are addressed. Finally, as introduced in Round 1 Comments, Staff believes it is a priority to develop clear, actionable expectations for engagement in future IRP/CEP development and review. Consistent with LC 80, Staff recommends the establishment of a working group that can operate in coordination with the broader investigation into the Commission's planning and procurement policies in 2024.

Cross-venue Engagement Planning

Staff recognizes that stakeholder engagement addressing critical issues, such as wildfire risk, transportation electrification (TE), and energy affordability is occurring in separate dockets and venues outside of the CEP process. As discussed at the informal December 19 meeting with PacifiCorp, Staff is encouraged by the Company's work to streamline input channels. In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in these adjacent dockets and venues to inform CBIs, CBREs, and portfolio decisions.

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[54] Staff and PacifiCorp meeting held December 19, 2023.
[55] PacifiCorp response to Staff DR 35 Attachment.
[56] Staff and PacifiCorp meeting held December 19, 2023.

Tribal Engagement

In Opening Comments, Staff recognized that engagement with Tribal Nations requires intentional recognition and a focused approach that the utility and industry as a whole is working to better understand and practice. Staff appreciates PacifiCorp's introduction of a Tribal TE CBI. Going forward, Staff expects the Company to provide updates to the CBIAG and Staff on the Tribal CBI development and strategy to actively increase Tribal Nation priorities in planning conversations and resource decision-making.

Notably, in December 2023, the U.S. Government reached a settlement agreement to support the Columbia Basin Restoration Initiative (CBRI) in partnership with the Six Sovereigns.[57] This comprehensive agreement leveraged the collective knowledge and priorities of Tribal Nations, Oregon and Washington states, federal agencies, and interest groups. The CBRI anticipates changes to the energy system as part of the work to restore fisheries while supporting decarbonization and resilient communities. For these reasons, Staff views the CBRI as an opportunity for PacifiCorp to improve its engagement strategy with Tribal Nations impacted by the construction and operation of the Columbia River Federal dams.

Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Staff Expectations:

- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
  - Organization/entity attribution or affiliation.
  - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
  - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp should conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

[57] *See* Northwest Power and Conservation Council memorandum, *Report on the US Government Commitments: Power Related Topics*, January 3, 2024, https://www.nwcouncil.org/fs/18579/2024_01_p2.pdf. The Six Sovereigns include the Nez Perce Tribe, Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, and the States of Oregon and Washington.

Resiliency Analysis Framework

PacifiCorp's CEP outlines the beginnings of the Company's Resiliency Analysis Framework. The Resiliency Analysis Framework combines census tract level community[58] and utility[59] resilience scores into a composite community-resilience score. The Company plans to use the community-resilience score to identify census tracts for additional analysis and project prioritization.[60] After identifying threats, probabilities, and consequences, PacifiCorp plans to use a risk-spend efficiency (RSE) or cost-benefit analysis (CBA) to account for the costs at specific project locations. The Company's goal is to include resilience risk scores in project and program prioritization, including when assessing the IRP, CBRE, and SSR.[61]

In Opening Comments, Staff requested an update on the Resiliency Analysis Framework timeline, which includes PAC's plan to incorporate community-utility resilience scores and risk drivers into CEP program planning by Q1 2024.[62] By extension, Staff asked how the Company planned to use the Resiliency Analysis Framework in the IRP, CEP, and/or DSP. Staff also asked for additional information on the resiliency scoring metrics.

Energy Advocates and CRITFC argued that PacifiCorp should improve community resiliency and consider how SAIDI/SAIFI/CAIDI data can be connected with information about lived experiences and community resources that can be used during an outage. Energy Advocates added that PacifiCorp should clearly define resiliency in the CEP and improve the readability of the CEP to include important definitions for SAIDI, SAIFI, and CAIDI. CRITFC discussed the link between healthy salmon ecosystems, utility resource planning to meet HB 2021 requirements, and tribal community resiliency.

In Round 1 Reply Comments, PacifiCorp did not directly respond to requests for information about resiliency planning and community data points. Instead, PacifiCorp stated that much of Staff and stakeholders' comments, questions, and concerns would be addressed in the next CEP.[63] PacifiCorp's future planning approach will, "evolve as [the Company] gain[s] experience and receive[s]additional stakeholder input."[64] PacifiCorp explains that it is still evaluating how to include additional community input.

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[58] To develop the community resilience score, PacifiCorp assigns social vulnerability and community resilience scores to census tracts using FEMA National Risk Index (NRI) values. PacifiCorp response to Staff DR No. 97.

[59] To develop the utility resilience score, PacifiCorp applies System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) including major events to calculate the annual number of customers and minutes interrupted at each transformer in each census tract. PacifiCorp response to Staff DR No. 97.

[60] For example, PacifiCorp explains that by sorting the largest census tract CAIDI values first, and then sorting by the lower NRI values the Company can identify customers experiencing longer system outages with lower community resilience or higher social vulnerability. PacifiCorp response to Staff DR No. 99.

[61] LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 29.

[62] *See* LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 32; *see also* PacifiCorp response to Staff DR No. 30.

[63] *See* LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48 (In Round 1 comments Staff requested an updated Table 9 timeline. PacifiCorp acknowledged Staff's request in its Round 1 Reply Comments but did not provide an updated Table 9 timeline.); *see also* LC 82, PacifiCorp Round 1 Reply Comments, December 1, 2023, page 49 ("PacifiCorp is also evaluating how to apply its resilience analysis to DSP and CEP programs and will provide additional information in its upcoming CEP consistent with Staff recommendations. … PacifiCorp is currently developing a preliminary resilience cost-benefit analysis and will include this framework in its upcoming CEP.").

[64] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48.

PacifiCorp did not address Staff's questions on how the Company's wildfire plan was incorporated into the CEP resiliency analysis beyond directing Staff to review the Company's Wildfire Mitigation Plan. PacifiCorp disagreed with Staff's assessment about its use of the terms "resiliency" and "reliability", but states it will be clearer in the next CEP. In response to Stakeholder requests, PacifiCorp has provided definitions of SAIDI, SAIFI, and CAIDI.

Staff also understands that PacifiCorp is currently evaluating the geographic scope of the Resiliency Analysis Framework to develop more granular resilience scores.[65] Of note, PacifiCorp's current methodology to calculate SAIDI/SAIFI/CAIDI scores at the census tract level results in higher values than under the traditional use, which applies these metrics to the state or utility level.[66] As stated in Staff Round 1 Comments, Staff is still interested in understanding how these census-level SAIDI/SAIFI/CAIDI data has been successfully used in the past for resiliency-related planning. Staff expects the Resiliency Analysis Framework to consider direct benefits to Oregon communities. Nevertheless, Staff is concerned that limiting the scope of resilience metrics to transformer outages within Oregon census tracts, as discussed in step two of the Resiliency Analysis Framework, may result in unnecessary grid-hardening at the expense of PacifiCorp's Oregon ratepayers or overlook cross-state resiliency issues such as wildfire, extreme weather, and load pockets.[67] Given the nascent state of the Resiliency Analysis Framework, Staff sees an opportunity to open discussions with the Company and Stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework.

PacifiCorp states it accounts for non-energy related resilience assets and services in the NRI values.[68] As noted in Round 1 comments, the NRI values use well known indices and Staff continues to find them helpful. That said, Staff would like further insight on how the Company plans to consider these assets and services to meet its goal to prioritize enhancing community resilience over acquiring additional capacity[69] and avoid extraneous utility projects and their associated costs. Staff also expects further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.

Staff understands that resiliency analysis is an evolving field and expects that PacifiCorp will significantly improve upon its Resiliency Analysis Framework in the next CEP. In the meantime, Staff recommends that PacifiCorp incorporate resiliency-related factors into the Q1 2024 SSR RFP and the CBRE Grant Pilot so that these efforts can bring tangible community benefits to their system.

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[65] *See e.g.*, PacifiCorp response to Staff DR No. 96.

[66] LC 82, PacifiCorp 2023 CEP, CBI, May 31, 2023, page 20.

[67] *See e.g., In the Matter of Investigation into House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 24-002 at page 25 (January 5, 2024) ("Grid-connected facilities located outside Oregon contribute to reliable service for Oregon electricity customers and to reducing GHG emissions on the grid, and facilities located inside Oregon do not serve Oregon customers exclusively. There may be resiliency benefits to in-state resources and resource strategies that are worthwhile to consider, but those must be based on reliability and resiliency analysis or related valuation methodologies, not assumed based solely on geographic location or the presence of specific electricity market transaction receipts.").

[68] LC 82, PacifiCorp response to Staff DR Nos. 102, 104.

[69] LC 82 PacifiCorp 2023 CEP, CBRE, May 31, 2023, page 45; *see also* PacifiCorp response to Staff DR 109.

Figure 3: SSR RFP Procurement Timeline[70]

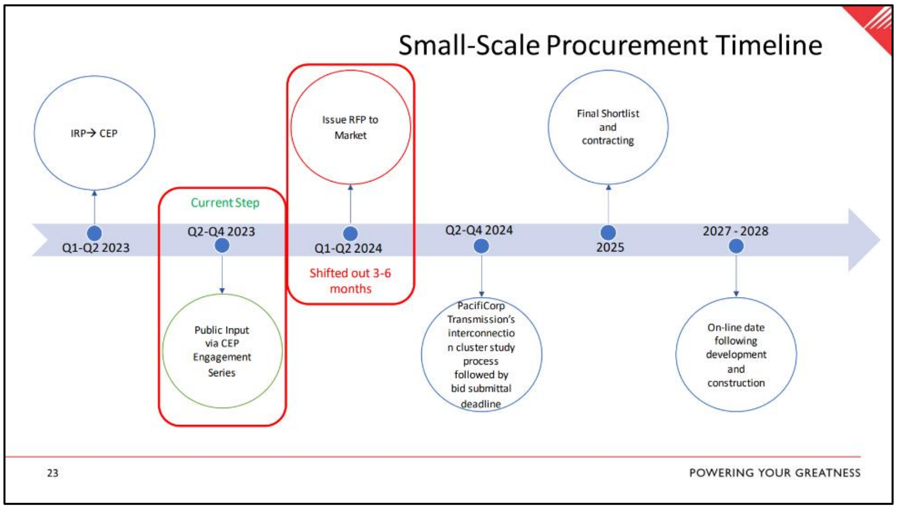
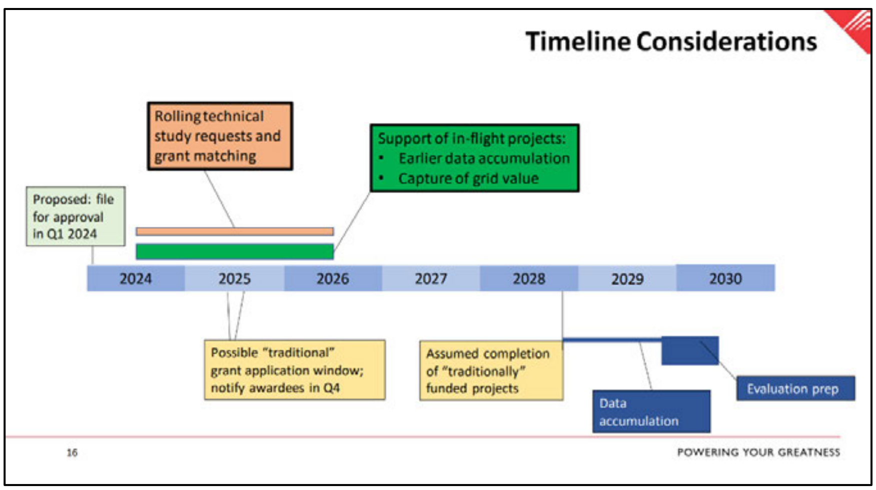


Figure 4: Timeline Considerations for the CBRE Pilot[71]



PacifiCorp's community-utility resilience score accounts for time and duration of outages through SAIDI/SAIFI/CAIDI metrics. It is not clear to Staff what additional information Stakeholders need regarding SAIDI/SAIFI/CAIDI methodologies and definitions. Prior to the next CEP filing, Staff expects PacifiCorp work with Stakeholders to identify gaps in Resiliency Analysis Framework comprehension and the vulnerabilities and complexities of these data sets as a measure of community level impacts.

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[70] PacifiCorp CEP Engagement Series, 4th meeting, slide 23 (August 25, 2023) available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

[71] PacifiCorp CEP Engagement Series, 4th meeting, slide 16 (August 25, 2023) available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Staff Expectations:

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.
- By the next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

Acquisition of Federal Incentives

One of the specifically enumerated, HB 2021 public interest factors for weighing CEP acknowledgement is the extent to which the availability of federal incentives were considered.[72] In Round 1 comments Staff joined Sierra Club and CUB in calling for PacifiCorp to fully incorporate the financing opportunities and tax credits made available through the Interest Reduction Act (IRA) more fully into its IRP/CEP analysis. This included rerunning variant portfolios. Specifically: apply a 30 percent reduction to transmission network upgrade costs for low cost, renewable projects in select cluster study areas; and, assuming low cost federal financing and loan guarantees be used for targeted early plant retirements. Suggestions also included regular reporting to the Commission on progress pursuing federal incentives, exploring how Justice 40 incentives could be used for CBREs, and applying tax bonus credits to eligible "energy communities" in Oregon.

PacifiCorp responded that it used the available IRA information at the time of filing and continues to examine evolving legislation for use in future analysis where appropriate. Further, the Company stated that the PLEXOS model did account for federal incentives, as appropriate. The Company also shared that it was actively pursuing EIR programs, financing it can qualify for, and applying for grants and that it will communicate the details of IRA financing and other incentives as they become known. Finally, the Company stated that a variant study can be reported once the IRA financing details are better known.

[72] ORS 469A.420(2).

Staff appreciates all of the work done by PacifiCorp, stakeholders, and especially Sierra Club, to highlight the enormous cost-saving opportunities available through the federal government's IRA initiatives. However, this funding is limited to $2 Billion, expires in September 2026, and utilizes a first-come, first-served competitive application process. In short, time is of the essence if PacifiCorp wants to secure low-cost financing for planned investments to replace aging infrastructure.

Staff Expectations:

- The IRP Update includes two variant portfolios that directly reflect Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments

In this section, Staff will not revisit all topics raised in our Round 1 comments on the IRP aspects of LC 82. Rather we have sought to prioritize those items which have the greatest bearing on acknowledgement/non-acknowledgement or are most critical for improvement in the next IRP/CEP.

Preferred Portfolio Modeling Process

Staff, RNW, and Sierra Club included an extensive number of comments on portfolio modeling for both improved development and selection. Most notable were the comments on the granularity adjustment, reliability adjustment, the inclusion of CEP resource additions (i.e., Oregon SSRs and higher levels of EE in Oregon), and the re-optimization of variant portfolios.

In developing the second round of comments, Staff's team explored the extent to which the processes around the granularity adjustment, the reliability adjustment, and portfolio reoptimization may have led to suboptimal portfolio development and selection.

Granularity Adjustment

In Round 1 comments, Sierra Club raised potential issues with PacifiCorp's application of granularity adjustments in their capacity expansion runs. PacifiCorp did not address Sierra Club's methodological questions about why the granularity adjustments did not seem to make sense and instead stated that there are "no logical alternatives" to the granularity adjustments, because they were "dictated by model math."[73] The Company's responses to earlier discovery from Sierra Club were similarly unclear.[74]

Staff engaged Synapse to further investigate the development and application of granularity adjustments. Synapse examined the workpaper that the Company used to develop the granularity adjustments,[75] and it identifies a potential errors and omissions in the calculations. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]. [BEGIN HIGHLY CONFDENTIAL]** [redacted]

[redacted] **[END HIGHLY CONFDENTIAL]**. Thus the Company may be adding erroneous adjustment factors to its capacity expansion modeling, which should be corrected. While the mistake does not appear to systematically favor **[BEGIN CONFIDENTIAL]** [redacted]

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[73] LC 82, PacifiCorp Round 1 Reply Comments, page 39.

[74] Sierra Club Round 1 Comments, page 41.

[75] [redacted]

[redacted] **[END CONFIDENTIAL].**

[BEGIN HIGHLY CONFDENTIAL] [redacted] **[END HIGHLY CONFDENTIAL]. [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[76] The inclusion of this adjustment introduces further subjectivity into the LT modeling and highlights the broader shortcomings of PacifiCorp's modeling approach.

[BEGIN HIGHLY CONFDENTIAL]

[redacted]

[redacted]

[redacted]

[END HIGHLY CONFDENTIAL]

The impact of the granularity adjustments, even with the limit of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, significantly changes the resource fixed prices. Figure 6 shows the capacity-weighted average fixed cost and granularity adjustments for each category of units. The granularity adjustments reduce fixed prices enough that they could have affected capacity expansion decisions in the model.

Ideally, PacifiCorp should improve the temporal granularity of LT modeling in future IRP proceedings so that granularity adjustments are no longer necessary. If this is not possible, the Company should at minimum revisit its methodology and correct its workpapers if necessary. It should also clearly explain

[76] PacifiCorp response to OPUC DR No. 240.

its methodology for this adjustment, including clarifying whether it uses the same set of granularity adjustments in each LT model run or whether it adjusts them iteratively. Importantly, PacifiCorp should be able to justify why its results, both with and without the price cap, are reasonable.

[BEGIN HIGHLY CONFDENTIAL]

[redacted]

[END HIGHLY CONFDENTIAL]

Reliability Adjustment

In Round 1 Comments, Sierra Club also raised concerns with the magnitude and potential subjectivity of the reliability adjustments that PacifiCorp made to optimized portfolios to meet reliability-based constraints. Sierra Club confirmed through discovery that PacifiCorp chooses which reliability adjustments to make based on the duration and timing of the shortage, the maximum size of the shortage in megawatts, and the location of the shortage.[77] However, the details of the Company's process are not transparent, including which resources it considers eligible for reliability adjustments and how it values eligible resources. As with the granularity adjustments, the Company stated in its Reply Comments that the reliability adjustments were "dictated by model math."[78] This explanation is even less satisfactory for the reliability adjustments than the granularity adjustments; while it is true that the model determines which hours have unserved energy, the decision about which manual adjustment to make in order to address this problem is at least partially subjective (as illustrated by the alternative portfolio of adjustments that Sierra Club developed for one of the variants in its Round 1 Comments).

[77] PacifiCorp response to Sierra Club DR No. 27.
[78] LC 82, PacifiCorp Reply Comments, page 39.

Staff engaged Synapse to further investigate the Company's reliability adjustments. Synapse confirmed Sierra Club's findings and similarly expressed concern regarding the magnitude of and lack of transparency in PacifiCorp's reliability adjustments.

Table 3 and Table 4 below quantify the reliability adjustments that PacifiCorp made in its preferred portfolio. The reliability adjustments more than triple the capacity of non-emitting peakers added during the study period, increase the amount of new batteries by 70 percent, and increase the amount of new solar by 26 percent. PacifiCorp shifted wind builds earlier, increasing the amount of new capacity by 129 percent between 2023 and 2030, but slightly decreasing the amount added over the entire study period.

In discovery, PacifiCorp stated that only non-emitting resources are eligible for reliability adjustments.[79] However, this is not quite accurate. The Company also manually adjusted the conversion and retirement dates for a number of its thermal resources. In the preferred portfolio, these adjustments took place in two stages. PacifiCorp started with a "Base" scenario, and then it hard-coded coal retirement dates and re-ran PLEXOS to produce a "Base Limited" scenario,[80] which it identified as the "initial" run used to create the preferred portfolio.[81] It then added further adjustments to produce the "reliable" portfolio. Table 3 cTable1ompares coal retirement and conversion dates across these three model runs. The large number of changes further underscores the extent to which PacifiCorp produced the preferred portfolio through manual adjustments, rather than configuring PLEXOS in a way that would allow it to optimize builds and retirements.

Table 3: Reliability Adjustments in Preferred Portfolio 2023-2030

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	375	1,770	1,394	371%
Coal – SNCR	(1,380)	-	1,380	-100%
Gas – EOL	247	247	-	0%
Nuclear	500	500	-	0%
Non-emitting peaker	-	606	606	Inf.
Battery	4,359	7,560	3,201	73%
Battery – LDES	482	-	(482)	-100%
Wind	1,934	4,431	2,497	129%
Solar	6,063	6,583	520	9%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

[79] PacifiCorp response to OPUC DR No. 233.
[80] PacifiCorp response to Sierra Club DR No. 40.
[81] PacifiCorp response to Sierra Club DR No. 25.

Table 4: Reliability Adjustments in Preferred Portfolio 2023-2042

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	(349)	0	349	-100%
Coal – SNCR	(2,335)	(2,335)	(0)	0%
Gas – EOL	(652)	(595)	57	-9%
Nuclear	1,500	1,500	-	0%
Non-emitting peaker	289	1,240	951	329%
Battery	4,643	7,910	3,267	70%
Battery – LDES	-	350	350	Inf.
Wind	9,251	9,113	(138)	-1%
Solar	6,246	7,855	1,609	26%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

Table1 5: Manual Changes to Coal Retirement and Conversion Dates in the IRP Preferred Portfolio

	Base	Base Limited	Reliable
Craig 1	Retires 2026		
Craig 2	Retires 2029		
Dave Johnston 1 and 2	Retires 2029		
Dave Johnston 3	Retires 2028		
Dave Johston 4	Gas conversion, retires 2040	Retires 2040	
Hayden 1	Retires 2029		
Hayden 2	Retires 2028		
Jim Bridger 1	Converts 2024, retires 2031	Converts 2024, retires 2031	Converts 2024, retires 2038
Jim Bridger 2	Converts 2024, retires 2030	Converts 2024, retires 2030	Converts 2024, retires 2038
Jim Bridger 3	Retires 2026	Unclear from workpaper	Converts 2030, retires 2038
Jim Bridger 4	Retires 2032	Unclear from workpaper	Converts 2030, retires 2038
Hunter 1	Retires 2031	SNCR, retires 2031	SNCR, retires 2032
Hunter 2	Retires 2031	SNCR, retires 2032	SNCR, retires 2033
Hunter 3	Retires 2030	SNCR, retires 2030	SNCR, retires 2033
Huntington 1	Retires 2030	SNCR, retires 2030	SNCR, retires 2033
Huntington 2	Retires 2026	SNCR, retires 2028	SNCR, retires 2033
Naughton 1	Converts 2026, retires 2032-2033	Converts 2026, retires 2032	Converts 2026, retires 2037
Naughton 2	Converts 2026, retires 2037		
Wyodak	Converts 2027, retires 2040	SNCR, retires 2040	

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx," "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xls," "(P)-LT-6530-23I.LT.Initial Run.20.PA0-.EP.MM.Base.xlsx," and Sierra Club Round 1 Comments at page 19.

Staff shares Sierra Club's concerns about both transparency surrounding PacifiCorp's process for making reliability adjustments and the magnitude of the adjustments. The reliability adjustments substantially change the resources in the preferred portfolio, calling into doubt the extent to which PacifiCorp's capacity expansion is economically optimized.

Portfolio Reoptimization

Sierra Club's Round 1 comments also raised concerns regarding the inconsistency of PacifiCorp's practice of re-optimizing portfolio variants. Because re-optimization generally finds the lowest cost way to meet a portfolio's constraints, failure to re-optimize a portfolio could lead to an over-estimation of the costs associated with the specific resource variation being examined by that portfolio. This may lead some portfolio variants to appear artificially more expensive than others. In response to this concern, PacifiCorp noted that they have limited time to conduct re-optimization and must prioritize. Additionally, the variant portfolios identified by Sierra Club for re-optimization were generally meant to test through a counterfactual portfolio, a choice within or not included in the Preferred Portfolio (i.e., P-17's exploration of Colstrip's early retirement).

PacifiCorp's decision to not-reoptimize the PLEXOS LT model for variants P13, P18, and P19 causes the resulting portfolios to retain excess capacity that ratepayers do not necessarily need for a reliable system. For example, the resource builds, conversions, and retirements are identical between the Preferred Portfolio and P13– Max DSM, despite this variant installing an additional ~4,000 MW of DSM capacity over the time frame.

Regardless of the ostensible "purpose" of a variant portfolio, this approach fails to allow Staff and stakeholders to properly compare the preferred portfolio to other variants due to the overbuilt nature of the selected variants. As stated above, P18 results in PacifiCorp having an additional 2,000 MW of capacity starting in 2029, and P19 results in additional 500 MW of capacity starting in 2028. Even though PLEXOS ST captures any cost savings associated with dispatch, it is important for PLEXOS LT to be re-optimized as well to give the opportunity for additional cluster resource and DSM capacity to displace other new resource builds and/or identify earlier retirement dates for existing plants. Without re-optimizing PLEXOS LT, stakeholders are unable to easily tease out which resources would be displaced and how that would impact GHG and PVRR outcomes.

In discovery, PacifiCorp stated that three of the variant studies (P13, P18, and P19) were conducted with the understanding that additional resources would likely result in higher cost PVRR outcomes, and that the purpose of these variants is to assess the magnitude of the impact for determining possible least-regret paths to consider for the preferred portfolio.[82] While the results as presented in this IRP may still be of interest to the Company, PacifiCorp should not be doing this in lieu of re-optimization.

For example, the Max DSM variant as modeled is not currently providing much value for comparison to the preferred portfolio due to the magnitude of the incremental installed capacity that has been required (~4,000 MW) and the magnitude of the PVRR delta ($3 billion). The benefits of pursuing

[82] PacifiCorp response to Sierra Club DR No. 43.

ambitious energy efficiency and demand response are to reduce system load, peak demand, and firm capacity reserve requirement, thus avoiding investments in generation and capacity resources and transmission and distribution infrastructure. By not allowing re-optimization of this portfolio, PacifiCorp fails to allow for a significant portion of DSM benefits to be realized in the PVRR result. This variant design also fails to account for the potential of DSM to reduce the SSR and CBRE requirements, further reducing portfolio costs.

In future studies, PacifiCorp should re-optimize all future variant portfolios that add incremental capacity to the preferred portfolio. This will allow the Commission and stakeholders to assess all variant portfolios on an equal playing field. If a variant does not result in the addition or subtraction capacity from the portfolio and can be fully evaluated using PLEXOS ST only, re-optimization may not be necessary. If there is a scenario where PacifiCorp would legitimately be expected to maintain a system with more resources than needed to cost-effectively meet customer needs (e.g. P21), or if there is a legitimate reason the Company could not change its resource plans in time (e.g. P17), then studies without re-optimization could be used. If the Company is still interested in assessing the magnitude of incremental costs from hard-coded resources without re-optimization, this should be done outside of the variant case analysis.

Table 6 below summarizes PacifiCorp's variant portfolios and how they were modeled.

Table 6: Variant Portfolios

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P01-JB3-4 GC	Yes		
P02-JB3-4 EOL	Yes		
P03-Hunter3-SCR	Yes		
P04-Huntington RET28	Yes		
P05-No NUC	Yes		
P06-No Forward Tech	Used P05		
P07-D3-D2 32	Yes		
P08-No D3-D2	Yes		
P09-No WY OTR	No	Used to evaluate the impact on P-MM if Wyoming's OTR was not enforced.	
P10-Offshore Wind	Yes		
P11-Max NG	Yes		
P12-RET Coal 30/33 NG 40	Yes		
P13-Max DSM	No	Used to evaluate the impact on P-MM if all DSM was selected.	Re-optimize capacity mix.
P14-All GW	Yes		
P15-No GWS	Yes		

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P16-No B2H	Yes		
P17-Col3-4 RET25	**No**	Used to evaluate if earlier retirement of Colstrip 4 would result in energy or capacity shortfalls.	
P18-Cluster East	**No**	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P19-Cluster West	**No**	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P20-JB3-4 CCUS	Used P02		
P21-DJ2 CCUS	**No**	Used to evaluate the impact of installing CCUS at DJ2.	
P22-DJ4 CCUS	**No**	Used to evaluate the impact of installing CCUS at DJ2.	
P23-RET Coal 30/33	Used P12		
P24-Gas 40-year Life	**Yes**		

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Staff Expectations:
Before the next IRP, PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP, PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

Coal Strategy

In its Round 1 Comments, Sierra Club raised concerns about the coal prices that PacifiCorp used in its modeling, which may have erroneously delayed the economic retirement date for Jim Bridger 3 and 4.[83] These units, which are co-owned by PacifiCorp (67 percent) and Idaho Power Company (33 percent) **[BEGIN HIGHLY** [redacted] **[END HIGHLY CONFIDENTIAL]. [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[86]

Fuel costs influence unit economics, so it is important for PacifiCorp to represent them correctly within PLEXOS so that the model is able to determine economic retirement and/or conversion dates. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]

Sources: [redacted] **[END HIGHLY CONFIDENTIAL].**
[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL].**

PacifiCorp's Round 1 Response Comments suggested that the Company accounted for the full cost of coal in the IRP, but represented some of the costs as fixed, rather than modeling all coal costs as variable.[88] **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**

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83 Sierra Club Round 1 Comments, page 44.
84 [redacted]
85 [redacted]
86 [redacted]
87 [redacted]
88 LC 82, PacifiCorp Reply Comments, page 82*:* "PacifiCorp did incorporate significant fixed costs for coal supply to Jim Bridger units 3 & 4."

However, PacifiCorp added the fixed costs for coal supply at Jim Bridger in post-processing rather than modeling them within PLEXOS.[89] As a result, PLEXOS sees only the variable portion of the coal cost (blue line in [redacted] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Unrealistic coal prices within PLEXOS may make Jim Bridger 3 and 4 appear more economic than they are in actuality, which could result in PLEXOS selecting a delayed economic retirement date. In the future, PacifiCorp should correct its PLEXOS modeling so that the full cost of coal at Jim Bridger is represented within the model.

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[END HIGHLY CONFIDENTIAL]

Sources: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**
[BEGIN HIGHLY CONFIDENTIAL] [redacted] **[END HIGHLY CONFIDENTIAL].**

Hunter and Huntington

Two of PacifiCorp's coal plants, Hunter and Huntington, are located in Utah and have experienced the impact of disruptions to the Utah coal market for reasons such as the Lila Canyon mine fire and unfavorable coal mining conditions. While it can be hard to fully predict future disruptions to coal markets and resulting impact on fuel prices, it is important to incorporate as much up-to-date information as possible in order to ensure model results are reasonably similar to reality. Synapse, on behalf of Staff, reviewed federal Department of Energy EIA 923 fuel receipts data for 2023 and determined that PacifiCorp paid between $1.79 and $4.19 per MMBTU for coal at Hunter. At Huntington, Synapse determined that PacifiCorp paid between $2.18 and $2.54/MMBTU.

[89] PacifiCorp response to Staff DR No. 228.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL].

On April 3, 2023, PacifiCorp filed its Transition Adjustment Mechanism in Docket No. UE 420 to update its net power costs for 2024. In Witness Owen's testimony, he states that "the significant production shortfall due to the Lila Canyon mine fire negatively affected all large coal consumers including PacifiCorp. Unfortunately, this negative impact is expected to continue into the foreseeable future."[92] If this is PacifiCorp's current position, then the 2023 IRP Update should incorporate the lasting impacts of unfavorable market conditions into its coal price forecast for these Utah plants.

[90] Confidential Attachment OPUC 229, "HTR-HTG Coal Update_2022 12 21 CONF".

[91] US Bureau of Land Management. 2022. *The Bureau of Land Management issues decision on Lila Canyon Mine.* Available at: https://www.blm.gov/press-release/bureau-land-management-issues-decision-lila-canyon-mine.

[92] *In the Matter of PacifiCorp's 2024 Transition Adjustment Mechanism*, Docket UE 420, Exhibit PacifiCorp/200, Owen/4.

Staff Expectation:
In the next IRP PacifiCorp should:

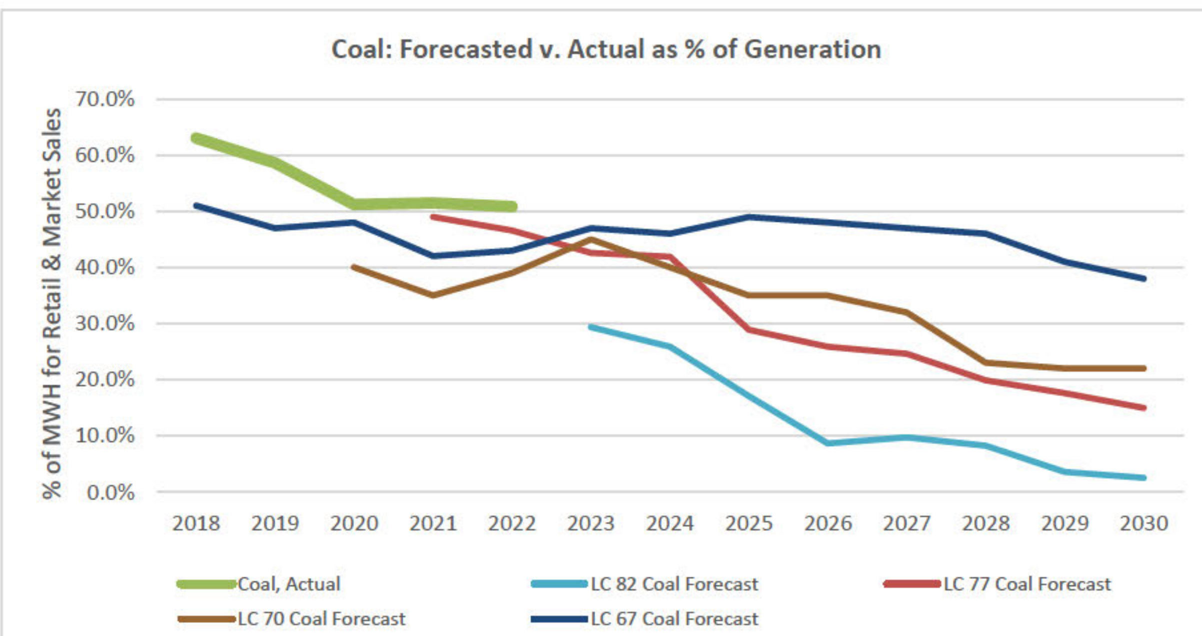
- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

At the LC 82 Special Public Meeting on December 12, 2023, Bob Jenks of CUB raised an interesting point regarding PacifiCorp's use of carbon pricing. He noted that PacifiCorp's IRPs generally begin to apply a price to carbon two years after the IRP. This has the effect of reducing forecasted emissions in the IRP, especially from coal plants, as PacifiCorp's models internalized this carbon price into simulated, future operations. CUB suggested that because a true carbon price has never actually internalized into operations, real-life emissions are systematically higher than IRP modeled GHG emissions. CUB also noted in its Round 1 comments that an effective GHG price could be developed by forecasting, "...the annual cost of carbon from wildfires (prevention and insurance), divide that by its carbon emissions, and allocate the costs of emissions directly to the emissions themselves." [93]

Staff conducted a brief analysis forecasted to actuals in an attempt to substantiate CUB's comments regarding the disconnect between planning that uses a carbon price and actual coal operations.

Figure 8: 3Comparison of Forecasted v. Actual Coal Use as Percent of Generation



Staff's simple analysis would seem to corroborate CUB's concerns regarding the realism of PacifiCorp's modeled coal dispatch in the IRP. Staff raised a similar concern in UM 2225 in discussing the role of

[93] CUB Round 1 Comments, October 25, 2023, page 8.

operational changes in achieving GHG reductions and the Commission adopted the following expectation:

> *For the first CEP and associated IRP, if the Preferred Portfolio relies on operational changes relative to expected economic dispatch to reduce GHG emissions, including, but not limited to, application of operating or emissions constraints, inclusion of a GHG emissions cost in dispatch decisions, or out-of-state sales of fossil fuel generation, the utility should:*
>
> - *Quantify the impacts of those operational changes relative to expected economic dispatch in terms of generation (curtailed, reduced, or sold) and GHG emissions (avoided); and*
> - *Describe how the utility intends to implement those operational changes (e.g. through the development of operating or emissions limits, application of GHG emissions penalties, or execution of contracts with out-of-state entities), to the extent that they impact forecasted GHG emissions in the Action Plan window.* [94]

Accordingly, if the GHG emissions reductions in the CEP depend on the reduction in coal generation that results from applying carbon prices to dispatch, Staff would expect PacifiCorp to quantify those impacts in terms of both generation and GHG emissions, relative to an assumption of economic dispatch without carbon prices.

Importantly, PacifiCorp removes all coal from Oregon rates prior to 2030 per SB 1547 and so Staff expects this issue may only affect the Oregon-allocated GHG emissions in the 2020s. Nevertheless, PacifiCorp's use of GHG prices in modeling operations could be resulting in an unrealistic trajectory of GHG emissions reductions and the lack of an operationalized carbon price could therefore affect PacifiCorp's ability to demonstrate continual progress in the 2020s.

Staff fully supports PacifiCorp's use of GHG prices in portfolio design to capture the risk of future GHG policies. However, Staff is concerned that including GHG prices in the dispatch simulation that informs the Company's Oregon-allocated GHG emissions could be resulting in an unrealistic GHG reduction trajectory.

Staff Expectation:
In the next IRP/CEP PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

[94] Order No. 22-446, Appendix A at page 21.

Candidate Resource Costs

In Round 1 comments, stakeholders raised concerns that PacifiCorp incorporated unreasonable price escalations for renewable resources. RNW's Round 1 Comments raised concerns on the cost assumptions PacifiCorp applied to its clean energy and energy efficient technologies, which include solar, wind (land-based and offshore), and storage resources.[95]

PacifiCorp sourced its cost data from WSP, an engineering and professional services firm, and later made some adjustments to the cost data to align with its view of future renewable resources market conditions.[96] WSP had relied primarily on the 2022 NREL ATB study to formulate renewable cost forecasts. The IRP states that PacifiCorp's cost-escalation curve differs from the NREL ATB forecast to account for observed market conditions, such as supply chain issues and long construction lead times.[97] RNW found that the company's ambiguous modifications to WSP's renewable resource cost estimates results in cost escalations that are 15-50 percent higher through the years 2023-2030.[98] PacifiCorp's sources or methodology behind large price escalations remain unclear. PacifiCorp has not clearly explained its resource cost modifications besides the "recent tighter trade tariff and inflation" observed in 2022.[99]

Staff agrees with RNW that the long duration of these high prices assumptions are concerning and not well proven. Manual adjustment of cost assumptions most likely affects resource selection and the preferred portfolio's economics.[100, 101] Due to the high capital cost forecast for renewable resources in PacifiCorp's IRP, the model selects over a GW of nuclear and non-emitting peaking resources through the years of cost escalations.[102]

While it is reasonable to assume cost escalations due to recent market conditions, PacifiCorp's estimates are far above the consensus. Compared to other studies that have adjusted for the recent market changes in renewable energy, PacifiCorp's adjustments have overstated the effects of inflation. Recently published studies have shown that cost increases may not be as persistent as PacifiCorp assumes. Lazard's most recent Levelized Cost of Energy Analysis from 2023 provides recent capital cost comparisons for renewable energy technologies based on a detailed analysis of observed new renewable builds across best-in-class renewables companies. This source provides a thoroughly vetted set of actual costs from newly installed projects.[103] Lazard's report states that "Even in the face of inflation and supply chain challenges, the LCOE of best-in-class onshore wind and utility-scale solar has declined at the low-end of our cost range, the reasons for which could catalyze ongoing consolidation across the sector—although the average LCOE has increased for the first time in the history of our studies."[104]

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95 Renewable Northwest, Round 1 Comments, page 31.

96 *Ibid.*

97 *Ibid.*

98 Renewable Northwest, Round 1 Comments, page 31.

99 LC 82, PacifiCorp Reply Comments, page 47.

100 Renewable Northwest, Round 1 Comments, page 32.

101 *Id,* page 32.

102 *Id,* page 32.

103 https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

104 Lazard. Levelized Cost of Energy Analysis-version 16.0. April 2023. Available at: https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

Regulators in other states are also assessing the reasonableness of using NREL ATB studies for the purposes of resource planning.[105] One South Carolina study found that relying on NREL ATB was reasonable and anticipates, "…a gradual decline in real-dollar costs due to industry learning curves and economies of scale, especially as renewable adoption accelerates. Therefore, we encourage Santee Cooper to remain open to upward adjustments in future procurement targets to capitalize on these anticipated cost reductions."[106] Staff finds this sentiment to be similarly relevant to PacifiCorp's resource cost methodology and would also encourage the Company to reassess overly conservative costs and monitor the market for anticipated cost reductions.

For example, PacifiCorp estimates a 34 percent increase in the cost for solar starting in 2023 and persisting for five years after, until cost declines in 2029. This results in a projected cost of $1,533/kW for a 200MW PV installation in Utah for 2023 through 2028.[107]

PacifiCorp's capital cost forecast for land-based and offshore wind is also unsupported by the 2023 NREL ATB and Lazard. For 2023 through 2028, PacifiCorp assumes roughly $2,000/kW for land-based wind and $5,900/kW for offshore wind. According to Lazard's 2023 Levelized Cost of Energy Analysis, capital costs for land-based and offshore wind reaches a high of $1,700/kW and $5,000/kW, respectively. [108]

Finally, PacifiCorp's resource storage assumptions are also significantly higher than NREL's projections. PacifiCorp's battery storage capital costs estimates are $454 and $477/kWh in 2022 and 2023 respectively, with no projected cost declines until 2029.[109] NREL 2023 study estimates capital cost of approximately $470/kW but assumes step cost decline afterwards with capital cost reaching a low $320/kW in 2032.

Staff, through its consultant, Synapse, conducted a high-level analysis to estimate the difference in the Preferred Portfolio's build costs if the utility had instead relied on NREL's 2023 ATB. This analysis relies on the current levels of near-term renewable builds presented in the 2023 IRP Preferred Portfolio and does not attempt to re-optimize the renewable builds based on these lower costs. This analysis reflects the situation where PacifiCorp conducts resource planning using elevated prices, and is able to procure renewable resources for lower cost in actuality.

Additionally, we highlight here that if PacifiCorp had incorporated supply-side costs for renewables that were more in line with PGE, CPUC, and NREL ATB, it is likely that PLEXOS LT would select more of these resources ***instead of*** higher-cost alternatives, such as nuclear, non-emitting peakers, and fossil units. It is important to note that the build costs shown in the PLEXOS LT outputs are shown pre-tax credits and without annualization, rate of return, or depreciation. This means that the final impact on the Preferred Portfolio revenue requirement will be different than the total cost delta presented below.

105 See South Carolina Public Service Commission, Report by PA Consulting *Independent Review of Santee Cooper's 2023 Integrated Resource Plan*. December 2023.
106 *Ibid.*
107 PacifiCorp file "(P)-Figure 7.3-7.5 History of IRP Renewables Cost Curves 2023 0119.xlsx".
108 https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.
109 Renewable Northwest, Round 1 Comments, page 38.

Table 9: Renewable Build Costs Summary Results

Category	Resource Type	NPV (2023-2030) ($M)	2023	2024	2025	2026	2027	2028	2029	2030
Capacity (MW)	Solar	n/a	-	-	1,069	2,524	483	1,907	-	-
2023 IRP Build Costs ($)	Solar	$7,037	-	-	$1,687	$4,020	$790	$2,946	-	-
ATB Build Costs ($M)	Solar	$6,034	-	-	$1,474	$3,440	$650	$2,530	-	-
Delta ($M)	Solar	$1,003	-	-	$213	$580	$140	$416	-	-
Capacity (MW)	Wind	n/a	-	43	296	-	100	300	1,900	-
2023 IRP Build Costs ($M)	Wind	$3,317	-	$85	$644	-	$212	$613	$3,394	-
ATB Build Costs ($M)	Wind	$2,427	-	$59	$405	-	$138	$414	$2,631	-
Delta ($M)	Wind	$890	-	$26	$240	-	$75	$199	$763	-
Capacity (MW)	BESS	n/a	-	-	754	2,929	628	1,900	1,149	-
2023 IRP Build Costs ($M)	BESS	$9,594	-	-	$1,364	$5,300	$1,136	$3,416	$2,009	-
ATB Build Costs ($M)	BESS	$8,590	-	-	$1,240	$4,767	$1,010	$3,018	$1,800	-
Delta ($M)	BESS	$1,004	-	-	$124	$533	$126	$398	$209	-
Total Delta ($M)	All	**$2,897**								

Staff Expectation:

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources

In Opening Comments, Staff raised concerns about the permitting timeline and fuel availability of nuclear resources in the Company's preferred portfolio.[110] Staff concerns about reactor fueling risks and permitting were shared in comments from the Sierra Club,[111] NewSun,[112] and Renewable Northwest.[113] As an example RNW documented the lengthy six-year timeline to final approval by the NRC of the only other small modular reactor (SMR) design to date, developed by TerraPower competitor NuScale Power Company.[114] RNW follows this discussion with a request for the Company to identify offramps that would provide adequate lead time for replacement of the Natrium facility with clean energy resources with comparable attributes, a request that Staff finds to be reasonable.

[110] LC 82 – Staff's Round 1 Comments, page 44.
[111] LC 82 – Sierra Club's Round 1 Comments, page 58.
[112] LC 82 – NewSun Energy's Round 1 Comments, page 5.
[113] LC 82 – Renewable Northwest's Round 1 Comments, page 21-22.
[114] Id.

In PacifiCorp's December reply comments, the Company stated that its consideration of nuclear resources in the 2023 IRP are consistent with Oregon IRP Guidelines 1(a), 1(b), and 1(c), and therefore those resources are limited to years outside of the action plan and CEP planning windows and require continued evaluation of their potential.[115] The Company further stated that it "cannot provide meaningful tracking and reporting" on the Natrium facility's NRC Construction Permit Application due to there being no commercial agreement with the facility's developer, TerraPower. The Company did provide that a construction permit (CP) is targeted for submission to the Nuclear Regulatory Commission (NRC) by Q1 2024, stating a generic timeframe for issuance of the CP by the NRC is 36 months.[116] Staff, assuming a similar 36-month timeline for issuance of the separate operating license (OL) for the Natrium facility from the NRC, contemplates substantial risk in selecting this resource in the preferred portfolio for inclusion in the year 2030. Staff finds comments from the Sierra Club, NewSun, and RNW regarding fueling cost and risk, permitting timeline risks, and the lack of adequate alternatives should permitting issues arise, to be compelling.

The Company's timelines for the availability of non-emitting peaking resources and nuclear resources have both been modelled for portfolio consideration in the year 2030 or beyond, intentionally outside of the action plan window and the current CEP compliance window.[117] As the Company states that it anticipates that non-emitting peaking resources will improve in performance and cost-effectiveness, Staff believes that the Company should also prepare for the possibility that both non-emitting peaking resources and nuclear resources may potentially fail to materially improve in those regards before the year 2030.[118]

In short, Staff finds that the overly optimistic timeline for both the Natrium nuclear technology and any potential non-emitting peaking technology - given both what is known and unknown - requires planning more reflective of implementation risks. Staff is not opposed to either technology per se and believes they may both be necessary to achieve HB 2021's 2040 target and for the broader region to decarbonize. However, we agree with RNW's observation that the 2021 IRP selection of Natrium in 2028, which was due in part to overly optimistic assumptions, impacted both the action plan and the scope of the subsequent RFP (UM 2193).[119] Staff finds that PacifiCorp appears to be repeating the same process in LC 82 with these long lead time resources. An additional implication of this approach in LC 82 is that it puts Oregon's decarbonization efforts at risk.

Per a December filing, NRC has scheduled a readiness assessment meeting for the TerraPower permit application on January 10, 2024.[120] The process to conduct the assessment will take four weeks and 45 calendar days, following which NRC staff will issue a public report on their findings. The approximate date for the publication of this report will be approximately around March 20, 2024. At the point of the NRC report's publication, the Company should have a clear understanding if the Natrium project is on track to begin construction under the very tight timelines found in LC 82.

In variant portfolio P06 – No Forward Tech, PacifiCorp explored the risk of neither the nuclear facility ***nor*** the non-emitting peaker being operational by the end of 2030. This portfolio showed no impact to

[115] LC 82 – PacifiCorp Reply Comments, page 94-95.
[116] PacifiCorp response to Staff DR No. 118.
[117] LC 82 – PacifiCorp Round Reply Comments, page 93-95.
[118] LC 82, PacifiCorp Reply Comments, page 93.
[119] Renewable Northwest, Opening Comments, page 20.
[120] *See Filing in NRC Docket 99902087, "Preapplication Construction Permit Readiness Assessment Plan," December 20, 2023.*

the timing of the planned retirements of approximately 2.5 GW of coal generation capacity between 2028 and 2032. Instead this variant portfolio showed more some additional solar and wind but most notably an additional 1.2 GW of batteries by 2033. This portfolio had some of the highest emissions compared to all other portfolios.[121]

As RNW notes, the Company's plan to replace SMRs should they not be viable is to largely replace them with non-emitting peakers.[122] The Company states that non-emitting peakers' limited presence in the 2023 IRP preferred portfolio supports the Company's position that the risks associated with these resources are reasonable.[123] Given the potential for neither to emerge and both the higher cost and higher emissions associated with this outcome – as evidenced by P-06 – the Preferred Portfolio's reliance on emergent nuclear and non-emitting peaking resources may prove to be an outsized risk.

Staff would note that in LC 80 the procurement of long lead time (LLT) resources posed a similar set of risks and procurement challenges for PGE. Given the uncertainty around timelines for both nuclear and non-emitting peaking resources, Staff believes that the Company should issue a request for information (RFI) for LLT resources. The RFI should be used to inform placement of LLT emergent resources in a preferred portfolio more realistically by accurately comparing them against more traditional, matured, resources. To gain a more accurate view of the entire resource landscape, the Company's RFI could also study advanced geothermal, pumped hydro storage, transmission costs associated with offshore wind, and any other resources identified by the Company or stakeholders. The Company might even coordinate with PGE in developing this RFI for a streamlined approach.

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Staff Expectations:

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Small Scale Renewables

In Opening Comments, Staff expressed an interest in exploring options to facilitate the development and acquisition of small scale renewables (SSRs) in a cost-effective manner, highlighting the RPS certification process in particular.[124]

[121] LC 82, PacifiCorp 2023 IRP, page 268, Table 9.14.
[122] Renewable Northwest, Opening Comments, page 22.
[123] LC 82, PacifiCorp Reply Comments, page 93.
[124] LC 82 – Staff's Opening Comments, page 46.

Staff greatly appreciates the Company's efforts to offer regulatory recommendations toward easing the acquisition of SSRs in its reply comments. Regarding the Company's recommendation that the OPUC amend or waive OAR 860-091-0030(1), Staff finds that this may be an unnecessary solution to a barrier that remains, in Staff's view, to be largely informational. The Company specifically cites an additional ODOE regulation, OAR 330-160-0035(2), that "may require…an explanation of the relationship between the applicant and the WREGIS account holder."[125] Staff does not understand how this requirement, nor RPS certification as a whole, are meaningful barriers to potential SSR project financing.

Staff agrees with the Company's recommendation that incentives might be refined or updated to better reflect system SSR needs through updated PURPA policies in the OPUC's UM 2000 proceeding.[126] Should these policies be updated to better reflect SSR acquisition costs, Staff would urge the Company to utilize PURPA policies to the greatest extent possible to streamline its SSR acquisition process, and additionally facilitate modelling of SSR acquisition in portfolio modelling as the SSR mandate will remain an ongoing compliance obligation. The ability to model SSR acquisition costs reliably and accurately will facilitate the modelling of marginal SSR needs and associated costs when system capacity acquisitions are made.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

In Opening Comments, Staff found that the Company's current resource adequacy and capacity valuation approaches are lacking necessary sophistication and should be updated with both more data and methodologies that better conform to best practices. Staff recommended that the Company incorporate WRAP into its next IRP, update its resource capacity contribution methodology, add more weather data, and perform a Loss of Load Expectation (LOLE) analysis on the preferred portfolio.[2]

RNW has a host of recommendations for the Company to modernize its reliability and resource adequacy modeling that are largely in line with Staff's opening comments. Among them, RNW recommends that the Company move beyond its current capacity factor method to something an Effective Load Carrying Capability (ELCC) method or something similar, such as the "Global Slicing Block" that is available in PLEXOS.[3] RNW also believes that the Company's 13 percent Planning Reserve Margin is unfounded.[4] Of greater concern to them, RNW finds that the Company's deterministic look at Loss-of-load-probability (LOLP) modeling is lacking and recommends that the Company incorporate stochastic parameters for weather risk factors that correlate with supply and demand.[5] Given that the Western Resource Adequacy Program (WRAP) may become binding as early as 2026, RNW also advocates that the integrate WRAP into the IRP process.[6]

The Company responded to comments made by both Staff and RNW in its Round 1 Reply Comments. Staff recommended that the Company update its capacity valuation methodology to incorporate multiple years of weather data, calculate and report the LOLE of the preferred portfolio in each year and explain why the Company chose to plan to its current level of reliability.
PacifiCorp agrees with Staff and RNW that incorporating stochastic conditions is a necessary part of identifying supply and demand risks and notes that neither wind nor solar nor energy efficiency savings were modeled stochastically in the 2023 IRP. The Company also agrees that the value of stochastic analysis is higher when multiple years of data are used but also notes that incorporating this is a significant undertaking. The Company states that it looks forward to further improvements to the LOLP and that it is always open to improvements in its RA modeling.[7] In response to Staff's and RNW's

[125] LC 82 – PacifiCorp Reply Comments, page 85.
[126] Id, page 86.

comments on WRAP, the Company states that it is actively evaluating the WRAP program and considering how to implement it in the IRP as early as 2026.[8] The Company did not appear to directly respond to RNW's recommendation to conduct an ELCC style analysis.

Staff recognizes that updating LOLP, capacity valuation, and RA modeling is a large undertaking that may take many months. While Staff continues to advocate for the use of more years of weather, load and generation data, Staff is supportive of these things being included in the Company's next IRP. Staff also agrees with RNW's comments advocating for stochastic modeling of supply and demand variable in LOLP analysis and recommends that wind and solar resources be modeled stochastically using observed weather and load correlation. Staff also agrees with RNW that switching to an ELCC style analysis of capacity valuation is a necessary modeling improvement that should be integrated into the next IRP. Staff reiterates its past recommendation that the Company model and report the LOLE of the preferred portfolio in a future IRP.

Staff continues to recommend that PacifiCorp consider WRAP participation, including potential future obligations and benefits, in the next IRP. Staff notes that another Oregon-regulated utility, Idaho Power, has chosen to model the benefits of WRAP in its current IRP, LC 84, and assumes that WRAP's operational program would provide some system capacity benefit starting in 2027.[127] While Idaho Power presents this merely as a first attempt at modeling WRAP benefits, Staff feels it necessary to point out that one of the Company's Oregon peer utilities has already begun incorporating WRAP into its IRP.

Front Office Transactions

Staff is concerned by the Company's reliance on FOTs in its IRP.[128] PacifiCorp's IRP allows for a certain amount of market purchases to contribute to system capacity needs. These purchases are referred to as Front Office Transactions (FOTs) and they have limits as shown in Table 5.8 in the IRP and reproduced below as Table 10.

Table 10: Reproduction of Table 5.8 of IRP[129]

Market Hub	Availability Limit (MW)				
	2023 IRP			2021 IRP	
	Short-term (2023-2027)	Long-term (2028-2042) Summer	Long-term (2028-2042) Winter	Summer	Winter
Mid-Columbia (Mid-C)	1979	500	350	500	350
California Oregon Border (COB)	424	0	250	0	250
Nevada Oregon Border (NOB)	200	0	100	0	100
4 Corners (4C)	398	0	0	0	0
Mona	325	0	300	0	300
Total	**3326**	**500**	**1000**	**500**	**1000**

In the IRP, FOTs are modeled as short-term purchases that can be made with little or no notice. However, this may be an oversimplification. Staff also notes that in order to demonstrate compliance with WRAP, an entity has to secure resources and contracts with a lead time of multiple months,

[127] LC 84, Idaho Power IRP Initial Filing, page 8.
[128] LC 82, PacifiCorp 2023 IRP, page 33, Action item 5a.
[129] 2023 IRP at 126.

meaning that the Company's choice to rely on short-term purchases may lead to the Company being out of compliance with WRAP's forward showing requirements. Further, given the suspension of the Company's RFP, UM 2193,[130] Staff anticipates that the Company will need to rely further on FOTs to offset resources that may come on later than what was expected at the beginning of LC 82.

In other proceedings, the Company has noted that the volume of transaction in regional wholesale markets has been steadily declining in recent years.[131] The Company models a constant level of FOT availability at its main five market hubs through 2027, which is incongruous with its operational realities of the last few years. Staff worries that the failure to align its action plan assumptions with the operational realities it uses as evidence in its power cost dockets could lead to a situation in which it neither has resources available to meet its load nor a viable counterparty to buy energy in a peak load hour.

Renewable Northwest also expressed concern with PacifiCorp's assumptions regarding future reliance on regional markets. RNW notes that near-term reliance on market purchases for capacity in this IRP is high. In addition, RNW notes that the Load and Resource Balance table in the IRP includes market purchases well above the stated FOT limits in Table 5.8. RNW notes, "regional markets are likely to experience increasing uncertainty in both depth and availability due to environmental policies and regional market initiatives, which increases the importance of hedging against the continued risk of high market reliance in the future." RNW recommends that PacifiCorp work with other regional planning organizations such as the Western Power Pool (WPP) to develop "a detailed, quantitative analysis on the likelihood of regional markets to provide reliable power at non cost-prohibitive prices." Staff acknowledged that a regional study could provide value in long-term planning, but notes that there are currently multiple organizations that already look at resource adequacy to assess whether there is a surplus of energy available in the region. For example, WECC releases frequent studies of regional capacity availability. The 2023 WECC Western Assessment of Resource Adequacy (WARA) finds that total planned resources in the WECC are not adequate to prevent substantial "Demand at Risk" hours in 2026-2028.[132] Demand at risk hours are defined as the number of hours in a year that are at risk for loss of load exceeding the one-day-in-ten-year outage threshold. As Figure 9 below shows, in August 2028, the WARA finds on average about 500 MW of Demand at Risk over 25 hours.[133] We note, however, that shortage predictions five years out can often change, as both demand and supply side resources respond in advance to potential shortfalls with incremental development activity.

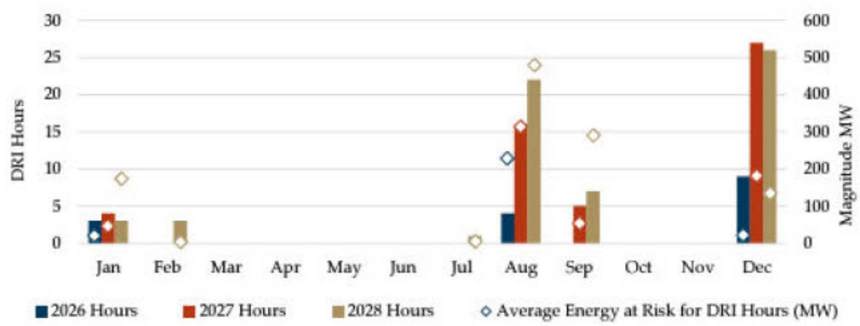
Figure 9: Mid-term DRI Hours and Magnitude for the Western Interconnection

[130] See the Company's September 29, 2023 filing in UM 2193.

[131] See UE 420, PAC/400, Mitchell/59 here.

[132] WECC. 2023 Western Assessment of Resource Adequacy, page 17.

[133] WECC. 2023 Western Assessment of Resource Adequacy, page 16.



The WARA finds that a significant increase in Demand at Risk hours in December can be attributed to increased load forecasts in the Northwest, while there are relatively few utility-scale resource additions planned in the Northwest. The WARA concludes that load serving entities may need to delay resource retirements if they cannot mitigate these risky hours in the next two years. However, we note that WARA may have less visibility into local small-scale supply and demand resource activity that could reduce the at-risk hours in those out years.

Notably, PacifiCorp's IRP relies on 944 MW of summer market purchases in 2027 and 493 MW in 2028.[134] Given WECC's showing of regional resource adequacy risk during August in those years (red bars in Figure 4 above), the expectation of nearly 1 GW of market energy being available for purchase during summer peak hours seems potentially risky. Further, PacifiCorp has suspended the 2022AS RFP that would have brought resources online from 2025 through 2027, further increasing the region's resource adequacy risk.

These findings are concerning and indicate that PacifiCorp should look seriously at reducing market reliance in the near term, whether through longer-term contracts or resource procurements. If PacifiCorp continues to plan its system around procuring capacity from the market that may not be available and is forced to delay fossil retirements as a result, the Company could be at risk for failing to meeting its HB 2021 Oregon emissions reductions targets and much higher power costs. To address this, PacifiCorp should consider actions to reducing near-term market reliance in the next IRP.

Staff also expects PacifiCorp to consider how WRAP participation might affect the Company's reliance on FOTs in the next IRP. The WRAP forward showing program will require PacifiCorp to secure enough resources to meet their obligations seven months in advance. Staff's understanding is that this requirement may limit FOTs to transactions that can be secured on that timeline. Staff also expects that information from the WRAP program may bring additional transparency into the depth of regional markets during constrained periods and that this information could help to inform future assumptions regarding FOT availability.

Staff Expectations:

By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.

[134] LC 82, PacifiCorp 2023 IRP, page 325.

- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

Transmission & Storage

In Round 1 Comments, Energy Advocates recommends, "PacifiCorp should expand future CEP/IRP's to look beyond storage co-location near generation sites and to identify substations and transmission lines that can use storage to flatten load peaks and avoid congestion and costly transmission and distribution upgrades."

In Reply Comments, PacifiCorp responded that the 2023 IRP allows standalone storage to be selected at generator and load locations, in addition to co-location near generation sites. PacifiCorp states, "Additionally, storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed anywhere on the system."[135]

PacifiCorp also notes that "[t]he specific substation and transmission would be identified in the request for proposals process after the 2023 IRP."[136] We note, however, that PacifiCorp should reconcile this statement with its unambiguous indication in the IRP itself that battery storage resource options are limited to co-location at generation sites.[137]

PacifiCorp's explanation partially addresses Energy Advocates' recommendation, although it does not directly explain how PacifiCorp considers the ability of storage to avoid transmission and distribution upgrades. PacifiCorp applies a Transmission and Distribution deferral credit to DSM resources in the IRP; however, it does not appear that PacifiCorp has used a T&D deferral value for storage in PLEXOS IRP modeling.

In evaluating PacifiCorp's consideration of T&D deferral value, it may be valuable to consider transmission deferral separately from distribution deferral. Regarding transmission, the PLEXOS modeling logic should be able to assess the potential for storage to reduce or defer the need for endogenously selected transmission resources. The model can generally make economic decisions about whether to upgrade the system with storage or to select a major new transmission investment.[138] However, there may be some transmission deferral value that is not considered in the IRP PLEXOS modeling. For transmission system investments that cannot be selected by the model, and are instead hard-coded, the model will not be able to see any opportunities to defer these resources by acquiring storage.

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[135] LC 82, PacifiCorp Reply Comments, page 73.

[136] LC 82, PacifiCorp Reply Comments, page 72.

[137] LC 82, PacifiCorp 2023 IRP, Chapter 8, page 233: "Batteries are assumed to **always** be co-located with other resources, enabling them to shift energy…". Emphasis added.

[138] PacifiCorp response to OPUC DR 190.

The IRP generally states that transmission resources are available for endogenous selection.[139,140] However, further clarification from PacifiCorp to verify whether this applies to all or only some planned transmission resources that could be deferred by storage would be valuable. There may be some transmission expenses that can be deferred by strategically located storage but are not included in the PLEXOS model. If these costs are significant, then applying a transmission deferral credit to storage resources in the IRP could be appropriate.

Staff Expectation:

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Management

Staff's Round 1 Comments supported PacifiCorp's plan to include near-term cost-effective EE in the Company's preferred portfolio. The long-term EE modeling however, appeared insufficient. Staff's analysis found that PacifiCorp had not included available and low-cost EE in the preferred portfolio after 2025.[141] Accordingly, Staff requested that PacifiCorp allow optimization of EE in the CEP to inform whether EE could reduce HB 2021 costs allocated to the CEP portfolio. Staff also requested PacifiCorp reoptimize the Max DSM scenario. Additionally, Staff found opportunities to improve PacifiCorp's avoided costs, such as including avoided planning reserve margin costs and considering HB 2021's emissions constraints.[142] Finally, Staff found PacifiCorp's short-term DR acquisition strategy reasonable but recommended additional measures to reduce NPVRR.

In Round 1 Comments CRITFC, CUB, Energy Advocates, and Sierra Club saw room for additional DSM measures in the preferred portfolio. By extension, they questioned whether PacifiCorp's long-term planning recognized the full implications of HB 2021. CRITFC, CUB, and Energy Advocates voiced concerns that the existing cost-effectiveness tests overlooked EE's non-energy values of improved community resiliency and reduced environmental and ratepayer burdens.

In Round 1 Reply Comments PacifiCorp did not allow the Max DSM Scenario to reoptimize the resource selections around the additional EE. PacifiCorp also declined to reoptimize EE in the CEP. According to PacifiCorp, this request was unnecessary because the model had selected an average of 91 percent of potential EE between 2023 to 2030, with few remaining potential EE measures to meet system needs. PacifiCorp further argued there is no statutory or regulatory mechanism requiring the Company to optimize EE for CEP requirements. Similarly, PacifiCorp argued it lacked Commission guidance to include HB 2021's constraints in avoided cost data. PacifiCorp stated that the Company's method is like the traditional concept of "capacity cost" with the added component of renewable energy compliance. PacifiCorp's standard renewable avoided costs reflect the cost of a renewable wind proxy starting in 2026; prices after that date would not include a forward market component. PacifiCorp further explained that calculating the avoided planning reserve margin cost was difficult due to the addition of

[139] LC 82, PacifiCorp 2023 IRP, page 221.
[140] LC 82, PacifiCorp 2023 IRP, page 213.
[141] LC 82, Staff Round 1 Comments, October 15, 2023, page 58, Figure 12.
[142] For example, in using the existing avoided cost method, Staff found the Company overlooked the need to purchase non-emitting resources rather than the least-cost market resources. These comments mirrored Staff's comments to PGE in LC 80. *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Corrected Opening Comments at pages 27-30 (July 27, 2023).

variable energy resources. Finally, PacifiCorp provided an update on its electrification modeling and agreed to consider DR measures encouraged by Stakeholders.

Staff's review of OPUC DR 80-1 found that the preferred portfolio selected only 80 percent of available EE between 2023 and 2030, which contradicts PacifiCorp's claim of 91 percent.[143] In either case, the model selected EE *without considering HB 2021,* which suggests that the model would select more EE once HB 2021 strategy is considered. Staff requests that the 2024 IRP Update address the discrepancy in EE acquisition and ensure that the model considers HB 2021 compliance in the preferred portfolio.

Further, PacifiCorp's 2023 IRP analysis relied on an Energy Trust potential study which used avoided costs from the 2019 IRP.[144] If the Company's long-term planning were to indicate that greater amounts of efficiency at higher avoided costs would benefit the system, Energy Trust could perform a new potential estimate that would likely result in a higher amount of available efficiency in Oregon. Therefore, Staff concludes that PacifiCorp's least cost, preferred portfolio likely includes more EE from the previously identified potential, plus additional new23 potential that may have been screened out of Energy Trust's potential study.

Given the impactful new requirements of HB 2021, the value of efficiency in Oregon should diverge substantially from the value of efficiency to some other states on PacifiCorp's system. Under Senate Bill 1547 (2016) and codified in ORS 757.054(3)(a), investor-owned utilities are required by law to acquire all cost-effective energy efficiency and demand response prior to acquiring new generating resources.[145] To meet this requirement, new approaches to avoided costs must be explored and Staff expects PacifiCorp to help update the accounting in UM 1893 to reflect current state policy. Staff expects that Oregon-specific avoided cost analysis will be included in PacifiCorp's IRP Update and future IRPs. The acquisition of higher-value Oregon EE in light of HB 2021 requirements, should be part of PacifiCorp's preferred portfolio in both IRP and CEP planning, not relegated to one or the other.

Staff will consider approaches to avoided cost valuation from other regions, such as the method used by New England energy efficiency program administrators.[146] PacifiCorp's current IRP modeling approach for calculating avoided energy costs has similarities with the New England AESC modeling construct and could be improved to better represent Oregon-specific benefits.
Staff reiterates prior recommendations from Round 1 Comments regarding demand response resources. Staff recommends acknowledgement of DR acquisition to 2026, but encourages the Company to consider additional classes of DR as part of the least cost, least risk portfolio in future analysis. Staff again cites the Northwest Power and Conservation Council's 2021 Power Plan recommendations for utilities to pursue frequently deployable, low-cost measures with minimal customer impact, including time-of-use rates and demand voltage reduction.[147] PacifiCorp did not respond to this request in Round

[143] See PacifiCorp response to Staff DR No. 80-1.
[144] Under OAR 860-030-011(2), utilities must provide energy efficiency avoided cost data based on the utility's most recently acknowledged IRP or update, or from the energy utility's most recent general rate case that has been resolved by a final order of the Commission.
[145] ORS 757.054(3)(a), https://oregon.public.law/statutes/ors_757.054.
[146] For every planning period (3 years), the efficiency program administrators sponsor an avoided energy supply components (AESC) study to determine the value of energy efficiency and other demand-side measures. Avoided costs are calculated for each New England state under a hypothetical future in which New England program administrators do not install any new demand side measures in future years.
[147] See 2021 Northwest Power Plan, page 47. https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf.

1 Reply Comments. Staff expects future IRP analyses will consider these two resources to help manage power costs and reduce emissions.

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Staff Expectations:

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

Conclusion

Despite the good work and hard effort of PacifiCorp staff, the decisions to both suspend the 2022 AS RFP **and** push all necessary revisions of LC 82 analysis to the IRP Update mean Staff and stakeholders lack the shared analytic understanding for making many of the needed acknowledgement recommendations required of this IRP/CEP. Until additional analysis is done, and the Preferred Portfolio is revised, many aspects of this IRP and the CEP cannot be acknowledged.

Staff proposes to truncate the LC 82 review process. Staff will file a motion to update the schedule so as to bring the recommendations from these comments forward for acknowledgement at the public meeting on February 20, 2024. Staff will seek a Commission order on those items that it believes can be acknowledged **and** on minimum analytic requirements for the IRP Update. Further, we recommend that the CEP be revised and resubmitted, per Staff's suggestions, with the IRP Update so that it has the potential to be acknowledged.

Dated at Salem, Oregon, this January 24th, 2024.

JP Batmale

JP Batmale
Administrator
Energy Resources and Planning Division

Appendix A: Summary of Recommendations

<u>RFP Suspension</u>
Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan**.**

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

<u>Action Plan Changes</u>
Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments:
<u>Community Benefit Indicators</u>
Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

<u>CBRE Resource Potential</u>
Staff Recommendation 7. Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

<u>Community Engagement</u>
Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

<u>Resiliency Analysis Framework</u>
Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

IRP Comments:
<u>Preferred Portfolio Modeling Process</u>

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Natrium and Non-Emitting Peaking Resources

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Demand Side Resources

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Appendix B: Staff Expectations

State Policy Compliance in IRP Portfolios

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

CEP Compliance Pathways

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP "actions", Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.
- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the action plan because the Company has already taken these actions.

CEP Comments:

Community Benefit Indicators

- In the next IRP/CEP, Staff expects PacifiCorp to:
    - Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
    - Better inform CBIs and methods with input from stakeholders and community.
    - Enhance tribal-focused CBIs.
    - Use CBIs to better reflect the health impacts of EE.
    - Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
    - Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
    - Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

CBRE Activities

- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

CBRE Inclusion in Preferred Portfolio

- In the IRP/CEP update:
  - Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

- By the next IRP/CEP:
  - Highlight and communicate the relative benefits of CBRE in load pockets.
  - Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[148]
  - Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
  - Organization/entity attribution or affiliation.
  - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
  - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp to conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

Resiliency Analysis Framework

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to

[148] ORS 469A.415(4)(d).

identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.

- By next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

Acquisition of Federal Incentives

- The IRP Update includes two variant portfolios that directly reflects Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments:

Preferred Portfolio Modeling Process

Before the next IRP PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

Coal Strategy

In the next IRP, PacifiCorp should:

- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

In the next IRP/CEP, PacifiCorp should:
- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

Candiate Resource Costs
- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources
- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

By the next IRP, PacifiCorp should:
- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.
- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Resources

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

PacifiCorp
2024 Oregon Small-Scale Renewable Request for Proposal

Pre-Issuance Bidder Workshop

January 24, 2024





PACIFICORP

POWERING YOUR GREATNESS

2024 Oregon Small-Scale Renewable RFP

Logistics

Workshop Date and Time

- Wednesday, January 24, 2024
- 2:00 – 4:00 PM (Pacific Standard Time)

Location

- Microsoft Teams meeting
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2024 Oregon Small-Scale Renewable RFP

Agenda

- Purpose/Resource Types
- Eligibility Requirements
- Contract Considerations
- Interconnection and Transmission Requirements
- Proposed RFP Schedule
- Evaluation and Selection Methodology
- Role of Independent Evaluator (IE)
- Next Steps
- Questions and Comments

2024 Oregon Small-Scale Renewable RFP

Purpose of Request for Proposal (RFP)

- To enable PacifiCorp to obtain, by 2030, approximately 490 megawatts (MW) of additional electrical capacity from small-scale renewable energy projects.
- The RFP supports PacifiCorp compliance with Oregon House Bill 2021 (OR HB2021) Section 37 and furthers PacifiCorp's Clean Energy Plan goals.

Energy sources accepted into the 2024 Oregon Small-Scale Renewable RFP must

- **Have a nameplate capacity of at least 3 MW but no greater than 20 MW *and***
- **Generate electricity utilizing one of the following sources:**
  - Wind energy
  - Solar photovoltaic and solar thermal energy
  - Wave, tidal and ocean thermal energy
  - Geothermal energy
  - Hydroelectric energy
  - Biomass that generates thermal energy for a secondary purpose
    - Biomass energy sources larger than 20 MW will be accepted, but only the first 20 MW of the energy source counts toward OR HB2021 requirement.
  - Energy sources listed above will be accepted to the 2024 Oregon Small-Scale Renewable RFP only if they meet the Renewable Portfolio Standard (RPS) criteria outlined in ORS 469A.025.

Note: Information in this presentation is subject to further change until RFP is issued.

2024 Oregon Small-Scale Renewable RFP

Minimum Resource Eligibility Requirements

- Eligible technologies consistent with ORS 469A.025.
- Eligible resources cannot be behind-the-meter, energy storage, microgrids or demand response technologies.
- Minimum 3 MW (ensures Energy Imbalance Market (EIM) eligibility); maximum 20[1] MW (supports Oregon HB2021 compliance).
- Possess Oregon Department of Energy Renewable Portfolio Standard (RPS) certification at time of commercial operation for contract effectiveness.
- Off-system bids not accepted; projects must be planned to interconnect to PacifiCorp transmission or distribution system in Oregon, Washington, California, Idaho, Utah or Wyoming.
- Completed interconnection study, confirming ability to interconnect to PacifiCorp's transmission or distribution system.
  - https://www.oasis.oati.com/ppw/index.html; https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Transmission_Wall_Map,_E-Size.pdf
- Site control required.
- Commercial Operation Date (COD) by December 31, 2028.
- Comply with co-location/proximity criteria based on Oregon OAR 860-089-0100, applied to a 20 MW threshold level.
- Bids for new and existing resources will be accepted provided the existing resources are not obligated in a contract effective as of the COD date above.
- Bid fee will be required for each bid proposal. Details provided at RFP issuance.
- All PPA bids must be fixed-price for the full term.

[1] As previously noted, Biomass resources larger than 20 MW *will* be considered, but only the first 20 MW will count toward OR HB2021 capacity requirement.

2024 Oregon Small-Scale Renewable RFP

Minimum Eligibility Criteria

1. Receipt of bid by deadline
2. Receipt of bid fee by deadline
3. Completed provided Bid Summary and Pricing Input Sheet, without modification
4. Capacity interconnected to PacifiCorp's transmission or distribution system
5. Completed PacifiCorp Transmission Interconnection Study or signed PacifiCorp Transmission Interconnection Study Agreement
6. Interconnection study results and/or executed Large Generator Interconnection Agreement (LGIA) consistent with and supports bid
7. Demonstrated ability to achieve COD deadline
8. Execute Confidentiality Agreement and allow appropriate disclosures to agents, contractors, regulators, etc.
9. No attempts to influence PacifiCorp
10. Entire bid held firm through Q2 2025
11. No commitments of all or part of bid to another entity
12. Must disclose real parties of interest
13. Compliance with Prohibited Vendors List (see pro forma PPA)
14. Bidder's credit information
15. Ability to meet credit security requirements
16. Non-modifiable standard pro-forma contract
17. Bidder not in bankruptcy proceedings
18. Proposal cover letter signed by authorized officer
19. Renewable Portfolio Standard (RPS) certification from Oregon Department of Energy
20. Performance report and model output including hourly output values; bid resource assumption (12X24 or 8760) includes all planned outages and losses, including planned and maintenance outages and curtailment due to protected species such as bats; third-party provided performance report preferred
21. Adherence to all applicable permits prior to and after construction. If applicable, Seller will also agree to Eagle Take Permit or alternative mitigation measures
22. Ownership of, leasehold interest in, or right to develop site, or valid title to property https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230823_OATTMaster.pdf
23. Oregon bidder agrees to the contractor labor standards attestation in OR HB2021, Section 26 https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
24. Compliance with OR HB2021 reporting requirements, including contractor diversity reporting requirement https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

2024 Oregon Small-Scale Renewable RFP

Key Contract Considerations

- **Contract form**. PacifiCorp's pro forma power purchase agreement (PPA) will be provided.
  - Standard-form power purchase agreement (PPA). **The PPA will be standard for all bidders with no individual form modifications permitted.**
  - Seller develops, operates and owns resource; PacifiCorp buys the output for a specific term.
- **Ownership.** PacifiCorp takes ownership of all capacity, energy and associated environmental attributes after delivery to PacifiCorp.
- **Contract pricing**. Fixed pricing for term of contract (flat or on-peak/off-peak).
- **Credit requirements.** Letter of credit or approved parental guarantee will be required.
  - **Project development security**. Seller security is required to support delay damages and/or default damages for failure to reach commercial operation date (COD).
  - **Default security.** Seller security is required to support default damages in the event of breach of contract.
- **Commercial Operation Date delay.** Seller will have up to 365 days to cure a delay in scheduled commercial operation date; delay damages will be assessed.
- **Post-execution Condition Precedent.** Agreement language will ensure PacifiCorp's ability to obtain designated network resource (DNR) transmission service at no additional cost.
- **Annual Performance Guarantee.** Agreement will require annual resource mechanical availability guarantee and threshold percentage.
- **Benchmarks.** To support 2030 OR HB 2021 compliance PacifiCorp may offer benchmark bids.
  - PacifiCorp develops, constructs, owns and operates a bid project.
  - Benchmark bids will be evaluated using methodology consistent with market bid evaluation.

2024 Oregon Small-Scale Renewable RFP

Interconnection and Transmission

On-system resources (Off-system resources not accepted)

- PacifiCorp Transmission interconnection studies and agreements should be consistent with the bid proposal's technology, size and commercial operation date. If studies and agreements are not consistent with the proposal, bidder will provide documentation from PacifiCorp Transmission that a material modification to their interconnection documentation is not required.
- Bidders are financially responsible to PacifiCorp Transmission for all interconnection costs as identified in their generator interconnection agreement.
- After a PPA is executed, PacifiCorp's merchant function is responsible for requesting and arranging transmission from the Point of Interconnection (POI) to load.

Acceptable Documentation of Interconnection

- Completed PacifiCorp Transmission Interconnection Study (system impact study and/or facilities study) or signed PacifiCorp Transmission Interconnection Agreement is due when bid is submitted.
- An *Informational* Interconnection Study is NOT sufficient interconnection documentation to be considered eligible for the 2024 SSR RFP.

Questions

- For questions regarding PacifiCorp Transmission's interconnection study process, please visit the PacifiCorp Transmission website and contact Generation Interconnection at: www.pacificorp.com/transmission/transmission-services.html

POWERING YOUR GREATNESS

2024 Oregon Small-Scale Renewable RFP

Equity Questionnaire

Facility proximity to community
Census track in which facility is located
Distance from facility to nearest residential home
Number of residential homes within 1 mile of facility
Number of residential homes within 6 miles of facility
How does this resource serve or otherwise impact vulnerable populations?
Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels?
Distance to nearest existing generation sources by fuel source within 6 miles of proposed facility;
Will the proposed facility replace/supplant identified generation sources?
If "yes," provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much megawatt-hour ("MWh")/year), and avoided emissions released into the community (within 6 miles of the project).

Population characteristics of community where facility is proposed
To be completed based on census track in which facility is located
Race and ethnicity
White (%)
Black or African American (%)
Amercan Indian and Alaska Native (%)
Asian (%)
Native Hawaiian and Other Pacific Islander (%)
Two or More Races (%)
Hispanic or Latino (%)
Population 25 years and over with no high school diploma
Unaffordable housing
Population five years and older that speak English less than "very well" and "not at all"
Population with income 185% below poverty
Population 16 years and older unemployed

Facility Job Creation
Total hires (number of jobs)
Will there be an apprenticeship or training program?
Will there be a project labor agreement (PLA)?
Will Bidder have a plan for outreach, recruitment and retention of women, minority individuals, veterans and people with disabilities to perform work under the contract?
Projected local hires from nearby communities (number of jobs)
Expected total employment (hires) of fossil fuel construction workers (number of jobs)
Duration of work (months of construction / years of operation)
Total Recordable Incident (TRI) of Bidder
Industry Average TRI for type of business (OSHA)
Bidder agrees to use Veriforce, or equivalent, to report safety
Estimate projected economic benefits to the local economy (direct and indirect) (annual $ from payroll taxes, property taxes, other taxes, services)
Minority-owned businesses (percentage of contractors and subcontractors) Woman-owned businesses (percentage of contractors and subcontractors) Service-disabled veteran-owned businesses (percentage of contractors and subcontractors) LGBT firms (percentage of contractors and subcontractors)
What percent of total work hours does Bidder target to be performed by women, minority individuals, veterans and people with disabilities?

Local Impacts
Is Facility a distributed energy resource?
Duration of construction
Source of water used during construction
Source of water used during operations
Is water a permitted or public source
Site disturbance - amount of disturbed soil during construction
Tree and pollinator seed re-planting after construction

Note: Above questionnaire was requested in the 2022AS RFP.

2024 Oregon Small-Scale Renewable RFP

Proposed RFP Schedule

Event	Date
Pre-issuance bidder workshop	1/24/2024
Independent Evaluator (IE) hired	2/16/2024
RFP issued to market and publicized	3/29/2024
PacifiCorp OATT[1] cluster study window open	4/1/2024
PacifiCorp OATT[1] cluster study window closed	5/16/2024
Bidder workshop No. 1	6/27/2024
Bidder workshop No. 2	TBD (September 2024)
Last day for bidder questions to PacifiCorp and IE	11/1/2024
Cluster study results posted to OASIS	~11/12/2024
Benchmark bid submissions due	11/15/2024
Benchmark final bid financial analysis provided to IE	12/20/2024
Market bid submissions due	12/23/2024
Bid eligibility screening complete	1/17/2025
Market bid evaluations complete	2/14/2025
IE final report	3/17/2025
Potential 2025 SSR RFP	3/28/2025
Contracts finalized and executed	TBD (June 2025)
Guaranteed commercial operations date (COD)	12/31/2028

[1] PacifiCorp's Open Access Transmission Tariff (OATT)

2024 Oregon Small-Scale Renewable RFP

Price Proposal – Bidder Inputs

Each Proposal is required to include a completed Bidder Inputs form, which provides PacifiCorp a “numbers based” overview of the bid offering:

Price Proposal - Bidder Inputs (Required for Bid Submittal)	**Location**
➢ Bid Summary ▪ Type of Bid: PPA or Benchmark ▪ Project Specifics (Generator Type, location, capacity, annual degradation) ▪ Bidder Contact Information ➢ PacifiCorp Interconnection/Transmission Information ▪ Queue Number or Cluster Study ▪ Cost of Interconnection Facilities and Network Upgrades ➢ Purchase Power Agreement Terms ▪ Start/End Dates ▪ $/MWh Price[1] (Flat or On- and Off-Peak Pricing) ➢ Benchmark Terms ▪ Date Operational ▪ Initial Capital Cost (Detail on Tab 3) ▪ ITC/PTC Qualification Questions	Tab 1
Expected First-Year Generation Inclusive of Degradation – 50th Percentile Estimate ➢ 8,760 hourly generation profile, OR ➢ 12 month by 24-hour generation profile (“12X24”)	Tab 2a, or Tab 2b
Benchmark Pricing (Not Applicable to Market Bids)	Tab 3
Benchmark Additional Information (Annual Operating and Capital Costs)	Tab 4

[1] Bid prices include direct interconnection costs. PacifiCorp includes network upgrade costs from PacifiCorp Transmission interconnection studies in the financial valuation model.

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2024 Oregon Small-Scale Renewable RFP

Evaluation and Ranking of Bids

- Objective is to acquire 490,000 kilowatts (490 MW) of new capacity from small-scale renewable energy projects at the lowest cost to Oregon customers
- Acceptable Bid Criteria:
  - Power purchase agreement and benchmark bids
  - Fixed pricing for Term of PPA (flat or on-peak/off-peak)
- Bids will be ranked based on the LOWEST Real Levelized Cost per Kilowatt of installed Capacity

Cost to PacifiCorp of Bid
PPA Cost or Revenue Requirement of Benchmark Bid
(Present Value)
+
Network Upgrade Cost
(Present Value)

−

Value of Generation Based on Oregon Avoided Costs. Includes Value of Capacity Contribution.
(Present Value)

=

Net Cost / (Benefit) of Installed Capacity
(Present Value)

Net Cost / (Benefit) of Installed Capacity
(Present Value)

÷

Installed Capacity (kW) over PPA Term or Asset Life.
(Real[1] Present Value)

=

Cost / (Benefit) Per Kilowatt-Year
(Real Levelized)

[1]Discussion of Real Levelized valuation methodology will be provided in June bidder workshop.

2024 Oregon Small-Scale Renewable RFP

Role of the Independent Evaluator (IE)

PacifiCorp is seeking the services of an Independent Evaluator to provide independent validation that:

- PacifiCorp's screening of eligible bidders based on published minimum eligibility requirements was consistently applied to all submitted market and benchmark bids; and
- PacifiCorp's cost valuation of all submitted market and benchmark bids was consistently applied.

2024 Oregon Small-Scale Renewable RFP

Next Steps

1. Questions or comments regarding this pre-issuance bidder conference should be sent to the following mailbox, even if an answer was provided verbally in today's meeting, to ensure all bidders receive responses: **2024SSR_RFP@pacificorp.com.**
2. Responses to questions (Q&As) received will be posted anonymously on PacifiCorp's 2024 Small-Scale RFP website.
3. 2024 Small-Scale RFP information will be provided it is developed and Q&As will be posted to: www.pacificorp.com/suppliers/rfps/2024-small-scale-renewable-rfp.html.

Supporting Materials

2024 Oregon Small-Scale Renewable RFP

PacifiCorp Transmission OASIS Interconnection Requests

Information on new generator interconnection requests and general interconnection and cluster study information please visit: https://www.oasis.oati.com/ppw/index.html

Question & Comments

To: PacifiCorp SSR RFP Team (2024SSR_RFP@pacificorp.com)
Subject: Oregon PUC Staff Initial Comments on SSR RFP

PUC Staff appreciates PacifiCorp releasing a draft of the Small Scale Renewable request for proposal (SSR RFP) for comments and the speed with which the Company is pursuing these resources. Staff's comments are organized around two themes. First, PacifiCorp's chosen SSR project characteristics are too narrow, leaving value on the table, driving up project costs, and failing to leverage the RFP as a market discovery mechanism. Second, Staff has suggestions for the structure of the RFP itself, based on our experience, that should help the Company meet its goals and the goals of the state while also assisting potential bidders.

Project Characteristics

Issue: Energy storage ineligibility
Staff position: Energy storage paired with renewable energy projects should be eligible.
Staff rationale:

- Allowing for the pairing of energy storage with renewables and dispatched as a single project enhances capacity value of SSR projects to system peak. Barring energy storage from SSRs appears to make projects less economic than other renewable systems and potentially drives up total costs of CEP compliance for Oregon ratepayers.
  - Energy storage allows for renewable projects to be dispatched in a way that better aligns with system need and to offset fossil fuel use (i.e., summer peak, after 6pm).
- PAC has outstanding capacity need that SSR projects with energy storage can help meet. Evidence:
  - Per the 2023 IRP, the Company has a 2028 summer capacity deficit over 6,000 MW.[1]
  - Per the Draft IRP Update, peak capacity will grow at an average annual rate of 1.7%.[2]
  - Company is seeking 100s of MW of energy storage by 2026 through bilateral contracts in wake of UM 2193 RFP suspension.

Given the outstanding capacity need, Staff questions why PacifiCorp would limit dispatchable load.

- PacifiCorp staff stated on the January 24, 2024 conference call that the Company had determined that the economics of SSR projects with energy storage would be uncompetitive. There is no data to substantiate this argument. Further, the purpose of an RFP is to discover what is available in the market. If project bids are uneconomic due to inclusion of energy storage that should be apparent in their RFP score.
  - Based on PacifiCorp's evaluation and ranking of bids, projects paired with storage will most likely provide more value and thus provide a higher benefit to ratepayers.
- CAISO and WREGIS allow for renewable projects to be paired with energy storage and to be dispatched as a single system.
- ODOE certifies RPS projects paired with energy storage.

[1] LC 82, PacifiCorp IRP, May 31, 2023, pgs. 165 – 172, specifically Table 6.11 and Figure 6.4.
[2] LC 82, Draft IRP Update, January 31, 2024, pg. 2.

Issue: 3 MW floor
Staff position: Allow for project sizes down to 25 kW.
Staff rationale:

- 25 kW is smallest size for Community Solar Program. A lower bid threshold allows for projects such as those waitlisted in the CSP to participate in the SSR RFP.
- Based on the size of PacifiCorp's CSP queue there are clearly many projects less than 3 MW in size that could submit viable bids.
- Function of an RFP is to discover what is available in the market. If project bids are uneconomic due to their smaller size, that will be apparent in the RFP scoring.
- WREGIS allows for renewable projects of any size to be registered.

Issue: CAISO EIM eligibility
Staff position: Should be optional for projects, not a requirement.
Staff rationale:

- Eliminates the potential for smaller projects.
- Imposes unnecessary costs on all projects.
- Reinforces need to allow batteries to be paired with projects as it would increase value of projects to ratepayers.

Issue: Required ODOE RPS Certification at time of commercial operation date (COD)
Staff position: Should be required only after COD and should be optional for projects, not a requirement.
Staff rationale:

- Timing is off. ODOE does not issue RPS certifications until after COD.
- Project does not need ODOE certification to be considered renewable energy resource. Just needs to be one of the technologies listed in ORS 469A.025. Imposes unnecessary costs on all projects.
- ODOE RPS certification requires WREGIS issuing a generating unit id. This requires equipment that is expensive for smaller projects. It also requires more time and raises project costs.
    - o The largest benefit to registering with WREGIS is the ability to generate RECs. As HB 2021 does not require REC retirement to demonstrate emission reductions – and as PacifiCorp will have over 50 million RECs in excess of its Oregon RPS needs by 2030[3] – Staff finds little to no value in requiring PAC SSRs to be WREGIS certified, even if the ODOE RPS verification is waived.

Issue: Contract pricing limited to flat or on-peak/off-peak.
Staff position: Contract pricing should include flat, on-peak/off-peak, or premium peak hours
Staff rationale:

- Projects with associated storage should have a contract pricing structure which incentivizes and rewards its dispatchable nature. More targeted hours will maximize the capacity value derived from these projects at little to no cost to the project.
- Hour derivation could be based on projected market prices or utility capacity needs.
- Structure could follow UM 1729 Solar+Storage rate with minor modifications.

[3] LC 82, PacifiCorp IRP, May 31, 2023, pg. 321, Figure 9.59.

RFP Structure Issue

Issue: Lack of non-price scoring.
Staff position: Include non-price scoring that captures information about benefits to Oregon communities.
Staff rationale:

- Staff appreciates the inclusion of the Equity Questionnaire from the 2022 AS RFP. However, the equity questionnaire is not mandatory in the SSR RFP and answers do not impact project selection.
- Elements should be improved *(see below)* and converted into non-price scoring or sensitivity that captures community benefits.
- The Commission stated that it will want information about direct benefits to communities in Oregon.[4] In fact, capturing more information about benefits and impacts to Oregon communities was identified as a necessary first step in impacting near-term decisions around utility procurement.[5]
- PacifiCorp and Oregon PUC staff agree that many projects could easily qualify as both SSR and as Community Based Renewable Energy (CBRE) projects, under HB 2021.

Issue: Equity questionnaire
Staff position: Equity questionnaire needs more explicit linkages to PacifiCorp's CBIs and reflect input from the Company's CBIAG.
Staff rationale:

- Staff appreciates the inclusion of the 2022 AS RFP Equity Questionnaire. However, the equity questionnaire does not necessarily reflect the Company's evolving CBIs from LC 82 and input from community members in both LC 82 and in the CBIAG.
- Some portion of the equity questionnaire should become the non-price scoring element to the RFP. *(See above.)*
    - These can reflect the Company's evolving CBIs and/or attempt to capture insights into elements like positive impacts to community resiliency or the offsetting of fossil fuels.
    - HB 2021 requires consideration of community benefits in meeting the emissions reduction targets, vis-à-vis offsetting fossil fuels, increasing community resiliency, and even economic development.[6]

Issue: Lack of locational value in evaluating and ranking of bids.
Staff position: PacifiCorp's evaluation and ranking of bids needs to explicitly take into account the locational value of capacity and energy from proposed SSR projects when assessing bids.
Staff rationale:

- Given that PacifiCorp has multiple load pockets across its system (e.g., five in Oregon) and uneven growth across its system (e.g., northeast Oregon load will grow incredibly fast over the next five years), the methodology to determine net cost/benefit of installed capacity needs to explicitly account for locational value.

[4] UM 2273, Order No. 24-002, January 3, 2024, pg. 23
[5] *Ibid.* Pg. 24-25.
[6] ORS 469A.400(2)(a),(b) and 469A.415(4)(d)

- This will encourage the selection of bids with the lowest realized cost to Oregon ratepayers while better capturing the value to the PacifiCorp system.

Issue: No contract negotiations or redlines
Staff position: Redlines should be allowed.
Staff rationale:

- In UM 2274, contract redlines will be used by IE to illuminate bid nuances and pricing so as to make project selection more transparent and so the IE can comment around tradeoffs or irregularities in ISL or FSL project selection. [7]
- Contract redlines allows for projects with more unique attributes to potentially offer lower cost bids and provide necessary flexibility.

Issue: IE Scope
Staff position: Include information that compares and contrasts IE scope and staff interaction in the SSR RFP to UM 2193.
Staff rationale:

- Staff appreciates the inclusion of an IE for this RFP but needs a clearer understanding of the IE's scope and ability to interact independently with stakeholders, and how similar the role will be to an IE selected for a procurement under Oregon's competitive bidding rules.
- Will the IE be responsible for responding to bidder questions?
- Will the IE be responsible for establishing the scoring rules, as well as scoring all, or a subset of bids?
- Will the IE be working for/reporting to PAC or OPUC staff?

Issue: Separation of PacifiCorp RFP and Benchmark staff in establishing scoring system, reviewing bids and contract negotiations.
Staff position: The final RFP needs to clearly state how PacifiCorp RFP and Benchmark staff will be entirely screened from one another throughout this RFP process. This includes naming all employees working as part of the RFP team or the Benchmark team, including their roles and associated dates of their work; ensuring Benchmark staff have had no access to 3rd party project information during this RFP and for at least two years after bids are submitted; and developing and enforcing separation protocols to ensure no confidentiality breech or anti-competitive use of confidential data.
Staff rationale:

- If PacifiCorp's SSR benchmark project development team has any access to RFP bidder information they will have an unfair advantage in their bids.
- All other RFPs require a separation of staff.
- It is standard practice in Oregon to name utility staff on RFP and Benchmark teams so the IE, Staff, and/or stakeholders can verify that a separation between RFP and Benchmark teams was maintained.
- Bidders who receive confidential utility information are embargoed from using it for two to five years after an RFP. The same should be true for utility staff.

[7] UM 2274, Order No 24-011 at 1.

In closing, an RFP functions as a market discovery mechanism. In Staff's experience, an RFP with too many restrictions on project eligibility limits the Company's and stakeholder's insights into available, competitive options. And for this RFP, Staff finds no downside to removing many restrictions (e.g., energy storage, RPS certification, size limit, two-types of pricing, etc.,) if project selection still rests mainly on price and the determination of value as proposed in the RFP's evaluation and ranking methodology. If acquiring 490 MW by 2030 is truly an "all hands on deck" moment, restricting participation – as this RFP currently does – would appear to be counterproductive.

Further, HB 2021's direction to consider community benefits by understanding what they are necessitates some evaluation of a bid's community benefits and impacts. However, the equity questionnaire does not reflect recent developments and is not mandatory. Without some sort of non-price scoring or sensitivity that attempts to capture/understand community benefits we lose a unique opportunity in this RFP to understand and learn while also undermining a key rationale for including SSRs in HB 2021.

Finally, Staff encourages the utility to adopt the changes proposed above and to make any additional improvements necessary to clarify the community benefits and impacts of SSR procurement and ensure a fair, competitive process that reflects HB 2021's evolving approach to the public interest, especially with regards to technical and economic feasibility. Such efforts will be necessary for the Commission to evaluate the prudence of any acquisition and to evaluate the steps PacifiCorp is making to demonstrate continual progress towards the HB 2021 reduction targets at reasonable costs to customers.

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: MARCH 5, 2024

REGULAR __X__ CONSENT ____ EFFECTIVE DATE ____N/A____

DATE: March 1, 2024

TO: Public Utility Commission

FROM: JP Batmale

SUBJECT: PACIFICORP:
(Docket No. LC 82)
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP). Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PacifiCorp's CEP or decline to acknowledge the CEP.

Whether the Commission should adopt Staff's recommendations for additional direction to PacifiCorp.

Applicable Law

See Staff's February 20, 2024 public meeting memo for a full description of the Applicable Law to this docket.

Analysis

Purpose of Memo
The memo provides a final set of Staff recommendations to aid in Commissioner deliberation at the March 5, 2024 public meeting. These final recommendations are informed by the February 20, 2024 public meeting, the discussion of the Commissioners in that meeting, and subsequent review of the issues. For more background information behind these recommendations, please see Staff's previous public meeting memo, filed February 7, 2024, and associated comments from Stakeholders and PacifiCorp.

The approach guiding Staff's final suggested recommendations for Commissioner consideration are as follows:

- Elements of the IRP can be acknowledged in part.
- Based on Staff's interpretation of statute, the CEP cannot be acknowledged – in whole or in part – due to the CEP's failure to meet the standard in ORS 469A.420 to be in the public interest and consistent with the emissions reduction targets.
- Based on comments made by PacifiCorp at the February 20, 2024 public meeting, the April 2024 IRP/CEP Update is not a viable vehicle for any substantial new or revised analysis.
- All recommendations for any new or revised IRP/CEP analysis should focus on the 2025 IRP/CEP, which PacifiCorp plans to file in April 2025, and are based on an expectation that that IRP/CEP will be timely filed.
- Recommendations for the 2025 IRP/CEP should be kept to a minimum. The focus is on identifying the least number of analytic improvements or qualitative additions necessary to develop an IRP/CEP that leads to an acknowledgeable CEP.
- Additional recommendations are not new to this proceeding, but instead are drawn from previously stated expectations or stakeholder comments. Staff will continue to work with the Company and Stakeholders in the lead up to the 2025 IRP/CEP to implement the expectations identified in Staff's Round 2 comments.

Staff's final, suggested recommendations for Commissioner consideration are organized into two parts:

1. **Original Recommendations**: These come from Staff's Round 2 Comments. They are also included as Attachment A to Staff's February 20, 2024 public meeting memo. The recommendations include suggested strike throughs.

2. **Additional Recommendations**: There are three sources for these new recommendations. The first is Staff's stated expectations. The second is utility and stakeholder final comments and/or suggestions at the February 20, 2024 Public Meeting. The final source is the PacifiCorp IRP/CEP.

Original Recommendations
Table 1 below details Staff's original thirteen recommendations and includes Staff's suggested redlines as of the date of this memo.

Table 1, Revised Original Recommendations from Staff

Recommendation Description	Suggested Commissioner Action on March 5
# 1: Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.	Retain in full.
~~#2: Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.~~	Remove in full
#3: Do not acknowledge the LC 82 CEP ~~and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update~~.	Change.
#4: Do not acknowledge Action Plan item~~s 1h and~~ 2a.	Change.
#5: Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.	Retain in full.
#6: Direct PacifiCorp to provide specific baseline metrics ~~prior to filing its next~~ in the 2025 IRP/CEP to allow for measured progress towards CBI goals. ~~If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.~~	Change.

Recommendation Description	Suggested Commissioner Action on March 5
#7: Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG and environmental justice groups.~~in Q1 2024~~	Change.
#8: Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, environmental justice groups, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.	Change.
#9: The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.	Retain in full.
~~#10: Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.~~	Remove in full. *Staff will have more specific directions in next table.*
#10 (Formerly #11): ~~Direct PacifiCorp to update Action Plan Item 1g (Natrium) to reflect actual events since the IRP/CEP was filed in May 2023.~~ In the 2025 IRP/CEP, direct PacifiCorp to update Natrium assumptions to reflect actual events.	Revise.
#11 (Formerly #12): Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.	Retain in full.
#12 (Formerly #13): Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.	Retain in full.

Additional Recommendations

Table 2 below details additional recommendations Staff believes the Commissioners should consider in the acknowledgement order. Recommendations number 13 and 14 are recommendations that should have been included with the original thirteen but were not due to a Staff oversight. We apologize for the error and seek to correct that by including those recommendations below.

The other seven remaining recommendations are all forward looking. They are designed to help the PacifiCorp IRP team by providing clear expectations for the 2025 IRP/CEP.

The table below also includes the source of the recommendation and a short summary of the rationale behind the recommendation's inclusion. While the text may not exactly match a recommendation attributed to a stakeholder, Staff sought to capture the essence of the recommendation. Finally, many stakeholders made outstanding contributions to this IRP/CEP in written and verbal comments, which Staff greatly appreciates. Staff apologizes in advance for any potential oversights in recognizing the contribution of a stakeholder organization toward these additional recommendations.

Table 2, Additional Recommendations

New Recommendation Description	Source and Rationale
#13: Do Not Acknowledge Action Items 1c and 1d from the action plan because the Company has already taken these actions.	**Source**: Staff expectations. **Rationale**: Should have been included in original recommendation. Do not acknowledge action items already undertaken and not already acknowledged.
#14: Acknowledge Action Plan Items 3a through 3e, 5a, 6a, and 6b.	**Source**: PacifiCorp IRP Action Plan. **Rationale**: Should have been included in original recommendation.

New Recommendation Description	Source and Rationale
# 15: In the 2025 IRP/CEP model, PacifiCorp must: (1) demonstrate that simultaneous compliance with all state-level policies is feasible with the least-cost, least-risk Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP under multiple allocation paradigms; (2) include expected CBREs in the Preferred Portfolio and ensure that the Preferred Portfolio meets Oregon's Small Scale Renewable Requirement; (3) adopt best practices in resource adequacy modeling, including consideration of load and resource performance under multiple weather years and calculation of loss of load expectation and capacity contributions using probabilistic analysis.	**Source**: Staff's expectations; CUB, Sierra Club, and RNW comments. **Rationale:** An optimized preferred portfolio that reflects law and best practices.
#16: In the 2025 IRP/CEP, PacifiCorp shall include an analysis of forecasted costs and annual emissions of the Preferred Portfolio using only actual carbon prices in effect in 2025 through the 20-year planning horizon.	**Source**: CUB comments. **Rationale**: Better forecast of actual emissions. Provides insight into the potential continuation of historical underperformance of the fleet's emission reductions relative to IRP forecasts.
#17: In the 2025 IRP/CEP, PacifiCorp shall calculate and report the costs and GHG emissions associated with each portfolio assuming that GHG prices are not reflected in dispatch decisions but still included in investment and retirement decisions.	**Source**: Staff expectations. **Rationale**: Improve understanding of tradeoffs in CEP construction.
#18: In the 2025 IRP/CEP PacifiCorp shall provide an explanation of renewable cost assumptions and a comparison to recent pricing information from such organizations as National Renewable Energy Lab and Lazard.	**Source:** RNW comments **Rationale:** Improve transparency of resource costs in portfolio development.

New Recommendation Description	Source and Rationale
#19: In the 2025 IRP/CEP, PacifiCorp shall confirm that coal generator cost assumptions reasonably reflect the structure and terms of any associated fuel supply agreements or fuel supply plans. Categorize variable costs that affect dispatch as variable costs in the model with as much accuracy as reasonably possible.	**Source:** Sierra Club **Rationale:** Improved transparency in pricing of coal resources.
#20: In the 2025 IRP/CEP PacifiCorp shall report on steps that the Company took to reduce the magnitude of reliability and granularity adjustments, how the Company engaged with stakeholders on adjustments, and describe the methodology and report the resulting reliability and granularity adjustments by resource. Include any supporting work papers demonstrating the granularity/reliability adjustments in the Data Disk.	**Source:** Sierra Club, RNW, and Staff **Rationale:** Improve modeling and portfolio transparency.
#21: In the 2025 IRP/CEP PacifiCorp shall provide an update on PacifiCorp's efforts to secure Energy Infrastructure Reinvestment (EIR) financing from the DOE Loan Program Office. Assume EIR financing through the DOE Loan Program Office in the Preferred Portfolio or include a variant portfolio that optimizes resource additions and retirements under the assumption of EIR financing.	**Source:** Sierra Club **Rationale:** Very low-cost financing for renewables should be pursued. Future resources – for either the System or for Oregon ratepayers – will be less costly due to EIR financing.

Conclusion

The twenty-two final proposed recommendations above are designed to aid in Commissioner deliberation at the March 5, 2024 public meeting. The memo includes updated recommendations from Staff's previous memo ***and*** updated recommendations based on various sources and in response to learnings from the February 20, 2024 public meeting.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's 2023 IRP, per Staff's recommendations. Decline to acknowledge PacifiCorp's CEP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-129:
Utah PSC on Pac 2023 IRP

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

PacifiCorp's 2023 Integrated Resource Plan	DOCKET NO. 23-035-10 ORDER

ISSUED: April 17, 2024

SHORT TITLE

PacifiCorp's 2023 Integrated Resource Plan

SYNOPSIS

We acknowledge that PacifiCorp's 2023 Integrated Resource Plan ("2023 IRP") substantially complies with the IRP Standards and Guidelines, with certain important exceptions. Most notably, PacifiCorp's inconsistent and disparate evaluation of the Natrium Demonstration Project ("Natrium"), non-emitting (hydrogen) resource technologies, Carbon Capture, Usage, and Storage ("CCUS") technologies, and new natural gas resources produced a preferred portfolio that likely does not identify the least-cost, least-risk resources. Consequently, we decline to acknowledge the portfolio selection process, the P-MM Preferred Portfolio, and the Action Plan.

TABLE OF CONTENTS

I. INTRODUCTION AND PROCEDURAL HISTORY

On May 31, 2023,[1] PacifiCorp filed with the Public Service Commission (PSC) its seventeenth Integrated Resource Plan ("2023 IRP"), pursuant to the IRP Standards and Guidelines ("Guidelines") adopted in Docket No. 90-2035-01.[2] PacifiCorp requests the PSC acknowledge the 2023 IRP in accordance with PSC rules and fully support the 2023 IRP conclusions, including the proposed action plan ("Action Plan").

The Division of Public Utilities (DPU) and the Office of Consumer Services (OCS) participated in the docket and the following parties intervened: the Utah Association of Energy Users (UAE), Utah Clean Energy (UCE), Western Resource Advocates (WRA), the Interwest Energy Alliance ("Interwest"), Sierra Club, Fervo Energy Company, and Utah Citizens Advocating Renewable Energy.

[1] On March 28, 2023, the PSC granted PacifiCorp's Request for a two-month extension and preliminary comment phase to file its final 2023 IRP due to changed model inputs that were driven by then-recent material changes, including the Ozone Transport Rule (the "OTR"), the Inflation Reduction Act ("IRA"), resource interconnection rules, the Oregon Clean Energy Plan, and Washington's Clean Energy Transformation Act. According to PacifiCorp, the changes required additional time to implement the accuracy of the model's outputs and did not allow stakeholders to review the model's results, including the Preferred Portfolio, before the 2023 IRP March 31, 2023 deadline. The PSC authorized a preliminary IRP and comment phase to accommodate the filing of a preliminary 2023 IRP on March 31, 2023 (PacifiCorp's submission was filed after business hours on Friday, March 31, 2023 and therefore it was submitted April 3, 2023), comments on the preliminary IRP by April 30, 2023, and the final 2023 IRP filing by May 31, 2023.

[2] *See In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, (Report and Order on Standards and Guidelines, issued June 18, 1992), Docket No. 90-2035-01. Future references to Guidelines contained in that order will be referred to by the Guideline number. For example, "Guideline 3" will refer to Guideline 3 from page 19 of that order, without referencing the 1992 order each time the Guideline is referred to in this order.

By December 12, 2023, the following parties filed comments: DPU, OCS, UAE, WRA, Interwest, Sierra Club, and UCE. On January 31, 2024, PacifiCorp, DPU, UCE, and WRA filed reply comments.

A. Summary of the 2023 Integrated Resource Plan

The 2023 IRP presents PacifiCorp's plan to supply energy and capacity to provide for and manage the growing electricity demand in its six-state service territory over the next 20 years. The report identifies PacifiCorp's preferred least-cost, least-risk plan ("Preferred Portfolio") to invest in a portfolio of power plants, transmission facilities, firm power purchases, and demand side management (DSM) resources, including energy efficiency and direct load control. The 2023 IRP identifies the type, timing, and magnitude of resource additions and provides a short-term Action Plan.

The 2023 IRP includes modeling advancements such as a Targeted Portfolio Reliability Analysis that allows the assessment of the reliability of resource portfolios by performing subsequent modeling of renewable resources that are selected in the portfolios that can identify capacity shortfalls. It also includes supplemental studies such as, among others, an energy storage potential evaluation that provides details on energy storage grid services and how they can be configured and sited to maximize benefits.

PacifiCorp selected its Preferred Portfolio,[3] which it asserts is the least-cost plan, adjusting for risk and uncertainty. To serve system-wide peak hour demand over the next 20 years, the Preferred Portfolio identifies cumulative supply additions (both long- and short-term resources) of 1,240 MW of non-emitting peaker resources, 9,113 MW of new wind resources, 7,855 MW of new utility solar resources, approximately 8,260 MW of battery storage, inclusive of 350 MW of long duration battery storage, 4,953 MW of incremental energy efficiency, 929 MW of new direct load control resources, 35 MW of pumped hydro storage, 1,500 MW of nuclear, and, through the 20-year horizon, approximately 390 MW of summer and winter firm power purchases, also referred to as front office transactions (FOT).[4]

The 2023 IRP Preferred Portfolio includes the end-of-life retirement of 1,141 MW of existing coal resources, the retirement of 2,335 MW of coal-fueled capacity with selective noncatalytic reduction retrofits, the transition of 1,770 MW of coal resources to other types of fuel, the end-of-life retirement of 595 MW of natural gas resources, the retirement of 23 MW of non-thermal resources, and the expiration of 22 MW of other resources.

The Preferred Portfolio and Action Plan include the retirement of co-owned coal units, the conversion of several coal units to natural gas, the closure of the Naughton South Ash pond, the development of Natrium, new resource acquisitions

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[3] *See* 2023 IRP, Volume I, at 307-324.
[4] *See id.*, Table 9.31 at 325.

through the 2022 and 2024 All Source Requests for Proposals, as well as continuing development and construction of the Boardman-to-Hemingway 500 kV transmission line, among other action items.[5]

Planned investment in the Preferred Portfolio differs from PacifiCorp's Fall 2022 Business Plan ("Business Plan") primarily due to reductions or delays in the 2020 All Source Request for Proposals wind, solar, and battery storage resources in the Business Plan.[6] The Preferred Portfolio also reflects lower reliance on FOTs. In addition, CO2 emissions over the study period decreased by 9 million tons relative to the Business Plan.[7]

B. The IRP Process and Standard of Evaluation

Utah Code Ann. § 54-1-10 requires the PSC to "engage in long-range planning regarding public utility regulatory policy in order to facilitate the well-planned development and conservation of utility resources." The PSC relies in part on PacifiCorp's IRP process to fulfill this planning requirement to meet the electrical needs of PacifiCorp's Utah service territory. In 1992, the PSC developed and approved the Guidelines that govern the IRP process.[8] PSC acknowledgment of an IRP means it substantially complies with these Guidelines. Such acknowledgment, however, does not constitute PSC approval of any specific PacifiCorp resource acquisition decision or

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[5] *See id.*, at 27-33.
[6] *See id.*, at 335-336.
[7] *See id*.
[8] Information on historic PacifiCorp Integrated Resource Plans can be found at the following link: https://psc.utah.gov/electric/historic-integrated-resource-plans/.

strategy for meeting its obligation to serve. Resource approval and cost recovery are addressed in dockets separate from the IRP.

II. SUMMARY OF ISSUES ADDRESSED IN COMMENTS

As discussed in more detail below, several parties urge us not to acknowledge this IRP. Many express serious concerns regarding the limited time afforded for their review, evaluation, and meaningful input. The challenges PacifiCorp has faced meeting IRP schedule deadlines are evident in the fact it has requested substantial extensions in each of the last three IRP cycles. Parties contend there was no opportunity for their review and feedback on modeling results and the P-MM Preferred Portfolio before the preliminary 2023 IRP was filed. Consequently, some dispute that the P-MM Preferred Portfolio represents the least-cost, least-risk resource portfolio. Additionally, many parties expressed concern over the suspension of the 2022 All Source Request for Proposals (the "2022 AS RFP") and its impact on the Action Plan. Finally, several parties, including the DPU and OCS, challenged various specific modeling inputs, assumptions, and studies, asserting:

a) inconsistent or insufficient analysis, or disparate treatment, of resources;

b) insufficient analysis of federal and state incentives and potential savings opportunities from the IRA and the Energy Infrastructure Reinvestment ("EIR") program;

c) insufficient discussion and analysis of regional transmission planning;

d) inadequate modeling and evaluation of advanced transmission technologies, grid-enhancing technologies ("GET"), and other alternatives to new transmission construction; and,

e) inadequate transparency and discussion related to PacifiCorp's reliability and granularity adjustments.

III. PARTIES' POSITIONS ON ACKNOWLEDGMENT OF THE 2023 IRP

Parties' Comments

DPU, OCS, and UAE recommend the PSC not acknowledge the 2023 IRP. DPU argues 1) its submission was two months late with the last of the supporting documents filed on June 20, 2023;[9] 2) Natrium was included in the Preferred Portfolio without sufficient analysis of costs, timing, and risks to customers in light of the large costs and schedule overruns of other nuclear projects in the country; 3) the 2022 AS RFP was suspended without explaining its impact on the Action Plan;[10] 4) the assumption that non-emitting peaker plant technology will be commercially available by 2030 is inappropriate given the technology is unproven and its operating costs are unknown; and 5) some resources and technologies, like nuclear and non-emitting

[9] DPU Comments, at 2 and 4, filed December 12, 2023 ("DPU Comments"). DPU comments this is the third straight instance the IRP was filed two or more months after the March 31 deadline.

[10] DPU explains the assumptions that served as model inputs may change significantly by the time PacifiCorp performs more modeling, reiterating that "[t]hrough the end of 2026, the 2023 IRP Preferred Portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022 AS RFP [was] … soliciting and evaluating resources to fulfill." *Id.*, at 15 (quoting the IRP, at 35).

peakers, are unjustifiably favored and others, like new natural gas resources and CCUS technologies, are unjustifiably excluded.[11]

OCS argues PacifiCorp failed to meet Guidelines 3, 4.b., 4.e., 4.g., and 4.h. OCS states PacifiCorp did not provide any modeling results to stakeholders for review and feedback until after it had filed the preliminary IRP.[12] Additionally, OCS joins DPU in asserting natural-gas-fired resources were not evaluated on a comparable and consistent basis relative to unproven technologies like Natrium and non-emitting hydrogen peakers. OCS also objects that an appropriate customer rates impact analysis was not provided. Finally, OCS notes the suspension of the 2022 AS RFP may negatively impact system reliability within the next four years, leading OCS to challenge whether the Action Plan reflects least-cost, least-risk resources.

UAE comments PacifiCorp withheld the results of any modeling runs, including the Preferred Portfolio, from stakeholders before filing its preliminary 2023 IRP, contrary to Guideline 3. UAE believes PacifiCorp's actions prevented UAE's reasonable and meaningful participation in the selection of the Preferred Portfolio.[13]

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[11] DPU notes that the CCUS technology was the top-performing variant case using medium gas/medium CO2 assumptions, with a present-value revenue requirement ("PVRR") of $507m under the P-MM Preferred Portfolio. It was also a top performer under various other scenarios. Regarding new gas resources, DPU explains PacifiCorp assumed a 10-year cost recovery period rather than a typical 40-year period (DPU Comments, at 24). This unusual assumption was made without stakeholder input and, to DPU's knowledge, was first announced after PacifiCorp submitted the preliminary IRP.

[12] OCS Comments, at 1-2, filed December 12, 2023 ("OCS Comments").

[13] UAE Comments, at 3, filed December 12, 2023 ("UAE Comments").

UAE also expresses concern about the inclusion of Natrium in the Preferred Portfolio. UAE explains the lack of information about Natrium's cost and performance assumptions impeded any independent evaluation. UAE states PacifiCorp in effect forced the model to select Natrium. This modeling approach cannot be viewed as providing consistent and comparable treatment of competing resources.[14]

UCE recommends the PSC acknowledge the 2023 IRP and explains UCE is encouraged by PacifiCorp's planned increases in wind, solar, and storage resources in the 2023 IRP.[15]

WRA takes no position regarding the acknowledgment of the 2023 IRP. But it joins other parties in asserting that time constraints negatively impacted the accuracy of the modeling and the opportunity for public input. WRA explains that the preliminary 2023 IRP, the final 2023 IRP, and the accompanying supporting workpapers include significant errors — far more than is typical. In WRA's view, many portfolio results don't make sense.[16] These discrepancies, according to WRA,

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[14] *Id.,* at 9.

[15] UCE Comments, at 3, filed December 12, 2023 ("UCE Comments").

[16] As an example, WRA described that several portfolios show inexplicable disparities particularly in early years where system resources should be more or less identical including a comparison of portfolio variant P05-No Nuclear and P06-No Forward Technology. WRA explains that given nuclear and non-emitting peakers are not selected in either portfolio until 2030, the expectation was that the portfolios would differ only in future years but that there were large discrepancies in market purchases appearing in the first three years of the modeling period, despite no difference in system need or expansion options in those early years. WRA Comments, at 11, filed December 12, 2023 ("WRA Comments").

undermine its confidence in the results and support its view the IRP was filed before it was ready for stakeholder analysis.

Interwest recommends either the PSC decline to acknowledge the 2023 IRP or conditionally acknowledge certain parts thereof and the Action Plan.[17] Interwest states the 2022 AS RFP's suspension casts extreme uncertainty over the Action Plan. Interwest calls for increased scrutiny of Natrium and non-emitting peaker resource technologies in the Preferred Portfolio, as they "do not reflect the least cost/least risk" resources".[18] Interwest also recommends the PSC direct PacifiCorp to resume the 2022 AS RFP as soon as possible.

Sierra Club recommends the PSC acknowledge the planned new renewable resources in the 2023 IRP but argues the Plan's coal retirement timelines, gas conversions, and nuclear additions "are extremely risky for ratepayers" and do not warrant acknowledgement.[19] Sierra Club also expresses concern about the suspension of the 2022 AS RFP.[20]

PacifiCorp's Reply

PacifiCorp asserts its 2023 IRP and Action Plan comply with the Guidelines and were developed after substantial stakeholder input. PacifiCorp asserts it held eleven public-input meetings and six state-specific input meetings.[21] The 2023 IRP public-

[17] Interwest Comments, at 3, filed December 12, 2023 ("Interwest Comments").
[18] *Id.*, at 6.
[19] Sierra Club Comments, at 3, filed December 12, 2023 ("Sierra Club Comments").
[20] *Id.*
[21] PacifiCorp Reply Comments at 12, filed January 31, 2024 ("PacifiCorp Reply Comments").

input process materials covered inputs, assumptions, risks, modeling techniques, and analytical results. PacifiCorp states it considered and implemented the PSC's direction in developing the 2023 IRP. It further asserts the Preferred Portfolio is supported by a detailed analysis of: 1) key inputs and assumptions to inform the modeling and portfolio-development process; 2) a wide range of resource portfolios; 3) a targeted reliability analysis to ensure portfolios have sufficient flexible capacity to meet reliability requirements; 4) evaluation of the resource portfolios to measure comparative costs, risks, reliability, and emission levels; and 5) development of a near-term resource Action Plan required to deliver resources in the Preferred Portfolio.[22]

PacifiCorp asserts the 2023 IRP benefited from various modeling advancements[23] and that through an extensive IRP process PacifiCorp was able to develop a Preferred Portfolio that meets its long-term goals of providing reliable and affordable service to its customers.

IV. DISCUSSION, FINDINGS, AND CONCLUSIONS

A. SUSPENSION OF THE 2022 ALL SOURCE RFP

OCS, DPU, Interwest, and Sierra Club assert the suspension of the 2022 AS RFP in September 2023 is problematic and, according to OCS, violated Guideline 4.e. OCS explains, and DPU agrees, the 2022 AS RFP suspension directly impacts the

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[22] *Id.*, at 4.
[23] See 2023 IRP, Volume I, at 18-19.

assumptions and selection of resources in the 2023 IRP because the types of resources that were expected to emerge from the 2022 AS RFP may no longer be available and may not be ready for commercial operation by the date required. According to OCS, this could result in increased exposure to market price risks, especially in the event of extreme weather like the September 2022 western heatwave.[24]

DPU and Interwest assert the suspension of the 2022 AS RFP raises serious doubts as to whether the 2023 Action Plan can be implemented.[25] Likewise, Sierra Club states it is highly concerned over PacifiCorp's decision to pause the 2022 AS RFP, especially after the 2023 IRP shows an even greater need for new renewable resources than was forecast in the 2021 IRP.[26]

PacifiCorp responds it suspended the 2022 AS RFP in September 2023, after it had filed the 2023 IRP.[27] It explains its decision was based on a stay of the U.S. Environmental Protection Agency's ("EPA") proposed OTR; ongoing EPA rulemaking on greenhouse gas emissions; wildfire risk and associated liability; and, evolving extreme weather risks.[28] It argues that it complied with Guideline 4.e. and that IRP acknowledgment means not that the Action Plan or Preferred Portfolio selections are

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[24] OCS Comments, at 4.
[25] DPU Comments, at 14; and Interwest Comments, at 5-6.
[26] Sierra Club Comments, at 3.
[27] PacifiCorp Reply Comments, at 16.
[28] The OCS argues that all of these factors were known and included in the final 2023 IRP when it was filed on May 31, 2023; and therefore, was surprised PacifiCorp named the same factors as the reason for suspending the 2022 AS RFP in September 2023.

valid into perpetuity but rather, that the IRP and resulting Action Plan are appropriate given the conditions at the time of filing.

We conclude PacifiCorp's decision to pause the 2022 AS RFP substantially impacts the Action Plan and greatly reduces its value and trustworthiness. The PSC recognizes at least some of the reasons PacifiCorp offers for pausing the RFP were known to PacifiCorp at the time it filed its final 2023 IRP in May 2023. Nevertheless, while certain parties recommend the PSC direct PacifiCorp to reinstate the 2022 AS RFP, such proposals are outside the scope of this docket.

B. MODELING ISSUES, ASSUMPTIONS, AND RESOURCE SELECTIONS

1. Consistent and Comparable Treatment of Resources

a. *Natrium*

DPU, OCS, UAE, and Interwest argue that PacifiCorp either forces the selection of Natrium in the Preferred Portfolio or inputs favorable assumptions to ensure the model always selects Natrium. For example, UAE notes that unlike every other generation resource considered in Table 7.1 of Chapter 7 of the 2023 IRP (showing costs and performance information for all supply-side resources), Natrium is not included.[29] Rather, PacifiCorp's cost and performance assumptions for Natrium are unknown to stakeholders. According to UAE, this allows the assumed costs of Natrium to "move" in the model such that they purportedly always provide benefits to

[29] UAE Comments, at 7.

customers.[30] UAE contends this also ensures that Natrium is always selected by the model.[31] PacifiCorp justifies this treatment by stating that it is in commercial discussions with TerraPower and will not move forward unless there are benefits for customers. UAE concludes Natrium's treatment in the model is not consistent and comparable with the treatment of other resources.

DPU states PacifiCorp has never responded to requests for 1) Natrium's costs and performance factors and 2) a timeline with major milestones that shows a path to achieving an online service date of 2030.[32] DPU also contends that since no details are available to stakeholders, it is impossible to evaluate Natrium on a comparable and consistent basis with other resources. DPU concludes that until an agreement is finalized, federal funding is certain, and a timeline is provided, Natrium is a speculative resource that should not be in the Preferred Portfolio.[33]

PacifiCorp responds that its selection of Natrium in the P-MM Preferred Portfolio was based on substantial grants from the Department of Energy (DOE), Natrium's development by TerraPower, the alternative path analysis, the OTR and other federal regulatory requirements, and the obligation to provide least-cost, least-risk portfolios.[34] It explains TerraPower bears all development risks and asserts it has not signed any agreements with TerraPower. It reiterates it will only move forward if

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[30] *Id.*, at 9.
[31] *Id.*
[32] DPU Comments, at 21.
[33] *Id.*, at 19.
[34] PacifiCorp Reply Comments, at 35.

Natrium brings value to customers. PacifiCorp indicates the risks associated with Natrium are mitigated because Natrium alternatives require much shorter lead-times than nuclear projects and ample opportunities to meet future electric demand will emerge, before it commits to Natrium.[35] PacifiCorp also reiterates the potential realization of Natrium does not fall within the two- to four-year Action Plan window and explains that Natrium was intentionally limited to years outside of the Action Plan.[36]

b. *Non-Emitting Peaker Plants*

DPU, OCS, and Interwest contend that PacifiCorp favors non-emitting peaker resources (turbines running on 100 percent hydrogen) by assuming they will be available and commercially viable by 2030 even though no such utility scale technology is currently operating. Both DPU and Interwest note the production and transportation plans for hydrogen for utility-scale energy generation are also currently only in the design phase.[37] They explain that while hydrogen could be delivered using a pipeline network from a centralized remote facility, these pipelines do not currently exist. Given these facts, the parties question the selection of the resource for the P-MM Preferred Portfolio.[38] DPU comments it is impossible to

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[35] *Id.*, at 36.
[36] *Id.*, at 37.
[37] DPU comments, at 3 and 22.
[38] In response to a data request, PacifiCorp responded that its modeling of this technology assumes 1) the expense of the needed pipeline, as well as 2) its ability to procure hydrogen at market prices based on forward price curves and projections showing low hydrogen production costs and federal tax credits for 100 percent hydrogen. DPU Comments, at 22-23.

analyze PacifiCorp's cost information since such plants are not commercially operating, and DPU has no way to test any data supporting PacifiCorp's assumptions.[39] DPU adds that the timelines PacifiCorp uses for availability of non-emitting peakers may also be optimistic, and argues that assuming a specific date for this non-emitting resource is speculative.

Interwest criticizes non-emitting peaking resources' selection in the Preferred Portfolio stating that a 20 percent hydrogen blending ratio is inadequate to achieve emission performance requirements because it achieves only a marginal decrease of 6-7 percent in carbon emissions at the gas generating unit.[40] Additionally, there is evidence a sustained green hydrogen supply-chain does not exist.

In response, PacifiCorp states that its main goal is selecting a Preferred Portfolio with the best combination of expected costs and associated risks and uncertainties.[41] Thus, in creating a 20-year plan, it does not limit resources to only those currently estimated to be commercially viable within the planning horizon. Rather, it considers associated risks when it includes resource options. PacifiCorp believes non-emitting peakers, like nuclear, will achieve wider commercial use outside of the two- to four-year Action Plan window and restricts their selection on that basis. PacifiCorp also explains that the alternative path analysis indicates ample

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[39] *Id.*, at 22.
[40] Interwest Comments, at 11.
[41] PacifiCorp Reply Comments, at 41.

opportunity for adjustment to these proxy resource selections based on future analysis.

c. *CCUS Technology*

DPU contends PacifiCorp's planning is biased against CCUS technologies. For example, DPU states that variant P20 JB3-4 CCUS ("P20") (which includes CCUS technology), was the top-performing variant case using the medium gas/medium CO2 assumptions, with a PVRR of $507 million *under* the P-MM Preferred Portfolio variant (using short-term ("ST") value).[42] Variant P20 was also the top performer under a risk-adjusted cost metric and was third in the CO2 emissions category.[43] It was also the top ST cost performer under both the medium gas/zero CO2 scenario and the high gas/high CO2 scenario, and was the top emission performer under both of these scenarios.[44]

PacifiCorp responds that CCUS technologies have shown significant cost uncertainty and only two major utility-scale CCUS retrofit projects are commercially operating.[45] PacifiCorp conceded the P20 variant was the top performer under both ST and risk-adjusted evaluations, but explained it did not choose it for the Preferred Portfolio because 1) the CCUS assumptions are not based on bids or proposals from CCUS technology companies but are proxy assumptions for project-specific costs and

[42] DPU Comments, at 24.
[43] *Id.*
[44] *Id.*
[45] PacifiCorp Reply Comments, at 39.

operational characteristics; 2) the scale of the proposed CCUS technology has never been demonstrated on a coal plant operating commercially anywhere in the world; 3) while feasibility studies for amine-based CCUS at Jim Bridger ("JB") units 3 and 4 have been done, PacifiCorp currently does not have evaluation or equivalent cost data to that of a front-end engineering and design study; 4) the updated fueling strategy to source coal for JB exclusively from the Powder River Basin has not been previously attempted by PacifiCorp; and 5) other limitations, challenges, and risks. In response to a question about whether these risks were analyzed by its model, PacifiCorp indicated its rejection of the P20 variant in the Preferred Portfolio was more of a judgment call.[46]

d. *New Natural Gas Plants*

According to DPU and OCS, PacifiCorp's planning is also biased against generating facilities fueled by natural gas and coal. For example, DPU states PacifiCorp informed stakeholders for the first time in the April 13, 2023 public input meeting that in most scenarios, the recovery period for the costs of new gas resources is assumed to be 10 years to account for PacifiCorp's perceived risks in investments in new carbon emitting resources.[47] DPU requested results from a portfolio variant assuming instead a 40-year cost recovery horizon as realistically in line with new natural gas resources and PacifiCorp responded by producing variant

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[46] DPU Comments, at 24-25.
[47] *Id.*, at 30.

"P24-Gas 40-year Life" ("P24"). PacifiCorp describes it as a variant of the P-MM Preferred Portfolio that changes the technical life assumption for proxy gas resources from 10 years in the base study to 40 years. According to PacifiCorp, this change produced different results. First, the model selected gas units as replacements for any coal retirements, instead of the nuclear or non-emitting peaking options in the P-MM Preferred Portfolio.[48] Second, the "cost of gas pipelines led the model to keep" the Hunter 2 and 3 coal plants running through 2042.[49] Third, the model selected significantly less early DSM.[50] DPU criticizes PacifiCorp's arbitrary decision to change the expected life of new natural gas plants arguing several natural gas plants are currently in different stages of development across the country.[51] DPU also notes the PSC declined to acknowledge the 2021 IRP for a similar reason — PacifiCorp's unilateral decision to force the model to exclude new natural gas plants altogether. DPU explains the decision to constrain the life of a new natural gas plant resulted in an inappropriate Preferred Portfolio. PacifiCorp responds that for the first time, it allowed the model to endogenously select natural gas conversions for a broader set

[48] *Id.*, at 26-27.
[49] *Id.*
[50] *Id.*, at 27 (DPU referencing the 2023 IRP, Volume I, at 305).
[51] DPU presents a map showing natural gas plants that were announced, in early development, in advanced development and under construction in 2023 which DPU states illustrates that many utilities do not attribute the same risks to natural gas plants that PacifiCorp does. DPU Comments, at 29 (Figure 5 – Planned New Natural Gas Plant (S&P)).

of units. According to PacifiCorp, this enhancement expands opportunities for natural-gas-fired operation compared to prior IRPs.[52]

DPU also challenges the final step PacifiCorp used to select the Preferred Portfolio. After all of the variants were run through the model, PacifiCorp explains its decision to select the P-MM variant as the Preferred Portfolio was driven by "consideration of current policies in motion and unmodeled risks for which ongoing trends recommend the adoption and development of tax-supported renewable projects … ."[53] In response to a request for calculations or other supporting data for these subjective criteria, PacifiCorp stated there were no records or calculations to review.

e. *We Find and Conclude PacifiCorp Failed to Treat Resources on a Consistent and Comparable Basis*.

Guideline 4.b. requires "[a]n evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis." In addition, 4.b.iii. states "resource assessments should include: life expectancy of the resources… ."

We find, based on the evidence, that PacifiCorp overlooked the negative attributes of Natrium in its analysis and withheld confidential costs and performance information that were necessary to compare Natrium on a consistent and comparable

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52 PacifiCorp Reply Comments, at 37-38.
53 2023 IRP, Volume I, at 306.

basis relative to other resources. Natrium certainly has potential due to its unique characteristics as described in PacifiCorp's reply comments.[54] However, the IRP contains no discussion of the potential for significant cost overruns or delayed construction timelines typical to the development and construction of nuclear projects. Natrium was selected as a least-cost, least-risk resource in the Preferred Portfolio based solely on its positive, unique attributes. We recognize the sensitivity of PacifiCorp's costs and performance assumptions for Natrium; however, our process provides protections for highly confidential information that may have allowed parties to perform at least a general cost analysis, and PacifiCorp failed to use it. We find it is impossible to compare Natrium with other resources on a comparable and consistent basis without cost and performance assumptions and a realistic assessment of all the potential attributes of Natrium, both positive and negative.

We also find disparate treatment by PacifiCorp of non-emitting resource technologies relative to CCUS technologies. For example, despite the P20 CCUS variant being the top or near the top-performing variant under five different scenarios,[55] PacifiCorp did not select it as a least-cost, least-risk resource in the Preferred Portfolio. The reasons PacifiCorp argues for rejecting CCUS, e.g., that cost assumptions are not based on bids and commercial operation is unproven, apply with

[54] PacifiCorp Reply Comments, at 36.
[55] *See* DPU Comments, at 24.

equal, if not greater, force to the Natrium and non-emitting resource technologies PacifiCorp includes in the P-MM Preferred Portfolio.

Finally, the use by PacifiCorp of a 10-year life for new natural gas plants was arbitrary and unjustified, and prevented their consistent and comparable treatment relative to other resources. The PSC recognizes risks may exist to natural gas plant lifespans attendant to the OTR and other federal regulations. Such risks are inherent in the planning process and require analysis and articulated reasoning on how best to measure and account for them. In this instance, however, the restriction on useful life is unilateral and arbitrary. Neither the OTR nor any other federal regulation changes the depreciable lives of natural gas plants from 40 to 10 years. Moreover, any Oregon, Washington, and California laws that may impact the lives of new natural gas plants do not apply in Utah. Accordingly, the PSC finds that PacifiCorp did not treat natural gas plant options on a comparable and consistent basis relative to other resources, contrary to Guidelines 4.b., 4.b.iii., and 4.h.

2. Reliability and Granularity Adjustments

Sierra Club requests PacifiCorp clarify its methodology for its reliability adjustments and explain the reason the long-term model produces significant energy shortfalls that must be manually addressed. Sierra Club also requests an opportunity to recommend alternative reliability adjustments, and clarification of the values

PacifiCorp uses in the granularity adjustments.[56] Sierra Club suggests that PacifiCorp base its coal units' granularity adjustments on total fuel costs.[57]

PacifiCorp explains that both reliability and granularity adjustments are specific measures that address specific enhancements and there are no logical alternatives because both procedures are dictated by model math.[58] It further explains that in extreme cases where the adjustments exceed plus or minus $100/kW-year, it limits the adjustment to plus or minus $100/kW-year to prevent the granularity adjustment from overwhelming long-term outcomes based on extreme values driven by conditions that will not be relevant in final reliable portfolios.[59] PacifiCorp comments it makes resource adjustments on the basis of measured deficiencies and by applying calculated resource values to determine the appropriate action to cover deficiencies. It states its approach is specific to stated goals and a direct application of model outcomes to improve results. We find PacifiCorp's explanations to be reasonable and sufficiently responsive to Sierra Club's requests. Therefore, we find that no additional information related to its reliability and granularity adjustments is necessary.

[56] Sierra Club Comments, at 4.
[57] *Id.*, at 4 and 42.
[58] PacifiCorp Reply Comments, at 19.
[59] *Id.*, at 20.

3. Customer Rate Impact Analysis

In response to OCS's claim that PacifiCorp failed to comply with Guideline 4.g. by not including a customer rate impact analysis, PacifiCorp states that the IRP includes an indicator of customer rate pressure over time among the initial portfolios relative to the P-MM Preferred Portfolio. It explains that Volume II, Appendix J, stochastic simulation results show incremental and cumulative estimated customer rate impacts over the 20-year planning period that apply equitably across all classes of ratepayers.[60] PacifiCorp indicates that while the approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for ratemaking purposes. PacifiCorp also explains that the IRP is informed by proxy resources where exact costs cannot be known until specific resources are known. We find, based on PacifiCorp's explanation and our review of Volume II, Appendix J, including the figures showing net differences in total system costs, that its analysis meets Guideline 4.g., and no additional analysis is necessary.

4. Miscellaneous Changes to the Presentation of Data

Alternative Portfolio Variants, Cluster Resources, and Scenarios. In response to Sierra Club's request for PacifiCorp to complete model runs of P01-JB3-4 GC, P04-Huntington RET28, and P17-Col3-4 RET25 variants under all of the different pricing

[60] *Id.*, at 22.

scenarios, PacifiCorp responds that because it is constrained from evaluating all studies under all possible conditions, it must prioritize which model variant to analyze. It bases its decisions on the likely investigative value. PacifiCorp states the P01, P04, and P17 results, for example, are so conclusive that further analysis under other, less likely, price scenarios doesn't add likely investigative value. PacifiCorp states that P17, for example, was examined only to determine the cost-effectiveness of an early retirement of both Colstrip units over the optimally selected approach of retiring one unit and continuing the other. PacifiCorp also explains the 2023 IRP evaluates portfolios under five price policy scenarios with attention to investigative value and resource availability. PacifiCorp states it cannot evaluate all studies under all possible conditions and therefore prioritizes cases. At the same time, PacifiCorp asserts, it has been responsive to stakeholder requests, conducting additional studies as time and resources allow.

PacifiCorp explains that the analysis of P18 and P19 likewise was conducted with the understanding that additional resources would likely result in a higher cost PVRR outcome and that the value of the studies was to assess the magnitude of that PVRR impact to determine possible least-regret paths to consider for the Preferred Portfolio. It further explains that the results of the studies supported the selection of the Preferred Portfolio without the additional marginal cluster resources in the East or West.

We find PacifiCorp's explanation that it cannot evaluate all studies under all possible conditions, and therefore prioritizes cases, is reasonable. We also find that PacifiCorp has been responsive to stakeholder requests for alternative and additional model runs, conducting additional studies as time and resources allow, and that running the proposed additional variants would produce more portfolios but would not change the final outcome and, therefore, be of limited value. Based on this, we find it is unnecessary for PacifiCorp to run the requested additional modeling.

Coal fuel costs for JB and pipeline capacity for conversions. We find PacifiCorp's response to the request that it use the base tier pricing from the 2023 JB long-term fuel plan for the JB plant, to be reasonable. PacifiCorp states that the fixed and variable cost structure assumed in the 2023 IRP captures the cost of continuing or ceasing coal-fired operation at JB units 3 and 4. It explains that opportunities to optimize coal supply for particular circumstances are ill-suited for modeling in the IRP and provide limited incremental benefit.

We also find PacifiCorp's response to Sierra Club's request that PacifiCorp provide an assessment of the availability and cost of firm interstate pipeline capacity necessary to supply its planned coal to gas conversions in the 2023 IRP Update, to be reasonable. PacifiCorp explains that due to confidentiality agreements between it and third-party entities, it is unable to disclose any terms on firm interstate pipeline capacity for planned conversions.

Carbon. Sierra Club recommends PacifiCorp increase the medium carbon price assumption to reflect recent federal regulations and incorporate the developments in the 2023 IRP Update. According to PacifiCorp, the request is based on a misunderstanding of the medium CO2 price assumption cost function. It explains that the medium CO2 price assumption is a proxy for future drivers. Its CO2 proxy cost forecast represents an established trend of decarbonization into the future and is based on a survey of (then) currently available forecasts. PacifiCorp explains that it is not the role of the proxy cost to drive decarbonization, rather its role is to represent drivers that can be reasonably forecast. It further explains its forecasting of the decarbonization trend will continue into the future. Regarding the request for elimination of "the medium gas price, zero CO2 price ('MN') price-policy scenario or zero CO2 ('LN') price-policy scenarios generally,"[61] PacifiCorp states this would generally eliminate a source of information from the robustness of portfolios that indicates what may occur if the expected case CO2 proxy forecast is not realized. PacifiCorp asserts that while the medium gas price-policy scenario is the most likely, eliminating it or any alternative, as requested, is unnecessary. We find PacifiCorp's response credible. On this basis, we find that it is unnecessary to run the requested analyses.

[61] *Id.*, at 26.

Collocated Resources. UAE recommends the PSC direct PacifiCorp to make its requested changes to Tables 9.31, 9.32, and 9.33, and Figures 9.60 and 9.62 in future IRP filings. UAE's main concern is that the tables lack detail on whether the generation and storage resources shown are collocated or standalone resources. PacifiCorp responds that collocation information is illustrated in Figure I.1 of the 2023 IRP. It lists the portfolio resources selected by location and year, including solar and wind resources that are collocated with storage. PacifiCorp also refers to the discussion on the expansion of collocation opportunities in section III.A.2 – *Process Improvements,* in the 2023 IRP indicating that collocation options are no longer constrained in the modeling. We find PacifiCorp's explanation is responsive to UAE's requests; therefore, we decline to order the requested changes in future IRP filings.

Surplus Interconnection. Sierra Club requests PacifiCorp allow storage to be paired with not only new renewable resources, but also existing fossil fuel resources. According to Sierra Club, this use of a thermal asset with a storage resource "would increase the flexibility of the asset and provide lower emission reliability services, such as spinning reserve" and likely "reduce operating costs as the storage asset could operate more responsively."[62]

PacifiCorp responds that it has modeled surplus interconnection in the 2023 IRP, where storage resource options were available to be selected with potentially

[62] Sierra Club Comments, at 55-56.

any technology or combination of technologies, allowing portfolio optimization to recognize the best location, size, and timing for storage concurrently with considerations of existing technology profiles, and also in tandem with thermal retirement options. PacifiCorp adds that storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed at any modeled location on the system. It explains that its strategy has exceeded the requests by allowing the model to make the best collocation determinations endogenously and refers Sierra Club to the IRP discussion of expanded collocation opportunities in section III.A.2 - *Process Improvements*. We find PacifiCorp's response to be reasonable and find that PacifiCorp has already modeled the requested interconnection scenario, and no additional modeling is necessary.

C. PROCESS ISSUES

DPU contends the 2023 IRP was filed after the March 31 deadline for the third IRP cycle in a row, and the continual filing delay disadvantages stakeholders as it compresses their opportunity to review and evaluate the IRP. DPU explains it agreed to PacifiCorp's extension request because it was the least objectionable alternative. OCS, UAE, and UCE also contend that PacifiCorp's failure to provide the modeling results to stakeholders before it filed the preliminary IRP prevented them from having any opportunity to review, evaluate, and provide public input, which OCS and UAE claim violates Guideline 3. DPU and OCS note that even the media knew the modeling results before stakeholders who invest significant time and resources into the IRP planning process. UCE agrees that PacifiCorp should provide the modeling results to stakeholders to allow for sufficient review before filing the IRP. WRA also joins DPU, OCS, UAE, and UCE in the overall concern that time constraints impact not only the ability to appropriately review, evaluate, and provide input, but also lessen the accuracy and quality of the IRP. WRA also asserts the current IRP process and timeline do not work and suggests the PSC make a structural change.

PacifiCorp responds the two-month extension to file the 2023 IRP by May 31, 2023 was necessary to allow PacifiCorp to incorporate recent federal and state law changes such as the OTR, the IRA interconnection rules, and other state regulatory requirements. PacifiCorp asserts that while several parties expressed concern over the requested extension, no one recommended the PSC deny it and notes that stakeholders requested PacifiCorp provide a draft IRP in comments related to the 2021 IRP. PacifiCorp further asserts the extended stakeholder engagement process enhanced the accuracy and comprehensiveness of the IRP that led to a significantly improved analysis in the final 2023 IRP. In sum, PacifiCorp notes that the public input process affords many opportunities for comment and quotes the PSC stating, "'[t]he purpose[] of the process is *not* to allow stakeholder[s] an early preview of what

PacifiCorp has [ultimately] elected to do. The purpose is to allow them an opportunity to provide meaningful feedback at each stage of a collaborative process.'"[63]

Our direction on the interpretation of Guideline 3 has been clear. The opportunity for stakeholders to examine and provide information during the IRP development, rather than after the fact, is an important aspect of the process.[64] The IRP is to be developed in consultation with stakeholders who must have ample opportunity for meaningful feedback and information exchange during the development of the plan and at each stage of the process.[65] In this docket, PacifiCorp did not share its modeling results and the Preferred Portfolio, two of the most critical aspects of the IRP, with stakeholders until after it filed its preliminary IRP on April 3, 2023. This is the first time that PacifiCorp has not provided modeling results and Preferred Portfolio selections before making its IRP public. However, this is also the first time that we have added an extended filing period that included the filing of a preliminary IRP and a comment deadline. In light of the uncertainties created by this new procedure, we do not find PacifiCorp violated Guideline 3. Nevertheless, we

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[63] PacifiCorp Reply Comments, at 11. In quoting the PSC's order about the purpose of the process, PacifiCorp unfortunately misinterpreted our language and quoted it out of context. The PSC was reacting to PacifiCorp's pattern of untimeliness, of presenting meeting materials at the last minute, and of making key modeling decisions without giving stakeholders time to review and provide meaningful input. A major purpose of the IRP Guidelines is to assure PacifiCorp collaborates and shares information with stakeholders before decisions, in particular crucial ones like the selection of the Preferred Portfolio, are made.

[64] PacifiCorp's 2017 Integrated Resource Plan, Docket No. 17-035-16, Report and Order issued March 2, 2018, at 7-8.

[65] *Id.*, at 7.

remain troubled by the evident lack of collaboration, in particular with respect to key decision points in the IRP planning process. Here, parties did not collaborate on the most consequential aspects of the IRP — modeling results and the Preferred Portfolios - before the preliminary IRP became public. Therefore, in this order we provide notice that in all future IRP dockets, Guideline 3 will apply to preliminary IRP disclosures and filings. As we have said before, PacifiCorp must provide parties ample opportunity to review, analyze, and provide meaningful input at all stages of the IRP process. Moreover, this must be done with adequate time for PacifiCorp to evaluate and, as appropriate, apply that input before filing any IRP, whether preliminary or final.

D. MISCELLANEOUS REQUESTS RELATED TO THE 2025 IRP

Modeling extreme weather events.

The OCS and DPU recommend PacifiCorp include in its modeling the effects of long-lasting extreme weather events. OCS specifically cites the September 2022 heatwave and the February 2021 Texas extreme cold event as examples of the types of weather events that should be modeled in order to identify potential system reliability issues. PacifiCorp responds that it already models several weather scenarios, and will continue to model them in upcoming IRP cycles. It explains that it not only considers climate change within its baseline forecast, but within multiple load forecast scenarios. As an example, PacifiCorp states that the 1-in-20-year extreme weather scenario evaluates peak weather impacts using the most extreme peak observed over the past 20 years. PacifiCorp also states the 20-year normal weather scenario evaluates the weather impacts on load assuming weather is consistent with the average temperatures observed over the prior 20 years.

We find PacifiCorp's modeling of weather scenarios amply addresses OCS's concerns. To the extent other methodologies for modeling extreme weather events arise, we encourage PacifiCorp to study and discuss them with stakeholders during the IRP planning process.

Modeling GET.

OCS asserts the IRP model does not, but should, contain a process to evaluate GET or other advancements to maximize the efficiency of the grid. OCS explains that by avoiding construction of very costly transmission lines or transmission interconnection activities, GET could enable the development of lower cost Preferred Portfolios. Likewise, Interwest recommends that PacifiCorp include GET in future IRPs.

PacifiCorp responds that Chapter 4 and Appendix E of the 2023 IRP review the potential for reconductoring with advanced conductors as well as using other GET. It states it considers and identifies network upgrades using advanced conductors and GET wherever feasible, and this approach provides adequate analysis for the long-term. We find the 2023 IRP sufficiently evaluates GET as evidenced in Chapter 4 and Appendix E. We therefore decline to direct PacifiCorp to perform additional analysis in this area.

Modeling Enhanced Geothermal Systems ("EGS").

UCE recommends PacifiCorp consider evaluating EGS technologies in the 2025 IRP cycle. UCE explains that Utah is home to the Utah Frontier Observatory for Research in Geothermal Energy ("FORGE") project[66] which is sponsored by the Department of Energy for developing, testing, and accelerating breakthroughs in EGS. UCE states that Fervo Energy is developing the 400 MW Cape Station project in Beaver County, Utah that is expected to go online in 2028. UCE concludes that EGS should be added to other emerging technologies like Natrium and non-emitting (hydrogen) resources that PacifiCorp evaluates.[67]

PacifiCorp responds that it studied and updated geothermal technologies as an option in the 2023 IRP, but they were not selected in the Preferred Portfolio. PacifiCorp states it intends to continue to include geothermal options and update its costs and technical assumptions in future IRPs and remains open to considering geothermal competitive bids in its RFP processes.[68] We find, based on PacifiCorp's explanation, that it has considered, and intends to continue to consider, EGS as another emerging technology for evaluation in future IRPs.

[66] UCE Comments, at 7.
[67] *Id.*, at 8.
[68] PacifiCorp Reply Comments, at 31-32.

Federal and state incentives.

Sierra Club recommends PacifiCorp apply tax bonus credits for "energy communities" to all qualifying communities and correct inaccuracies and update its supply side resource workpapers to include the investment tax credits and production tax credits granted under the IRA for storage resources.[69] PacifiCorp responds it will continue to pursue opportunities to share government funding updates with stakeholders.[70] PacifiCorp also states that not all resources planned in the 2023 IRP over the 10-year period qualify for EIR, as Sierra Club appears to imply.

For example, PacifiCorp explains that only company-owned resources would be expected to qualify, and this would exclude non-owned purchase power agreements selected by the RFP process.[71] PacifiCorp reiterates that the long-term IRP is based on proxy resource selection. PacifiCorp asserts that cost-saving opportunities, such as those provided by federal incentives, are addressed during the acquisition process and will manifest through an all-source RFP. PacifiCorp encourages stakeholders to actively monitor PacifiCorp press releases to look for new funding developments.

We find PacifiCorp's response is reasonable. No additional analysis on federal and state funding opportunities is necessary in the IRP. We find that incentive-based

[69] Sierra Club Comments, at 3.
[70] PacifiCorp Reply Comments, at 29.
[71] *Id.*

savings opportunities associated with specific resources are more appropriately considered in the acquisition approval regulatory process.

Participation in Regional Transmission Planning.

Interwest contends that solar-rich regions of PacifiCorp's service territory could provide valued capacity and energy diversity and recommends PacifiCorp include in the next IRP detailed participation updates regarding coordination between NorthernGrid and WestConnect regional planning authorities.[72] Additionally, Interwest suggests the PSC direct PacifiCorp to participate in and report on other transmission planning efforts such as the Western Transmission Expansion Coalition. Interwest further recommends that PacifiCorp include an analysis of potential interconnection points to other utilities.[73]

PacifiCorp responds that participation in regional planning authorities is important and that it is an active member of NorthernGrid and coordinates with WestConnect through NorthernGrid via Interregional Coordination meetings.[74] PacifiCorp points to Volume I, Chapter 3 - Planning Environment, of the 2023 IRP for information on the Western Energy Imbalance Market, Extended Day-Ahead Market, the WRAP, "Markets+" a Southwest Power Pool day-ahead market offering, and other developments to demonstrate it takes an active role in regional planning. It also states

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[72] Interwest Comments, at 25.
[73] *Id.*
[74] PacifiCorp Reply Comments, at 43.

that collaborating with other utilities is a common practice in transmission planning, and where feasible, collaborations with other utilities can be used to inform the IRP.[75]

The PSC finds the IRP sufficiently discusses and analyzes PacifiCorp's participation in regional planning and provides adequate information on PacifiCorp's regional market participation and the significant benefits that current energy imbalance market participation brings to customers. The PSC finds it is not necessary to require the requested additional analysis.

Integration costs reporting.

Interwest urges PacifiCorp to study and report in the 2025 IRP the costs of inflexible thermal resources in assigning integration costs.[76] PacifiCorp explains that integration costs represent the incremental cost of holding reserves for additional renewable resources. It states that the number of reserves required is reduced because wind and solar resources are added to a pool of reserve requirements that includes load, wind, solar, and non-dispatchable thermal and hydro resources.[77]

PacifiCorp explains that using a pool of reserves to cover variations reduces the reserve requirement. For example, higher than expected wind output may offset lower than expected solar output, load may drop at the same time as wind output, and both circumstances can result in a reduced need for reserves to be deployed.[78]

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[75] *Id.*
[76] Interwest Comments, at 30.
[77] PacifiCorp Reply Comments, at 44.
[78] *Id.*

PacifiCorp states that as part of the 2025 IRP, it intends to develop updated reserve requirements for load, wind, solar, and non-dispatchable resources, and will present the analysis and results as part of the public input process for stakeholder feedback. PacifiCorp adds that as part of model optimization, PLEXOS ensures these reserve requirements are met by dispatchable resources specific to a given portfolio, where portfolios with more dispatchable resources can fulfill those requirements at lower cost.[79] As a result, integration costs are embedded within the reported cost results. PacifiCorp states that portfolio results do not have a dollar per megawatt-hour integration cost added for wind and solar generation, as these costs are part of the core optimization calculation and in any case differ widely across portfolios and future conditions.

The PSC finds PacifiCorp's explanation that integration costs are embedded within the reported cost results satisfies Interwest's request. Other than PacifiCorp's plan to develop updated reserve requirements and the presentation of its analysis as part of the 2025 IRP public input process, we find that no other analysis at this time is necessary.

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[79] *Id.*, at 44-45.

E. PROPOSED STRUCTURAL CHANGES TO THE IRP PROCESS

We recognize this is the third cycle in a row that PacifiCorp has requested and received additional time to finalize its IRP. WRA provides evidence that since 1992, almost half of the IRPs were filed after significant delay and only three were unequivocally timely filed.[80] In this instance, the 2023 IRP, its Action Plan, and Preferred Portfolios were developed in the context of rapidly changing laws and energy policies. This necessitated an extension of the schedule to provide some opportunity for stakeholders to review the modeling results and the Preferred Portfolios. The two-month extension turned out to be too short. Both DPU and WRA note that non-confidential supporting information was not made available to stakeholders until April 17, 2023, confidential information supporting the filing was made available on May 1, 2023 after the April 30, 2023 comment deadline, and final confidential supporting information was filed on June 16 and June 20, 2023. The last of the finalized information was filed more than 11 weeks after the 2023 IRP original due date.

It is evident once again in this IRP cycle that the current IRP planning process, even with the authorized extensions, does not provide sufficient time 1) for PacifiCorp to develop an effective IRP, and 2) for stakeholders to review, evaluate, and provide

[80] WRA states, "[o]f the fifteen planning cycles [since] 1992, three were unequivocally timely; one provided a partial filing on the required date but added an addendum three months later; three were late by days rather than months; but six, close to half, were more significantly delayed … rang[ing] from one month to two-and-a-half years with a median delay of five months." WRA Comments, at 6.

meaningful input at all phases of IRP development. Consequently, we direct DPU, and invite OCS and other IRP participants, to file in this docket by May 30, 2024 recommendations concerning changes to the IRP schedule that will better provide PacifiCorp and all IRP participants adequate time to meet the public collaboration and participation objectives of the Guidelines and described in this and prior IRP orders. We will issue an order outlining the next steps in our consideration of changes to the IRP schedule after reviewing parties' recommendations.

F. THE P-MM PREFERRED PORTFOLIO AND THE LEAST-COST, LEAST-RISK RESOURCE

The fundamental objective of the IRP planning process is to arrive at the least-cost, least-risk resources otherwise known as the Preferred Portfolio. As discussed in detail above,[81] the disparate and inconsistent treatment of Natrium, non-emitting resources, new natural gas plants, and CCUS technologies, resulted in a Preferred Portfolio that fails to withstand scrutiny. Most parties recommended we not acknowledge the 2023 IRP, in part, due to the lack of analytical consistency. DPU put it best that "… small assumptions or changes in inputs can have a large impact on the resource mix ten years down the road … ."[82] The impact of consequential decisions like a dramatic change in the cost recovery period for new proxy gas plants is even greater and should not be made arbitrarily and unilaterally. For these reasons, we

[81] *See* Section IV.B.1. of our Order.
[82] DPU Comments, at 29.

find and conclude the portfolio selection process, and the P-MM Preferred Portfolio, lack credibility and do not acknowledge them.

G. THE ACTION PLAN

The 2023 Action Plan identifies specific actions PacifiCorp intends to take over the next two- to four-year period to deliver resources included in the Preferred Portfolio. PacifiCorp requests that we acknowledge and express support for this Action Plan. Utah Admin. Code R746-430-1 defines "Action Plan" and outlines the contents and supporting information and analysis required. It also states: "Nothing in these rules requires any acknowledgment, acceptance[,] or order pertaining to the Action Plan submitted." Despite that provision, for clarity we state explicitly that we decline to acknowledge or approve the Action Plan submitted with the 2023 IRP. We agree with parties who assert the suspension of the 2022 AS RFP must certainly and substantially impact the Action Plan, yet, on this record we have no way to know exactly how or to what precise degree. Additionally, as with the Preferred Portfolio, the unjustified inconsistencies in the modeling of various resource types cast serious doubts as to the trustworthiness of the resulting Action Plan. In particular, we find the decision to model a 10-year technical life for a proxy new natural gas plant impacts near-term decisions that could prevent customers from potentially attaining significant savings starting in the 2028-2030 period.[83] This finding is corroborated by

[83] *See* Figure 9.45, 2023 IRP Volume I, page 306.

DPU, OCS, and several other parties that urge us to refrain from acknowledging the Action Plan.[84]

V. SUMMARY AND CONCLUSIONS

We recognize the substantial body of quality work completed by PacifiCorp in preparing the 2023 IRP. PacifiCorp filed extensive documentation and workpapers with the 2023 IRP. The level of detail is useful, and the information provided is well organized. We encourage PacifiCorp to continue to provide such detailed back-up data and workpapers in future IRPs.

We also appreciate the diligent efforts and thoughtful comments provided by all parties. We recognize the frustration expressed by many participants with the limitations on their opportunities to provide timely feedback at each stage of the planning process.

After fully considering the 2023 IRP and the parties' comments and reply comments, we acknowledge that, with the exceptions noted, PacifiCorp substantially adhered to the Guidelines in developing its 2023 IRP. Nevertheless, the identified exceptions are of such significance they undermine our confidence in the portfolio selection process, the P-MM Preferred Portfolio, and the Action Plan. Accordingly, we do not acknowledge these aspects of the IRP.

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[84] *See e.g.,* Section IV.A. and IV.B.1. of our Order.

VI. ORDER

We direct DPU, and invite OCS and other IRP participants, to file in this docket by **Thursday, May 30, 2024**, recommendations concerning changes to the IRP schedule that will better provide PacifiCorp and all IRP participants adequate time to meet the Guidelines' public collaboration and participation objectives, including those described in this and prior IRP orders.

DATED at Salt Lake City, Utah, April 17, 2024.

/s/ David R. Clark, Commissioner

/s/ John S. Harvey, Ph.D. Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#333432

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the PSC within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC fails to grant a request for review or rehearing within 30 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G-4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on April 17, 2024, a true and correct copy of the foregoing was served upon the following as indicated below:

By Email:

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Administrative Assistant

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-130:
Idaho PUC on Pac 2023 IRP

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP'S APPLICATION FOR ACKNOWLEDGEMENT OF THE 2023 INTEGRATED RESOURCE PLAN	)))))	**CASE NO. PAC-E-23-10** **ORDER NO. 35977**

On March 31, 2023, Rocky Mountain Power, a division of PacifiCorp ("Company"), filed an application ("Application") with the Idaho Public Utilities Commission ("Commission") requesting acknowledgment of the Company's 2023 Integrated Resource Plan ("IRP"). On May 31, 2023, the Company submitted an amended 2023 IRP ("2023 IRP").

The Company represented that it submitted the 2023 IRP filing in compliance with Order No. 22299, Case No. U-1500-165, dated January 1989; whereby the Commission ordered biennial filings of the electric integrated resource plan. The Company stated that its plan was also submitted to the Commission as the Resource Management Report on the Company's resource planning status.

The Company represented that the 2023 IRP contains information outlining how the Company has addressed the Commission's integrated resource planning requirements, and the Company requested that the Commission acknowledge the 2023 IRP in accordance with the Commission's rules, and fully support the 2023 IRP conclusions, including the proposed action plan.

The Company files an IRP on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. The Company represented that the 2023 IRP fulfills the Company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. 2023 IRP Vol. 1 at 35.

The Company represented that the 2023 IRP was developed through a collaborative public input process with involvement from regulatory staff, advocacy groups, and other interested parties, and that the Company's selection of the 2023 IRP preferred portfolio was supported by comprehensive data analysis and an extensive public-input process, and includes substantial new renewables, facilitated by incremental transmission investments, demand-side management ("DSM") resources, significant storage resources, advanced nuclear, and non-emitting peaking resources. *Id.*

The Company represented that the 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals ("RFP") including 1,792 megawatts ("MW") of wind and 495 MW of solar additions with 200 MW of battery storage capacity. *Id.* The Company stated that these resources will come online in the 2024-to-2025 timeframe, and that the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. *Id.* The Company also represented that through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022 All-Source RFP is currently soliciting and evaluating resources to fulfill. *Id*.

The Company represented that the 2023 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium demonstration project, anticipated to achieve online status by summer 2030, 1,000 MW of additional advanced nuclear resources through 2033, and 1,240 MW of non-emitting peaking resources through 2037. *Id.* Additionally, the Company stated that over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar. *Id.*

The Company represented that the preferred portfolio includes the construction of a 416-mile 500-kilovolt ("kV") transmission line known as Gateway South connecting southeastern Wyoming and northern Utah, the 59-mile 230 kV transmission line in eastern Wyoming known as Gateway West Segment D.1, and the 500 kV, 290-mile transmission line across eastern Oregon and southwestern Idaho known as Boardman to Hemingway (B2H). *Id.*

STAFF COMMENTS

Based on Staff's review of the Company's 2023 IRP and Staff's participation in the series of 2023 IRP Stakeholder Meetings, Staff believed that the 2023 IRP addresses the requirements outlined in Commission Order No. 22299. Staff recommended that the Commission acknowledge the 2023 IRP.

However, Staff is concerned that recent change in federal policy exposes the Company's customers to higher costs and risks as the Company accelerates its transition away from dispatchable coal-fired generation toward other dispatchable resources. Staff is also concerned that technological and permitting challenges for implementing the new Natrium Nuclear plants add potential risk and higher cost if these plants are not completed as forecast; and that highly variable natural gas prices relative to more stable priced coal exposes customers to higher energy costs in both the near-term and long-term as the Company relies on more natural gas to maintain dispatchable capacity for its system as it transitions away from coal as part of its coal unit conversions and exits.

Based on its review of the 2023 IRP, Staff recommended that:

1. The Company review its practices for hedging natural gas fuel supply to mitigate fuel-supply risk as it continues to step away from coal and into increased use of natural gas for dispatchable generation;
2. The Company keep the Commission informed with regular updates on the Company's progress toward implementation of the Natrium Nuclear plants;
3. The Company consider strategies to address potential delays in the capacity provided by the B2H transmission line; and
4. The Company begin forecasting the benefits of WRAP when it is projected to become a binding participant in the next IRP.

COMPANY REPLY COMMENTS

The Company noted that its risk management policy, which includes the power and gas limits program, is reviewed/revised at least once per year. The Company also stated that it is open to providing the Commission with updates to the status of the Natrium demonstration project as needed. Additionally, the Company represented that the 2023 IRP process includes ongoing evaluation of the Boardman-to-Hemmingway project, and that the Company remains open to suggestions for future analysis. Finally, the Company explained that it expects that its 2025 IRP will include discussion of the impacts of WRAP compliance and will include appropriate modeling of planning reserve margin and resource requirements.

PUBLIC COMMENTS

The Commission received seventeen (17) public comments, all of which reflect the same basic concern that the Company is not doing enough to commit to reducing greenhouse gas emissions.

COMMISSION FINDINGS AND DECISION

The Company is a public utility as defined in *Idaho Code* §§ 61-119 and -129, and the Commission has jurisdiction over it and the issues in this case under Title 61 of the Idaho Code, including Idaho Code § 61-501. Having reviewed the record, the Commission finds that the Company's 2023 IRP satisfies the requirements in the Commission's prior orders, and the Commission acknowledges the 2023 IRP.

In doing so, the Commission once again reiterates that an IRP is a working document that incorporates many assumptions and projections at a specific point in time. An IRP is a plan, not a blueprint, and by issuing this Order we merely acknowledge the Company's ongoing planning process, not the conclusions or results reached through that process.

The Commission does not approve the 2023 IRP, or any resource acquisitions referenced in it, endorse any particular element in it, opine on the Company's prudence in selecting the 2023 IRP's preferred resource portfolio, nor allow or approve any form of cost recovery. The appropriate place to determine the prudency of the Company's decisions to follow or not follow the 2023 IRP, and the validation of predicted performance under the 2023 IRP, is a general rate case or other proceeding where the issue is noticed.

ORDER

IT IS HEREBY ORDERED that the Company's 2023 IRP is acknowledged.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date upon this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* §§ 61-626 and 62-619.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 31st day of October 2023.

ERIC ANDERSON, PRESIDENT

JOHN R. HAMMOND JR., COMMISSIONER

EDWARD LODGE, COMMISSIONER

ATTEST:

Jan Noriyuki
Commission Secretary

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-131:
FERC Western Energy Markets Explainer

Western Energy Markets Explainer

This explainer offers a comprehensive overview of the electricity markets in the Western United States. It covers key features of the markets that enable coordinated and efficient management of the region's electric transmission grid system. This explainer will help you understand how new developments in electricity markets in the West may impact energy costs, system reliability, and the implementation and achievement of state-level energy policies.

This explainer is organized with four major sections:

This explainer offers a summary of publicly available information about Western markets and should not be relied upon as a legal document.

Key Terms

Balancing Authorities oversee electricity transfers and ensure grid stability by maintaining a balance between the production and consumption of electricity. They typically oversee long-term efforts to maintain that key balance on the grid, such as resource planning, as well as short-term balancing by committing electricity supply resources to operate and real-time load-frequency control within a balancing authority area. Certain electric utilities and power marketing administrations (see below) are typical examples of balancing authorities.

A **Balancing Authority Area** is a geographic region that incorporates a collection of generation facilities, transmission lines, and loads (aggregated consumer demand for electricity) where electric metering is performed by a balancing authority. The responsibility of maintaining a balance between the load and resources (supply of electricity) within this area falls under the jurisdiction of the balancing authority. One example of a balancing authority area is a utility service territory.

Congestion occurs when a portion of the transmission grid becomes overloaded with electricity. Congestion can occur when a line or transformer reaches its limit and cannot carry any more electricity. When congestion occurs, the lowest-priced electricity cannot flow freely to a specific area.

Congestion Revenue Rights are financial tools used to manage the cost variability of congestion on the grid based on the electricity pricing approach used, called locational marginal pricing (see below). Such rights are often acquired to hedge against congestion costs in the day-ahead market, but sometimes are purchased as an investment.

A **Day-Ahead Market** is a voluntary financial market where individuals and companies can buy and sell wholesale electric energy at financially binding prices for the next day.

Hedging is the act of engaging in transactions to reduce risk from price volatility (see below) for a company and/or customers. Hedging transactions can help electricity suppliers meet their customers' demands while reducing or eliminating the risk of fluctuating prices.

Locational Marginal Pricing or Prices (LMP) refer, respectively, to the overall pricing scheme or the actual prices paid for wholesale electric energy at a specific location within an electric transmission grid at a specific point in time. LMP data is used to track the prices of electricity in different parts of the grid and to help manage supply and demand for electricity.

Price Volatility describes how quickly or widely prices can change. In the energy industry, price volatility can refer to electricity or natural gas supply prices, relative to consumer demand. Volatility is measured by the day-to-day variation (percentage difference) in the price of the commodity.

A **Power Marketing Administration** is a federal agency within the Department of Energy that markets electric power produced by federal dams and multiple-purpose water projects providing service to customers.

A **Real-Time Energy Market** is a spot market that allows consumers, companies, and energy distribution businesses to buy and sell wholesale electric energy in real-time, usually an hour before delivery. The real-time market balances the differences between day-ahead resource commitments and demand forecasts and the actual real-time demand for and production of electricity.

Resource Adequacy is the ability of an electric transmission grid to meet consumer demand for power. Resource adequacy ensures that there is enough energy generating capacity and reserves to maintain a balanced supply and demand across an electric system.

Wholesale Electric Energy, also referred to as wholesale electricity, is electric energy that is purchased or sold for resale, whereas retail electric energy is electric energy that is purchased by or sold to the ultimate consumer.

California ISO Extended Day-Ahead Market is a voluntary day-ahead electricity market designed to deliver significant reliability, economic, and environmental benefits to balancing areas and utilities throughout the West. The initial structure of EDAM was approved, in most part by the Commission in December 2023.

Introduction

In the U.S., the power grid is a complex network of power plants and transmission lines with extra-high-voltage connections between utilities. This expansive infrastructure allows the movement of electricity from one part of the network to another.[1] Over time, the U.S. power grid has evolved into three large interconnected systems, which are shown in Figure 1:

1. the Eastern Interconnection that operates in states east of the Rocky Mountains
2. the Western Interconnection that covers the Pacific Coast to the Rocky Mountain states
3. the Texas Interconnected System, known as ERCOT

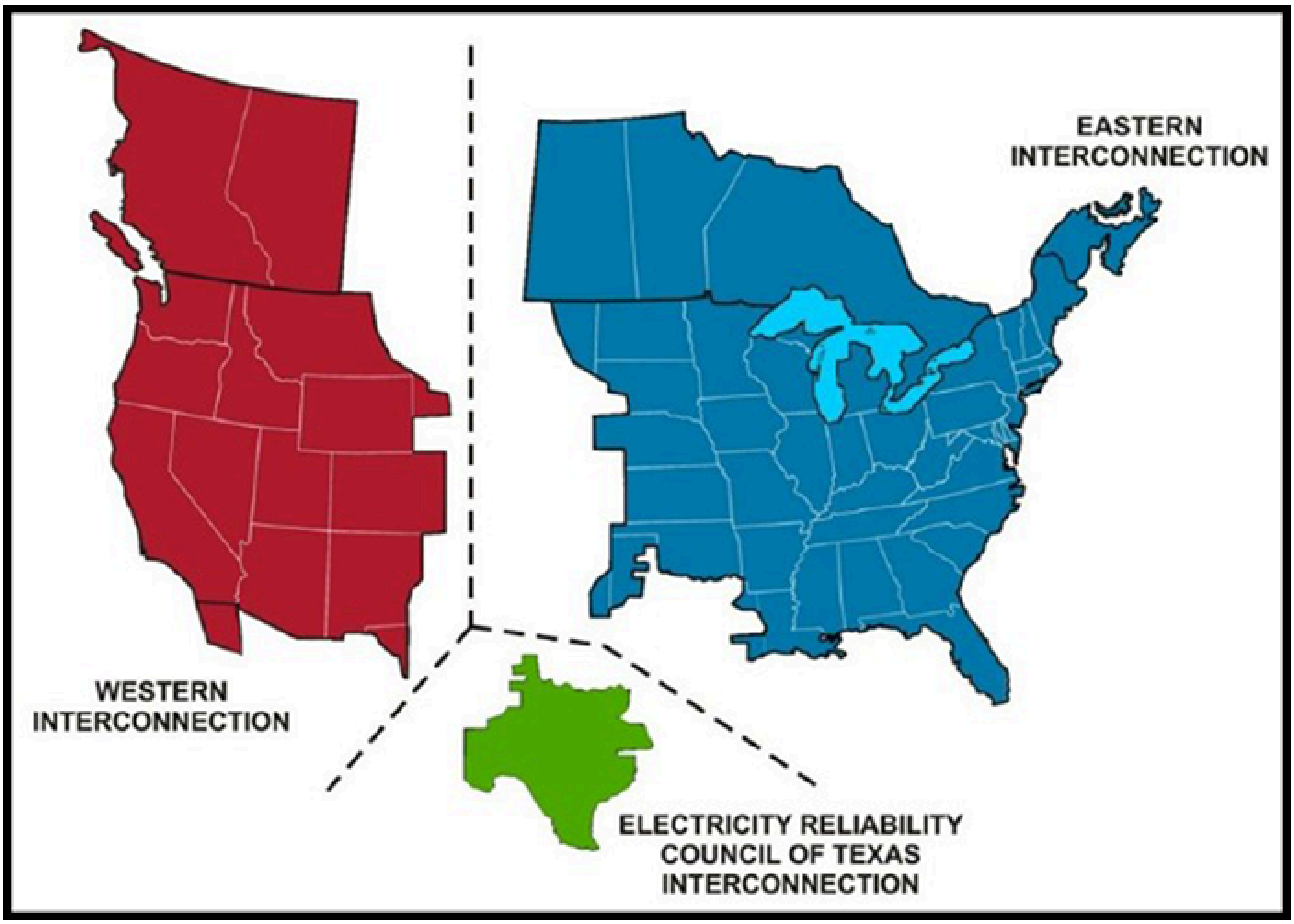


Figure 1. The Three Major Interconnections of the U.S. Electric Power Grid. Source: North American Electric Reliability Corporation.

The electric grid must comply with standards developed by the North American Electric Reliability Corporation (NERC) to ensure reliability of the grid. Because these three systems encompass unique geographic areas, NERC also assigns responsibilities to six regional entities who apply standards and act as compliance authorities. In the Western Interconnection, the Western Electricity Coordinating Council (WECC) is the regional entity, which oversees bulk power system reliability and security in the region. [2]

In the late 1990s, FERC initiated significant reforms in the electricity sector to support competition in the energy marketplace. The milestones included:

- Order No. 888 (1996): established the foundation for organized wholesale markets by promoting independent system operators (ISOs).[3] These entities were designed to foster competition among electricity generators at the wholesale level.
- Order No. 2000 (1999): encouraged utilities to join regional transmission organizations (RTOs). The aim was to enhance the operation of transmission systems and to develop equitable transmission management practices.[4]

Today, RTOs and ISOs play a crucial role in electricity policy. They serve approximately two-thirds of U.S. electricity consumers, managing both power markets and regional transmission systems (Figure 2 shows the boundary areas the RTO and ISO regions).[5]

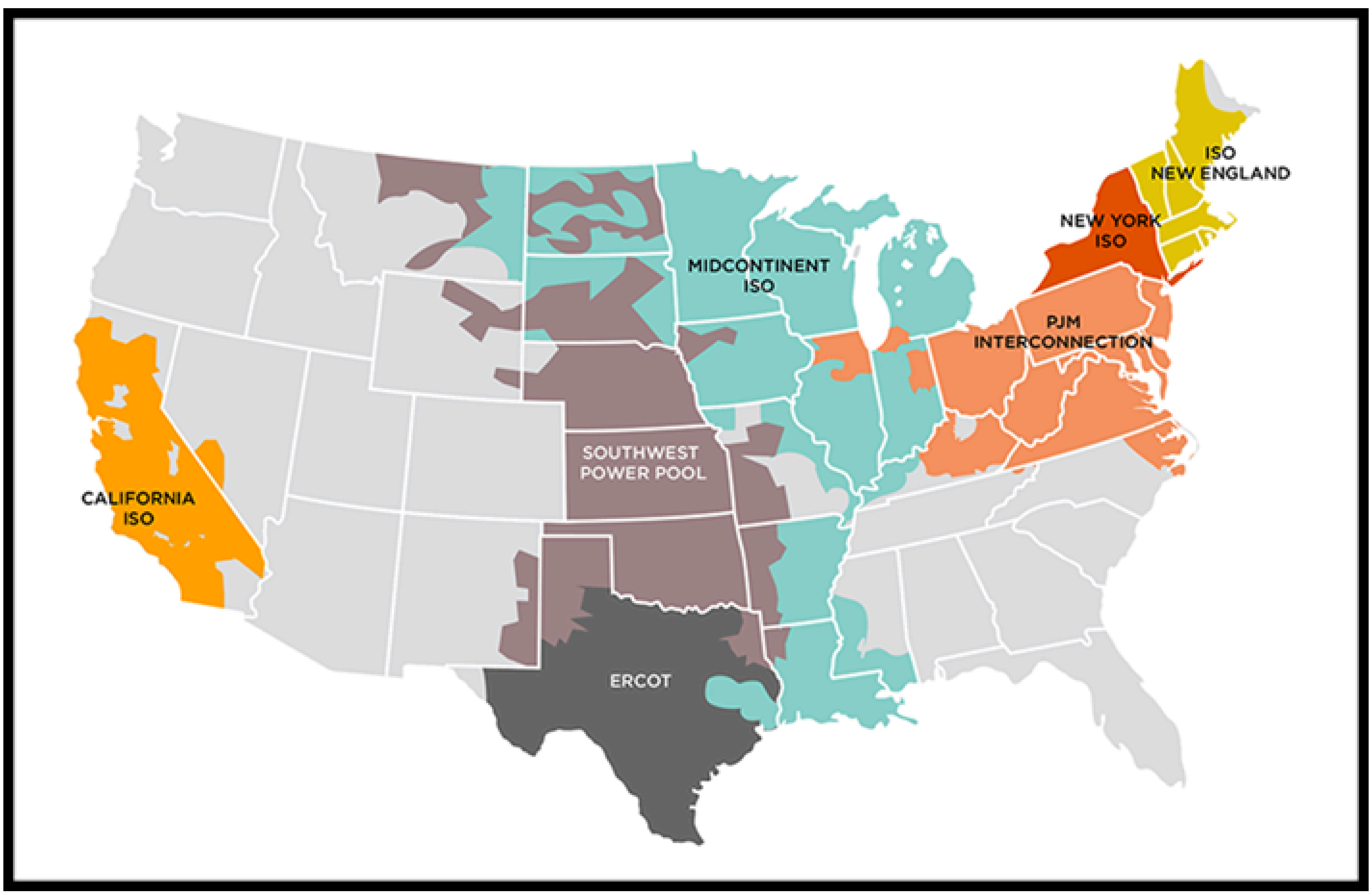


Figure 2. Seven RTO and ISO Regions in the Continental United States.

The West has progressively developed its regional wholesale electricity markets, adopting new systems and improvements step-by-step. Unlike other regions that may implement large-scale changes all at once, the West has chosen to evolve its electricity markets gradually, with each stage of development building upon the last.[6] For example, a single organized market manages energy trades for most of California—the California Independent System Operator (CAISO)—and there are currently no multistate RTOs (although, as seen in Figure 2, CAISO territory includes a small area of Nevada).[7]

The West uses a coordinated system of regional real-time energy supply markets and bilateral trading between a specified buyer and a specified seller of electricity. The Western Area Power Administration and the Bonneville Power Administration, two Western Power Marketing Administrations within the Department of Energy, sell electric power produced by federal dams to utilities (Figure 3 shows the boundary areas of the four Power Marketing Administrations).

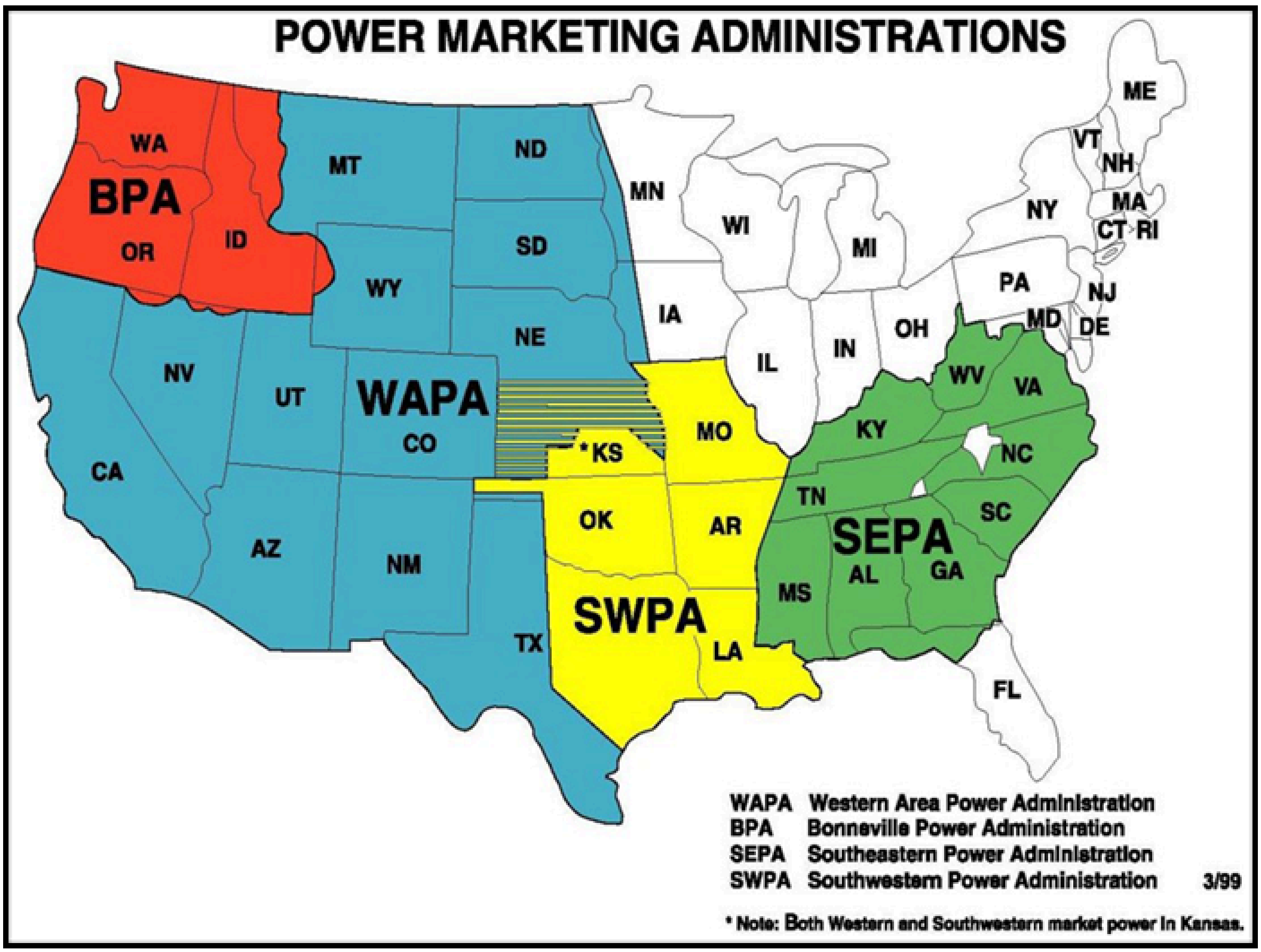


Figure 3. Power Marketing Administrations in the Continental United States. Source: SPP

While CAISO is currently the only ISO in the West, FERC has approved several market initiatives in the last twenty years that have led to a more integrated Western electric system that encompasses several Western states. The rest of this explainer will discuss CAISO as well as other initiatives and entities that contribute to the region's electricity landscape.

Overview of Electricity Markets in the West

California Independent System Operator (CAISO)

Figure 4. California Independent System Operator (CAISO) area.

The California Independent System Operator (CAISO)[8] was founded in 1998 and became a fully functioning ISO in 2008. CAISO manages the flow of electricity across the high-voltage, long-distance power lines serving 80% of California and a part of Nevada (Figure 4 shows the boundary areas of CAISO).[9]

CAISO provides open access to the transmission lines it operates and performs long-term transmission planning. In managing the grid, CAISO centrally dispatches generation and coordinates the movement of wholesale electricity in the area shown. CAISO's wholesale energy markets comprise day-ahead and real-time processes that include energy products, such as real-time energy, day-ahead energy, ancillary services, and congestion revenue rights. The Commission also approved, in most part, CAISO's Extended Day-Ahead Market proposal in December 2023.

Western Energy Imbalance Market (WEIM)

In 2014, CAISO initiated the Western Energy Imbalance Market (WEIM) with the purpose of expanding real-time market access to utilities in the Western Interconnection who are not members of CAISO. Utilities participating in the WEIM include utilities and balancing authorities outside of CAISO's territory. Among other benefits, the WEIM provides its participants with access to least-cost electricity across the region. There are also operational and reliability benefits to the sharing of electricity through WEIM. For example, when one part of the West is experiencing an electric energy shortage while others are not, there can be sales of excess electric energy to the area that needs it.

Concerning day-to-day operations, the WEIM is a real-time energy market that allows participating utilities to balance their supply and demand within 15 minutes or 5 minutes of delivery using the least-cost resources available across a wider footprint, helping to manage system needs. This creates a coordinated system of regional real-time energy supply markets, which, while not a full RTO or ISO, offers a structured approach to energy trading and system balancing in the West.

Since the WEIM began offering real-time market access to utilities outside of CAISO's territory, the WEIM has grown to serve parts of Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Texas, Utah, Washington, and Wyoming, and extends to the border with Canada and Mexico, totaling 22 participating entities representing 79% of the energy load in the WECC.[10] The WEIM's ability to leverage CAISO's market optimization tools to service the needs of the utilities outside its ISO structure have led to reported cost-savings.[11] Presently, the WEIM claims to have delivered more than $5 billion in benefits by connecting a broader area with access to lower-cost electricity.[12]

The WEIM is governed by a five-member body with shared authority from the CAISO Board of Governors on rules specific to participation in the WEIM.[13] As designed by regional stakeholders, the WEIM Governing Body is nominated by a committee of Western stakeholders. The WEIM Governing Body and CAISO Board of Governors frequently hold public sessions that include a toll-free number for members of the public to listen to the meeting. These public sessions include opportunities for public comment following briefings on policy initiatives as well as WEIM benefits and market updates.

Southwest Power Pool (SPP)

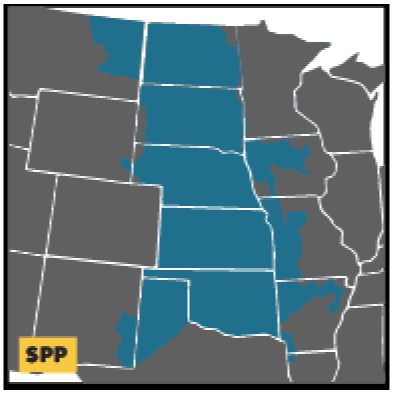


Figure 5. Southwest Power Pool (SPP) area.

The Southwest Power Pool (SPP), an RTO operating primarily in the Midwest, operates energy markets in both the Eastern and Western interconnections. Founded in 1941 as an 11-member power pool that allowed for power sharing among participating utilities, SPP achieved RTO status in 2004. Based in Little Rock, Arkansas, SPP manages transmission in portions of fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Its membership comprises investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers, and independent transmission companies.

In 2015, SPP's footprint expanded when the Western Area Power Administration—Upper Great Plains (WAPA-UGP) region, the Basin Electric Power Cooperative, and the Heartlands Consumer Power District—joined the RTO. The expansion nearly doubled SPP's service territory and added more than 5,000 MW of peak demand and over 7,000 MW of generating capacity. WAPA-UGP is the first federal power marketing administration to join an RTO.

In January 2025, FERC also approved, subject to condition, SPP's Markets+ proposal.

Additionally, in March 2025, FERC approved, subject to condition, SPP's RTO West proposal.

Western Energy Imbalance Service (WEIS) Market

In 2020, SPP established the Western Energy Imbalance Service (WEIS) market with the purpose of providing real-time market access to utilities in the Western Interconnection who are not members of the SPP RTO. Like CAISO's WEIM, SPP's WEIS seeks to provide participants with access to least-cost electric energy and to create reliability and operational advantages, such that power from areas with excess electric energy can flow to an area experiencing a shortage (such as during a weather emergency).

WEIS centrally dispatches generation to balance supply and demand in real-time and allows parties to continue to trade wholesale electricity bilaterally. Additionally, the WEIS has a goal of allowing participants to hedge against transmission congestion while coordinating the movement of wholesale electricity. In 2022, according to the WEIS Benefit of Market Report, WEIS claims to have provided $31.7 million in net benefits to its 12 participating Western utilities.[14]

SPP's independent Board of Directors provides ultimate oversight of the WEIS's administration; however, the Western Markets Executive Committee is responsible, through its designated working groups, committees, and task forces, for developing and recommending policies, procedures, and system enhancements related to the administration of the WEIS by SPP under the Western Joint Dispatch Agreement in the Western Interconnection.[15] In coordination with the Western Markets Executive Committee, the Western Markets Working Group provides a public forum for customers to engage in matters of governance and strategy with other stakeholders.[16] In 2024, all Western Markets Executive Committee meetings will be joint with the Western Markets Working Group. Members of the public may register on www.SPP.org for these meetings and attend in-person or by phone.

Western Power Pool (WPP)

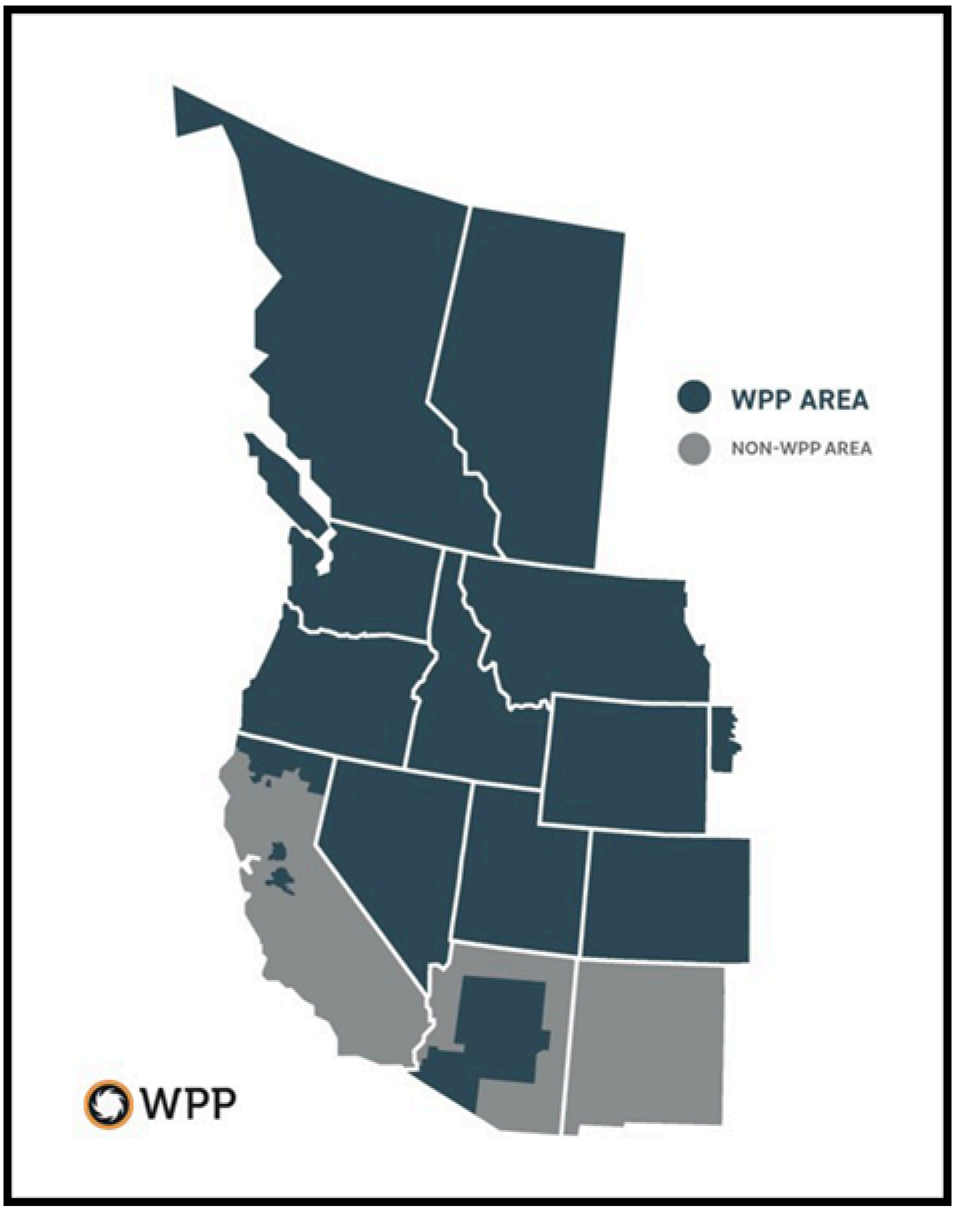


Figure 6. Western Power Pool (WPP) area. Source: WPP

The Western Power Pool (WPP), previously known as the Northwest Power Pool, is a group of utilities and other entities that coordinate and share resources in the Western Interconnection (Figure 6 shows the boundary areas of WPP). The WPP provides services to its members, such as transmission planning and tariff administration.[17] The WPP was formed in 1983 to promote increased efficiency, competition, and coordination in the electric power industry.[18] The WPP is governed by a Board of Directors, a Governing Body, and various committees and working groups that represent the interests of its members and stakeholders. The WPP also collaborates with other regional entities, such as the WECC, SPP, and CAISO, to enhance the reliability and efficiency of the Western Interconnection. While the WPP does not provide transmission service and is not an RTO/ISO, it does provide significant benefits by ensuring reliable energy capacity and reserves across the electric system.

To that end, in August 2022, the WPP filed at FERC the Western Resource Adequacy Program (WRAP) proposal, in Docket No. ER22-2762, which is intended to enhance resource adequacy. Resource adequacy ensures that there is enough energy capacity and reserves to maintain a balanced supply and demand across the electric system.[19] The WRAP was approved by FERC in February 2023 and is expected to launch in mid-2025.[20]

Western Resource Adequacy Program (WRAP)

The WRAP is not an organized market like CAISO's WEIM or SPP's WEIS but is instead a program WPP runs to ensure that the electricity supply in the West can meet the demand and reliability needs of customers. When implemented, the WRAP will have two main components: (1) a forward showing program, where participants demonstrate their ability to meet their peak demand plus a reserve margin for the next year; and (2) an operations program, where participants monitor and report their daily resource availability and demand as well as comply with dispatch instructions from the program operator. SPP acts as the program operator and, as directed by WPP, provides services for the WRAP, such as modeling, analytics, real-time operations, and technical improvement.

The WRAP is designed to be compatible with existing markets and programs in the West, such as the WEIM and the CAISO markets. The WRAP is also open to area participants who want to join the program and benefit from its regional approach. The WRAP seeks to help participants address the challenges of resource adequacy in the West in a manner consistent with state goals, such as increasing demand, retiring coal plants, and integrating variable renewable energy sources.[21]

To Learn More

Additional information on the topics discussed is available on FERC's website, including the FERC rulings cited in this explainer, the 2024 Energy Primer, as well as on the:

- CAISO website
- SPP website
- WPP website

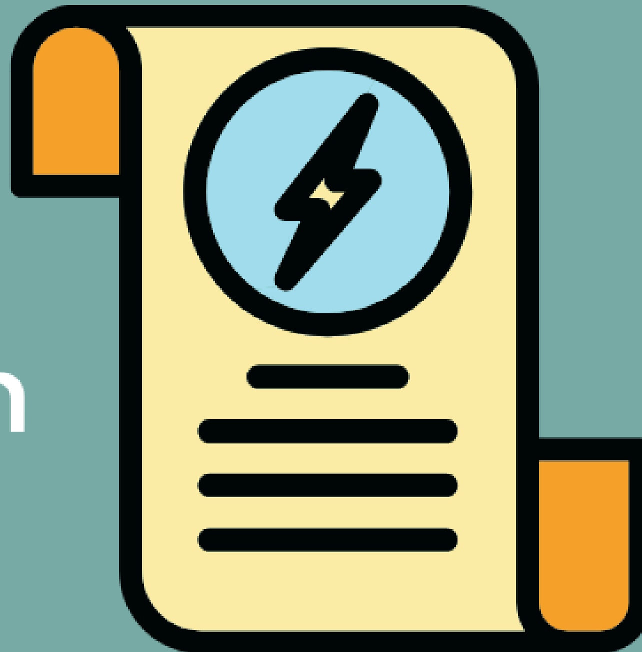
In addition to the existing markets and programs discussed above, the Western area markets may continue to develop and change. To follow FERC matters relevant to the expansion of the Western markets, you may:

- Subscribe to the Office of Public Participation (OPP) newsletter;
- Follow stakeholder processes with the stakeholder centers of CAISO and SPP; and
- eSubscribe to electronically receive information related to a particular FERC docket or set of dockets in which you have an interest.

OPP is dedicated to helping the public understand and participate in FERC proceedings. Members of the public can contact OPP for assistance in navigating FERC proceedings and receiving information on when and how to comment, intervene, or file motions during proceedings.

Please contact OPP by e-mail at OPP@ferc.gov, by phone at (202) 502-6595, or see our website at www.FERC.gov/OPP for additional information and resources.

Western Markets Expansion



CAISO

Order No. 2000

CAISO ISO Open Access Transmission Tariff (OATT)

Western Energy Imbalance Market WEIM (CAISO)

147 FERC ¶ 61,231 (2014)

Docket No. ER14-1386

EIM Section to CAISO OATT

Western Energy Imbalance Service WEIS (SPP)

173 FERC ¶ 61,267 (2020)

Docket Nos. ER21-3/ER21-4

WEIS OATT

Western RA program WRAP (Western Power Pool)

182 FERC ¶ 61,063

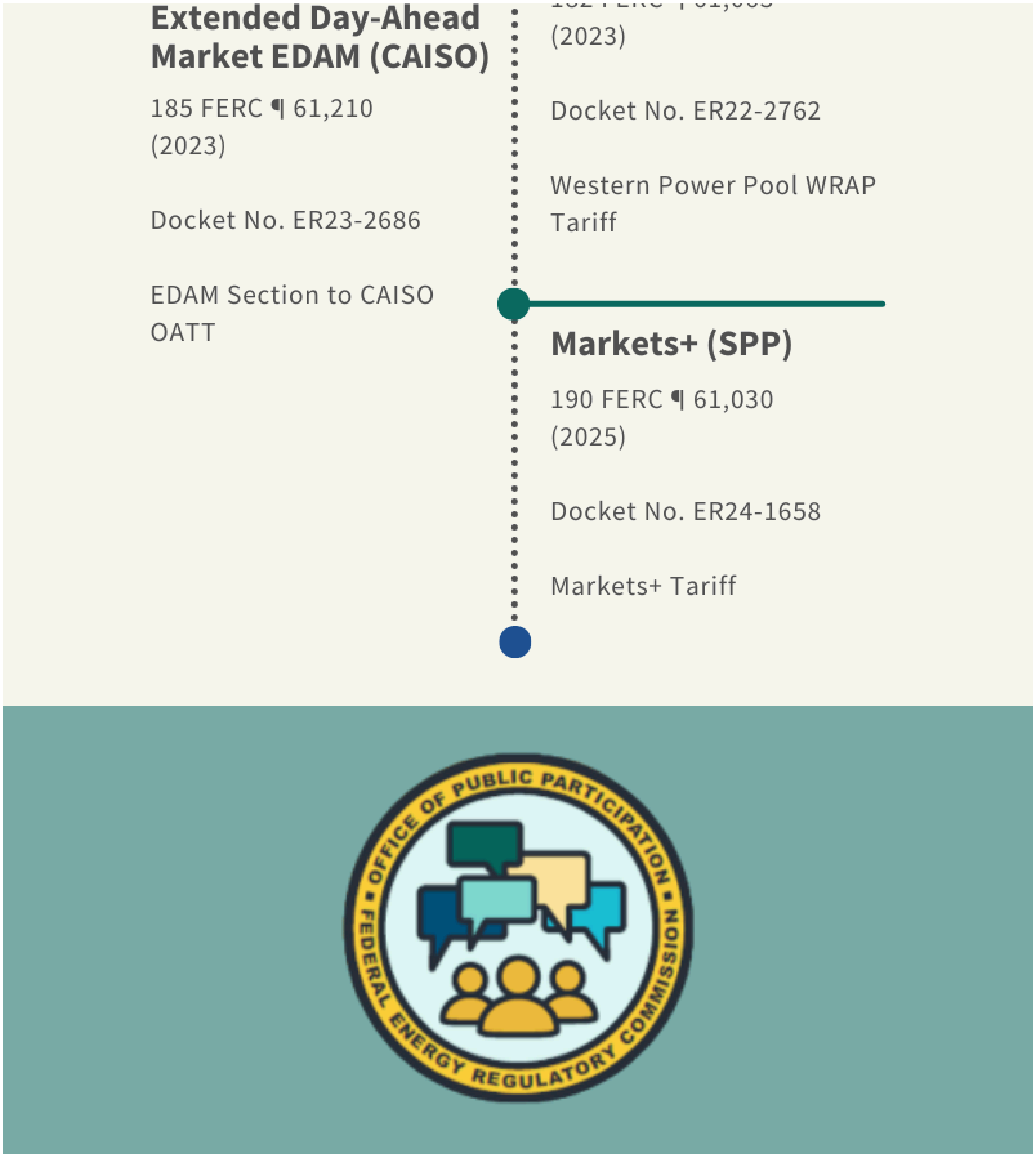


Figure 7. Western Markets Expansion infographic.

[1] Transmission Agency of Northern California. https://www.tanc.us/understanding-transmission/the-western-us-power-system.

[2] Specifically, FERC mandated NERC to oversee the reliability of the bulk power system, which includes parts of Mexico and Canada. For further information, see the Office of Public

Participation's Reliability Primer. https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[3] Electricity Markets Explainer. https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission.

[4] Order 2000 can be viewed at: https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

[5] Electric Power Markets. https://www.ferc.gov/electric-power-markets.

[6] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[7] In the case of CAISO, the ISO has chosen not to seek RTO status. RTOs are electric power transmission system operators that coordinate, control, and monitor a multistate electric grid. ISOs are like RTOs, which also coordinate, control, and monitor the operation of the electrical power system. However, ISOs cover geographic areas within a state or a smaller region.

[8] Understanding and Participating in CAISO Processes. https://www.ferc.gov/understanding-and-participating-california-iso-caiso-processes.

[9] CAISO. http://www.caiso.com/about/Pages/OurBusiness/Default.aspx.

[10] CAISO. https://www.westerneim.com/Documents/weim-first-quarter-benefits-for-2023-reach-418-million.pdf.

[11] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[12] WEIM. https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

[13] WEIM. https://www.westerneim.com/Pages/Governance/GoverningBody.aspx.

[14] SPP. https://spp.org/western-services-documents/?id=371676.

[15] SPP. https://spp.org/documents/61046/wmec%20charter%2020221018.pdf.

[16] SPP. https://spp.org/western-services/weis/.

[17] Western Power Pool. https://www.westernpowerpool.org/private-media/documents/WPP_WRAP_Interoperability_with_Markets_June_2023.pdf.

[18] Western Power Pool. https://www.westernpowerpool.org/.

[19] CAISO. https://www.caiso.com/Documents/Resource-Adequacy-Fact-Sheet.pdf.

[20] *Northwest Power Pool*, 182 FERC 61,063 at P 13-14 (2023).

[21] Western Power Pool. https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

Quick Links

- Introduction to Western Markets Expansion

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-132:
Power Council Overview

Northwest **Power** and
Conservation Council

Established to inform and advance a regional vision for power and fish and wildlife in the Columbia Basin

REGIONAL POWER PLAN

The Council develops a 20-year Power Plan, revised every five years, that ensures the Northwest has an adequate, efficient, economical, and reliable power supply.

Key components of the plan include:

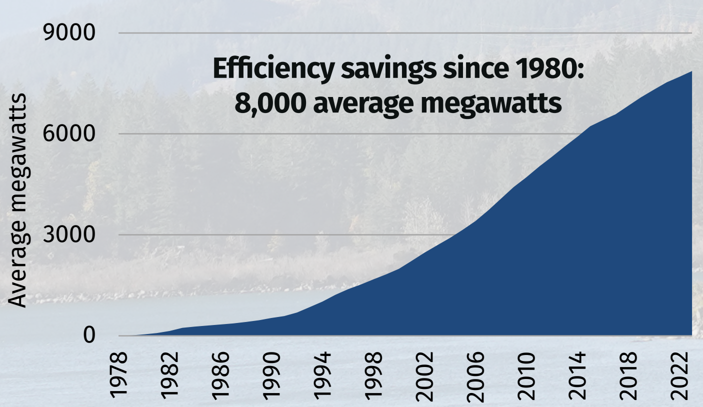
- Electricity demand forecast
- Electricity and fuel price forecasts
- Assessment of cost-effective energy efficiency and demand response
- Least-cost generating resources portfolio
- Ensuring the resource strategy meets the Council's adequacy metrics and thresholds (these standards protect the Northwest power supply's adequacy at peak demand periods)

Bonneville Power Administration funds the Council's work and must act consistently with the Council's plan when acquiring resources. The Council's power planning under the Northwest Power Act emphasizes cost-effectiveness and flexibility, mitigating risk in electric power investments, and ensuring the system's reliability and adequacy. The Power Plan offers regional insights to utilities and regulators.

The Council is in the process of developing its Ninth Power Plan, with a goal of releasing a draft to the public by mid-2026 and adopting it by the end of that year. Challenges include significant regional load growth and a shifting resource mix. Growth in demand for electricity is being driven by data centers, electric vehicles, regional population and economic growth, electrification of buildings, and other sectors.

COST-EFFECTIVE ENERGY EFFICIENCY

Energy efficiency plays a key role in reducing electricity consumption and making loads more flexible and easier to manage in the Northwest. Over the past several decades, energy efficiency has been a go-to way to meet demand at costs much lower than building new plants. This has been an ideal fit with the low-cost, reliable hydropower generated by the Columbia River. Over the past 20 years, power supply shortages have been rare in the Northwest – even as extreme weather events have increased – while regional power costs remain among the lowest in the U.S.



Thanks to effective implementation of the Council's past power plans, the Northwest is a national leader in acquiring cost-effective energy efficiency.

Since 1980:

- The region has met more than half its load growth with energy efficiency
- Almost 8,000 average megawatts has been saved, enough power for more than seven Seattles or the average annual output of three Grand Coulee dams
- $5 billion saved in lower bills for energy consumers and avoided energy costs

COLUMBIA RIVER BASIN FISH AND WILDLIFE PROGRAM

The vision: A Columbia River ecosystem that sustains an abundant, productive, and diverse community of fish and wildlife.

The Council's Columbia River Basin Fish and Wildlife Program represents a 40-year effort to protect, mitigate and enhance salmon and other fish and wildlife in the basin affected by the hydropower system. It is one of the largest mitigation efforts in the world. The Council has tracked important progress on goals and objectives, but significant work still remains.

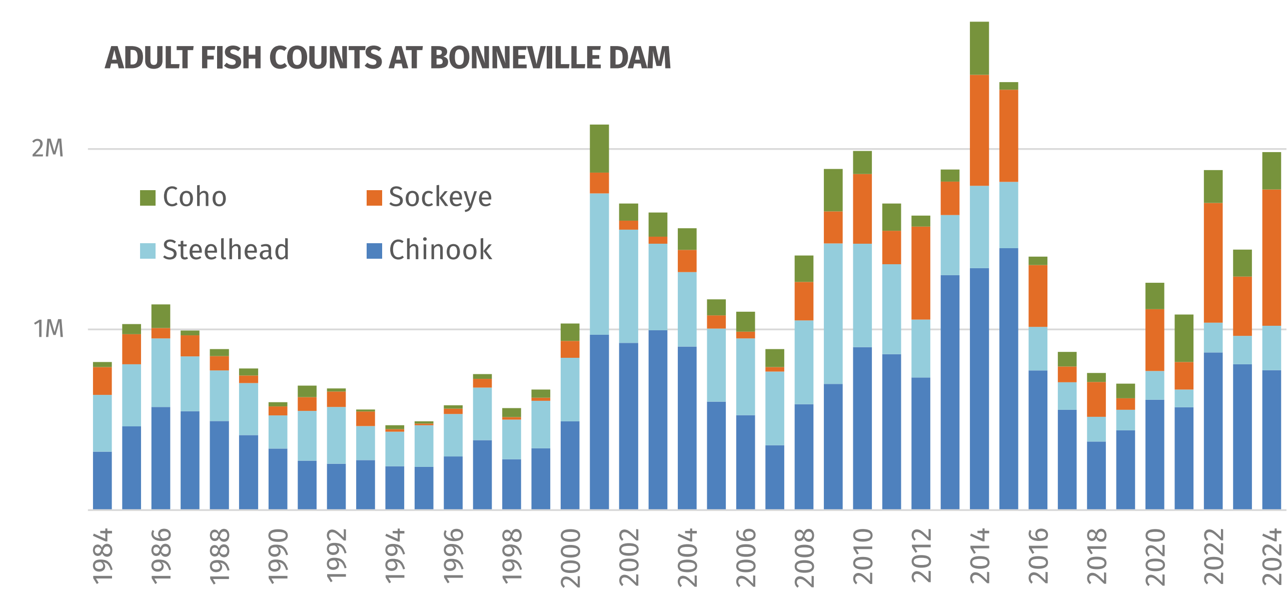
The Program incorporates a variety of strategies, including recommendations for dam operations that improve conditions for fish passage and survival, habitat mitigation, and hatcheries. Target species include salmon, steelhead, and resident fish such as sturgeon and bull trout.

The Council updates the Program every five years based on recommendations from state and federal agencies, tribes, and others. Relevant projects are reviewed by an independent scientific panel.

To date, the Program has:

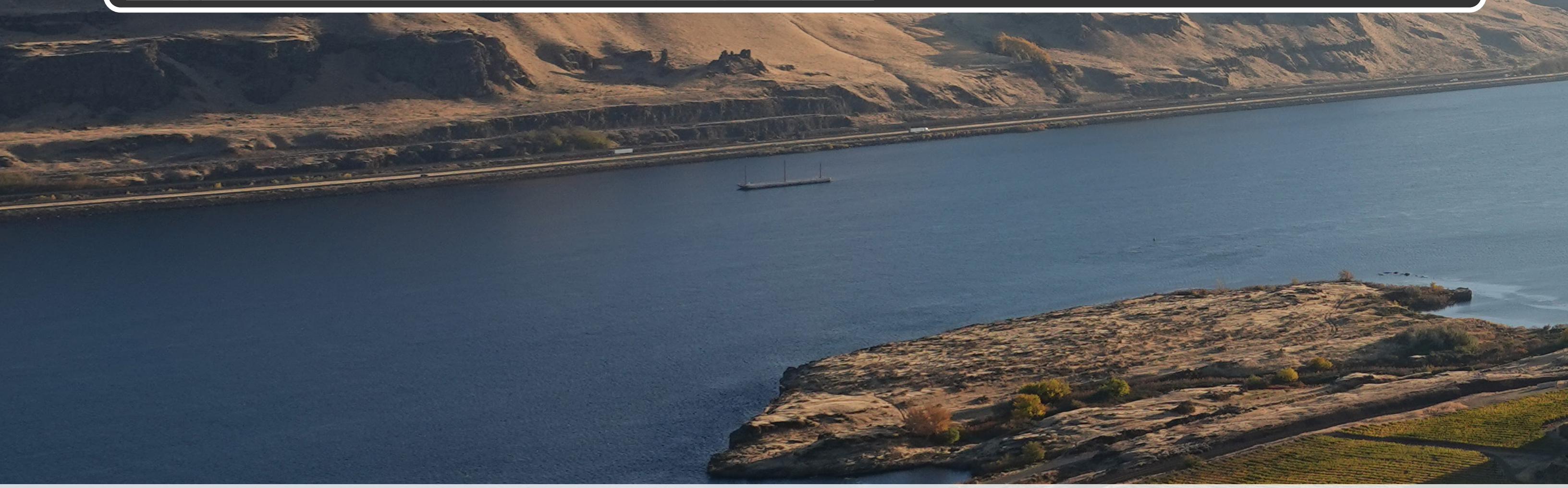
- Improved water management, flow, and passage to protect and increase survival at Columbia and Snake River dams
- Protected more than 300,000 acres of habitat through purchase or conservation easement*
- Improved over 760,000 acres of habitat through restoration actions**
- Protected 44,000 miles of undammed Northwest rivers and streams

* 1992-2022 ** 2005-2021



In 1980, Congress passed the Northwest Power Act, authorizing the states of Idaho, Montana, Oregon, and Washington to form the Northwest Power and Conservation Council, an interstate compact agency, giving the region a greater voice in how we plan our energy future in the Pacific Northwest and manage natural resources in the Columbia River Basin.

The Act requires the Council to develop, with broad public participation, a regional power plan and a fish and wildlife program.



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Thomas (Les) Purce, Vice Chair

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)) Emergency Order: Tri-State) Generation and Transmission) Association, Platte River Power) Authority, Salt River Project,) PacifiCorp, and Xcel Energy)	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-133:
Power Council 2021 Power Plan

THE 2021 NORTHWEST POWER PLAN

Northwest **Power** and **Conservation** Council

Contents

document 2022-3 / March 10, 2022

Section 1: Introduction

Electricity generating resources in the Northwest – carbon-free hydropower and nuclear, gas, coal, wind, and solar – plus energy efficiency – have served the region's electricity needs well, providing capacity and energy supporting a reliable, adequate, efficient, and economical power system. In the years since the Council last revised the power plan, however, the power system has experienced changes that place more emphasis on renewables, such as wind and solar generation.

In this 2021 Power Plan, the Council recognizes those states that have requirements and policies pursuing emission reductions that support cleaner electricity generation. Influenced by these policies, this plan includes significantly more renewable generation than all our previous power plans. The Power Act requires that the Council review the plan at least every five years. For this reason, the Council's work focuses most intently on the period between its release and the next one – the time we call the action plan period. However, the plan's forecast through 2041 indicates the region can expect a more substantial transformation in the fleet of regional resources used to generate electricity. Through this transformation into the future, hydropower and energy efficiency will continue to be a fundamental part of the region's power system.

The plan recognizes that there are social, political, and economic drivers leading to the region's turn toward cleaner sources of generation, primarily wind and solar. These intermittent or variable technologies are becoming less expensive to build and are seen as the primary path to reducing emissions associated with generating electricity. This emerging paradigm shift in how the region produces electricity is addressed in the plan's resource strategy. To forecast the potential impacts of this shift, the plan reflects the results of several energy models, public policy, technology, a blend of climate change assumptions, and economics in preparing for the action-plan period and for the longer 20-year plan.

This paradigm shift's attendant risks and the critical importance of reliability raises reasonable questions about the amount of future development of the low-cost renewable resources called for by the plan and the availability of transmission capacity needed to move these resources to load centers. There is also uncertainty regarding whether Western market resources identified by the plan will be available to the region when needed to reduce costs or meet demand, in particular those periods when reliability is at greater risk. Electrification-focused policies in certain states could potentially increase utility loads rapidly, requiring building resources beyond the recommendations laid out in the plan. The plan's recommendations balance a range of uncertainty described both by the underlying analytical work and the wide-ranging expert assessment considered by the Council. These uncertainties that expose anxiety over meeting regional demand with a rapidly evolving electric system have been addressed by the plan using the best information available to the Council and its advisory committees. As the future unfolds, the Council recognizes that new information could prompt reconsideration of the recommendations and that the Council's work to monitor and evaluate the region's evolving system and policies must keep pace and not be tied to traditional timelines.

The Council's work has focused on developing a resource strategy during a time when the region is undergoing significant changes and uncertain futures. This strategy will assure the region an efficient, adequate, economical, and reliable power supply that is available, sufficiently dispatchable, and deliverable within the region's transmission system, where electricity is produced to where it is needed. The Council's work also indicates that as more intermittent or variable generation from wind and solar power is added to the system, a corresponding increase in reserves is necessary. These reserves are accommodated by our existing hydropower, gas, nuclear, and remaining coal generation. In the end, the region's resources must be instantaneously balanced with the region's demand to reliably provide electricity across the entire Northwest power system.

The 2021 Power Plan contains 12 sections that provide more detail and specifics on its components. Section 6 details new and existing resources anticipated to meet future demand for electricity. Our work indicates that the region's large amount of hydropower, nuclear, and traditional thermal resources, including those that burn natural gas and coal, remain an essential part of providing reliable electricity for the region. We also expect that continued acquisition of energy efficiency now and in the future will play a critical role in meeting the region's future demand for electricity. As the Western electricity market changes in such fundamental ways, one thing remains true and certain: Energy efficiency is a very important and fundamental way to address resource adequacy, and its contribution to capacity makes it an important resource during periods of uncertainty. In addition, the future system will be supported by the ongoing development of new renewable resources that are anticipated to provide needed energy while reducing greenhouse gas emissions. We also recognize new demand response opportunities that can be expected to support and reduce system capacity needs. Finally, trading electricity with our neighboring regions in energy markets will continue to support current and future reliability.

The plan is intended to help transition the region into a new paradigm of cleaner energy that includes the use of our abundant hydropower, existing gas, nuclear, and remaining coal generation to provide reliability during the action plan period, while also integrating current and expected future renewables into the power system. As we look to the future, we anticipate that the transition to a new paradigm will be accompanied by risk and uncertainty. The region has dealt with and overcome risk and uncertainty in the past, and it can be expected to do so in the future. Through ranges in values (e.g., natural gas price forecasts, hydro conditions) and in scenario analyses, the plan embraces and addresses uncertainty and risk and provides a strategy for a low-cost, reliable, and adequate system to meet the electricity needs of this time. Implementing the strategy in this plan will require the same flexibility and collaboration used in the past to address the challenges of a new era, while maintaining the reliability expected by Northwest electricity customers.

The Council's work to monitor and evaluate the region's evolving system and policies will keep pace with new data and analysis in this rapidly changing industry. Any changes or unexpected developments will be reported as available, and reflected in the 2021 Power Plan's mid-term assessment.

Section 2: Power Act Requirements and the Power Plan

In December 1980, in direct response to a set of linked problems the region faced concerning increasingly difficult resource issues and the decline of Columbia River salmon and steelhead runs, Congress enacted a comprehensive and innovative legislative solution–the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). The Northwest Power Act was enacted 1) to encourage conservation and efficiency in the use of electric power and the development of renewable resources within the Pacific Northwest; 2) to assure the Pacific Northwest an adequate, efficient, economical, and reliable power supply; 3) to provide for the participation and consultation of states, local governments, consumers, customers, users of the Columbia River system, federal and state fish and wildlife agencies, Indian tribes, and the public at large in the development of regional plans and programs, facilitating orderly planning of the region's power system, and providing environmental quality; and, 4) to protect, mitigate, and enhance the fish and wildlife of the Columbia River and its tributaries, including related spawning grounds and habitat.

The Act was groundbreaking in its use of the Federal Columbia River Power system to achieve cost-effective conservation, its prioritization of conservation and renewable resources, its fish and wildlife protection and mitigation obligations, as well as its required considerations of environmental quality, and, ultimately, its regional power planning process. Remarkably, the Act also implicitly recognized the inherent uncertainty in planning for a future electric power system, with its power planning provisions and planning process providing a venue to accept and manage that uncertainty.

To carry out the Act's purposes, the Northwest Power Act authorized the states of Washington, Oregon, Idaho, and Montana to form an interstate compact agency–the Council–and directed the Council to: 1) prepare and review a "regional conservation and electric power plan" not less than once every five years; 2) prior to each plan, prepare and periodically amend a program to protect, mitigate, and enhance fish and wildlife affected by the Columbia River Basin hydropower system; and 3) develop both the power plan and the fish and wildlife program in a highly public process with broad consultation and participation.

Beyond charging the Council with these specific responsibilities, the Act also specifies, in Sections 4(d) through 4(g) of the Act, the process the Council is to follow in developing and amending the plan; what the Council must include in the power plan; what the Council must do prior to the review of the power plan (undergo a separate process to develop or amend the fish and wildlife program addressed in Section 4(h)); and finally, in Sections 4(d)(2) and Section 6(a) through 6(c), how the Bonneville Power Administration is to use the power plan in implementing conservation measures and acquiring new generating resources.

Public Engagement and Process for Developing the Power Plan

While the Council is directed to prepare a regional conservation and electric power plan, a corresponding directive to the Council, and principal purpose of the Act, is to provide for broad public participation and consultation in the development of that power plan; Sections 4(d)(1) and 4(g) describe how the Council is to implement this mandate and engage the public throughout development and review of the power plan.

Per section 4(g)(3), in the preparation, adoption, and implementation of the power plan, the Council and the Bonneville Power Administration administrator (Bonneville), must encourage the cooperation, participation, and assistance of appropriate federal agencies, state entities, political subdivisions, and Indian tribes. And, Sections 4(g)(1) and (2) add that the Council and Bonneville, in forming regional power policies, must maintain comprehensive programs to inform the public of major regional power issues, obtain public views concerning major regional power issues, and secure advice and consultation from Bonneville's customers and others. Further, the Council and Bonneville must consult with Bonneville's customers, include the comments of such customers in the record of the Council's proceedings for the power plan and fish and wildlife program, and recognize and not abridge the authorities of state and local governments, electric utility systems, and other non-federal entities responsible for the planning, conservation, supply, distribution, and operation of the electric generating facilities.

In practice, these provisions result in a multi-year, highly public process to develop the Council's regional conservation and electric power plan. For the 2021 Power Plan, the Council officially began the power planning process in February 2019 with a webinar that was open to the public and provided information regarding the history of the Act, the planning process, and opportunities for public participation, including through the Council's advisory committees, groups of technical and policy experts from around the region. Early and throughout the process, the Council utilized these advisory committees to gather information on priority issues for the region; conduct analytical work for the power plan; and discuss and review the findings for the power plan.

All advisory committee meetings, and their materials, are open to the public, with broad public notice provided through the Council's website and email distribution lists. The Council discussed substantive issues in its power committee and at regularly scheduled full Council meetings. All meetings are open to the public, again with broad public notice provided through the Council's website and via email distribution, with opportunities for public comment during full Council meetings. In addition, the Council welcomed comment and informal participation and collaboration throughout the planning process through one-on-one meetings with staff and written communications. The comments provided through these opportunities were closely considered by the Council and informed the development of the power plan.

Once the draft power plan is issued, Section 4(d)(1) of the Act requires that the Council hold public hearings on the draft power plan in each of the Northwest states. In addition to the public hearings required under the Power Act, the Council also largely follows the notice and comment procedures of the federal Administrative Procedures Act. Therefore, the Council also provides wide public notice of the draft power plan and ample opportunity to submit written comments, as well as opportunities to provide comment at regularly scheduled monthly Council meetings and testimony at the public hearings. Further, the Council uses this public comment period to conduct consultations with Bonneville, Bonneville's customers, Indian tribes, state and federal agencies, and non-governmental entities to solicit their advice and comment as contemplated under Section 4(g).

Lastly, as a component of the final power plan, the Council explains and describes how comments were considered and responded to during the development of the power plan, including any changes from draft to final. While the process presents unique challenges, broad public participation, engagement, and consultation remain constant in the development of each plan.

Substantive Considerations and Elements in the Power Plan

Section 4(d)(1) provides the basic directive to the Council–to prepare, adopt, and transmit to Bonneville a regional conservation and electric power plan. However, Sections 4(e) and 4(f) provide the substantive priorities, considerations, and elements that the power plan must contain. Section 4(e)(1) specifies that the power plan is to give priority to resources that the Council determines to be cost-effective, with priority given first to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency, and fourth to all other resources.[1] Given this set of priorities, Section 4(e)(2) then focuses on what the Council is to deliver in its power plan, and that is a "scheme for implementing conservation measures and developing resources…to reduce or meet the Administrator's [Bonneville's] obligations." Further, Section 4(e)(2) requires that the Council must develop this resource scheme (or resource strategy) "with due consideration for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan." Therefore, taken together, these provisions require that the Council develop a cost-effective resource strategy to reduce or meet Bonneville's obligations, and, in doing so bring each of these considerations to bear.

Section 4(e)(3) lists the following specific elements the Council is to include in the power plan, but leaves it to the Council to describe the elements "in such detail as the Council determines to be appropriate":

A. An energy conservation program, including model conservation standards

B. Recommendations for research and development

C. A methodology for determining quantifiable environmental costs and benefits under Section 3(4) of this Act [definition for cost-effective]

D. A demand forecast of at least 20 years, to be developed in consultation with Bonneville, customers, states (including state agencies with ratemaking authority over electric utilities), and the public,

1 Cost-effective is defined in the Act in Section 3(4)(A), and a resource is cost-effective if it has an "estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof." Therefore, cost-effectiveness is a comparative exercise of resources.

in such a manner the Council deems appropriate, and a forecast of power resources estimated by the Council to be required to meet the administrator's obligations and the portion of such obligations the Council determines can be met by resources in each of the priority categories. The forecast of power system resources shall also include (i) regional reliability and reserve requirements, (ii) the effect, if any, of the requirements of the Council's fish and wildlife program on the availability of resources to Bonneville, and (iii) the approximate amounts of power the Council recommends should be acquired by Bonneville; this may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired

E. An analysis of electricity reserve and reliability requirements and cost-effective methods of providing reserves designed to insure adequate electric power at the lowest probable cost

F. The fish and wildlife program promulgated prior to the power plan by the Council under Section(h) of the Act

G. Any surcharge recommendation relevant to implementation of the model conservation standards and a methodology for calculating the surcharge

Lastly, Section 4(f) provides and details the model conservation standards to be adopted into the plan and the associated surcharge authority, both addressed as elements of the plan in Section 4(e)(3). While the Act prescribes the elements, it also provides the Council with a substantial amount of discretion to use its expertise to develop and craft these elements for each plan.

For this power plan, the Council decided to structure the plan in such a way that each plan section corresponds with an element identified under the Act. For example, Section 5 details the energy conservation program and Section 9 details the cost-effective methods of providing reserves, while Section 6, Resource Development Plan, comprehensively describes the resource strategy for the 2021 Power Plan. However, specific components from the energy conservation program are also included in the resource strategy discussion of Section 6, as well as analysis and findings from the cost-effective methods of providing reserves detailed in Section 9, which illustrates the way each of these elements work together to inform the Council's power plan.

Relationship of the Power Plan to the Region and Bonneville

As noted above, per Section 4(d)(1), the Council is to prepare, adopt, and transmit to Bonneville a regional conservation and electric power plan, and, per Section 4(e)(2), the Council's power plan is to set forth a "scheme for implementing conservation measures and developing resources… to reduce or meet the Administrator's obligations." Therefore, under the Act, the Council's power plan must consider the entire region while planning for Bonneville's resource obligations. This is because when adopting the Northwest Power Act, Congress envisioned that Bonneville, the federal power marketing agency selling the electrical power produced by the Federal Columbia River Power System, would be the major engine for adding new resources as needed for the region and the purposes of the Act would be achieved through the use of the federal system. Thus, Sections 6(a)(2)(A) and (B) of the Act authorize and obligate Bonneville to acquire sufficient resources to (A) meet the agency's contractual power sales obligations and (B) to assist the agency in meeting the requirements of Section 4(h) of the Act, which is the Council's fish and wildlife program. Moreover, Section 4(d)(2) and Sections 6(a), 6(b), and 6(c) tie Bonneville's implementation of conservation and acquisition of new resources directly to the Council's power plan by requiring that Bonneville's resource acquisitions and conservation implementation be consistent with the Council's power plan, with certain narrow exceptions.

Accordingly, the Act requires the Council to include in the power plan a number of elements concerning Bonneville's resource acquisitions, specifically: A resource strategy to reduce or meet Bonneville's obligations (Section 4(e)(2)); an energy conservation program to be implemented under the Act (Section 4(e)(3)(A)); and a forecast of power resources estimated by the Council to be required to meet Bonneville's obligations and the portion of such obligations the Council determines can be met by resources in each priority category.

The forecast is required to include the approximate amounts of power the Council recommends Bonneville acquire on a long-term basis and may include, to the extent practicable, an estimate of the types of resources (Section 4(e)(3)(D)). For the 2021 Power Plan, to more explicitly recognize this relationship between the Council's power plan and Bonneville, the Council included specific plan sections for Bonneville (See Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity and Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation).

Even though the only legal link provided in the Northwest Power Act to the Council's power plan is to Bonneville and its resource acquisition decisions and conservation implementation, because Bonneville is the primary provider and marketer of electric power in the region, the Council's power plan necessarily affects those entities that purchase power from Bonneville. In addition, the State of Washington's Energy Independence Act tied Washington utilities' conservation potential directly to the Council's methodology for conservation. The Council's power plan is also an influential resource for other entities making resource decisions, as well as for legislators, regulators, and state energy offices around the region. The power plan remains a proper venue for examining the potential implications of policy decisions on the regional system, and how to plan and manage in the face of uncertainty.

Fish and Wildlife Program

One final important piece of the Council's power plan is the development of the Council's fish and wildlife program pursuant to Section 4(h) of the Act. Specifically, Section 4(h) requires that the Council, "prior to the development or review of the plan, or any major revision thereto," call for recommendations from state and federal fish and wildlife agencies and tribes and adopt or amend a program to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by the development and operation of any hydroelectric facilities on the Columbia River and its tributaries. The fish and wildlife program process is heavily circumscribed, with the recommendations requested at the start of the process becoming the base from which the Council builds the program.

Per Section 4(e), the Council's fish and wildlife program is an element in the Council's power plan, and the Council has an obligation to develop the power plan's resource strategy with due consideration for the protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish. Additionally, pursuant to Section 6 of the Act, Bonneville has an obligation to acquire sufficient resources consistent with the Council's plan to not only reduce or meet the administrator's obligations but to also meet the fish and wildlife protection and mitigation requirements reflected in the Council's fish and wildlife program. Thus, the Council's fish and wildlife program necessarily comes before the Council's power plan so that the Council may determine the non-power constraints on the hydrosystem necessary to protect, mitigate and enhance fish and wildlife, and then use the power planning process to assure an adequate, efficient, economical, and reliable power supply for the region. Sections 11 and 12 further discuss the integration and consideration of the fish and wildlife program.

Supporting Materials

Throughout this power plan, there are references to supporting materials–information, data, and analysis–that provide the basis for the conclusions, recommendations, and explanations in the plan. For example, Section 5 describes the conservation program, which is a required element of the power plan; however, sitting beneath Section 5 in the supporting materials is data and analysis to inform the conservation program, including the Council's methodology for estimating the energy efficiency resource potential for the region, estimated energy efficiency potential by sector, as well as the energy efficiency supply curve bins and workbooks. For another example, Section 6 provides the resource strategy, and sitting beneath that section are supporting materials providing detailed information and analysis on the existing system, potential system needs, and resource costs developed in the supporting materials. These are just a few examples of the data and information found in the supporting materials that support the power plan's recommendations and explanations addressing each of the required elements outlined in the Power Act. The supporting materials are available for review at: nwcouncil.org/2021powerplan_sitemap

Section 3: Demand Forecast

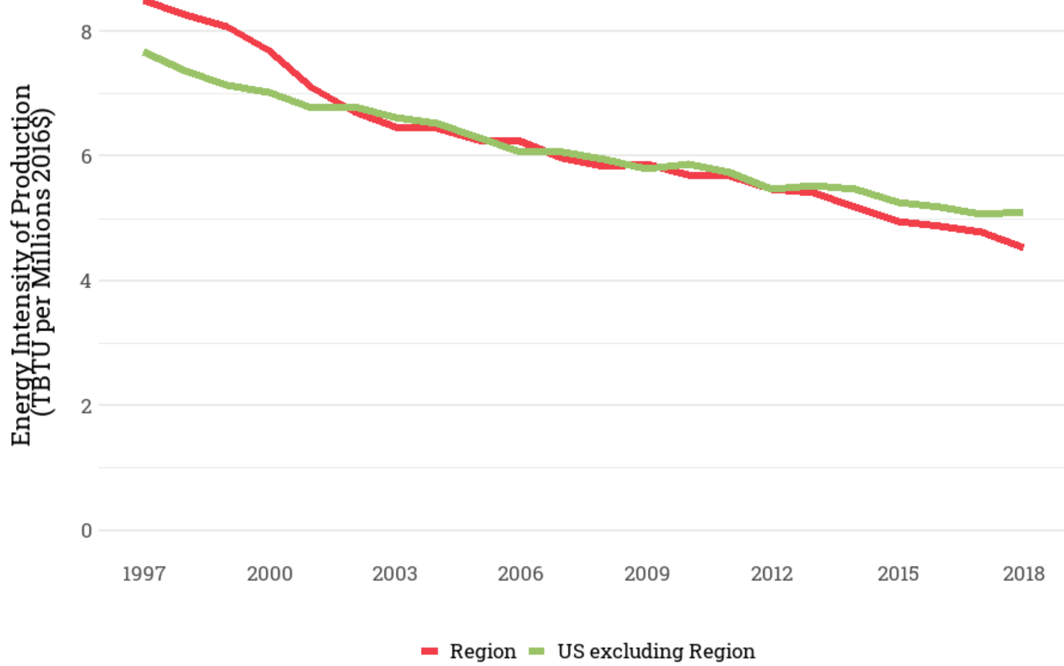
The Evolving Role of Electricity in the Northwest

Electricity is so ubiquitous it's often overlooked. Our economy would hardly function without electricity. But increasingly, society is looking to electricity as a solution to reducing greenhouse gas emissions. Whether in electrification of light-duty vehicles or reducing fossil-fuel use in industrial applications, the use of electricity is broadening rapidly. At the same time, technologies like LED lighting have greatly increased the efficiency of long-standing uses for electricity.

The Northwest historically had industries with higher energy consumption than the rest of the United States, but that shifted over the last couple of decades. Now the regional consumption of energy is lower than the rest of the United States per dollar of production.

Increasing the efficiency of our energy use and expanding the electricity available at a

Energy Intensity of Regional Production is Falling Faster than the Rest of the U.S.



reasonable cost helps both grow the regional economy and accomplish the region's goals for reducing greenhouse gas emissions. An important requirement of the power plan is the development of a demand forecast. The Council develops a demand forecast for both electricity and natural gas use in homes and buildings and examines both risks and opportunities in its forecast.

Potential New Sources of Load

Transportation – the movement of people and goods – is a large energy consumer. According to the U.S. Energy Information Administration, as much as 28 percent of all the energy consumed annually is for transportation, and most of that energy is delivered from petroleum-based fuels like gasoline and diesel. As a result, total greenhouse gas emissions from the transportation sector have reached parity with the emissions associated with electricity generation. Light duty plug-in electric vehicles provide better efficiency and lower fuel and maintenance costs than their gasoline counterparts and are gaining favor with the consumer. Electric passenger vehicles are also gaining favor with state clean policymakers as the vehicles have zero tailpipe emissions and are poised to disrupt the automobile and petroleum-product business models over the next decade.

For the 2021 Power Plan, we have developed a forecast of transportation and its related fuel usage. In the near term, the electrification of light duty cars, trucks, and vans results in cleaner and more efficient use of energy. Over the longer term (more than 10 years), heavy-duty vehicles, like long-haul trucks, offer further opportunity to electrify. Heavy vehicles are more challenging for plug-in battery technologies. The development of hydrogen fuel-cell powered trucks may become key for continued electrification of transportation, and the associated production of hydrogen required to fuel these vehicles could result in significant growth in the demand for electricity in the region.

The Council recommends policymakers and utilities that are pursuing regional emissions reductions utilize strategies that increase the adoption and use of zero- or low-emission vehicles. Battery electric vehicles are especially suited to meet passenger car and light truck requirements. Consumers in some areas within the region may be more concerned with range anxiety related to reduced battery electric vehicle performance in severe cold weather. Plug-in hybrid vehicles with gasoline engine range extenders, or hydrogen fuel cell vehicles may provide a better option. The hybrid and fuel cell vehicle technologies may also provide a solution for some heavy-duty vehicles like delivery trucks and large freight trucks. As these strategies are pursued, we recommend working with the Council, other regional bodies, and power planners to ensure an adequate electric system through the vehicle stock transition.

Direct Use of Natural Gas Forecast

To form a more comprehensive understanding of expected regional emissions, we forecast the need for energy end-uses like transportation or space heating. An end-use is the need or purpose that is served by energy, such as electricity delivered over the electric distribution system, gasoline bought from a fueling station, or natural gas delivered by a pipe to a home or a business. We then estimate the proportion of the different end-uses that are served by different types of fuel. A residence can be heated either by a heat-pump that uses electricity or a furnace that burns natural gas.

End-use consumption of natural gas tends to be seasonal, with peaks in the winter months and lulls in the summer. Homes with gas hookups are the largest consumer of natural gas. Many residences use a gas furnace for heating during the winter, and roughly 75 percent of the residential usage occurs in the months of November through March. Overall, the forecast is showing slight growth in the end-use of natural gas through the planning horizon; roughly 0.5 percent per year on average.

Renewable Natural Gas

Renewable Natural Gas (RNG) is biogas that has been conditioned and upgraded so that it can directly displace fossil natural gas. The ability of RNG to replace fossil natural gas use is limited in scope – recent studies suggest that regionally produced RNG could replace less than 10 percent of the natural gas end-use demand.[2] For this power plan, the Council modeled a blended RNG/ fossil gas supply as part of the forecast for end uses. This blend reflects the impact of regional RNG supply entering the existing natural gas pipeline system and displacing conventionally sourced fossil natural gas that is currently imported from Canada and the U.S. Rocky Mountain region.

The end combustion of RNG emits CO_2 just like fossil natural gas, and it is not always a net zero carbon product as its carbon intensity varies by feedstock. RNG, however, generally provides a lower carbon footprint than fossil natural gas. RNG that is produced from organic waste streams that

Forecast of End-Use Natural Gas Consumption

Units in TBTU	2020	2025	2030	2035	2040	2045
Total Natural Gas	478	476	460	508	510	533
Fossil Natural Gas	478	473	451	487	479	492
Renewable Natural Gas	0	2	9	21	31	41

2 nwcouncil.org/2021powerplan_renewable-natural-gas

would otherwise release methane directly may be especially beneficial because the warming potential of methane is over 80 times that of carbon dioxide over a 20-year timeframe. RNG that displaces natural gas use can also reduce upstream methane emissions associated with the extraction and transportation of fossil gas. Reliable, locally sourced RNG could also help reduce gas price volatility.

The Council recommends incorporating renewable natural gas into utility and other regional long-term planning, including identifying the least-cost and lowest net emission profile projects to produce renewable natural gas that may be blended into the gas system. The Council also recommends regional utilities support renewable natural gas, when appropriate, as a method to reduce end-use natural gas emissions, supply low-carbon fuel for transportation, and provide diversity and price stability with a regionally sourced fuel product.

The Impact of Climate Change on the Use of Electricity

When looking at the impact of climate change on the use of electricity, the Council considers both the direct and the indirect effects. The direct effects look at existing buildings and businesses and their current equipment that uses electricity and estimates the impact of changing temperatures and precipitation on the amount of electricity needed. For example, as temperatures increase, the air conditioning equipment currently installed at homes and businesses uses more electricity.

To estimate the direct impact of climate change on the use of electricity, the Council uses temperature projections downscaled for our region from three different General Circulation Models.[3] These models were selected to represent a broad range of possible conditions associated with an increased concentration of greenhouse gasses in the atmosphere.[4]

The indirect impacts of climate change look at decisions or events where we anticipate different outcomes because of climate change. For example, more people moving to the region from hotter climates increases

3 The three models selected were CanESM2, CCSM4, and CNRM, further details on these models and the selection process can be accessed using the link for the supporting material at the end of this section

4 For more information on the River Management Joint Operating Committee efforts on downscaling General Circulation Models see: www.bpa.gov/p/Generation/Hydro/Pages/Climate-Change-FCRPS-Hydro.aspx

the population. The increase in population in turn increases the need for energy.

To estimate the indirect effects of climate change, the Council examined a broad range of sources and consulted with regional experts on climatic and demographic data. These data needed both sufficiently detailed projections and near-term impacts that fit within the 20-year forecast period we include in this plan. They also needed to be related to the demand for electricity.

Direct Impacts of Climate Change

The models we use to estimate the need for electricity estimate the number of days the region is likely to use cooling or heating for buildings. These are represented as Cooling Degree Days and Heating Degree Days.[5] Fewer heating degree days means that there is less

Projection of Average Heating and Cooling Degree Days for each Global Climate Model

	Heating Degree Days			Cooling Degree Days		
	2020-2029	2030-2039	Decrease	2020-2029	2030-2039	Increase
CanESM2						
Oregon	4409	4116	6.7%	451	486	7.8%
Washington	4669	4350	6.8%	364	403	10.9%
Idaho	5726	5398	5.7%	785	815	3.8%
Montana	6965	6527	6.3%	410	423	3.2%
CCSM4						
Oregon	4542	4417	2.7%	385	401	3.9%
Washington	4847	4717	2.7%	299	327	9.1%
Idaho	5892	5534	6.1%	641	746	16.3%
Montana	7242	6966	3.8%	330	393	19.1%
CNRM						
Oregon	4686	4222	9.9%	371	450	21.4%
Washington	4962	4482	9.7%	309	358	15.9%
Idaho	6073	5499	9.5%	673	713	5.9%
Montana	7378	6721	8.9%	353	362	2.6%

5 Cooling Degree Days are calculated by adding up the degrees above 65 degrees Fahrenheit of the average daily temperature for each day in the period being examined. Heating Degree Days are calculated similarly by

of a heating need in the winter, lowering the use of energy. Whereas, more Cooling Degree Days means that there is more energy needed in the summer.

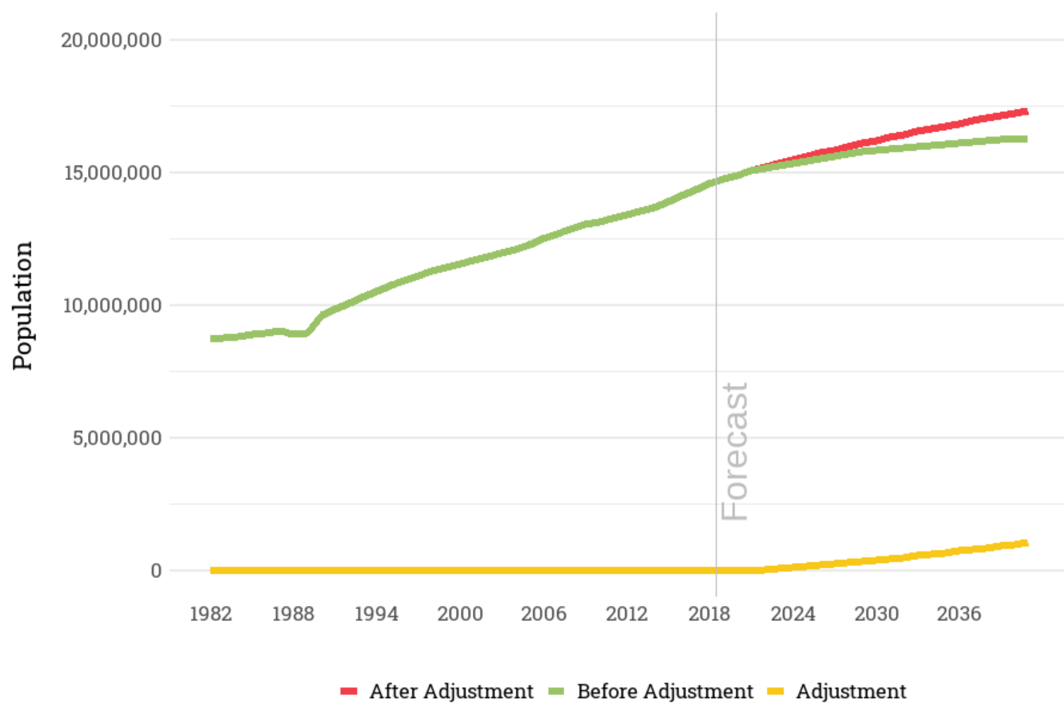
Projection of Average Heating and Cooling Degree Days for each Global Climate Model

Another direct impact of climate change we anticipate is a change in regional precipitation. Our models look at the electricity used to pump water for agricultural irrigation. The use of electricity for agriculture and irrigation averaged about 690 average megawatts per year between 1986 and 2018. With more precipitation, less water needs to be pumped to fields for irrigation which, in turn, uses less energy. With less precipitation, the opposite holds, and more energy is used. However, an increase in irrigated land based on increasing regional population is included in our forecast as an indirect effect of climate change.

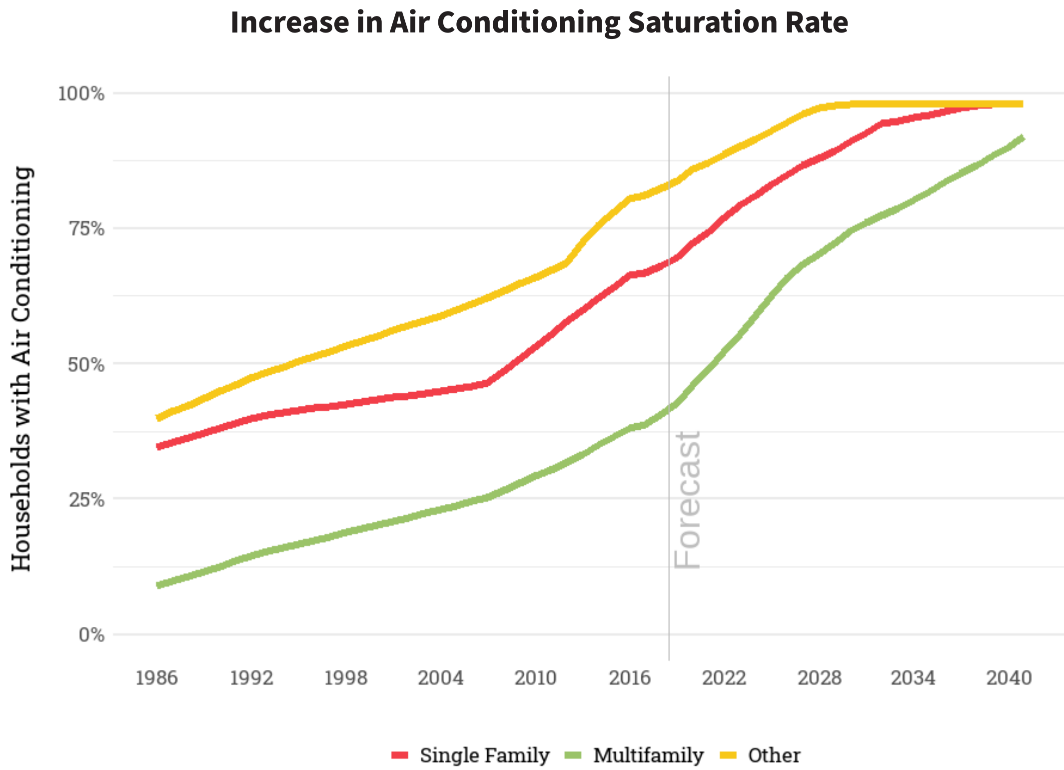
Indirect Impacts of Climate Change

There are many indirect impacts of climate change that could impact the demand for electricity. Events like flooding and wildfires with destructive effects on buildings and infrastructure that use electricity are difficult to forecast and quantify. In those cases,

Regional Population Adjustment for Indirect Climate Change Impacts



adding up the degrees below 65 degrees Fahrenheit of the average daily temperature for each day in the period being examined.



we are unable to incorporate the potential impacts into our demand forecast but acknowledge these are potential impacts to electricity use in our region that deserve continued study.

Some effects of climate change are easier to estimate. Where it has been possible to do so in a robust manner, we have included those impacts in our forecast. One adjustment we made is an increase to forecast population. Studies looking at the impact of climate change on migration[6] show a net increase in regional population. Using these studies, we have adjusted population projections in our forecasts.

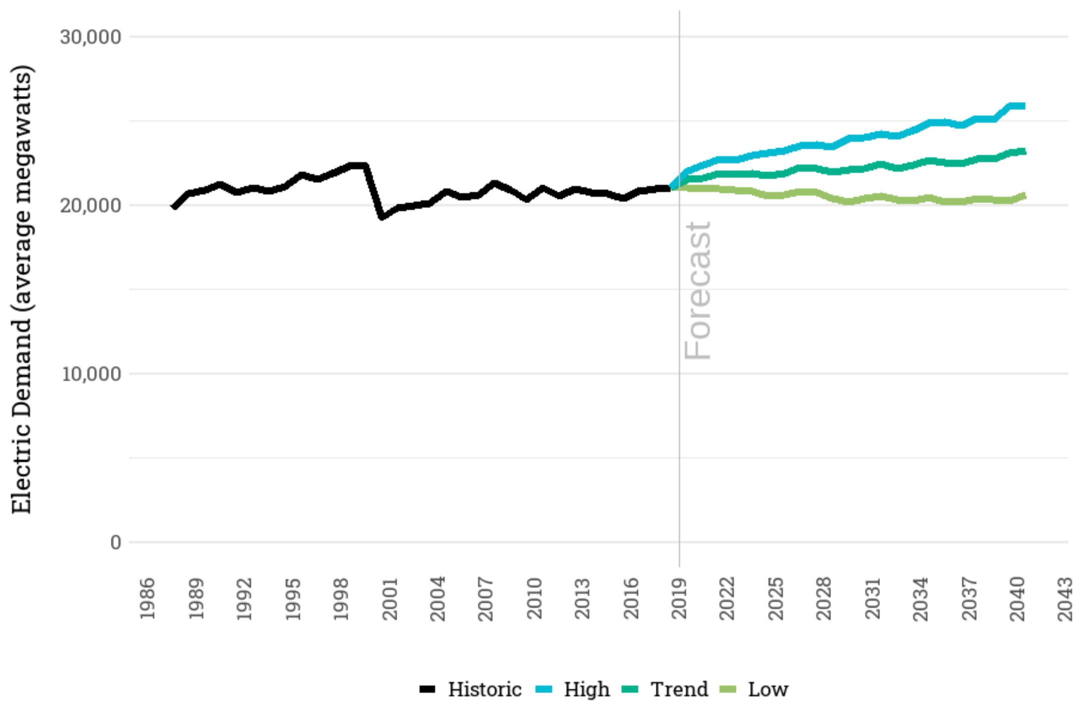
We also adjusted the saturation of air conditioning in new construction for the region. We have seen a growing penetration of air conditioning installed in residential construction. With climate change, we see that penetration continuing to climb and have adjusted our forecasts to grow to a 98 percent penetration by 2050.

Forecast of Regional Demand for Electricity

Over the next 20 years, the Council forecasts the demand for electricity will be driven by many factors including economic growth,

6 For detailed information on the studies and the population adjustment, see the supplemental material link at the end of this section.

Range of Regional Demand for Electricity Based on Economic Conditions



climate change, regional demographics, and expanding applications of electricity to reduce the use of fossil fuels. With all these considerations, we realize that no single forecast could appropriately capture the risks and opportunities to consumers and suppliers of electricity. To better assess the impact on the region, we forecast a possible range for electricity demand.

These forecasts are more uncertain further into the future. To some extent that is considered when we use a range in our analysis. However, our ability to predict what will drive demand for electricity has limits. Thus, the Council updates our forecasts as we get new information. Our forecasts in this power plan are updated and do not match the forecasts included in the last power plan. It should be expected that forecasts beyond the first 5 or 6 years could be missing key drivers that lie outside what would be considered a reasonable forecast at this time. Those drivers will be much clearer in the power plan that follows this one. The Council also forecasts based on current state and federal legislation and does not attempt to predict future legislative change. While recent experience demonstrates it is unlikely that there would be no legislation impacting the use of energy over the next 6 years, exploring this type of uncertainty is left to our scenario analysis. Our scenario analysis includes an examination of added demand for electricity driven by policies or activities aimed at reducing greenhouse gas emissions. Details of our scenario analysis are included in the *Section 6 Resource Development Plan*.

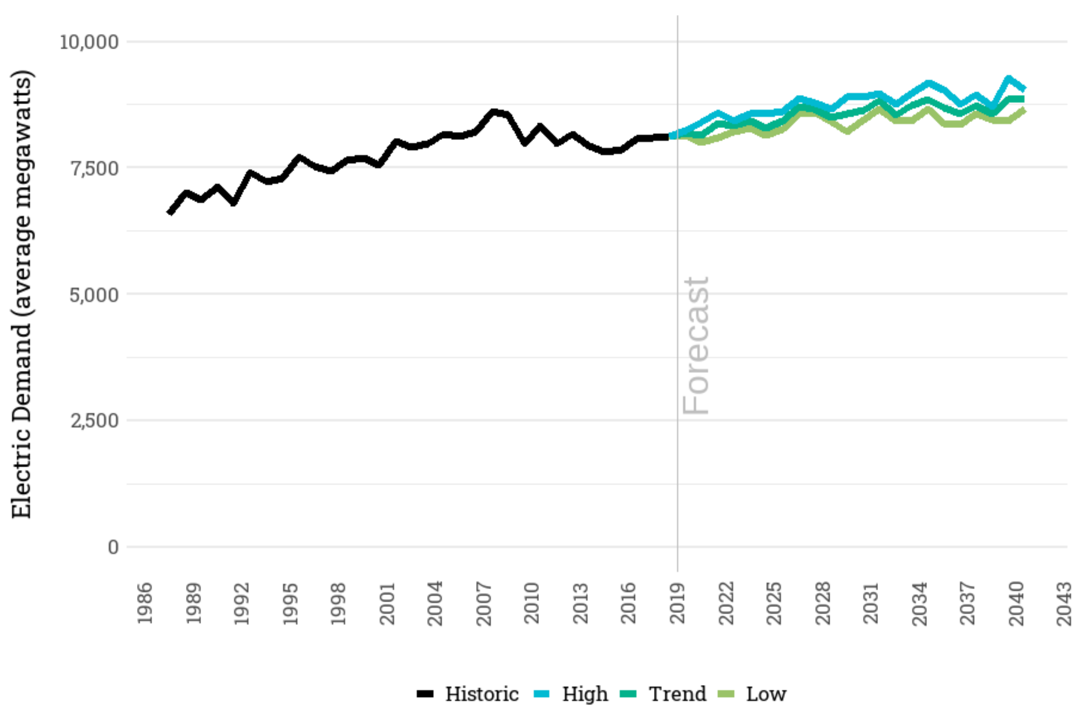
For economic growth, we forecast a range of conditions with a pessimistic estimate of around -8% and an optimistic estimate of +7%. Higher economic output drives higher use of electricity, and so demand for electricity is highest in the optimistic estimate. During the action plan period, the range of uncertainty is lower, + 4% and -5%.

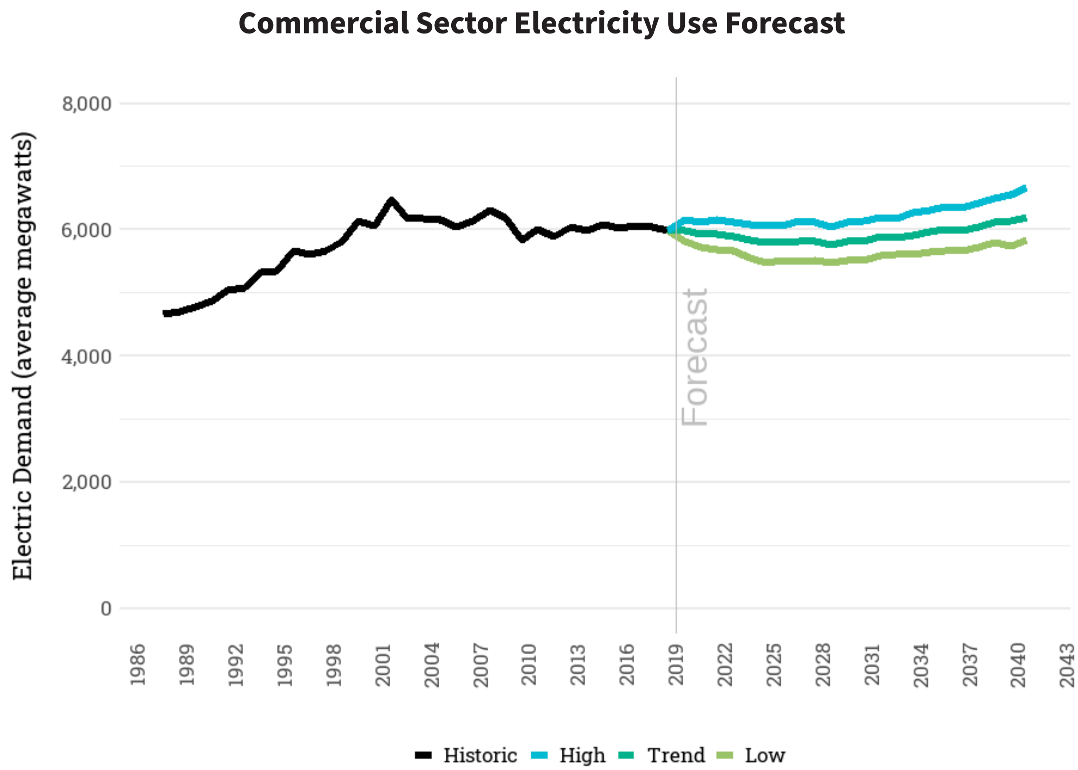
The Council uses this forecast to estimate what additional resources and reserves are adequate to supply the region's need for electricity.

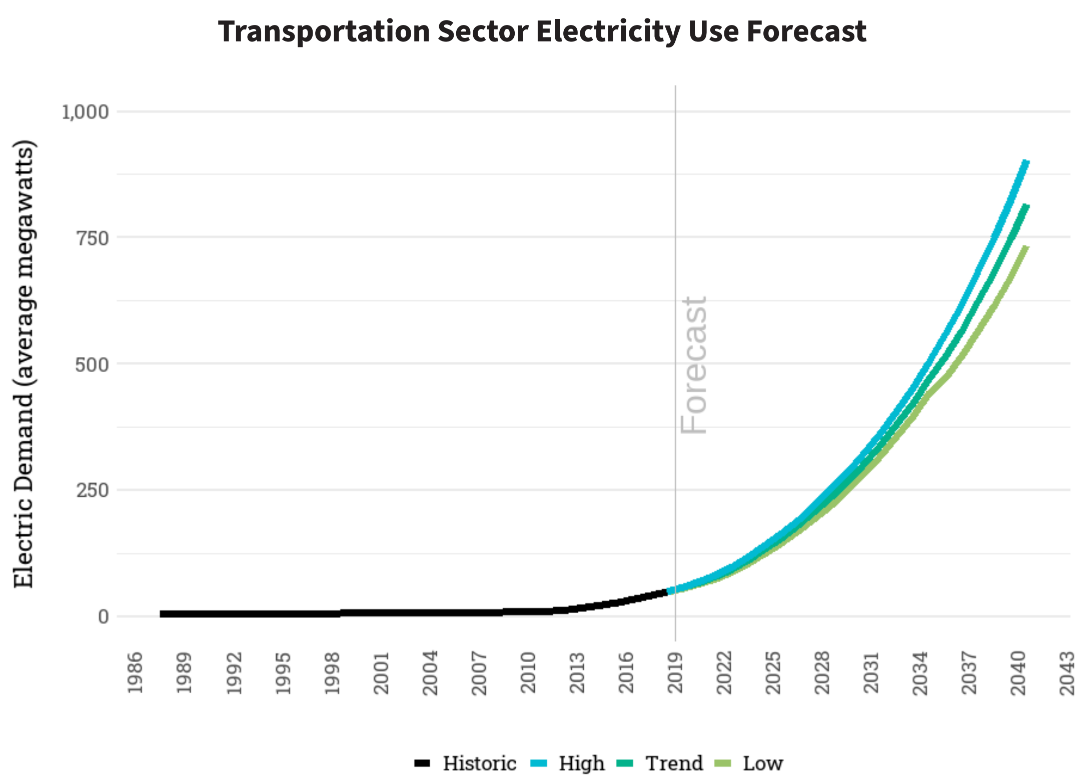
Demand by Sector

The Council's forecast is an end-use forecast. That is, it starts with the different uses for electricity, e.g., lighting or drying clothes, and builds up to sector-level forecasts. We anticipate a range of future loads. We estimate different economic and demographic drivers and then incorporate simulated temperatures from general circulation models. Including these temperatures means the forecasts are not smooth like forecasts that do not include weather variation. For example, anticipated energy needs for the residential sector are particularly sensitive to temperature variation. The loads range from 8,014 average megawatts to 9,726 average megawatts. An

Residential Sector Electricity Use Forecast




Commercial Sector Electricity Use Forecast
Electric Demand (average megawatts)
8,000
6,000
4,000
2,000
0
Forecast
1986
1989
1992
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
Historic
High
Trend
Low


Transportation Sector Electricity Use Forecast
Electric Demand (average megawatts)
1,000
750
500
250
0
Forecast
1986
1989
1992
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
Historic
High
Trend
Low

average megawatt[7] represents one megawatt of load for a full year. But the minimum and maximum happen in different years. While this means that each year may not reflect a specific likelihood of a load above or below our forecast, the use of these loads as a way of testing different resource strategies and helps highlight the natural variation in electricity use that will happen with different temperatures.

By contrast, the commercial sector load forecast shows less variation based on weather. The range of the commercial load is forecast to vary from around 6,000 average megawatts in the near-term to a high of around 7,359 average megawatts.

Industrial loads in our forecast range from a low of under 4,000 average megawatts to a high of just shy of 8,000 average megawatts. Irrigation loads are anticipated to grow to a range of 937 average megawatts to 1,734 average megawatts. Municipal loads like street lighting are anticipated to stay flat or decline at or under 300 average megawatts.

Our forecast also includes a quickly growing regional electric load in the transportation sector and for data centers. In the case of transportation, we anticipate substantial growth relative to the amount of electricity used today. Whereas with data centers, we've seen substantial regional growth already that we are projecting will continue.

Taking the whole picture together creates a regional forecast for the use of electricity that shows a range of energy needs anywhere from 20,580 average megawatts to 25,895 average megawatts in 2041. The table below shows the range of loads in 2041 by the different sectors compared to the expected load in 2021. These forecasts have

Forecast Range of Electricity Use in Average Megawatts by Sector

Sector Forecast	Expected Electricity Use in 2021	Forecast Electricity Use in 2041		
		Low	Medium	High
Residential	8148	8674	8860	9049
Commercial	5938	5833	6202	6673
Industrial	6186	4147	5892	7541
Transportation	67	733	816	904
Street Lighting and Water Services	271	252	280	303
Irrigation	1016	941	1164	1465
Data Centers	657	952	1179	1369

7 For context on what you can power with a megawatt see nwcouncil.org/news/megawatt-powerful-question

interactive effects so they do not add to the same range of loads as the total regional load, but they should give a sense of which sectors have more uncertainty and how they are anticipated to change throughout the forecast.

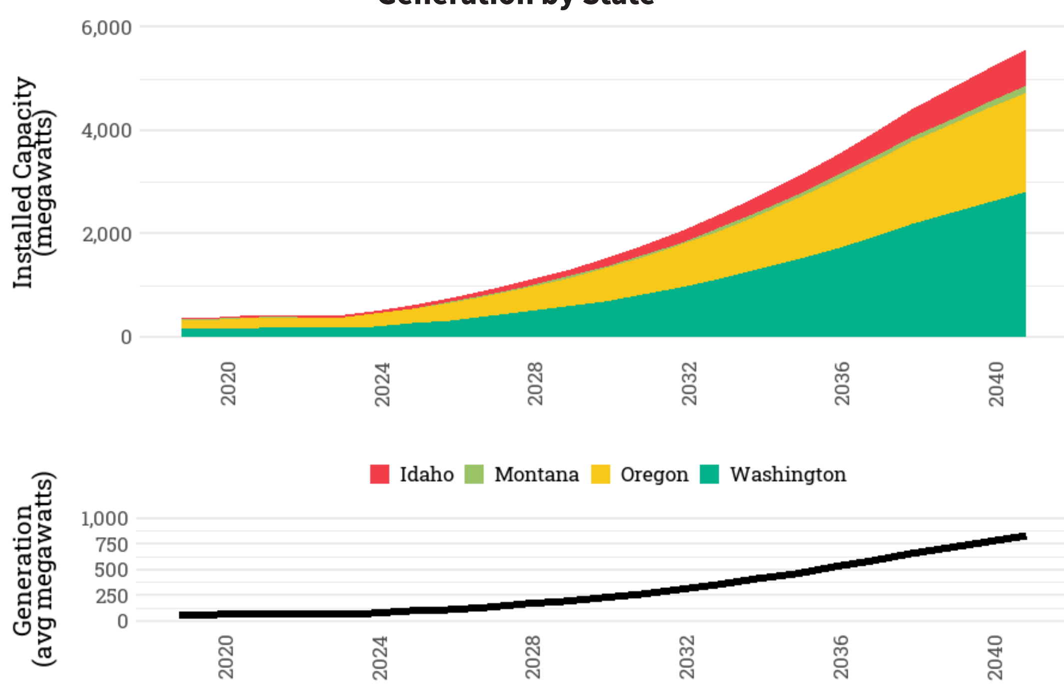
The Impact of Rooftop Solar on the Demand for Electricity

The Council's forecast includes an outlook for behind-the-meter solar installations in the region, which are generally rooftop-mounted systems in the residential, commercial, and industrial sectors. Solar panels are relatively simple to install and operate on homes and businesses. The cost to install and operate home solar has significantly declined and it is expected to continue to decline in our forecast.

Behind-the-meter solar installations in the Northwest have tripled in the five years from 2014 through 2018. By the end of 2018, nearly 90 percent of the 326 megawatts of overall capacity in the region was installed in Oregon and Washington.

The forecast for solar from our model is fairly aggressive. Because of cost declines, we anticipate the growth of installations could be rapid. The graph below shows our forecast of behind-the-meter solar installations by state for our region.

Forecast of Behind-the-Meter Solar Installed Capacity and Generation by State



Section 4: Forecast of Regional Reserve and Reliability Requirements

The fundamental objective of power system operations is to continuously match the supply of energy from electricity generators to customers' electrical demand at all times. This involves proper long-term planning to ensure that the power supply has sufficient generating capability, and that the transmission system can deliver that power within an acceptable range of frequency[8] and voltage.[9] The United States Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas[10] and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

8 Frequency is controlled by maintaining a stable net interchange between neighboring balancing authority areas. The basic test of success for this is called the Area Control Error (ACE). ACE is a measurement, calculated every four seconds, based on the imbalance between load (demand for electricity) and generation within a balancing area, taking into account previously planned imports and exports and the frequency of the interconnection. The North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic premise is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called Automatic Generation Control (AGC), which monitors the frequency of the system and correspondingly adjusts participating generators' output (within seconds) to bring the frequency back in line.

9 Voltage can be controlled in several ways with different types of system components installed at generating stations and the transmission system.

10 Control areas (also referred to as Balancing Authorities) are entities, often utilities, that ensure the power system demand and supply are balanced on a section of the electric grid. When supply and demand become too far out of balance, equipment on the transmission and distribution system will disconnect creating local or widespread electric power outages.

In general, ancillary services provide frequency and voltage control, load-following capability,[11] short-term protection for system component outages and flexibility to cover daily, hourly, and moment-to-moment variations in the electrical demand and generation.

While the fundamental objective will not change, the electricity grid seems poised to go through a paradigm change with an increasing penetration of new variable renewable generation displacing an increasing amount of the electricity that would have otherwise been generated by the existing fossil-fuel-based thermal generating fleet. The region and the rest of the West in the future will likely need to rethink how system capacity needs are measured and what different resources accomplish in providing for those needs.

Power Act Definition of Reserves

The Northwest Power Act defines reserves as "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator… (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers." Electric power that averts operating shortages (operating reserves) falls into four general categories and are either spinning (available for immediate dispatch) or non-spinning (must be at full output within 10 minutes).

- Regulation reserves – provide minute-to-minute increases or decreases in generation to match electrical demand
- Load following reserves – bridge the gap between regulation reserves and hourly energy markets
- Balancing reserves – cover within-hour variations in electrical demand, and variations in wind and solar generation
- Contingency reserves – provide short-term (up to 60 minutes) protection against system component outages (transmission and generation)

The Council's adequacy model assigns operating reserves (regulation, load following, and balancing) and contingency reserves to appropriate resources.

What Does it Mean for a Power System to be Adequate?

While the terms "adequacy" and "reliability" are related, they have specific and distinct

11 In the utility industry, the electrical demand is often called load. Load-following refers to a service provided by electric generators that increases or decreases the output of electricity to match the use of electricity.

meanings for power system planning. A power system is defined to be reliable if it is both adequate and secure, where adequacy generally refers to having sufficient generating capability and security generally refers to having a robust transmission system.

- An adequate power system can supply the aggregate electrical demand of all customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements, and
- A secure power system can withstand sudden disturbances, such as electrical short circuits or unanticipated loss of system elements

The Council uses assumptions established by transmission planning organizations to estimate the ability to deliver electricity around the Western electric grid. However, substantial retirements or additions of generation on the system may go beyond the scope of these limits. The Council in our work assumes that transmission planning organizations and utilities will work together to ensure appropriate investment is made into the transmission system to at a minimum maintain the current ability to deliver electricity around the West. While we do not study expansion of the transmission system in this plan, we recommend the region work with transmission planning organizations to explore the costs and benefits of doing so.

Council's Resource Adequacy Standard

One of the key objectives of the Council's power plan is to develop a resource acquisition strategy that will ensure the region of an adequate, efficient, economical, and reliable power system, while taking uncertain future conditions into consideration.

The Council's overarching goal for its adequacy standard is to *"establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."*

The standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity in future years. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

The metric used to measure resource adequacy is the annual loss-of-load probability (LOLP). The LOLP is assessed by simulating the operation of a future year's power system many times with different combinations of river flows, temperatures,[12] wind and solar generation, and generator forced outages. Whenever demand for electricity is not served, it is considered a shortfall event. The LOLP is calculated as the number of simulations in which at least one shortfall event occurred divided by the total number of simulations. The Council deems the power supply to be adequate if the LOLP is 5 percent or less. That is, the power supply is adequate if the likelihood of having one or more shortfalls in an operating year is 5 percent or less.

Method for Assessing Regional Power System Needs to Maintain Adequacy

The Council uses its evaluation of the adequacy of the existing system to establish a method for assessing potential regional power system needs to maintain resource adequacy under a broad range of different scenarios and conditions. In projecting how the region could meet these system needs we evaluate both the magnitude of those needs and the varying capability of different generating technologies or demand-side resources to meet them.

Gaps Between Existing System Capabilities and Anticipated Future Requirements

Using the Council's adequacy standard, the needs to maintain adequacy are defined as any gaps between existing system capabilities and anticipated future requirements that fall outside that standard. The existing system capabilities are evaluated on an hourly basis accounting for operational and fueling limitations, in addition to generating or demand-reduction capability for all the resources in the existing regional power system. The anticipated future requirements incorporate both regional demand and reserve requirements. The gaps between existing system capabilities and anticipated future requirements are evaluated for each quarter, which broadly can be defined as the fall, winter, spring, and summer seasons using a broad range of estimated hydro conditions, electrical demands, and renewable generation output.

The methodology to identify the size of shortfall events that need to be addressed to maintain adequacy is as follows:

1. The shortfall events in our simulations are sorted from highest magnitude to lowest magnitude on an annual basis, including the simulations where we have no shortfall events or the magnitude of the shortfall event is zero.

12 Temperatures impact the amount of electricity used; for example, during extremely hot days the regional needs more electricity for air conditioning

2. The top 5 percent of the simulated shortfall events (those of the highest magnitude) are assumed to be acceptable under the Council's standard. We do not consider these further.

3. We take the highest magnitude shortfall events remaining for each season as the gap between the existing system capabilities and anticipated future requirements necessary to maintain the Council's adequacy standard. If there are shortfalls greater than zero in more than 5 percent of the simulations, then these seasonal gaps will be non-zero.

The size and composition of the gaps varies between scenarios. When we implemented the climate change projections into the analytics that support the plan, we have projections on temperatures and precipitation going into the future. These projections are not intended to be used as what the expected weather will be in any individual future year, rather they illustrate the types of temperatures that can be expected and the data are designed so that the range of weather over each decade represents an estimate of the range of conditions driven by climate change. The following table shows the maximum energy need (in average megawatts) with the decade for the calendar quarters[13] generally associated with winter and summer. This helps illustrate how much the needs varied between the different scenarios explored in this plan with some scenarios showing substantial needs even within the

Highest Decadal Increment Energy Needs for Select Scenarios (average megawatts)

	2022 to 2029	2030 to 2041
July to August – Early Coal Retirement		
Average	1071	1429
Maximum	2987	3579
January to March – Early Coal Retirement		
Average	1008	1393
Maximum	2884	3648
July to August – Partial Decarbonization		
Average	2461	11120
Maximum	5201	15689
January to March – Partial Decarbonization		
Average	2857	9578
Maximum	6012	14420
July to August – Organized Markets		
Average	0	1
Maximum	0	189
January to March – Organized Markets		
Average	14	742
Maximum	514	2744

13 Our Regional Portfolio Model uses estimated distributions of hourly loads for each calendar quarter. It is certainly possible to have a heat event in June or a cold event in December. These are included in the analysis but not explicitly listed here for the sake of brevity.

2020s. We discuss the gaps resulting from this method for different scenarios in *Section 6: Resource Development Plan*.

Future Resource Capability to Fill Gaps

When exploring the capability of future resources or reserve additions to fill the gap described above, the Council evaluated the attributes of each resource and how they interacted with the existing system to change the total regional capability to meet anticipated future requirements. The existing system, including the region's hydropower generation, can adapt in different ways that fill these gaps. When adding resources that increase the need for reserves, like wind and solar generation, it may reduce the existing system's peak capability.

The ability of the regional hydropower system to support the regional electric grid in different ways is a valuable attribute. However, the demands on the system must be balanced, making sure not to double count the contribution of these resources. Further, the regional hydro system has many purposes beyond generating electricity that take priority and must also be accounted for in any future projections of what the power system can rely on from these resources. The Council models reserves required from both the existing system and any new resources to capture this important dynamic. The examination of future resource characteristics included operational and fueling limitations on an hourly basis in addition to generating or demand-reduction capability within the context of the existing regional power system.

To determining how a resource or combination of resources[14] fill the gaps in the existing system capabilities, we:

1. Simulate the regional power system in 2031 with high demand, all the regional coal units retired, and no new resource additions, then record the maximum gap between existing system capability and system obligations.
2. Simulate the regional power system in 2031 with high demand, all the regional coal units retired, and with a combination of new resource additions. Then record the maximum gap between existing system capability and system obligations.
3. Take the difference in the gaps from the simulations step 1 and 2 and divide that difference by the total nameplate resource additions from the combination of new resources in step 2.
4. Use that percentage as a multiplier when assessing the capability of a combination of new resources to meet any identified gaps.

14 For all combinations not explicitly tested, a multilinear interpolation allows the capability of any new combination of new resources considered in the resource strategy analysis to be identified and considered when attempting to address gaps associated with peak conditions.

Section 5: Energy Conservation Program

Background on Energy Efficiency in the Northwest

Energy conservation is defined in the Power Act as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production or distribution."[15]

In recent years, the Northwest region's utilities have spent about $480 million dollars per year on energy efficiency. This includes investments in incentive programs, market transformation initiatives, evaluation, and research such as in market research, building stock assessments, and emerging technologies. Estimates indicate that in our region, over 100,000 people are employed working with energy efficiency at utilities, the Northwest Energy Efficiency Alliance (NEEA), the Energy Trust of Oregon, state agencies, and at the many trade allies and contractors that work to implement programs and deliver efficiency services.[16]

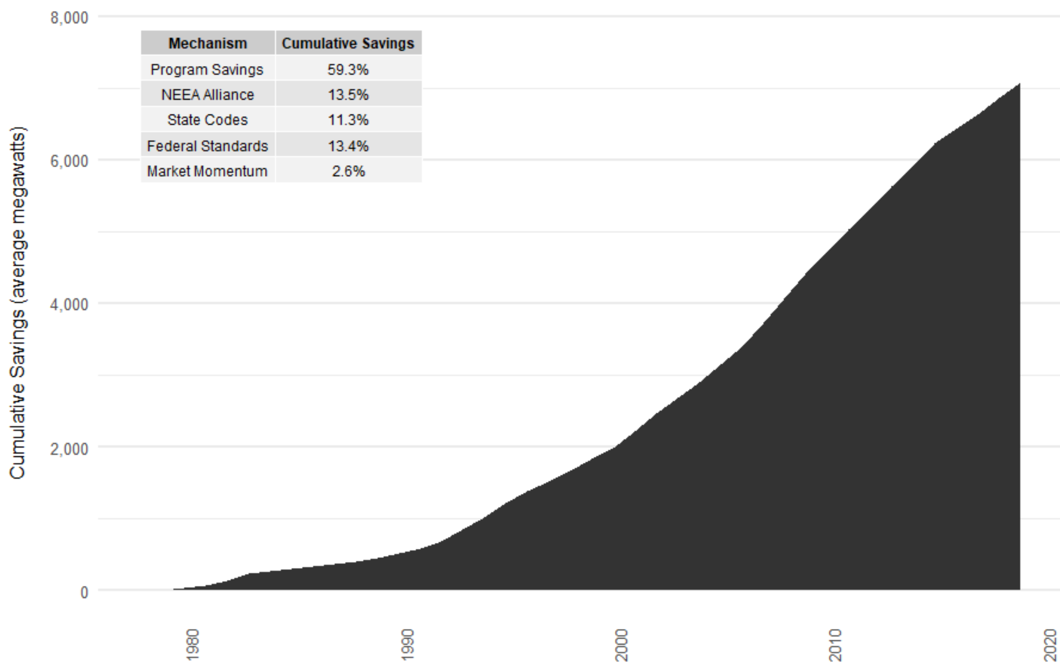
This investment has resulted in more than 7,200 average megawatts of savings since 1978. About 60 percent of those savings are from direct utility program incentives.[17] The remainder is from NEEA market transformation initiatives, improvements in codes and standards, and other market adoption. These savings amount to a regional resource second only in magnitude to hydropower and are equivalent to the annual energy consumption of around 5.1 million Northwest homes. By reducing electricity generation from fossil-fuel power plants, the savings have avoided more than 22.2 million metric tons of carbon dioxide emissions. The cumulative efficiency savings since 1980 have reduced consumer electricity bills by about $4 billion per year. Efficiency has also shown to provide reductions in other non-energy consumables, such as water, and provide additional benefits to consumers in the form of health, comfort, and productivity.

15 Northwest Power Act Section 3(3), 94 Stat 2698

16 U.S. Energy and Employment 2020 report www.usenergyjobs.org

17 More information on conservation achievements can be found on the Regional Technical Forum website rtf.nwcouncil.org/about-rtf/conservation-achievements/2019

Cumulative Regional Energy Efficiency Savings by Mechanism



In recent years, with all the accomplishments and increasing efficiency levels, the future amount of low-cost efficiency available has diminished. One key example is LED light bulbs that have transformed the industry; a 9-watt LED bulb provides at least as much illumination as the traditional 60-watt incandescent. These are significant savings, and future lighting improvements cannot be as profound. However, savings remain[18] in lighting and other end uses, and continued investment is needed to ensure low-cost efficiency remains available.

Regional Recommendations on Energy Efficiency

Amount of energy efficiency the region should acquire

The Council recommends that the region acquire between 750 and 1,000 average megawatts of energy efficiency by the end of 2027 and at least 2,400 average megawatts by the end of 2041.[19] The lower end of this recommended range represents cost-effective energy efficiency acquired at a

18 See New Opportunities for Energy Efficiency in Section 6: Resource Development Plan for further details.
19 More details on the basis for the level of the recommendation can be found in the supporting materials, here: nwcouncil.org/2021powerplan_Cost_Effective_Conservation_Recommendation_Summary

moderate pace, whereas the higher end of the range represents cost-effective efficiency that is acquired more rapidly.[20]

We expect that most of the short-term savings will be via direct-funded utility programs, but this recommendation also includes efficiency accomplished through market transformation initiatives through NEEA, building codes, appliance standards, and natural market adoption. Regional support of all mechanisms is needed for long term achievement and continued availability of energy efficiency.

The Council's regional recommendation includes efficiency acquired at all regional utilities, including the Bonneville customer utilities. Our specific recommendations to the Bonneville Administrator regarding energy efficiency are included in *Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation*.

To achieve this overall goal, all utilities within the region will need to deliver energy efficiency to their end-use customers. For utilities within urban centers, efficiency may be more readily accomplished, given greater availability of contractors and suppliers of efficient products and easier access to a large and diverse number of customers. In contrast, utilities with a rural customer base (primarily residential and agricultural) have significant challenges and fewer resources for implementing cost-effective efficiency programs. These challenges are recognized, and Bonneville and/or other regional organizations such as NEEA should support these rural utilities in reaching efficiency goals.

Continued investment in NEEA and efficiency-related research and development[21] is critical to achieve the long-term goals. To help ensure a robust efficiency infrastructure, work is needed all along the product adoption curve: Continuing research into emerging technologies to introduce new efficiency opportunities; working with retailers and manufacturers to increase the availability of efficient products; and encouraging acceptance by consumers. NEEA and utilities will need to be diligent in ensuring progress in all these facets of the market. As such, to help ensure that the necessary levels of cost-effective conservation are acquired, we recommend the region's utilities:

1. Maintain ratepayer-funded efficiency programs (utility direct programs and market transformation initiatives) at a funding level sufficient to achieve the 2027 goals;

20 The cost-effectiveness methodology for conservation can be found here: nwcouncil.org/2021powerplan_cost-effective-methodology

21 See Section 10: Recommendations for Research and Development for more discussion on this topic.

2. Continue to fund research and development on emerging technologies in an amount commensurate with 2020 levels or greater;

3. Continue to fund regional market research, stock assessments, and related analysis in an amount commensurate with 2020 levels or greater;

4. Support initiatives to enhance building codes and appliance standards, at both the state and federal government-level.

In addition to the amount accomplished under the target, we recommend the region continue to invest in weatherization programs, targeting those homes that are leaky (in need of duct or air sealing) and/or have zero or limited insulation. These measures are critical to provide livable homes for all people.[22] Much of this work is currently being accomplished through low-income weatherization programs, co-sponsored by utilities and state and federal agencies. However, there may be homeowners or renters who do not qualify under those programs but live in substandard housing, and utilities should strive to weatherize those structures as well. In some cases, the structures' needs may be beyond weatherization services, and home replacement programs should be considered.[23] Utilities should consider coordinating with other agencies (such as community action agencies, state agencies, and/or nonprofits) and explore co-funding options to best serve these homes.

Utilities should also begin utilizing energy use intensity (EUI) data for commercial buildings to identify buildings that have consumption levels significantly higher than other comparable buildings. This approach can provide a market-sector-neutral way of identifying those customers in the greatest need of efficiency measures and otherwise previously missed by programs. For example, utility program managers have indicated (and supporting data suggest) that small commercial customers typically have higher EUIs than their larger counterparts. All customers with these higher-than-average EUIs should be targeted for implementation of cost-effective conservation.

Objectives of Conservation Programs

All conservation actions or programs should be implemented in a manner consistent with the long-term goals of the region's electrical power system, as established in the 2021 Power Plan. To achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to ensure levels of efficiency that are cost-effective for the

22 Some of these measures will not be cost effective relative to the plan but should still be included in the programs.

23 For example, some utilities have programs replacing an old manufactured home with a new efficient model.

region and economically feasible for the consumer.

2. Conservation acquisition programs should target conservation opportunities that are not anticipated to be developed by consumers.

3. Conservation acquisition programs should be designed so that their benefits are distributed equitably.

4. Conservation acquisition programs should be designed to secure all measures in the most cost-efficient manner possible.

5. Conservation acquisition programs should be designed to take advantage of naturally occurring "windows of opportunity" during which conservation potential can be secured by matching the conservation acquisitions to the schedule of the host facilities or to take advantage of market trends. In industrial plants, for example, retrofit activities can match the plant's scheduled downtime or equipment replacement; in commercial buildings, measures can be installed at the time of renovation or remodel.

6. Conservation acquisition programs should be designed to capture all cost-effective conservation savings in a manner that does not create lost-opportunity resources. A lost-opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken to develop it or hold it for future use.

7. Conservation acquisition programs should be designed to maintain or enhance environmental quality.

8. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve.

Not all energy efficiency provides equivalent value to the regional electric system. Some distinguishing attributes, such as cost and savings shape, have been captured in the portfolio analysis. However, energy efficiency's ability to improve building resilience[24] and grid flexibility[25] is not well modeled. These attributes are important to maintaining a robust electric system infrastructure, and energy efficiency that provides these values should be prioritized,

24 Building resilience refers to the building's ability to withstand a power outage or extreme weather event. For example, a well-insulated home will maintain its conditioned temperature for longer during an outage or extreme temperatures.

25 Grid flexibility refers to a building's ability to respond to the needs of the grid. Energy efficiency that enables this flexibility could have additional value. For example, an efficient lighting system that has embedded controls could be tapped by a utility to balance the grid.

and we will endeavor to improve our estimates over the action plan period. The Council's Regional Technical Forum (RTF) should explore the mutual benefits of energy efficiency and demand response in providing grid flexibility.

Consequences of not achieving the regional recommendations

The minimum of 750 average megawatts of energy efficiency by the end of 2027 is what we have determined to be more cost-effective than pursuing other resources when considering risk and uncertainty of meeting adequacy needs, decarbonization, renewable resources availability and reliability, and future market pricing. Not achieving this efficiency may result in higher costs to the system and impede development of a more equitable energy system. This efficiency will maintain jobs, lower greenhouse gas emissions, reduce energy burdens for households and businesses, and avoid adequacy shortfalls. In developing this target, the Council also considered specific values for measures to improve a home's resilience to power outages and enable future interconnectedness with the electric grid. Thus, the cost-effective efficiency will help enable a robust electric power system. In addition, investment in measures to improve livability of poorly insulated houses will help toward achieving equity of residential energy burden.

Model Conservation Standards

The Northwest Power Act directs the Council to adopt and include in its power plan a conservation program that includes model conservation standards (MCS). The MCS are applicable to (i) new and existing structures; (ii) utility, customer, and governmental conservation programs; and (iii) other consumer actions for achieving conservation. The Act requires that the standards reflect geographic and climatic differences within the region and other appropriate considerations. The Act also requires that the Council design the MCS to produce all power savings that are cost-effective for the region and economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

In addition to the requirements set forth in the Act, the Council believes the model conservation standards in the plan should produce reliable savings and that the standards should, where possible, maintain and improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles) found in typical buildings constructed before the first standards were adopted in 1983.

The Power Act provides for broad application of the MCS. In the earlier plans, a strong emphasis was needed to improve residential and commercial building construction practices beyond the existing codes. Beginning with the first standards adopted in 1983, the Council has adopted a total of seven model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions to electric heating systems, and the standard for conservation programs not covered explicitly by the other model conservation standards.[26] Since the Council adopted its first model conservation standards, all four states within the Northwest have adopted strong energy codes that largely incorporate the standards.

The MCS for the 2021 Power Plan have two main components. The first is that the Council adopts two specific components to the standards to ensure equity in efficiency adoption through codes and standards. The second component provides the standard for conversions (similar to prior MCS) to an electric space or water heating system from another fuel.

The focus of the codes and standards component of the MCS is on two areas intended to improve equity around efficiency acquisition through codes and standards. These areas include supporting common appliance standards in the Northwest and discouraging backsliding or reducing codes or standards.

In addition, as municipalities around the region are considering reducing their carbon footprint, electrification of end-use equipment has gained interest. The second component of the MCS is the standard for conversions (similar to prior MCS) to an electric space or water heating system from another fuel. The Act definition of conservation clearly excludes fuel switching as energy efficiency. However, if fuel switching were to be promoted, this MCS directs action to ensure the switching is performed with all cost-effective electric energy efficiency incorporated.

Common Appliance Standards

The minimum efficiency requirements of many appliances and equipment are regulated at the federal level.[27] These standards are a low-cost, equitable means of achieving cost-effective efficiency. For products without a federal standard, states may adopt their own minimum efficiency requirement. In the past few years, several states have adopted their own standards,

26 The 2021 Power Plan model conservation standards and surcharge methodology supersede the Council's previous recommendations.

27 www.energy.gov/eere/buildings/appliance-and-equipment-standards-program

including Washington[28] and Oregon.[29] Often, these standards are consistent with those in California, allowing for a uniform market in the western-most United States. This commonality is preferred by manufacturers to minimize regulatory confusion and multiple product lines. To further efficiency and limit market disruption, Northwest states should consider adopting common standards and work to synchronize updates. Coordinating with additional states, such as through initiatives by the Appliance Standards Awareness Project,[30] would strengthen the likelihood of compliance and manufacturer buy-in.

No Backsliding on Codes or Standards

Once a code or standard has been adopted, no state or federal agency should change the standard such that a subset of buildings or appliances are subject to a less stringent standard. Codes and standards are a low-cost, equitable means of achieving cost-effective conservation. When markets are segmented into product classes and thus subject to differing requirements, this dilutes the efficacy of the code or standard and decreases efficiency. This in turn has impacts on the ability for the region to equitably provide low-cost energy efficiency to all Northwest consumers.

Conversion to Electric Space Conditioning and Water Heating

Per the Power Plan analysis, jurisdictions pursuing economy-wide decarbonization goals should pursue multiple approaches to reduce carbon, including significant energy efficiency investment. While the Power Plan does not include electrification of end uses in its resource strategy, the Council recognizes that some jurisdictions may pursue electrification as part of a decarbonization strategy. Those jurisdictions (state or local governments) or utilities with such decarbonization goals that include electrification should take actions through codes, service standards, user fees or alternative programs, or a combination thereof, to achieve electric power savings from buildings. The efficiency level of new electric space conditioning or water heating equipment in these jurisdictions should be at least equivalent to the lowest-efficiency measure included in the 2021 Plan or adopted by the RTF (whichever is more recent). While some of the measures may not be cost-effective under the Council's current methodology, the Council believes they would be for jurisdictions with deep decarbonization initiatives. Similarly, for those jurisdictions, any existing inefficient electrical space or water heating equipment

28 www.commerce.wa.gov/growing-the-economy/energy/appliances
29 www.oregon.gov/energy/energy-oregon/Pages/Appliance-Standards.aspx
30 appliance-standards.org

should also be upgraded to a minimally efficient level at time of replacement.[31]

Surcharge Recommendation and Methodology

The Power Act authorizes the Council to recommend a surcharge that the Bonneville administrator may impose on customers that have not implemented conservation measures that achieve energy savings comparable to those that would be obtained under the Model Conservation Standards in the plan. Section 4(f)(2) of the Northwest Power Act directs the Council to include a surcharge methodology in the power plan. The surcharge must, per the Act, be no less than 10 percent and no more than 50 percent of the administrator's applicable rates for a customer's load or portion of load. The surcharge is to be applied to Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards.

The Council does not recommend a surcharge to the administrator under Section 4(f)(2) of the Act at this time. The Council intends to continue to track regional progress toward the plan's MCS and will review its decision on the surcharge recommendation, should accomplishment of these goals appear to be in jeopardy. Should utilities fail to enact these standards, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the administrator be granted the authority to place a surcharge on those utilities' rates to recover those costs.

The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth.

As stated above, the Council does not recommend that the administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council's plan set forth a methodology for surcharge

31 There may be cases where the savings are minimal relative to the expense (e.g., installing ductless heat pumps in small multifamily units) and may not be a priority efficiency investment. Jurisdictions will need to consider policy goals in determining what a reasonable cost-effectiveness limit should be.

calculation for Bonneville's administrator to follow.

Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is as follows:

Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards set forth within this chapter.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

2. If the customer is not purchasing firm power from Bonneville under a power sales contract but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

Section 6: Resource Development Plan

How the Electric Sector Has Changed

The Council's 2021 Power Plan is significantly different than its Seventh Power Plan, adopted just five years ago. This is due to changes in the economics of renewable resources and the adoption of regional clean energy policies. The rapid cost reduction for solar and wind power technologies, when coupled with federal and state inducements, has provided an incentive for building large amounts of utility-scale solar and on-shore wind power across the region and put increased competitive pressure on thermal generators that operate at higher costs.[32]

Along with this changing economic landscape, the plan also recognizes clean-energy policies and goals implemented at state, city, and utility levels in many jurisdictions across the Western electricity interconnection and their impact on the future development of significant renewable and non-carbon emitting resources. The combination of increased competitive pressure and clean energy policies has resulted in the early retirement of less efficient thermal generators, and increased thermal generator planned retirements during the initial five-year "action period" of the plan. This indicates that the capacity of coal-fired power plants in the region will be reduced by more than 60 percent over the next decade.[33] Furthermore, uncertainty remains over the role of existing natural gas-fired power plants beyond this decade, and the future development of new gas-fired generators within the region.

Perhaps even more uncertain is the extent to which clean energy policies will affect other sectors of the economy and the demand for electricity. There is an increasing number of jurisdictions within the interconnection that have established policy goals and timelines to reduce greenhouse gas emissions economy-

32 To this point, the accelerated addition of renewable generators operating without fuel costs to the power supply has led to lower electricity prices, sometimes crossing below zero during intra-day trading.

33 Uncertainty regarding the future of existing coal plants in the region was apparent during preparation for the Seventh Power Plan, becoming a central issue for utility resource planning. Accordingly, the planned retirements of Centralia units 1 and 2, Boardman, and North Valmy units 1 and 2 between 2020 and 2026 were incorporated into the power plan.

wide, leading to potentially high levels of new demand. For example, in the transportation sector, the focus is on converting fossil fuel-fired vehicles to electricity or hydrogen. The widespread use of electric- and hydrogen-fueled vehicles would have a substantial impact on future electricity load growth. To this point, our early modeling work indicates significant electric system demand devoted to hydrogen fuel production for transportation – demand perhaps double the average output of the existing hydroelectric system. Combined, these actions signal a major paradigm shift for the electricity sector in the region (and elsewhere), presenting challenges to maintaining and enhancing an adequate, efficient, economical, and reliable power supply.

In the Seventh Power Plan, energy efficiency – the priority resource in the Northwest Power Act – was the clear, least-cost resource, with cost-effective energy efficiency acquisitions meeting most of the load growth through 2035. The region was undergoing a shift from a focus on energy needs to a focus on capacity - in particular peaking capacity - and ensuring an adequate system in poor water years or extreme weather conditions when the hydropower system has limited flexibility to meet peak needs. Deployment of demand response was also recommended to meet and reduce system capacity needs. Following energy efficiency and demand response, new natural gas-fired generation was the most cost-effective resource. The plants, and greater utilization of existing gas-fired plants, were part of the least-cost strategy to meet remaining resource needs and reduce carbon dioxide emissions from the electricity system. Finally, renewable resources were acquired near the end of the 20-year planning period to meet state renewable portfolio standards (RPS). Utilities were largely in compliance with near-term RPS targets due to earlier wind resource development, which saw the region build about 8 gigawatts in five years in the late 2000s and early 2010s.

For the 2021 Power Plan, the outlook is much different. There is less low-cost energy efficiency potential available due to the same price competition from solar and wind resources that now impacts thermal units, although the total cumulative potential at the end of the planning period remains the same. Ongoing construction of inexpensive renewable resources is influencing the wholesale electricity market, with low prices, particularly in the middle of the day, when solar PV is producing at its peak. In light of the construction of renewable resources anticipated in this plan, these low prices are likely to become increasingly negative through time, making it very difficult for resources with variable operating costs (like thermal plants) to commit and compete, leading to concerns about the adequacy and reliability of the system. The region's hydropower system – the biggest generating resource and "battery" in place – will also be facing long-term alterations in flow from climate change effects on weather and precipitation, as well as ongoing requirements to spill water to enhance fish passage. Water that is spilled cannot be used to generate power. These challenges are magnified when the hydropower system is increasingly used for flexibility and integrating new renewable resources.

In summary, the electric grid is shifting to renewable resources at an aggressive pace. This shift, along with the speed at which the system must react to demand for power, creates potential risks to system operations that we address in the plan. These changes also point to significant levels of low- or no-cost power available to the region during most daylight hours throughout the year. It is through the efficient management of these resources that the region will assure a reliable and economical power supply.

Recommended Resource Strategy

The Northwest Power Act requires the Council to prepare a regional conservation and electric power plan that assures the region an "adequate, efficient, economical, and reliable power supply." Since the first power plan in 1983, the Council considers a range of uncertainties and potential futures to determine its preferred resource strategy. The strategy balances analytical findings, policy expectations, and operational limitations within the grid. The resource strategy covers the entire plan horizon of 20-years (2022-2041) with a focus on a near-term, six-year action plan period (for this plan, the action plan period is 2022-2027).[34]

The resource strategy provides guidance to the entire Pacific Northwest region – encompassing both public and private utility territories - on how best to meet the electric power system needs. It is similar to integrated resource plans (IRPs) conducted by many utilities in the Northwest and around the country. Both consider supply- and demand-side resources as comparable means to meeting future needs and account for state policies that influence resource options. However, the Council's plan differs from IRPs in some important respects. By being a regional strategy, specific balancing authority or utility nuances are not necessarily captured. For example, the plan's strategy does not have specific requirements for additions to the transmission or distribution systems.[35] In addition, as a regional plan, there is less specificity on resource

34 The years represent water year, or October 1 – September 30.

35 *Section 10: Recommendations for Research and Development* includes a recommendation for the region to conduct a study on the ability of the transmission system to incorporate the proposed renewable power additions. The recommended resource strategy accounts for an estimated value of deferring transmission and distribution; however, utilities may have location-specific needs that are high-value that would have a costs and

acquisition recommendations than what may be provided in an IRP.

Regional Resource Recommendations

The 2021 Plan resource strategy includes recommendations on energy efficiency, generation, and demand response. Together, these will help support an adequate, efficient, economical, and reliable power supply while limiting greenhouse gas emissions. The recommendations for the Bonneville Power Administration, in part highlighted here, are specified in *Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation*.

The Council recommends Bonneville and the regional utilities plan to acquire between 750 and 1,000 average megawatts of cost-effective energy efficiency by the end of 2027 and a minimum of 2,400 average megawatts by 2041. This level of efficiency is cost-effective for meeting energy needs and is a low-risk approach to meeting adequacy needs (further described in *Section 9: Cost Effective Methodology for Providing Reserves*) by providing a hedge against reliance upon the availability of other resources at the time needed and supporting opportunities to unlock additional hydropower system flexibility. The addition of efficiency-based resources will also defer need for transmission and distribution system upgrades, reduce emissions, and support jurisdiction-specific decarbonization goals. In addition to the energy efficiency acquisition recommendation, *Section 5: Energy Conservation Program*, outlines other recommendations related to ensuring this efficiency is prudently acquired. Section 5 also provides the Model Conservation Standards and Surcharge Recommendation and Methodology, two required components of the plan.

Our recommendation is based on energy efficiency supply curves developed using estimated costs and savings data available through early 2020 for many different potential energy efficiency measures. We understand and expect the costs to acquire energy efficiency measures will vary between utilities and from one year to the next. This will likely alter the mix of efficiency measures available through utility programs in the region during the action-plan period. How much any particular utility invests in conservation, and which measures the utility invests in, are decisions for the utility to make based on a number of factors, including whether it makes economic sense to the utility in its particular circumstances. Given this reality, there will always be some

benefits that differ substantially from an estimated regional value. For more information see the supporting material at nwcouncil.org/2021powerplan_global-assumptions-power-plan. The analytics in the plan do not co-optimize individual utilities specific investment opportunities in generation, transmission, and distribution infrastructure. Regional utilities should consider the Council's recommendations within this context.

uncertainty of whether the amount of conservation that is cost-effective regionally will be acquired. Because of these factors, we believe it prudent to monitor progress in the acquisition of energy efficiency resources over the action plan period, including the cost to deliver such resources to customers. Further, we encourage greater collaboration between utilities to advance the overall effectiveness of energy efficiency resources.

For generation resources, the Council recommends the region acquire at least 3,500 megawatts of renewable resources by 2027, as a cost-effective option for meeting energy needs and reducing emissions. The Council also recommends that policymakers and utilities pursuing aggressive emissions reductions evaluate adding more renewables as a means of displacing emissions both within their portfolio and in the broader market. While these recommendations are part of the least-cost resource strategy, it is also important to note that we project there will be times that market conditions will result in substantial generation curtailment of both these new renewable resources and the existing renewable resources in the region. That is, there will be times when there is more electricity being produced than demand for electricity, and the region, as well as the broader West, will need to reduce the amount of generation on the system, in part by not using the total capability of renewables.

The plan evaluates broad regional trends but should not be seen to preclude more local and site-specific needs and opportunities. The Council acknowledges regional utilities will evaluate the suitability and efficacy of a broad range of resources, including resources not explicitly modeled as options in the power plan to meet those needs. Further, the Council acknowledges that all energy infrastructure development and construction – including new solar and wind plants and any potential new or upgraded transmission required to deliver that energy – has an impact on the environment. The Council recommends that the region be mindful of individual and cumulative impacts when siting new resources so that new renewable resource development is carried out in a manner that also protects the wildlife, fish, and cultural resources of the Pacific Northwest.

These resource additions will depend on sufficient transmission capability on the system to deliver electricity from the source of generation to the locations where electricity is needed. The Council understands that utilities with existing transmission rights should be compensated for the investments needed to construct large transmission projects. In our resource strategy, we do not identify what rights are available for adding renewable resources, but we understand regional utilities building these projects will need to use a variety of approaches to fit this expansion of renewable resource generation into the existing transmission system, respecting the rights of the transmission system owners and operators.

The Council recommends utilities examine two demand response products: residential time-of-use (TOU) rates[36] and demand voltage regulation (DVR) to offset the electric system needs during peaking and ramping periods and to reduce emissions. A given utility's time of need may differ from the region's, but these products are likely still part of a cost-effective strategy. Our assessment shows about 520 megawatts of DVR and 200 megawatts of TOU available by 2027.

With unique assets at each utility and across the region, the most strategically valuable program offerings may vary, so there may be other similar products that are also frequently deployable, low cost, and with minimal customer impact that could provide similar benefits; those should also be considered in utility planning. In addition to benefits on the power system side, demand response could be used to relieve transmission constraints and defer transmission and distribution system upgrades. The Council will track regional demand response implementation to assess progress, recognizing that the lack of a regionwide economic signal for capacity makes adopting demand response challenging. Based on the scenario analysis, the Council recommends Bonneville and regional utilities consider the value of adequacy, capacity, and emissions reduction when evaluating demand response in integrated resource plans and other analyses. As organizations and utilities develop demand response capability, they should do so by leveraging existing energy efficiency infrastructure and considering them together as part of an integrated demand-side management approach to optimize delivery of both resources holistically and equitably. We recognize, however, that our demand-response target recommendation depends, in part, on investments made by utilities to install advanced meters (AMI) across their service territories. While many utilities have installed advanced meters and the back-office architecture necessary to implement TOU rate designs, those that have not may need financial support to accomplish it. Therefore, we encourage Bonneville, regulators, and utility leadership to support investment in AMI architecture as a tool to encourage the most efficient use of grid resources.

36 The Council included both price (or tariff)-based and control-based products in the demand response supply curves. As a tariff-based product, TOU is not dispatchable and does not have a cash incentive for customers to participate and thus utilities have less ability to deploy for emergency needs. However, for a consistent, short-duration period of need, TOU can be beneficial. TOU was included in our demand response supply for analytical purposes, utilities may choose different analytical approaches in determining the value for their system.

In addition to these resources, the Council recommends Bonneville and the regional utilities, along with their associations and planning organizations, work together and with others in the Western electric grid to explore the potential costs and benefits of new market tools, such as capacity and reserves products, that contribute to system accessibility and efficiency. We would expect to see significant cost savings from greater regional collaboration to drive more efficiency into the system operations. A more aggressive examination would expand such a cost and benefit analysis to include the development of an organized or independently operated electricity market across the region. While any market design should protect the region's investments in its existing generation and transmission system, there may be reliability and cost benefits from the central dispatch of resources across a broad footprint. We also recommend the region concurrently work toward more collaborative understanding of the impacts of changes in market liquidity outside the region and the implications, especially for peaking and ramping periods, and pursue additional collaborative approaches to mitigate identified risks.

Historically, the Council has prepared a mid-term assessment of the plan a few years after its release and before work begins on the next plan. The primary purpose of the mid-term assessment is to check on the region's progress in implementing the plan.

The 2021 Northwest Power Plan includes many recommendations to the region and to Bonneville. We recognize that the regional power system is in an extraordinary time of change with many uncertainties associated with future system operations. The Council monitors the region closely and prepares annual adequacy assessments, forecasts, and other reports.

In the mid-term assessment for the 2021 Power Plan, we will update and examine its findings and examine any changes since it was finalized. While some circumstances will undoubtedly change after publication of the plan, we will examine if anything calls into question its fundamental strategy.

The Process of Developing the Recommended Resource Strategy

To make a recommendation to the region on how to meet the future needs for electricity most effectively, the Council assesses capabilities of the existing system and estimates the cost of adding new resources to keep up with system demands. The Council also needs to understand the costs of building and operating the system and how those costs change with different strategies to meet future energy needs. But both the system needs and the future cost of the system are uncertain. So, we project more than just an expected future need and associated costs; rather, we look at a wide range of potential system costs and needs.

This is done with a combination of computer-based mathematical models and analysis. The Council uses the Energy2020 model[37] to estimate the future need for energy. The output demand for electricity, which is part of the total energy need, is then carried into the AURORA model[38] that is used to estimate electricity prices and the GENESYS model[39] used to evaluate if the regional electric system can adequately meet the demand for electricity. We also use the output demand for electricity to formulate supply curves for energy efficiency and demand response. And we use the output of all these models and analyses in our capacity expansion model, the Regional Portfolio Model[40].

These models, used in conjunction with our staff expertise and consultation with regional experts, inform the Council's recommended resource strategy. All these models are made to explore a range of possible future conditions and outcomes. We cannot pinpoint the future the region will experience, but we can hope that by exploring how resource strategies perform under a wide range of potential future uncertainty, our recommendations will be adaptable and reduce the risks our region faces going forward.

Forecasts Used in Developing the Recommended Resource Strategy

To estimate the impacts of the recommended resource strategy, the Council forecasts elements that impact the cost, operation, environmental impact, and reliability of the regional electric system. Some elements that impact the cost of supplying electricity include the price for importing electricity from outside the region and the cost of fuel for power plants that operate inside the region. There are dozens of power plants operating in the region that consume fossil fuels like natural gas and coal; in particular, natural gas-fired generation has been growing. These fossil-fuel-based power plants become especially important to the region during low-water years when hydropower generation is limited. The price of fuel for these generating resources, or power plants, is a key determinant of the cost of the electricity they generate. This makes the fuel price forecast an important input for the power plan.

While these forecasts are directly tied to the cost of providing electricity, we also need to estimate how much electricity will be

37 www.energy2020.com

38 energyexemplar.com/solutions/aurora

39 nwcouncil.org/energy/energy-advisory-committees/system-analysis-advisory-committee/ genesys-–-generation-evaluation-system-model

40 nwcouncil.org/regional-portfolio-model

needed. The Council uses its 20-year demand forecast, which covers a range of future potential electricity needs, when developing the resource strategy.

The electric system is part of the broader regional use of energy, and increasingly there are technologies that can switch between using fossil fuels and electricity. One example of this is electric vehicles that use electricity to charge a battery rather than the traditional internal combustion engine vehicle that uses gasoline or diesel. Understanding the future need for electricity requires that the Council adopt a broader view of energy use in the region. This allows the Council to forecast how much of the demand for energy will be served by electricity and gain a holistic view of greenhouse gas emissions related to different energy choices in the region.

Electricity Price Forecast

To forecast the future electricity price, the Council must look at the broader Western electricity grid. How many and what types of power plants utilities and other power producers around the West operate, build, or retire impacts the price of electricity in our region. The ability or lack of ability to move electricity from where it's generated to where it's needed also impacts the price we pay for electricity.

There are many factors that impact what power plants are built in the Western electric grid – the cost of different generating technologies, state and federal legislation intended to limit greenhouse gas emissions, the services and support needed to maintain the balance of supply and demand for electricity, and the regulatory barriers to building new fossil-fuel-based power plants, are examples of the influences that affect where a facility is located and its technology.

Further, no power plant is built without available transmission to deliver its output to the utility network or location paying for the output. The Council looks at a variety of scenarios that have different compositions and magnitudes of the plants built to produce electricity. These are developed in consultation with regional experts to understand the factors that will influence electric utility decisions.

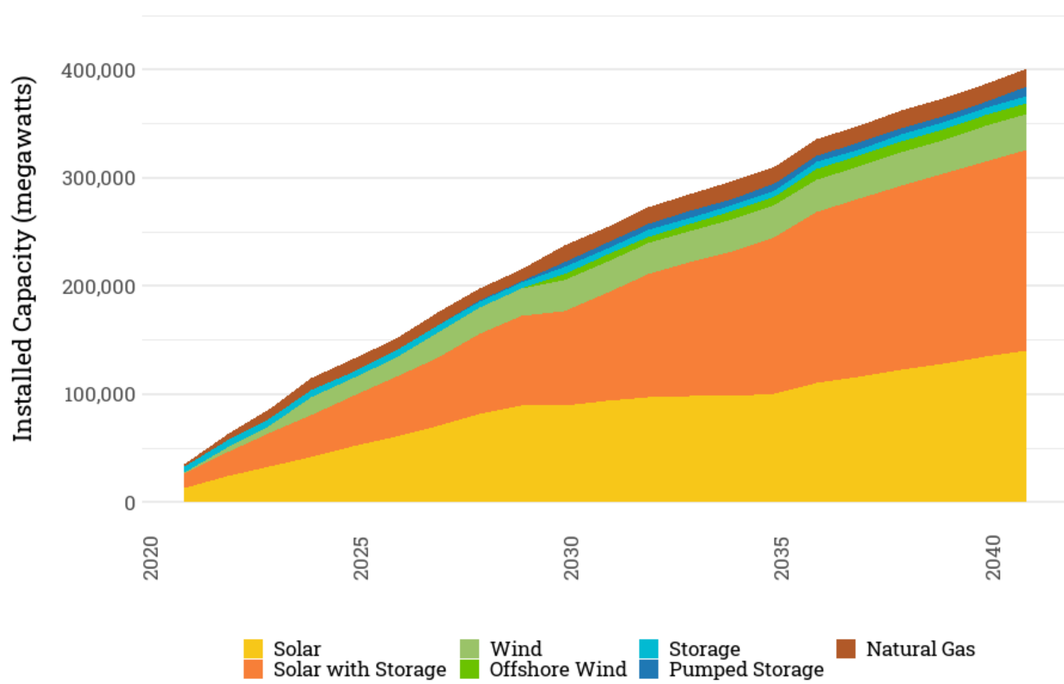
Considering the Council's' duty to assure an adequate and economically efficient supply of electricity for the region while respecting the renewable and clean energy targets of many Western states, the Council forecasts an extremely large addition of renewables. For example, the Council's baseline electricity price forecast adds around 400 gigawatts of nameplate capacity[41] to the Western electric

41 The nameplate capacity of a power plant is the maximum amount of electricity it can generate when it's fully functional and under optimal conditions or using the maximum amount of fuel. Another way of representing nameplate capacity is the manufacturer's rated output of the generator. Nameplate capacity should not be seen as representing the capacity contribution to system peak needs for any of the generating technologies

grid by 2041. The size of this addition meets the estimated reliability requirements for utilities outside the region and the states' requirements for renewable and clean power. It also limits the amount of new natural gas power plants to be built within region. To be clear, this forecast doesn't represent a forecast of power plants the Council expects will be built in the future. Rather, it shows what we estimate it would take to meet all the various requirements put on Western electric utilities.

However, such a large addition of new renewable power plants leads to a substantial oversupply of electricity during certain hours of the day and seasons in the year. The amount of electricity that could have been produced but instead is expected to be curtailed increases substantially through time with an addition of this magnitude. The next chart shows how the

Projected Generation Additions



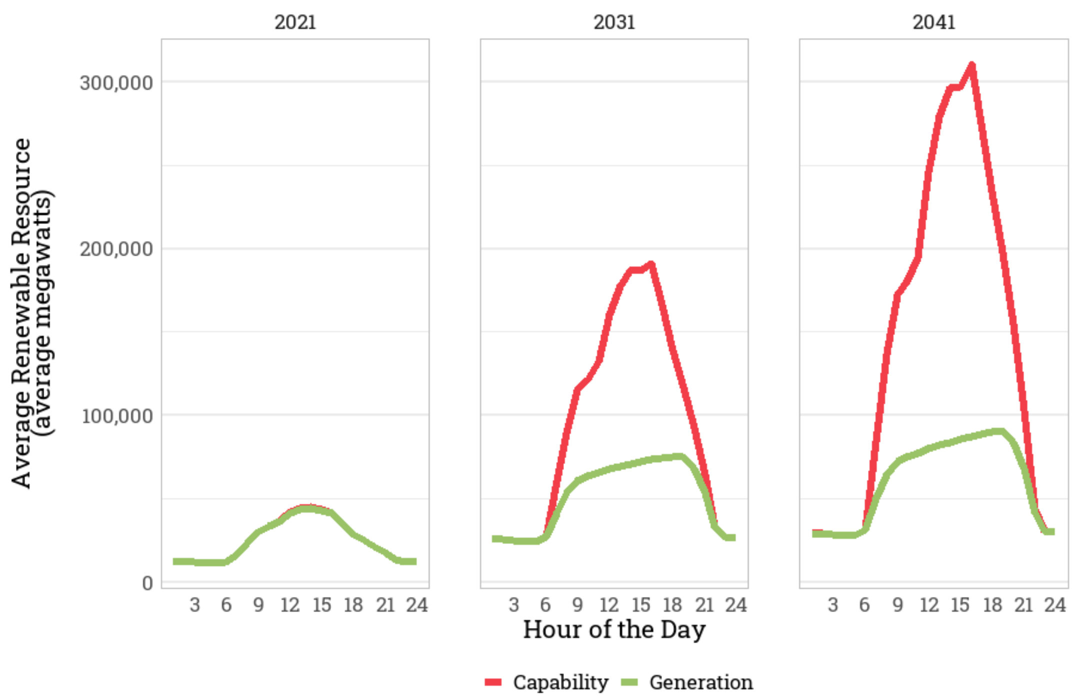
examined in this plan. For example, a wind plant with a 100-megawatt nameplate capacity will generate 100 megawatts when every turbine in the wind plant is at maximum output. However, during many hours when there is not enough wind, the wind plant will produce less electricity. Depending on location, a wind plant may average between 30 and 40 megawatts of generation over a whole year. In this case, the wind plant has between a 30- and 40-percent capacity factor. Further, neither nameplate capacity nor capacity factor should be confused with the capacity contribution to system peak needs, which is discussed in Section 4: Forecast of Regional Reserve and Reliability Requirements.

average amount of curtailed renewable generation increases substantially in 2031 and 2041 compared to 2021.

Regardless of how many power plants are built, the Council expects electricity prices to vary from year-to-year based on natural variability in demand for electricity and the available supply of electricity. In our region, electricity generated by hydropower is a substantial portion of the electricity we use. But the amount of electricity that can be produced depends on the weather. The weather can also drive demand for electricity, with extreme cold in winter or extreme heat in summer increasing the need for heating or air conditioning, requiring more electricity than normal.

From the River Management Joint Operating Committee (RMJOC) recent report on climate data analysis,[42] the Council selected three out of nineteen RMJOC climate scenarios to analyze the boundary conditions of potential regional climate change impacts.[43] From analysis of the temperature and streamflow data of the three RMJOC climate scenarios, the Council projects, in general, increasing winter hydropower generation due to increasing fall and winter streamflows from

Renewable Resources in the Western Electric Grid: Average Generation Versus Capability by Hour of the Day



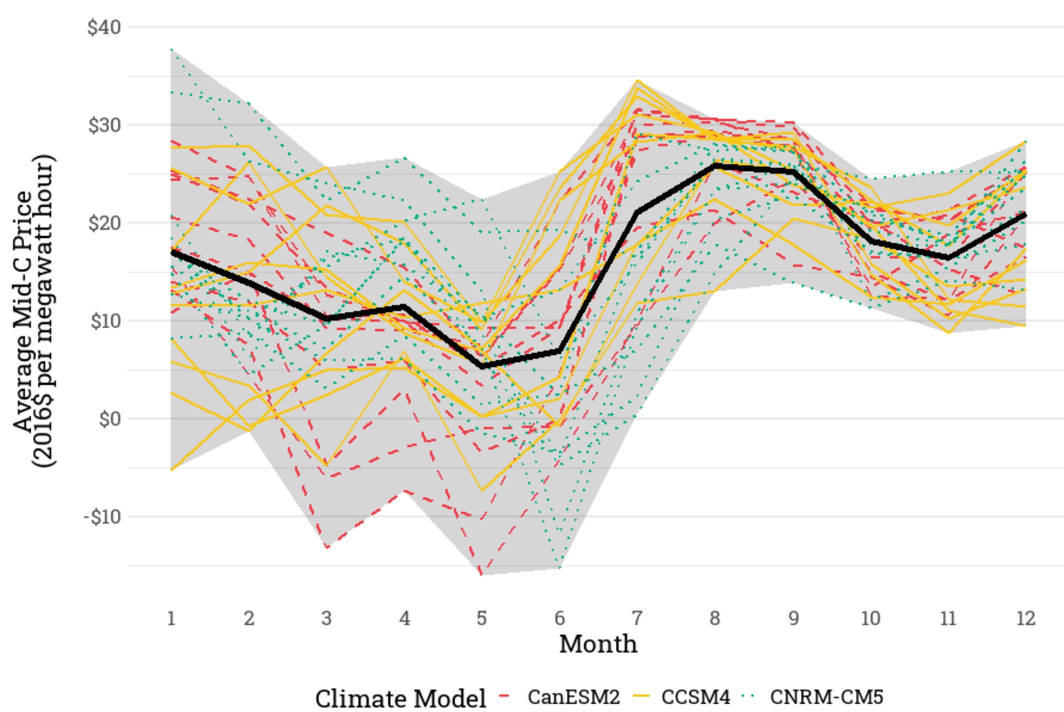
42 nwcouncil.org/2021powerplan_summary-climate-change-scenarios

43 nwcouncil.org/2021powerplan_climate-change-scenario-selection-process

having more precipitation which also falls as rain rather than snow, and in contrast, decreasing summer hydropower generation from decreasing summer streamflows caused by a shrinking snowpack and less summer precipitation.[44] Based on these data, the Council also forecasts, in general, a trend of less frequent extremely cold winter temperatures but more frequent extremely warm summer temperatures.[45] These climate impacts put downward pressure on winter electricity prices and align regional needs in the summer with the predominant electricity use in the Western electric grid. The Western electric grid uses more electricity in the summer than in the winter. All these factors taken together will put upward pressure on summer electricity prices.

The Council selected data for 30 different potential temperature and water conditions from the three climate scenarios for each year of the forecast horizon.[46] These data also include a decadal shift showing different anticipated conditions for the 2020s, 2030s, and 2040s. The changes from one decade

2026 Forecast Electricity Prices by Climate Model Hydro Conditions



44 nwcouncil.org/2021powerplan_trends-in-historical-and-climate-change-river-flows

45 Extremely cold regional winter temperatures are defined as those at or below 20F. Extremely warm regional summer temperatures are defined as those higher than 90F.

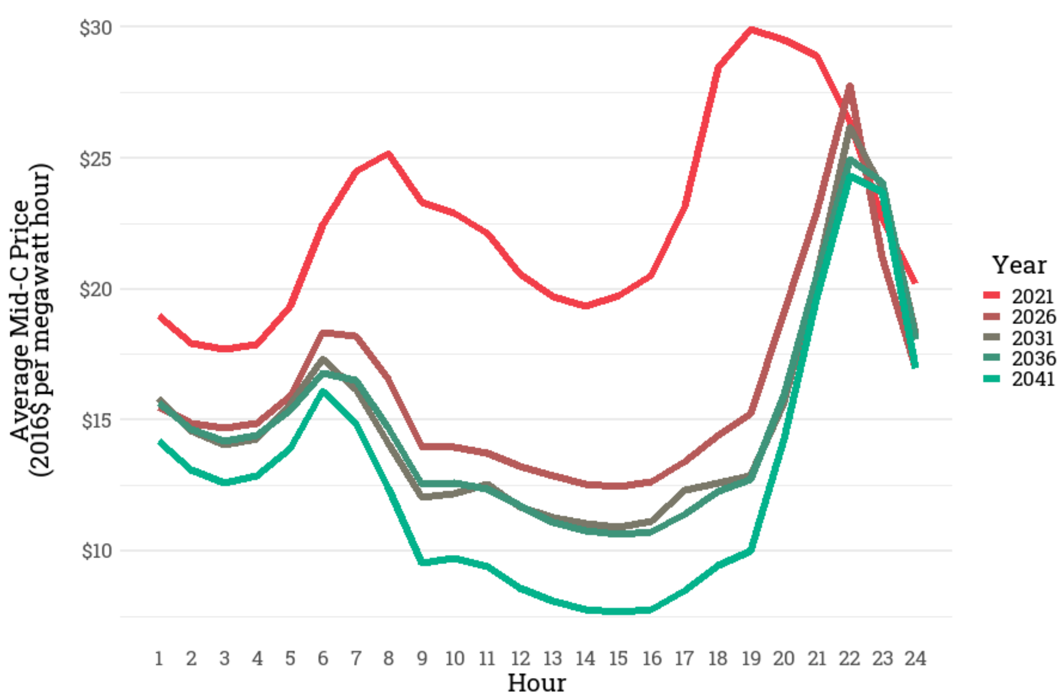
46 nwcouncil.org/2021powerplan_integrating-climate-change-policies-and-data

to the next reflect the continued impact of climate change.[47] Hydropower conditions with more water available for generating electricity cause lower electricity prices, whereas conditions with less water and thus less hydropower generation cause higher electricity prices.

Using the estimated range of electricity demand, the range of expected hydropower generation, and the range of expected wind and solar generation, the Council estimates electricity prices 20 years into the future. These prices help test the resource strategy under a wide range of potential electricity prices. In summary, the Council finds that:

- Timing and magnitude of wind and solar generation and how the generation aligns with electricity demand is a major driver of prices throughout the West
- Different amounts of water going through the hydropower system continue to be a major driver of seasonal price variation within the region
- At some level of building additional renewable generation, extremely low or

Mid-Columbia Average Hourly Prices



47 Specifically, the Council uses the Representative Concentration Pathway (RCP) 8.5 which reflects an end-of-century radiative forcing of 8.5 watts per square meter.

even negative prices occur, and these are aligned with times when we see substantial curtailment of renewable generation

- Prices for natural gas and coal continue to impact the electricity price during hours when fossil-fuel-based power plants are needed to preserve the balancing of the supply and demand for electricity

Altogether, this shows a downward trend for prices when looking at averages. Certain hours, especially during the evening, continue to show potential for higher prices, but prices during the middle of the day are driven down by an increasingly large amount of solar generation throughout the West.

Natural Gas Price Forecast

Generally, the price of fuel is a function of supply and demand. Factors that impact regional supply include how much gas can be extracted and processed, the capability to deliver natural gas to the region over pipelines, and how much gas is stored and ready to be delivered. The natural gas consumed in the Northwest originates from extraction fields in British Columbia, Alberta, and the U.S. Rockies. From there, high-pressure interstate pipelines move the natural gas into the region, where it is distributed to power plants, gas storage facilities, and homes, businesses, and industrial plants. Demand for gas typically peaks in the heating season, and if there are disruptions to supply, such as pipeline ruptures or equipment “freeze-offs,” prices on the spot market can quickly escalate.

When this power plan was being developed, natural gas supply in North America was setting all-time high records through extraction techniques like hydraulic-fracturing and horizontal drilling. As might be expected, this resulted in low prices. In 2020, the average daily spot price for natural gas at the Sumas Hub on the Washington-Canadian border was $2.15 per MMBtu. Ten years ago, the price per MMBtu in current dollars was $4.60, and in 2005 it was $9.50. With the expectation of a sustained abundant supply and robust infrastructure, the Council forecasts continued low natural gas prices. However, as the region experienced in October 2018 with a pipeline rupture[48] in British Columbia, as well as the 2021 troubles in Texas,[49] natural gas prices can skyrocket on a daily or even monthly basis.

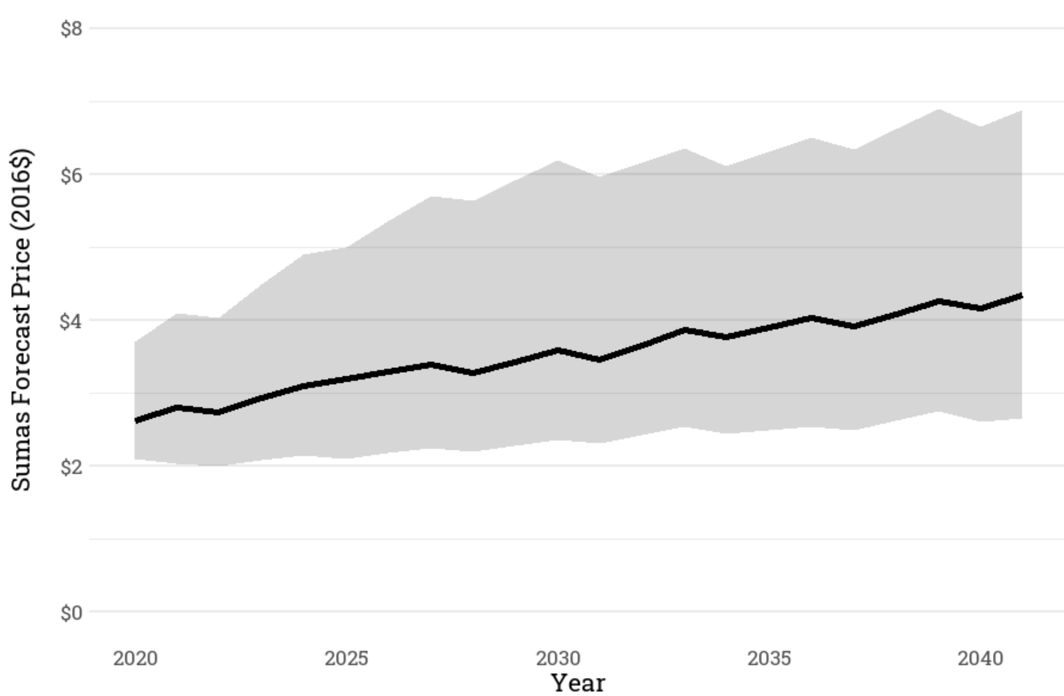
For the plan, the Council developed a range of prices across a suite of gas delivery points, including major gas hubs, power plant delivery points, and the city gate.[50] The figure

48 nwcouncil.org/news/gas-prices-spike-response-late-winter-cold-spell-and-pipeline-constraints

49 www.naturalgasintel.com/texas-investigating-natural-gas-pricing-during-february-winter-storm

50 City gate is the point where a natural gas local distribution company takes the gas off the pipeline system to distribute to customers. City gate prices are a common price point to look at for retail market prices.

Natural Gas Price Forecast for the Sumas Hub



above is the forecast of annual prices at the Sumas gas hub.

Coal Price Forecast

The price forecast for coal – which represents the delivered fuel price to each state from the Powder River Basin in Wyoming – is relatively flat and stable. Wyoming is the largest coal-producing state in the United States and a single mine – the North Antelope Rochelle/ Peabody Mine – supplies 13 percent of the coal in the country.

Forecast of Delivered Coal Price in 2016 $/MMBtu

State	2020	2025	2030	2035	2040	2045
Montana	$1.37	$1.46	$1.51	$1.52	$1.55	$1.56
Oregon	$2.19	$2.33	$2.41	$2.43	$2.45	$2.46
Washington	$1.91	$1.90	$1.89	$1.91	$1.93	$1.94

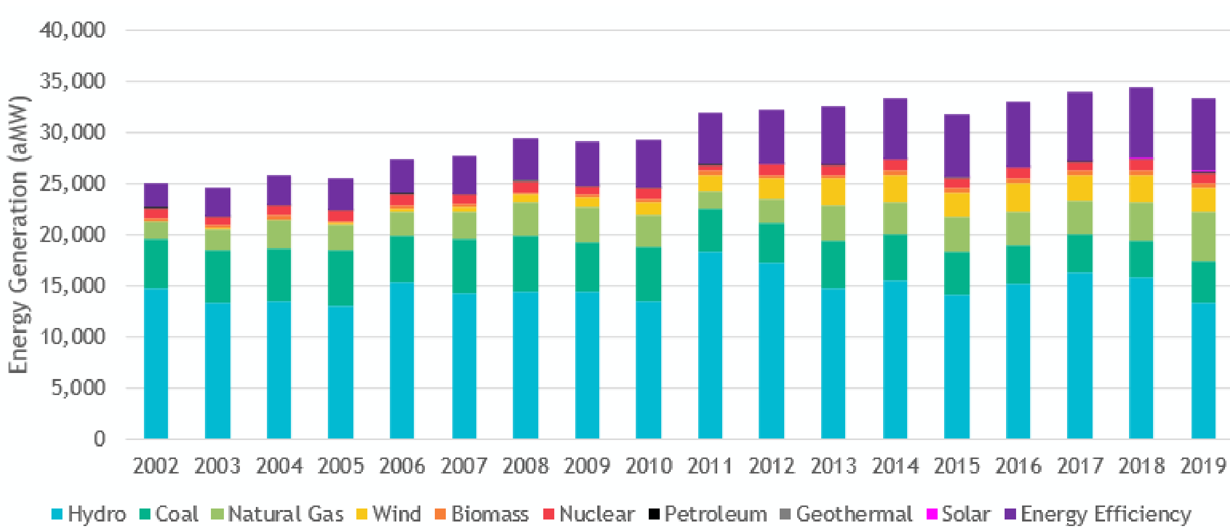
Assessing the Capabilities of the Existing Regional Electric System

The Pacific Northwest power system is undergoing a major shift that will alter the current energy supply landscape over the next several decades. New state and local policies are affecting existing resource dispatch and future resource development. Coal-fired generators are being phased out due to economics and initiatives to reduce greenhouse gas emissions. The future of natural gas development and contributions to the system are uncertain. Inexpensive wind and solar development continue to dominate new construction. Energy storage is becoming more common in the West, both as a stand-alone resource technology and partner to renewables, with the cost for the technology declining substantially in the last few years.

Resources

There are about 63,000 megawatts[51] of generating resource capacity either installed in the Pacific Northwest or located just outside the region and under contract. In addition, some of these megawatts installed in the region are also serving load outside of the region, such as wind projects under long-term power purchase agreements to California and surplus supply exported outside the region through the electricity markets. On average, the region's resource portfolio generates about 26,000[52] average megawatts annually. When energy efficiency

Pacific Northwest Annual Energy Production, including Energy Efficiency



51 See nwcouncil.org/news/megawatt-powerful-question

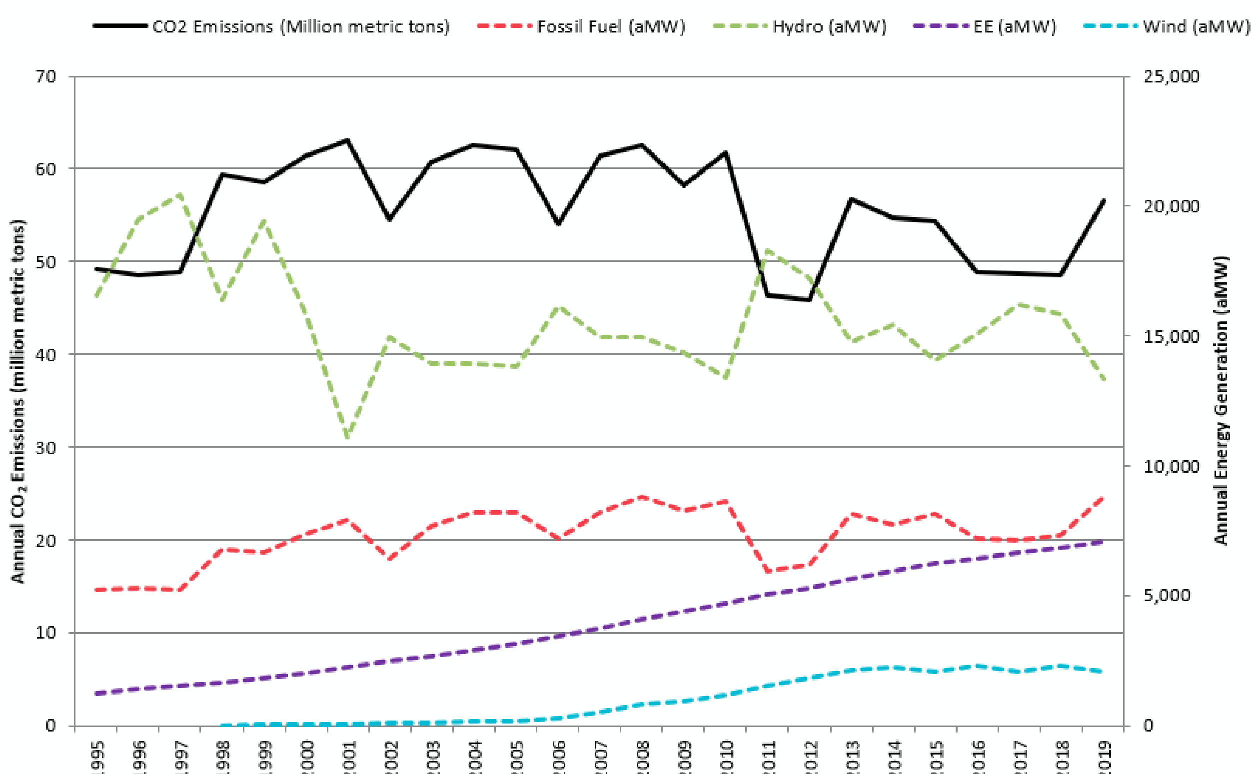
52 From 2012 to 2018 the total generation in the Western electric grid was about 99,131 average megawatts so the region is about a quarter of the total load.

is included, that number increases to about 32,500 average megawatts.

Hydropower generation remains the cornerstone of the Pacific Northwest power system, dominating the regional energy supply. However, hydropower generation varies significantly from year-to-year, depending on weather conditions and snowpack levels. The regional dispatch of fossil fuel resources is directly related to how much electricity is produced with hydropower. In years with lots of water flowing through the hydropower system (for example, 2011), coal and natural gas resources generate less electricity, whereas in years with less water (for example, 2019) they generate more.

The Pacific Northwest has one nuclear plant – Columbia Generating Station – that produces consistent and predictable generation, following a biennial springtime refueling schedule. Onshore wind has made an increasing annual contribution to the region's energy supply, as wind development picked up in the mid-2000s in response to state renewable portfolio standards and federal tax incentives. Solar photovoltaics (PV) began to appear in the region in 2010, and while

Direct Carbon Emissions (left y-axis) from the Generation of Electricity Compared to Amount of Generation by Fuel (right y-axis)



the current solar PV fleet is relatively small compared to other resources, it is expected to increase because the cost of solar has declined so significantly. Rounding out the region's energy generating portfolio are biomass resources, geothermal, and standby petroleum plants.

In addition to generating resources, demand side management resources play a significant role in the region. Energy efficiency is the region's second largest resource. Since 1978, the region has achieved more than 7,000 average megawatts of efficiency savings – around three times the average output of the Grand Coulee Dam, the region's largest generating plant.

Over the past 25 years, annual carbon emissions from the generation of electricity have averaged 55.5 million metric tons of carbon dioxide (not including upstream emissions). The relationship between hydropower generation and fossil fuel dispatch leads to the region's carbon dioxide emissions varying from year-to-year. This can make it difficult to decipher overall trends, although there are indications that demonstrate emissions have been decreasing overall – and that is because of fossil fuel generation dispatch. While fossil fuel generation largely dispatches based on hydropower conditions, overall, fossil fuel generation has been steadily increasing. However, the dynamic between coal and natural gas dispatch is changing. On average, coal generation has been slowly declining in the past few years due to coal plant economics and low natural gas prices. Conversely, natural gas dispatch has been increasing thanks to low fuel prices and increased natural gas availability. In 2018, natural gas generation surpassed coal generation on an annual basis for the first time. As coal units in the region are scheduled to retire, and as energy efficiency, wind, and solar continue to increase, emissions will begin to noticeably decline on a consistent basis.

Upstream Methane Emissions

Natural gas has been undercutting coal economically for some time, and the combustion of gas emits less carbon dioxide (CO_2) than coal. However, the primary component of natural gas is methane (CH_4); a greenhouse gas that when released directly into the atmosphere has a warming potential over 80 times[53] that of CO_2 over 20 years.

There are two primary greenhouse gases related to the combustion of natural gas – CO_2, and CH_4. Direct emissions refer primarily to the CO_2 emissions released at the point of use. Upstream emissions occur as methane is released or accidently leaked to the atmosphere as fossil natural gas is extracted and transported to the point of use.

53 www.epa.gov/ghgemissions/understanding-global-warming-potentials

The global atmospheric concentration level of methane has been steadily growing since NOAA[54] began taking measurements in 1983. Some of the largest annual increases have occurred in recent years, indicating the problem is getting worse. It's not clear what all the causes are, but oil and natural gas activities contribute to the overall global methane emissions. By estimating upstream methane emissions related to fossil fuel use in the region, the Council gets a more accurate picture of greenhouse gas emissions related to regional energy use. With an increased focus on the upstream methane release issue, the Council expects there will be fewer releases in the future.

Policies

The adoption of state renewable portfolio standards (RPS) in Washington, Oregon, and Montana[55] in the mid-2000s, combined with federal and state tax incentives and renewed opportunities for PURPA-qualifying facilities, contributed to a significant increase in renewable resource development over the last two decades. Now, as tax incentives phase out and upcoming RPS targets are on track for compliance, a new policy movement is developing – decarbonization of the electricity system. States, utilities, and communities have instituted aggressive clean-energy targets and economywide greenhouse gas reduction goals that will influence the future construction of generating plants in the region, Western electric grid, and national electric system. In the Northwest, Washington and Oregon have statewide clean-energy regulations, requiring a 100-percent clean, non-emitting electricity supply by 2045 and 2040, respectively. Idaho and Montana also have state greenhouse gas reduction goals, and utility- and community-level clean electricity goals that, in addition to a state RPS, lead to considerable aggregate state clean-energy goals.

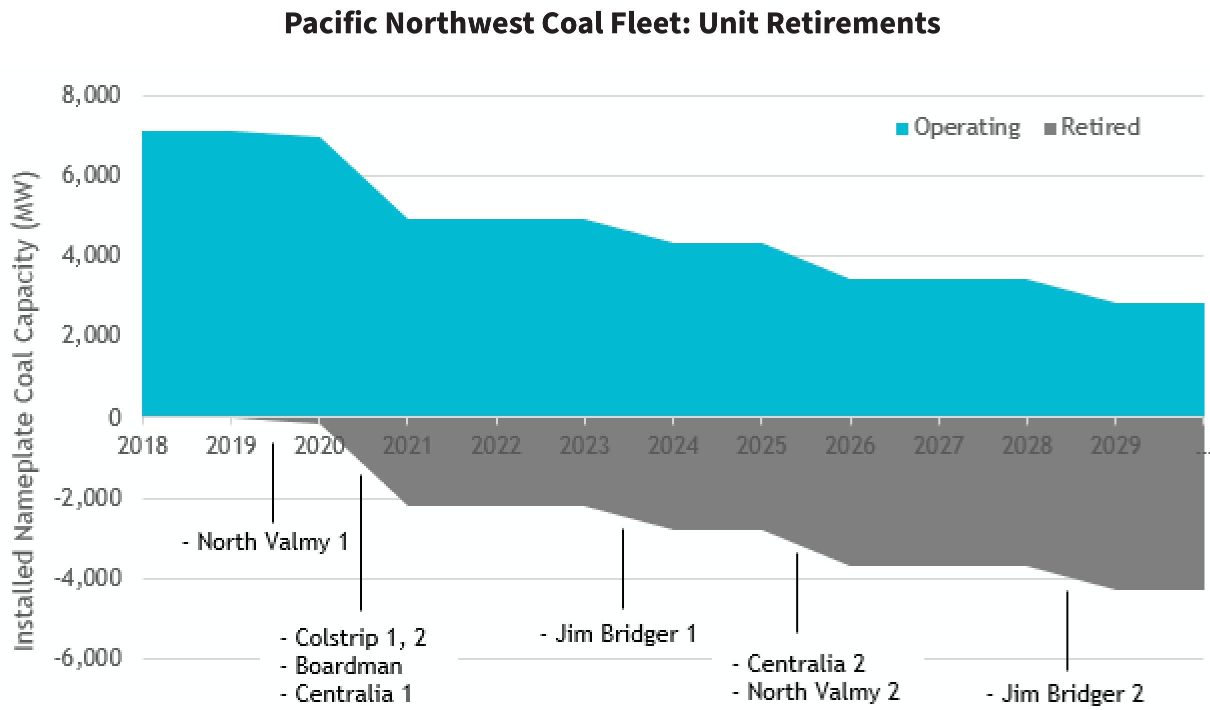
Retirements

With the increasing emphasis on decarbonization, specific policies that prohibit coal-fired generation in the future have been enacted in several states in the West – including Oregon and Washington. In addition, the economics that previously favored inexpensive coal-fired generation have dramatically swung to favor natural gas generation due to consistently low natural gas prices and low-cost renewable resources that have low or no variable operating costs. This has led to the early closure of coal-fired generators in the region and across the West.

In 2018, the region's coal fleet totaled around 7,000 megawatts of capacity. In just a few short years, with the retirement of Colstrip units 1 and 2, Boardman, Centralia unit 1, and Idaho Power's exit from North Valmy unit 1, the coal fleet is now just under 5,000

54 gml.noaa.gov/aggi/aggi.html

55 Montana repealed its RPS in May 2021



megawatts. By the end of 2028, that number will decrease even more to around 2,400 megawatts through the planned retirements of Jim Bridger units 1 and 2, Centralia 2, and North Valmy unit 2. While some coal units remain in 2029, with multiple owners and competing interests for each remaining unit, the future of these resources is uncertain.

Assessing the Potential for New Resources

In assessing the potential for new electricity resources, the Council considers not only the cost of maintaining and fueling the existing electric system, but also the cost of adding new resources to meet changing and expanding needs for electricity in the region. The Council estimates the cost and potential for resources that the region can use to meet these needs. This helps in getting a complete picture of the cost of supplying the region's future electricity needs. In developing a resource strategy, the Council analyzes the difference in cost and performance of potential additional resources to make recommendations for the most effective way to adequately meet regional demands for electricity.

New Opportunities for Energy Efficiency

Energy efficiency is a reduction in the use of electric energy from the increased efficiency of energy use, production, or distribution. Historically it has been the least cost resource acquired by energy providers. As such, energy efficiency acquisition reduces system costs and is specifically referenced in the Act as the priority resource to be selected by the plan before renewables, natural gas plants, and other generators are considered. Energy efficiency has helped the region avoid the need for, and the costs associated with, building and maintaining numerous power plants, as well as the price risk associated with fuel purchases needed for thermal plant operations. In addition, energy efficiency supports system reliability and hydro system flexibility, and it has been used to avoid or delay distribution system investment to serve peak load. For these reasons, assessing the potential for energy efficiency to meet future system needs is an essential part of the plan. The Council assesses all efficiency completed through utility programs, energy codes, appliance standards, and natural market impacts prior to the start of the plan. These are included as part of the demand forecast and not included in the forward-looking energy efficiency potential estimates.[56]

The starting point for assessing the potential for energy efficiency as a resource is to define each unit of savings, or "measure." A few examples of these measures[57] include efficient light bulbs, insulation, better windows, heat pump water heaters, and more efficient fans. The energy savings per unit (e.g., electricity consumption of a heat pump water heater relative to a standard electric resistance unit), combined with the number of units (e.g., number of homes with electric water heating) provides the amount of savings potential for a given measure. Adding up all the possible measures for homes, businesses, and industries results in a forecast of efficiency potential.

In addition to the electricity savings, a measure is defined by the incremental cost to install or implement the efficiency and a variety of other costs (e.g., maintenance cost) or benefits (e.g., additional water savings). The Council takes all the costs and benefits and adjusts the total cost[58] of these measures to come up with a cost that can be compared to other types of resources.

The amount of energy efficiency available during the planning horizon is developed and formulated into a supply curve, which gives the amount in average megawatts of savings at different measure costs (in dollars per megawatt-hour). The energy efficiency supply curve below shows all energy efficiency

56 Energy building codes and appliance efficiency standards established prior to the end of 2019 are accounted for in the Council's baseline forecast.

57 To define the individual measure costs and savings, several sources are used. Primary among them is the Regional Technical Forum (RTF). For measures not considered by the RTF, the Council relies on secondary studies from both regional (e.g., NEEA) and national sources (e.g., DOE). The total number of units (e.g., number of homes) in the region is largely based on the sector-specific stock assessments conducted by NEEA.

58 The measure costs include total system cost (per the Northwest Power Act), and both costs and benefits combined into a net levelized cost, referred to as the Northwest Resource Cost. This levelized cost is the net present value of the measure costs divided by the measure savings. In this manner, the costs for conservation are developed consistently with other generating resources.

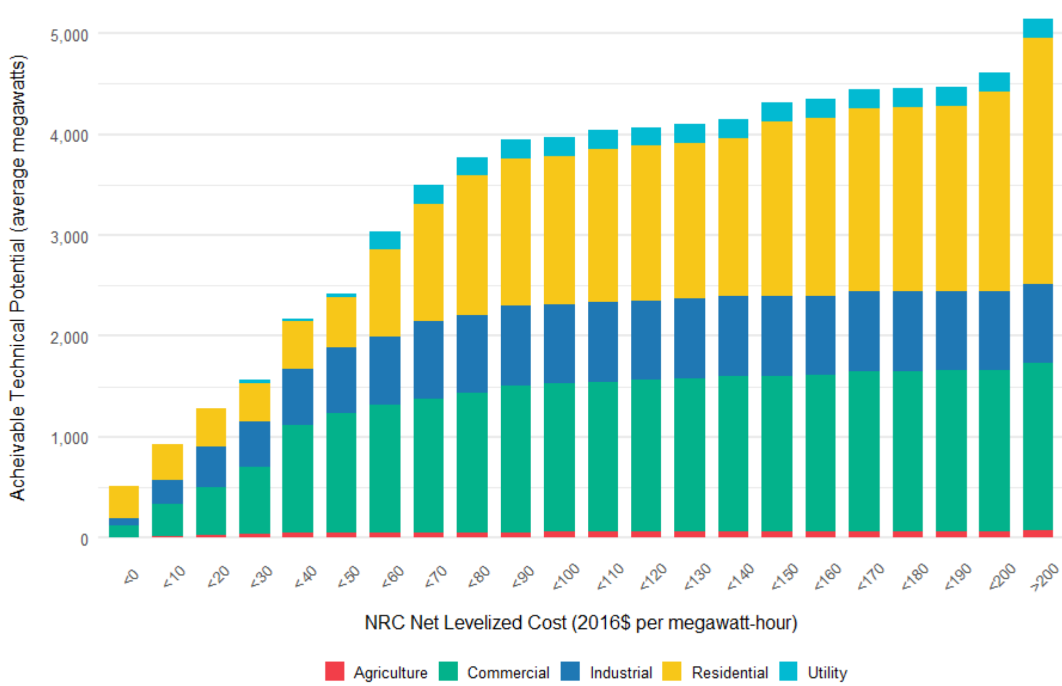
available through 2041, differentiated by sector and by cost. The figure shows 1,337 average megawatts as the total amount of energy efficiency potential by 2027 and 5,144 average megawatts by 2041, accounting for technical and feasibility limitations. The supply curve is used to compare energy efficiency to other electricity resources, providing an amount of efficiency available at increasing costs, and can be used to meet future regional electric system needs.

The timing of when the savings from energy efficiency occur is also an important part of our analysis. As the price of electricity varies by day and by season, the value of the energy efficiency will also vary, depending on the timing of savings. For the supply curves, energy savings are greater during winter than summer. The shape of the savings for the complete set of energy efficiency is developed by combining all the individual measure shapes.

Demand Response Supply Curve

Demand response (DR) is "*a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/ transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating*

Energy Efficiency Supply Curve, Differentiated by Sector for 2041



parties."[59] The need for demand response arises from the mismatch between power system costs and consumers' prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is that consumers do not have the information that might encourage them to curb consumption at high-cost times and/or shift consumption to low-cost times. The ultimate result of the mismatch of costs and prices is that the increased power system needs require building more peaking capacity, building more transmission, and incurring more system upgrades than would be necessary if customers changed their use in response to price changes in the market. Programs and policies to encourage demand response are efforts to provide this information to consumers and create the infrastructure to allow them to respond to price signals in the market.

The Council evaluated demand response products that impact residential, industrial, commercial, and agricultural sectors, as well as the utility distribution system. Demand response products evaluated include utility-controllable and price-responsive options across the sectors. Utility-controllable products give the utility the ability to change the operation of end-use equipment to reduce peak. Price-responsive products give the end-use customer the ability to choose how to modify loads based on a price signal from the utility. In general, price-responsive products are less expensive because equipment needs are lower, but the utility has less control over the resulting impact.

In total, 23 demand response products were incorporated into demand response supply curves. The Council estimates about 3,721 megawatts of summer load reduction potential and 2,761 megawatts of winter load reduction potential.[60] This potential was focused on reducing load during times of system need, though it is recognized that demand response could also be used to increase loads during low or negative prices to balance with supply. The potential is based on an estimated impact per participant and the potential number of participants based on eligibility (e.g., customers need to have air conditioning to participate in an air conditioning control program); assumptions of willingness to participate; and participation rates for any given demand

59 This definition was developed by the Demand Response Advisory Committee nwcouncil.org/energy/energy-advisory-committees/demand-response-advisory-committee

60 The difference in load reduction is based on the underlying demand response measures. Some programs, like curtailment of residential air conditioning only impact the summer season, while other programs like space heating only impact the winter season. While the potential numbers referenced here give a sense of the impact of demand response relative to other resources, the deployment of demand response by utilities could differ based on needs.

response event (a customer may opt out of any given event).

Products range in cost from $5 per kilowatt-year up to $250 per kilowatt-year (2016 dollars). These costs include setup, operation and maintenance, equipment, marketing, and incentives. The Council also incorporates benefits (or negative costs), such as deferring buildout of the transmission and distribution system by reducing electricity use during times of the highest electricity need.

New Generating Resources Potential

New generating resource technologies are assessed based on their cost, operating, and performance characteristics, and developable potential in the region. Resources that are commercially available and proven and have the potential to meet future needs in the region are further developed into reference plant estimates representative for the Pacific Northwest – with a designated plant size and configuration, performance attributes, costs, and other attributes such as construction schedule and economic life.

The Council developed reference plants for utility-scale solar photovoltaics (PV), solar PV + battery storage, stand-alone battery storage, onshore wind, natural gas combined cycle turbines, natural gas peakers, and pumped storage. In addition, one emerging technology reference plant was developed as a proxy for the many promising new technologies (for example, offshore wind, small modular nuclear, and enhanced geothermal systems) that could provide value to the region in the future.

The costs of renewable resources – and in particular solar PV – have decreased significantly.[61] Despite recent price fluctuations due to tariffs on imported materials and cells, the cost of solar PV is expected to further decrease in the future. While the cost of natural gas combined-cycle plants has largely remained the same, the cost of a natural gas frame unit – operated in simple cycle mode as a gas peaker – has decreased due to lower equipment costs and greater competition among vendors to secure fewer project development contracts. The costs of conventional geothermal and pumped storage hydropower resources are extremely site-specific, so it can be difficult to see any major trends.

61 According to the Lawrence Berkeley National Lab, over the past decade the installed cost of solar has declined about 70 percent and the installed cost of wind has declined about 40 percent. (emp.lbl.gov/webinar/utility-scale-wind-and-solar-us)

New Generating Resource Reference Plants: Capital Cost (2016$/kW) Trends

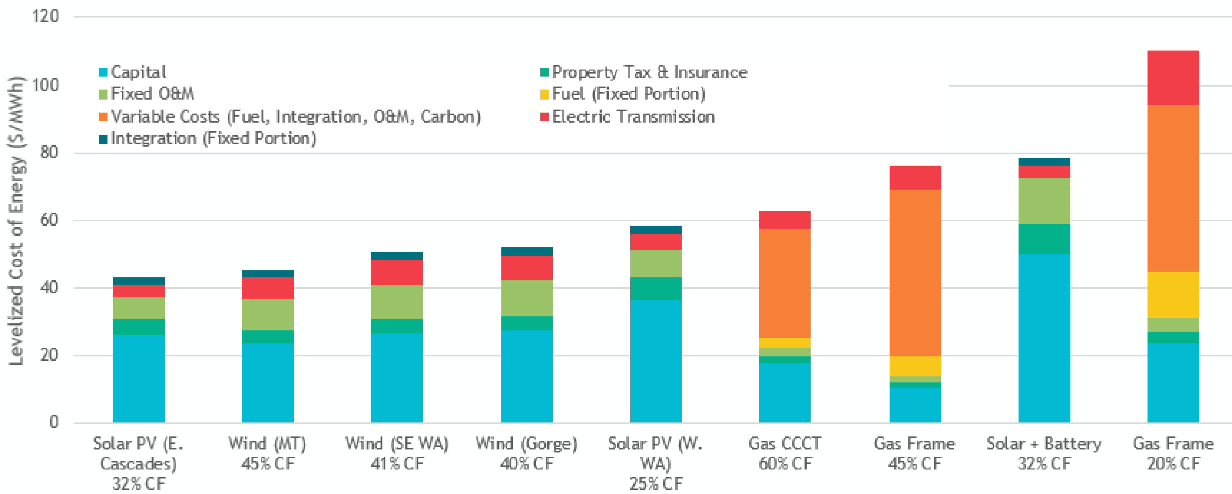
Resource	Seventh Plan (2016$/kW)	2021 Plan (2016$/kW)	Trend
Onshore Wind	$2,382	$1,450	Significant decrease
Solar PV	$2,566; $1,792 (low cost)[62]	$1,350 (E. Cascades); $1,465 (W. WA)	Significant decrease
Solar PV + Battery Storage (4 hr)	–	$2,568	–
Battery Storage (4hr)	–	$1,400	–
Pumped Storage	–	$2,300	–
Geothermal	$4,575	$5,400	No significant change
Natural Gas - Combined Cycle Combustion Turbine	$1,220	$1,150	No significant change
Natural Gas – Peaker (Frame)[63]	$859	$550	Decrease
Proxy Emerging Tech – Small Modular Reactor	–	$5,400	–

One way to compare the cost of a resource against another is to look at the levelized cost of energy, which is a metric used to estimate the cost of energy across a resource's expected economic life. It is calculated as the cost per unit of energy a resource is expected to generate (under an assumed level of dispatch or capacity factor) that also includes variable costs such as fuel. Although the initial cost for solar and wind may be higher than gas resources, with minimal operating costs (no fuel purchases), the overall cost of producing energy can be significantly less.

62 When the Council was evaluating solar PV in 2015 for the Seventh Power Plan, costs were dropping so quickly that a lower-cost solar PV resource option was added to the model analyses.

63 This price decrease also reflects a change in the reference plant technology class

New Generating Resource Reference Plants: Levelized Cost of Energy ($/MWh)[64]



While the Council doesn't explicitly model all new resource options, there are other commercially available resources with smaller-scale, location-specific potential in the Pacific Northwest (for example, biomass, small hydropower, distributed generation) that if cost-effective should be considered viable resource options for future power planning.

Planning for an Uncertain Future

The electric sector is in a time of transition. A wave of coal unit retirements will happen over the next decade. Climate change is altering hydropower generation, and policies designed to limit greenhouse gas emissions constrain how the electric sector expands the supply of electricity.

Utilities and regulators are looking to replace coal with completely different generating technologies like wind and solar generation. The cost of building solar and solar with on-site batteries has fallen substantially. But relying more on new technologies requires changing how the electric grid operates. The expansion of the Western Energy Imbalance Market makes the operation of the Western electricity grid more automated and intertwined. But it's just a start on the scope of change needed to transform the way electricity is generated.

The future of Northwest utilities will be different than the past.

64 In this graph, CF denotes capacity factor. For each generator, the capacity factor indicated the average amount of energy over a year relative to the installed capacity that was used in the levelized cost calculations for comparison.

Exploring Key Power Supply Questions Through Scenario Analysis

Understanding the potential future risk that will impact the electric sector of the economy takes a broad range of analyses. Some analyses involve creating a range for potential risks. For example, the Council forecasts a range of natural gas prices. The Council uses analytical approaches to consider the implications of natural gas prices that deviate from our expectation.

Other risk analyses involve setting up scenarios, or a set of high-level questions, that help assess future alternatives. The Council builds these scenarios by asking what conditions and processes would change and then reflecting them in our analytics.

Ultimately, scenario analyses help inform decisionmaking when developing the recommended resource strategy for the region and for Bonneville.

How the Scenarios Were Selected

The Council looked at high-level themes in the electric sector and the Northwest Power Act in constructing the scenario analyses. To incorporate Power Act requirements, the Council first focused on analyses that examined the adequacy of generating resources to meet the regional needs. Given the expansion of the Energy Imbalance Market in the West since the last power plan, the Council saw changing and expanding markets for electricity as an important theme for this plan.

The Council also used analyses to distinguish between the impacts of a resource strategy on Bonneville's portfolio of resources and the demand for electricity Bonneville is obligated to serve with those resources. Finally, the Council expected that understanding the implications for greenhouse gas emissions for the region was an important part of looking at future strategies on how the region can meet the demand for electricity.

After identifying these high-level themes, the Council examined seven scenarios to guide the analyses. The scenarios connected to one or more of the high-level themes and created distinct narratives that the Council determined would help construct an overarching resource strategy.

How the Scenarios Were Constructed

To construct the scenarios, the Council developed models and analyses that would be part of this plan. The Council then identified, given the narrative for each scenario, where the models and analyses had parameters that would differ. Each scenario involved exploring a range of different values and combinations for these parameters.

Scenarios Explored

The Council explored a range of scenarios designed to answer key questions about the future of the electricity grid. These scenarios echo previous Council plans and also break new ground. The scenarios are:

Change in Reliance on Extra-Regional Markets for Resource Adequacy – an analysis of the impacts of relying on markets outside the region for resource adequacy.

Organized and Limited Markets for Energy and Capacity – an analysis of potential impacts from changing the structure and reliability of markets outside the region.

Early Retirement of Coal Generation – an analysis of the implication of accelerating planned retirement dates for coal generation throughout the Western electricity grid.

Robustness of Energy Efficiency – an analysis of how the resource strategy would change with different estimates and assumptions regarding the supply of energy efficiency.

Analyze the Bonneville Portfolio – an analysis of the Bonneville administrator's obligation to provide electricity and the available federal resources dedicated to meeting that obligation.

Greenhouse Gas Regulation and Cost Impacts – an analysis of the impacts of limitations, financial or otherwise, on greenhouse gas emissions from the electricity sector.

Pathways to Decarbonization – an analysis of the impact on the electricity sector of efforts to substantially reduce economywide greenhouse gas emissions.

Findings From Our Scenario Analyses

The Council has different methods for accounting for uncertainty. While some uncertainty or risk is modeled using ranges of values, for example the range of future electricity prices, some uncertainty does not lend itself to using a range of values. For those types of uncertainty, the Council uses scenario analysis. While scenario analysis is a useful method to describe uncertainty, it often looks at very unlikely outcomes to help in understanding the direction that policies or goals lead. The following descriptions of our scenario analyses focus on what we learned from these exercises. They should not be taken as a forecast of what is likely or as the sole basis for how we formulate a resource strategy.

Change in Reliance on Extra-Regional Markets for Resource Adequacy

The Northwest spent billions building transmission to connect to the rest of the West. This enables surplus electricity sales that offset the regional cost of electricity and allows purchases when the regional need exceeds the capacity of regional generators. Relying on electricity purchases from outside the region defers the need to build new generators, which reduces the cost of using electricity. However, maintaining reliable electricity requires both transmission to the Northwest and available generators outside the region.

Our baseline setup limits the amount of imports from the external market. After accounting for imports from power plants that are located outside the region but have contracts or obligations to deliver electricity to the region, the analysis limits regional imports to no more than 2,500 megawatts in the winter and 1,250 megawatts in the summer. Those limits are well below the ability of the region to import electricity on our transmission system. Because the Council has less information on the supply and demand for electricity outside the region, the Council uses these limits to represent uncertainty about the availability of electricity during times when the region is short of generation and fuel.

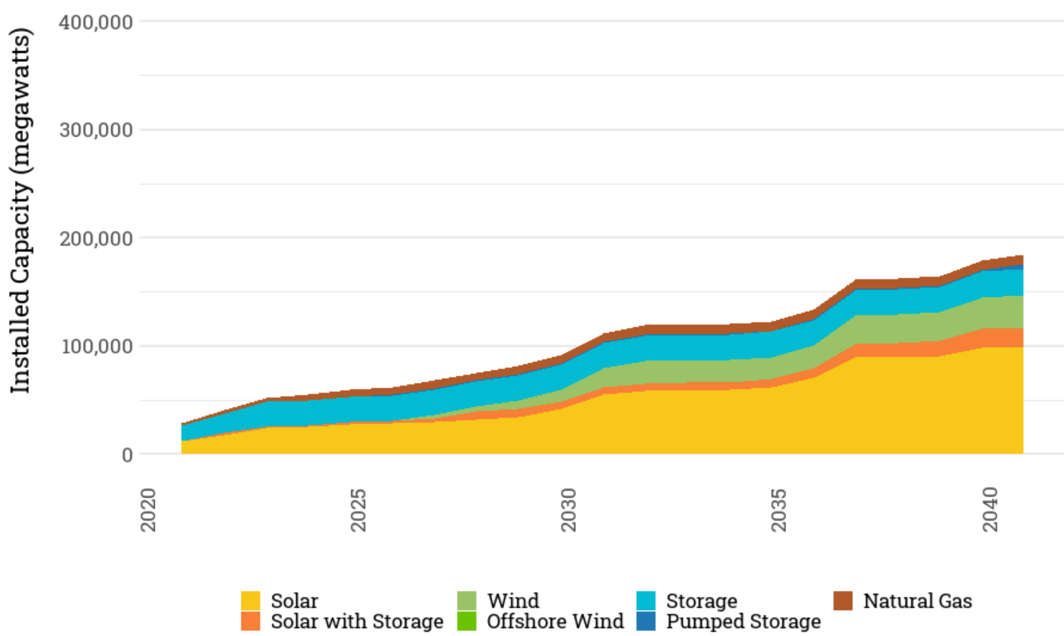
For this scenario, the Council relaxed these limits to allow the region to import up to the capability of the transmission system. While this reduced the adequacy-needs input into our resource analysis, the results from our models had minimal changes to the resource additions examined. While there were some minor changes to the pace at which renewable generators are built within the region, the overall results did not indicate removing these limitations would change the resource strategy.

Organized and Limited Markets for Energy and Capacity

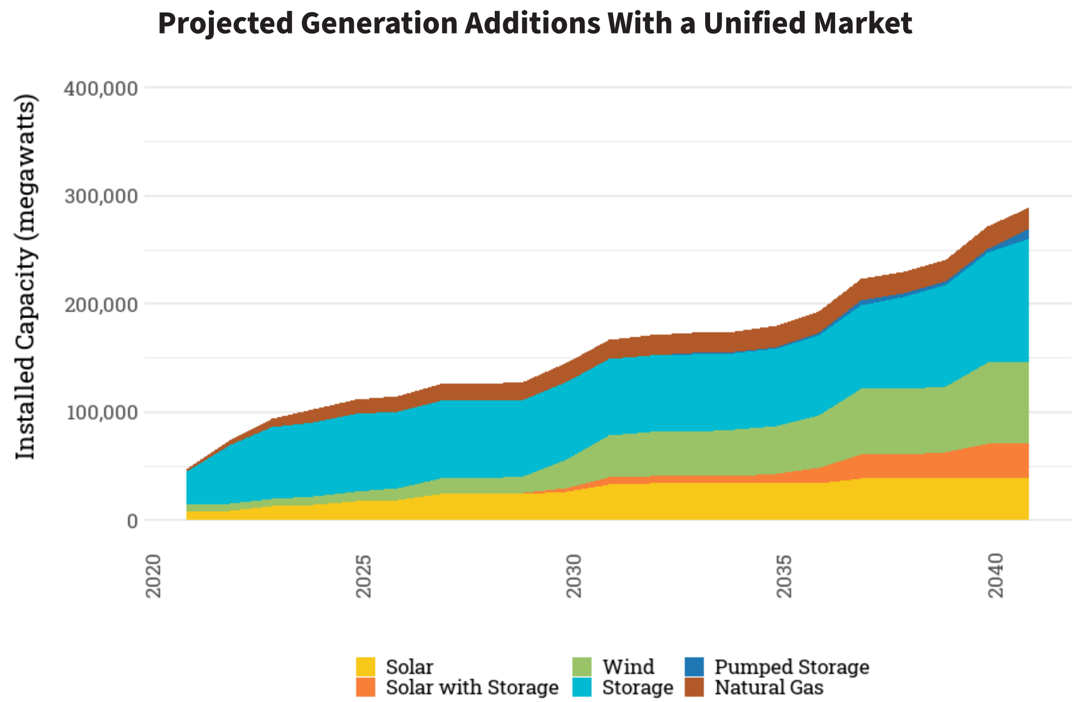
The Council's analysis for this power plan has shown that the costs and risks faced by the region are connected to the policies and decisions beyond our borders. The choices of utilities in the rest of the West on what resources to build and retire directly impacts cost and reliability of power in the region.

To help explore the impacts of electricity markets outside the region, the Council developed several different external generating resource addition projections and looked at the impacts of those different additions on the resource strategy.

Projected Generation Additions With Limited External Market Supply



In one projection, the Council substantially limited the supply of electricity outside the region. This projection met the current renewable portfolio standard or RPS requirements and the clean-energy requirements that limit the types of generation used in some Western states through about 2035, but fell slightly short of meeting these policies after then. By intent, the Western grid outside the Northwest did not have sufficient generation to meet the demand for electricity under stressful conditions. However, the Council did still see a substantial addition of solar power to both meet policy goals and at least partially replace retiring generation.

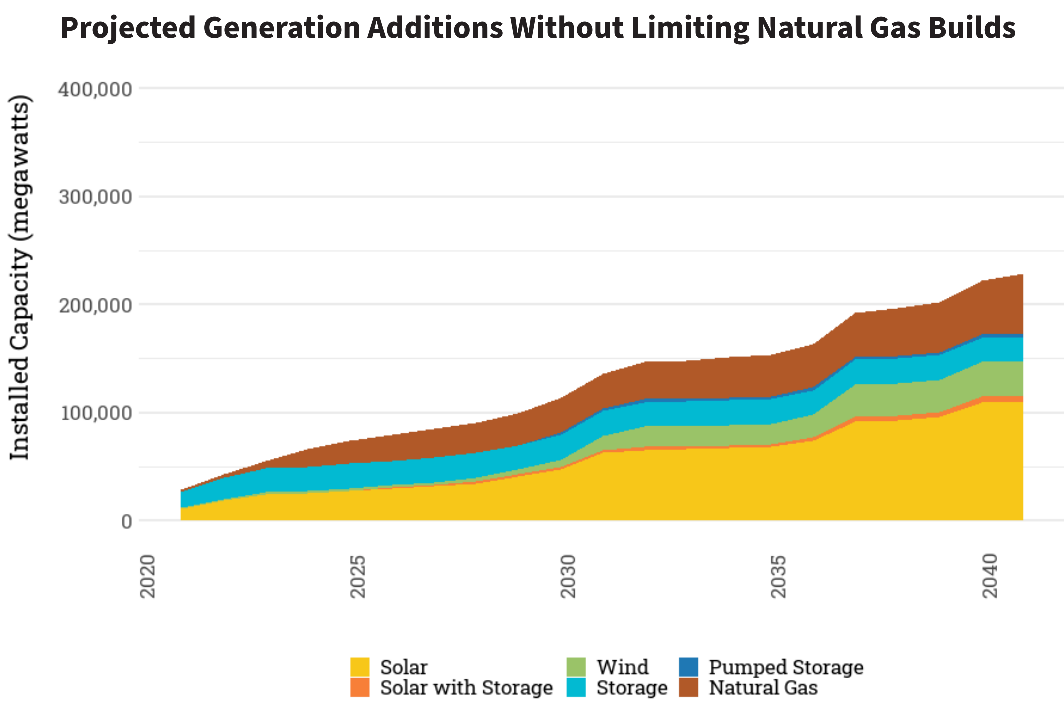


In another projection, the Council also explored resource additions if utilities created a combined approach to planning for new resources and created a unified transmission rate.[65] This was a proxy for how centrally dispatched markets with a consistently applied adequacy standard could impact decisions about resource additions.

Currently the Western electric grid has many different markets with a variety of manners for determining when generating resources are dispatched. There are standards that grid operators must meet set by FERC and NERC, but the operators in an inadequate system may be forced to selectively shut down electricity to parts of the grid to meet these requirements. Consistently applied adequacy standards would make the chances of curtailing electric service both lower and consistent from one region to the next.

In both projections, the Council included limits on the amount of new natural-gas-fired generation that could be built within

65 The important distinction is that access to the transmission system is available at the same rate everywhere, so dispatch is not driven by different transmission charges in different regions of the electric grid. This does not mean a unified transmission rate is necessarily cheaper, nor does it mean that transmission owners would all get the same return. This scenario should not be considered an indication that transmission right owners would either benefit or be disadvantaged from unifying a transmission rate. Discussing how unifying a transmission rate would work is beyond the scope of this scenario analysis.



the Western electricity grid. These limitations were based on both Council expertise and consultation with regional experts on their expectation about resource selection around the West.

However, these limitations substantially increased the addition of solar and wind generation outside the region. To assist in understanding the impact of limiting new natural-gas-fired generation, the Council removed these limits and projected what adding natural gas generation would look like. In this case, the Council saw over 26 gigawatts of natural gas generation added by 2027, and over 55 gigawatts added by 2041. There was also a corresponding reduction in the addition of renewable resources, though there still were over 33 gigawatts of solar generation built by 2027, and over 115 gigawatts built by 2041.

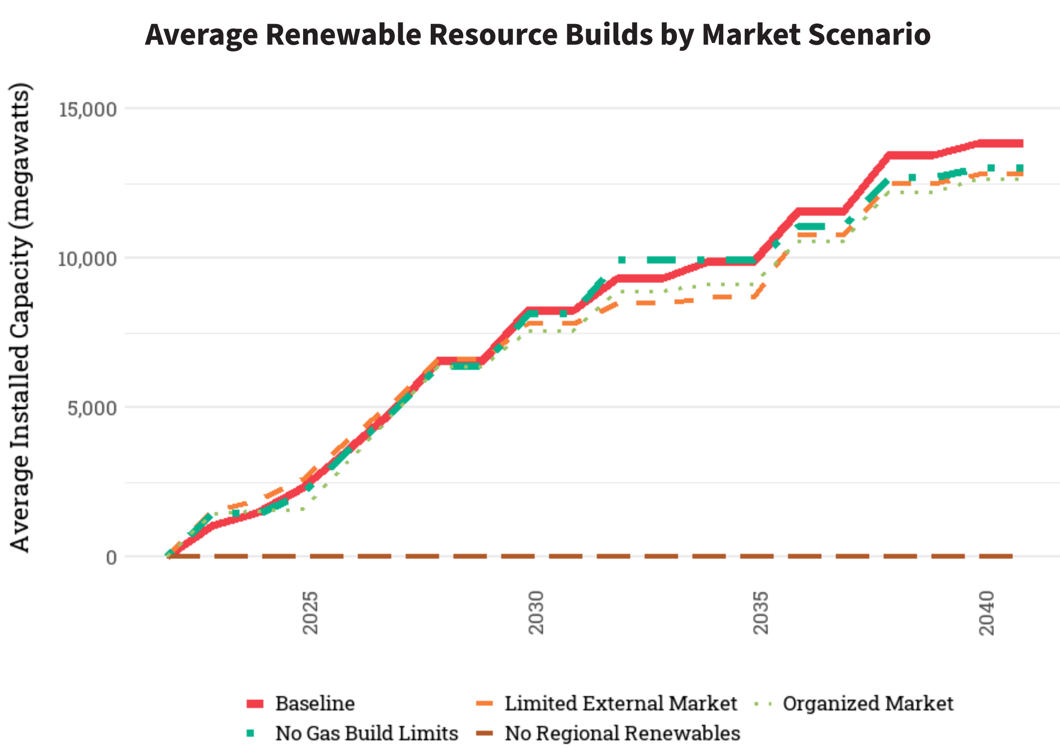
The Council also wanted to isolate the impact of renewable generation included in the regional resource addition to help show the impact of additions within the region compared to additions outside the region. To implement this, the Council removed renewable generation from the resource selections in our analysis and examined the impact to the resource addition.

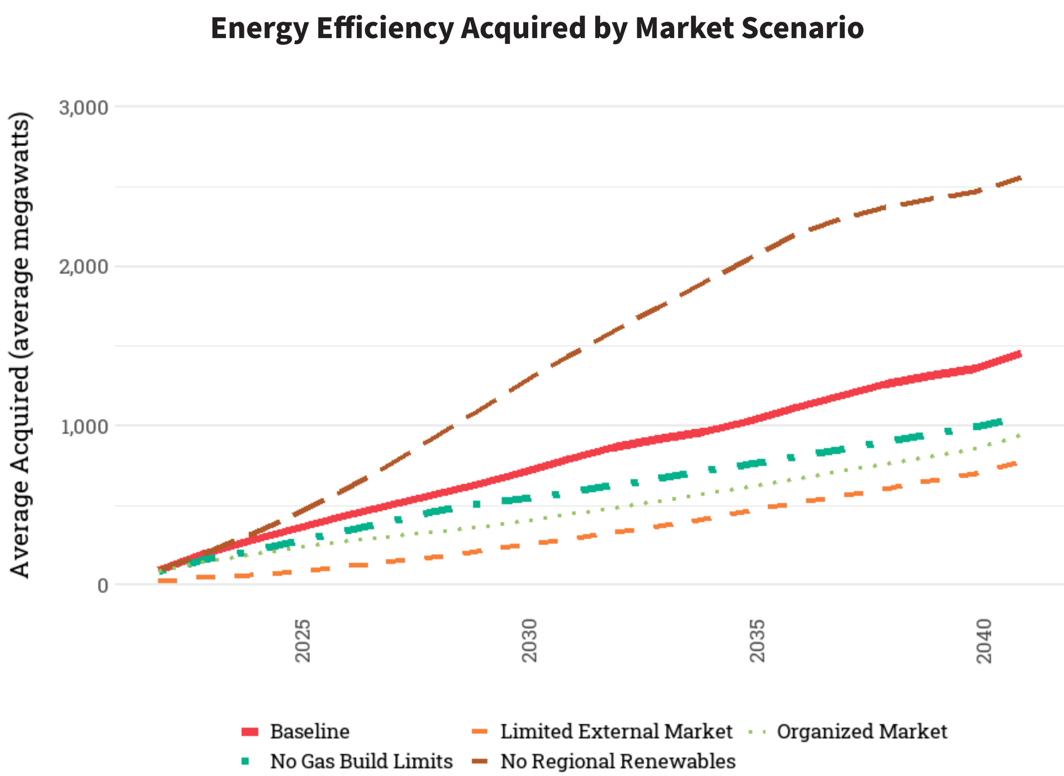
While the regional electricity prices associated with these additions varied, the addition of renewable resources only had minimal changes throughout all these projections except the one where renewable generation in the region was specifically excluded.

This indicates that renewable resource additions at this level are likely required to meet regional policy targets, in addition to being part of the least-cost portfolio under various assumptions about external markets.

In the projection where the Council eliminated regional renewables, there was a requirement for new natural-gas-fired generation to meet adequacy requirements. In this scenario, there was a high probability of adding at least one new power plant.

However, the biggest impact was on the addition of energy efficiency. In the projection where no renewables were built in the region, almost 750 average megawatts of energy efficiency were developed. In the projection with limitations on the external market, less than 150 average megawatts were developed.





These results show that while the regional addition of renewable generation was not particularly sensitive to electricity market prices, the addition of energy efficiency was sensitive.

Early Retirement of Coal Generation

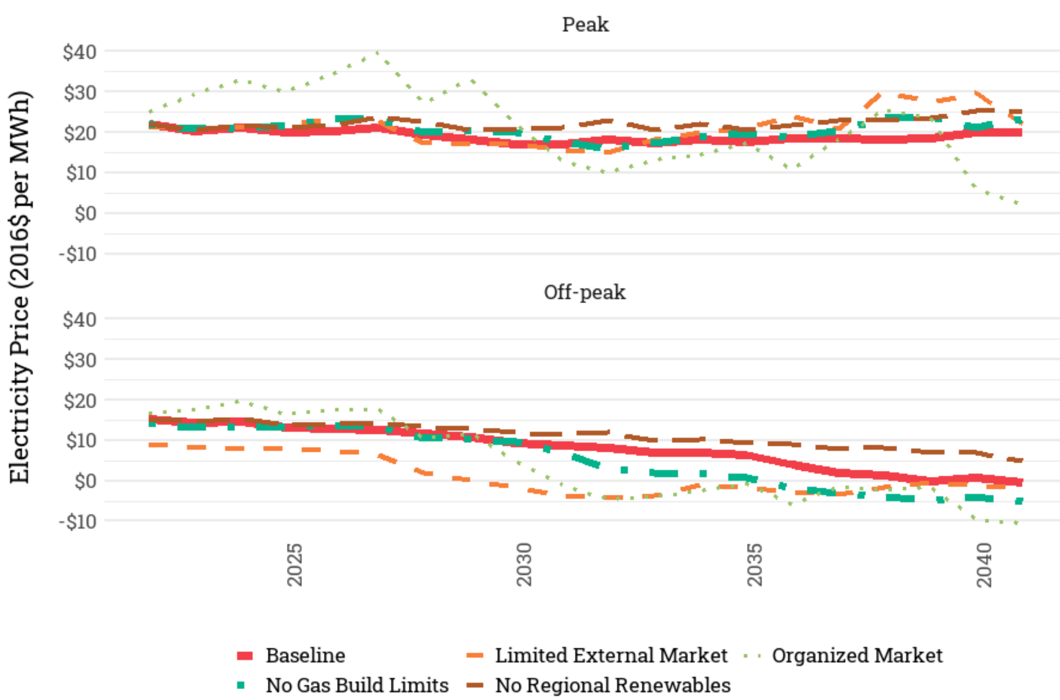
Since the last power plan, utilities in the region and outside the region have announced the retirement of coal-fired power plants at dates that precede the end-of-useful-life dates that have been previously assumed in analyses by the Council and others. The Council understands that there is risk in retiring resources sooner than planned, especially coal-fired generation. This scenario explores this risk using the coal-fired generation fleet in the West. There are likely other types of generation that could have retirement dates accelerated based on economics or regulation. The Council did not analyze the likelihood of early retirement for all types of generation. Thus, this should be considered a directional analysis that was used to help the Council understand this observed risk.

To implement this, the Council assumed that all regional coal-fired power plants were retired by the end of 2026. For coal plants outside the region, the Council assumed that all plants were retired by 2030.[66]

Our analysis shows with this scale of retirement, emissions in the West would decrease just under 40 percent after all the coal plants are fully retired. Emissions in the Northwest would decrease over 80 percent.

The emissions reductions are greater in the region because the hydro generation in the region has resulted in a smaller natural gas-fired generation fleet relative to the rest of the West.

Regional Electricity Price by Market Scenario



66 These dates are not intended to represent likely dates that the coal-fired power plants would retire, rather they are intended to be a stress test of the power system and be informative on coal-fired generation's impact on greenhouse gas emissions.

Regional Coal Plant Unit Retirement Scenario Assumptions

Coal Plant Unit	Nameplate Capacity (MW)	Announced/ Existing Retirement Date (EOY)	Baseline Conditions Retirement Assumptions[67]	Early Coal Retirement Scenario Assumptions
Colstrip Unit 1	358	2019		
Colstrip Unit 2	358	2019	Retired	Retired
Boardman	601	2020	Retired	Retired
Centralia 1	730	2020	Retired	Retired
North Valmy 1	277	2019[68]/2021	Retired	Retired
Centralia 2	730	2025	2025	2025
North Valmy 2	289	2025	2025	2025
Jim Bridger 1	608	2023	2023	2022
Jim Bridger 2	617	2028[69]	2028	2026
Colstrip 3	778	–	2037	2025[70]
Colstrip 4	778	–	2037	2025
Jim Bridger 3	608	–	2037	2026
Jim Bridger 4	608	–	2037	2026

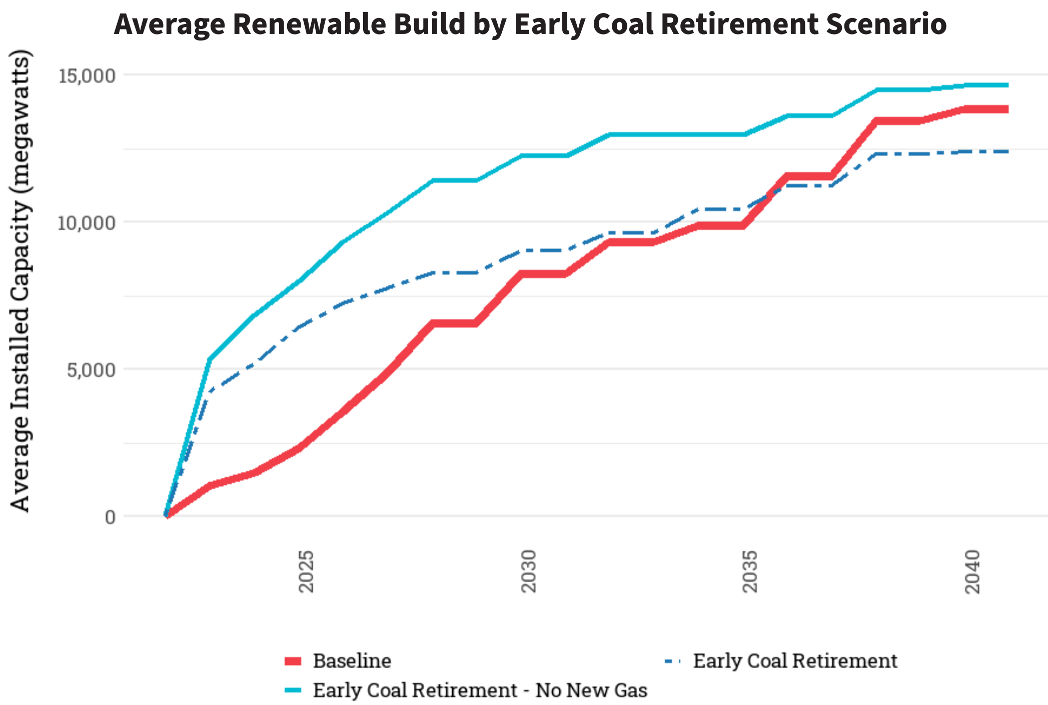
Without limiting the types of new generation, the expected resource addition by 2030 includes around 1,400 megawatts of nameplate capacity of new natural-gas-fired generation. Considering the decisions that would lead to early coal retirement, it seems unlikely that new natural-gas-fired generation would be considered for replacing retired coal generation. By eliminating new natural gas-fired generation from consideration, the expected renewable-energy addition in the region substantially increases.

67 For our baseline assumptions we use either the announced retirement dates or end-of-useful life dates used in utility IRPs.

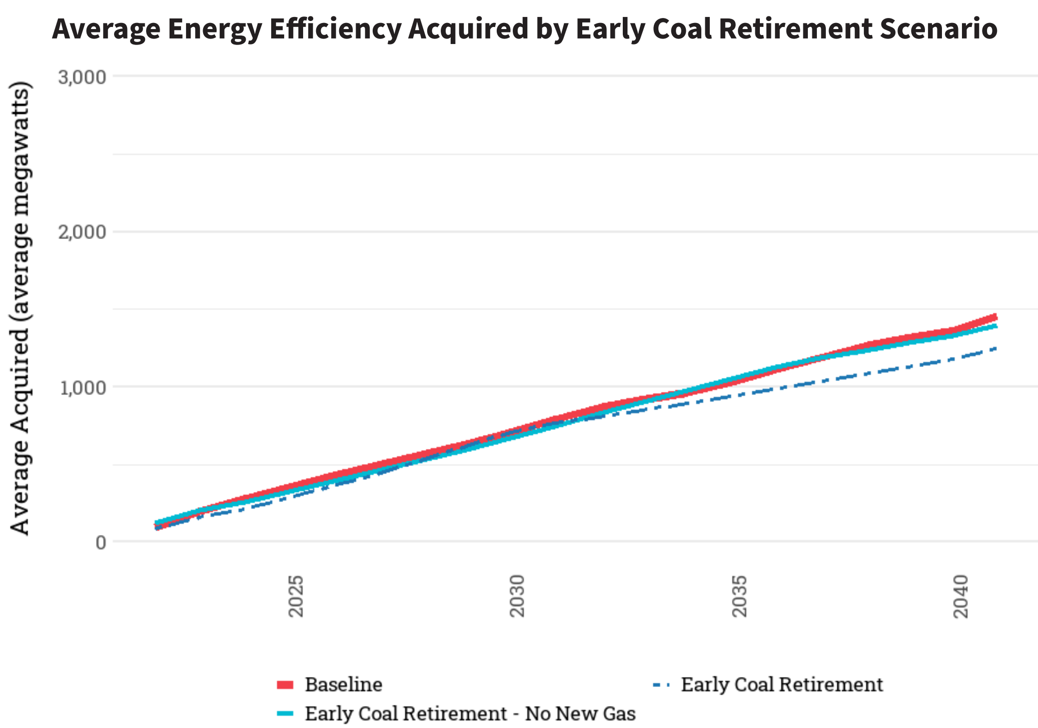
68 Idaho Power ended its participation in this unit in 2019.

69 PacifiCorp and Idaho Power are still working out details of the accelerated retirement of Bridger 2, this date should be considered tentative.

70 For a potential early retirement date for Colstrip Unit 3 and Unit 4, 2025 was selected based on the Washington state utility requirements in the Clean Energy Transformation Act.



While the Council sees a response in the renewables addition for this scenario, there is relatively little change in the addition of energy efficiency.



The Council also sees an expected increase of 7.2 percent in residential electricity bills in this scenario.

Robustness of Energy Efficiency

Energy efficiency has been the cornerstone resource of the Northwest since the first power plan. For this scenario, the Council explored assumptions about the supply of energy efficiency and the drivers that impact acquiring more or less of this resource.

Specifically, the Council looked at the impacts of differing regional adequacy needs, rate of acquisition, the amount available, the contribution to regional capacity needs, and the impact of varying our treatment of emissions on portfolio costs. The Council examined how it collects supply curves for portfolio analysis and then ran a sensitivity on how other resource decisions would change under high and low acquisition of energy efficiency.

When the Council increased or decreased the regional adequacy need, especially when testing an extremely high regional need to develop new generating resources, the energy efficiency resource acquired came close to doubling.

Altering the rate of acquisition of energy efficiency and the amount available resulted in more and less energy efficiency acquired for faster and slower ramps respectively. The increase and decrease of energy efficiency were driven by the differing availability of efficiency in the early years of the study. However, in both cases the Council also observed an increase in the overall system cost. In the case where there was an increase in energy efficiency, there was not a significant difference in the unit cost of the energy efficiency being acquired, but the increased amount resulted in more money spent on the resource in total. In the case of decreasing energy efficiency acquisition, the increased costs manifested in purchasing more expensive resources. While acquiring more energy efficiency absent other changes would increase the reliability of the system, the Council saw the faster acquisition of energy efficiency alter other resource decisions in a manner that resulted in no meaningful increase in the reliability of the system.

The contribution of energy efficiency to capacity needs is estimated using the best data that are available to the Council on the timing of the use of electricity. However, some of these data are outdated, and the region is currently conducting research that will allow for updated information to be used in the next power plan.[71] The Council tested how resource additions would respond if the capacity contribution of energy efficiency was increased. In part, this test assumed that the updated data may show better alignment between peak electricity needs and energy efficiency. The test showed changes in other types of resources built in response to the overall change in system need based on the contribution of energy efficiency to the peak

71 neea.org/data/nw-end-use-load-research-project

system need. However, the Council did not see additional acquisition of energy efficiency in this test.

When the Council constrained energy efficiency to look at the impact of suboptimal acquisition, acquiring more energy efficiency led to a more expensive system by displacing less expensive resources and by acquiring more resource than was needed. With less energy efficiency acquired, the result was a less reliable system.

In our baseline for our analyses, the Council incorporated an emissions cost based on the Social Cost of Carbon from the Intergovernmental Panel on Climate Change into the portfolio cost. For this scenario the Council tested the impact of this on the acquisition of energy efficiency. When removing this impact on portfolio costs, the Council saw some reduction in the near-term acquisition of energy efficiency and a larger reduction in the total energy efficiency acquired over the 20-year plan duration.

Analyze the Bonneville Portfolio

Bonneville is a central part of the Northwest electric system. A large portion of the transmission in the region is owned and operated by Bonneville. The Council considers a broad array of information from all the various analyses included in this plan when making recommendations to Bonneville. One key part of that perspective is understanding the obligations Bonneville has to provide electricity and the federal resources and contracts that are designated to be used to meet those obligations – that is, the Bonneville portfolio.

The Council analysis see a small need for additional resources. The Council describes the existing federal resource capability and

Energy Efficiency Acquired in Robustness of Energy Efficiency Tests

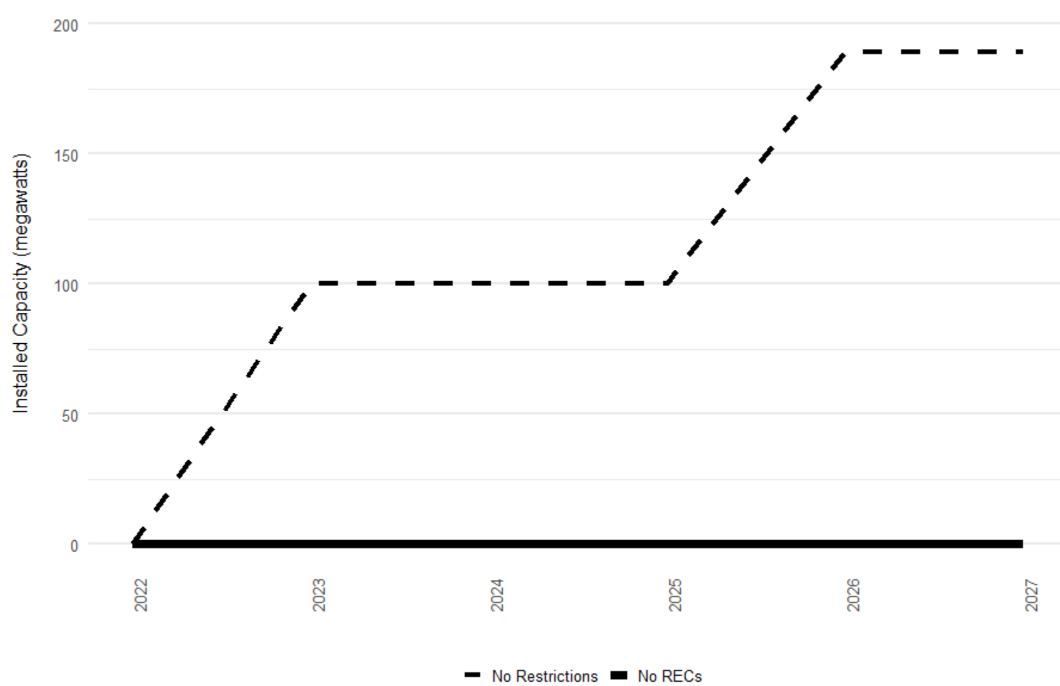
Scenario / Test	Energy Efficiency Acquired (average megawatts)	
	2027	2041
Baseline Conditions	500	1462
Change Supply Curve Binning	470	993
Increased Acquisition Ramp and Potential	1362	2562
Decreased Acquisition Ramp and Potential	370	1235
No Emissions Related Portfolio Cost	175	780
Increased Adequacy Requirements	932	2656

obligations in *Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity*. Under many of the forecasts for an increase in the Bonneville obligation, the Council sees that existing resources are sufficient to meet the need. However, there are infrequent circumstances where an increase in the demand for electricity exceeds the seasonal firm energy in the federal power system. Our analysis shows the least-cost way to meet these needs is a combination of energy efficiency, demand response, and renewable resources.

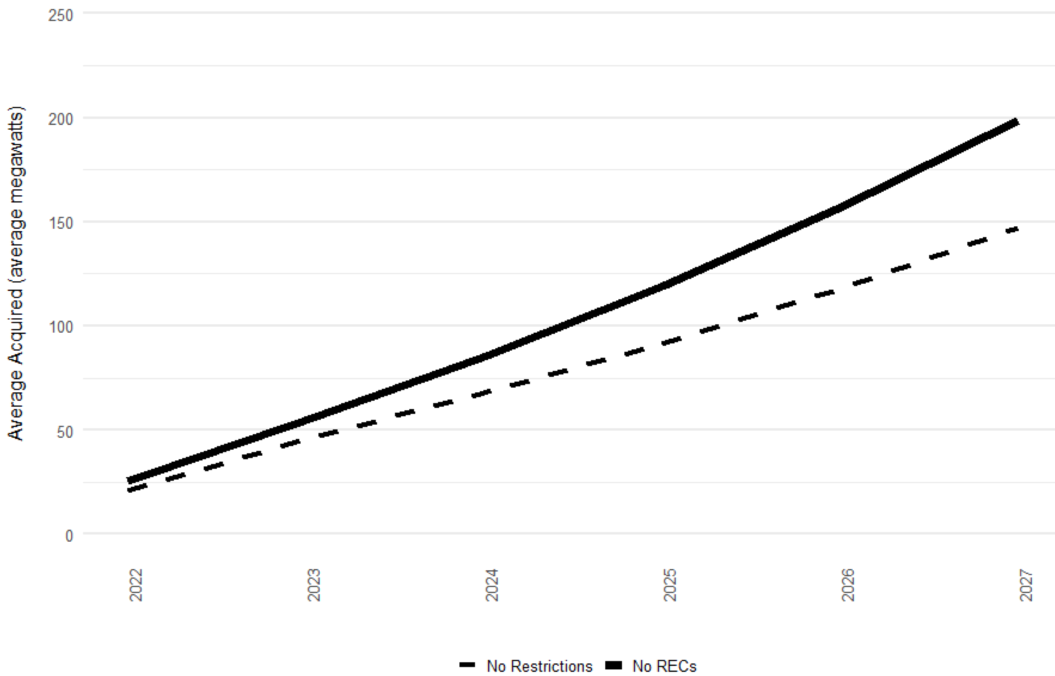
Part of this analysis was looking at the cost of resources. When examining the cost of renewable resources, the treatment of renewable energy credits (RECs) altered the amount of renewable generation additions to the portfolio. When the RECs were assumed to offset the cost, more renewable resources were selected as part of the portfolio. However, currently Bonneville passes RECs through to its customer utilities, so they do not accrue value to the Bonneville portfolio. When excluding the value of the RECs, the addition of renewable generation is much more limited.

The treatment of RECs also impacts the amount of energy efficiency acquired. Because renewable resources meet part of the energy need, there is a reduced need for energy efficiency.

Renewables Build With and Without Accounting for the Value of RECs



Energy Efficiency Acquired With and Without Accounting for the Value of RECs



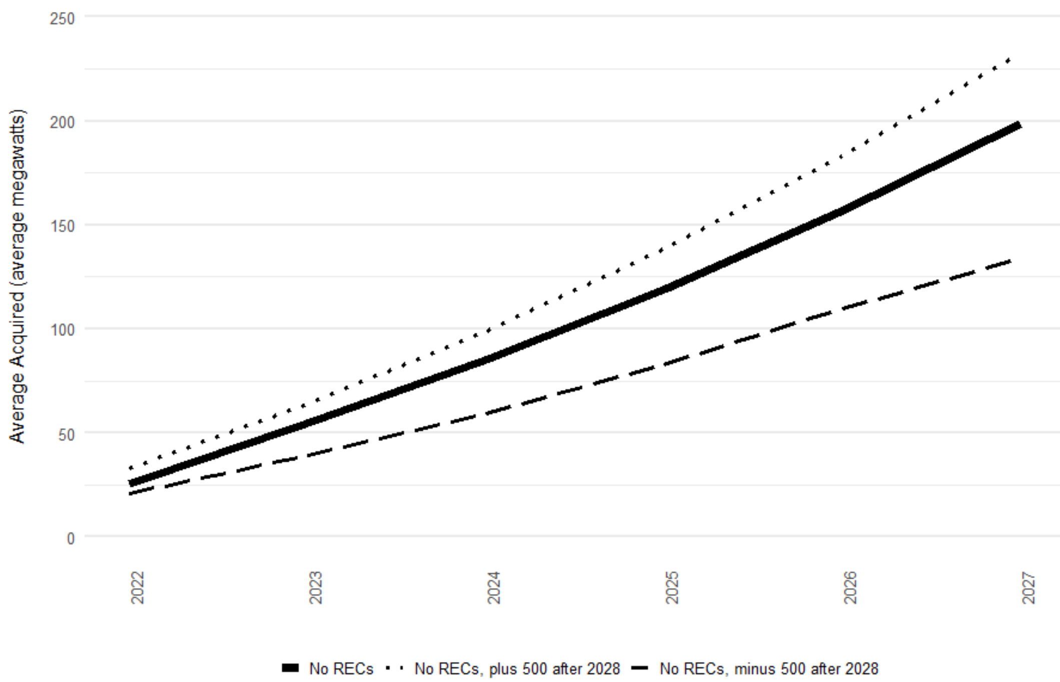
The Council also tested the demand response measures seen to be low-cost and part of the resource additions in the regional analyses. The measures examined were demand voltage regulation (DVR) and time-of-use rates (TOU). These measures reached 300 megawatts of capacity by 2027 in the portfolio.

The Council also examined the implications of a change in obligation after the Bonneville contracts expire in 2028.[72] The purpose was to see if there would be near-term changes in resource additions based on the obligation change in 2028. To test this, the Council added and removed 500 average megawatts from the Bonneville obligation in 2028. When adding obligation, the Council saw additional near-term resource additions as the least-cost solution. When removing it, the Council saw lower near-term resource additions. Adding to the obligation in 2028 increased the addition of energy efficiency by 2027 by 35 average megawatts. Decreasing the obligation removed around 65 average megawatts of energy efficiency.

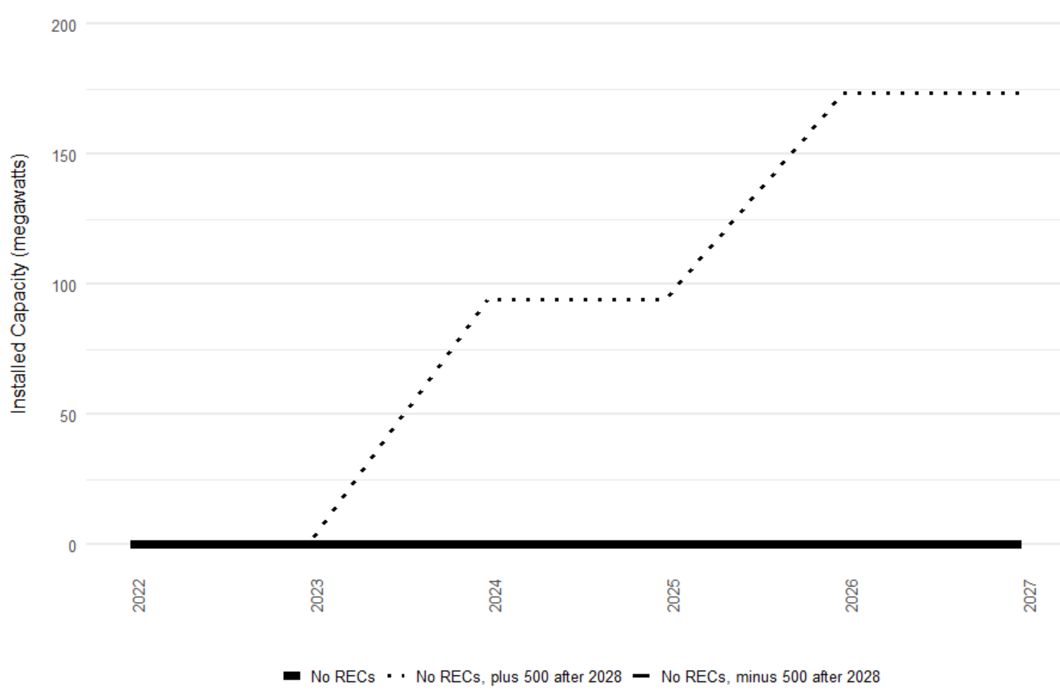
Similarly, for renewable resources – when excluding the value of RECs – our analysis shows an increase of almost 175 megawatts

72 The eventual size of Bonneville's obligation to serve after 2028 adds a level of uncertainty to our needs forecast that may not be fully realized until the end of the plan's action period and may require further analysis by the Council to determine the full impact of Bonneville's future contractual obligations.

Energy Efficiency Acquired with Obligation Changes After 2028



Renewables Build with Obligation Changes After 2028



of nameplate capacity additions by 2027 when the obligation increases in 2028. Decreasing the obligation does not impact near-term resource additions and shows no additions of renewable resources after 2028.

Greenhouse Gas Regulation Cost and Impacts

The Council has been analyzing greenhouse gas emissions and the impact of regulation to reduce emissions on the electricity sector throughout most of its history. Analysis of emissions first appeared in the 1991 Power Plan.[73] However, in recent years the scope and variety of regulation related to emissions have expanded, not just in the region but throughout the West.

This plan has aggregate renewable energy requirements and clean-energy requirements. The Council also included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation. However, the Council did not assume generating resources that emit greenhouse gases would dispatch with emission pricing included in their variable cost.

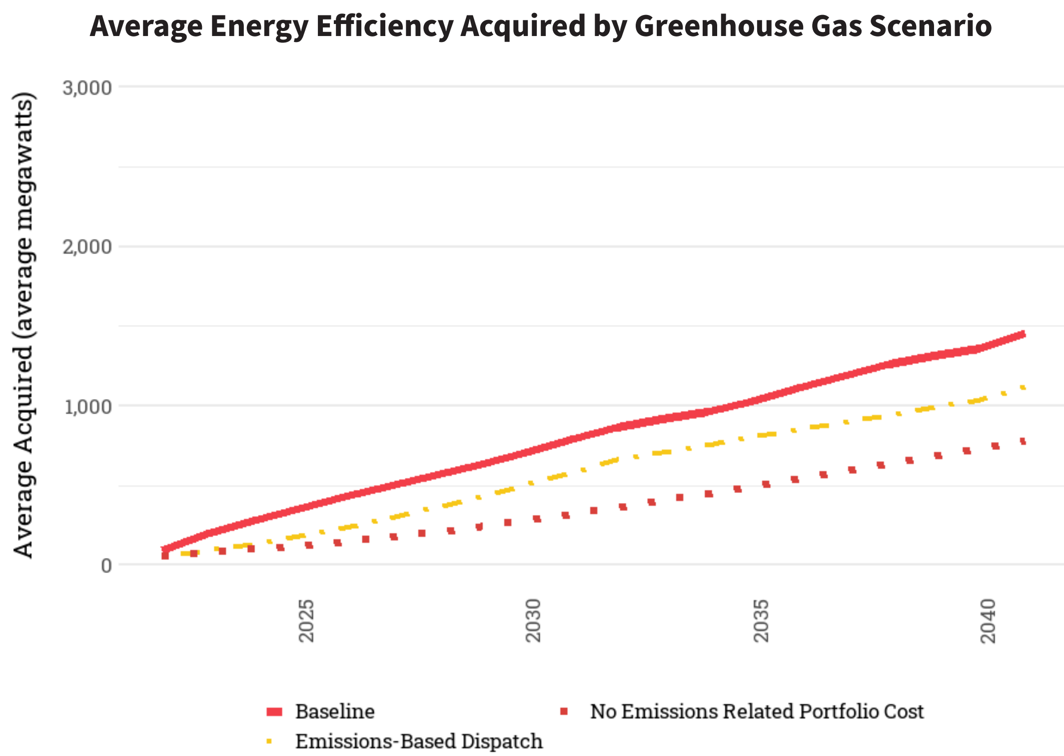
The Council developed this scenario to explore the implications of regulation throughout the West intended to limit or reduce greenhouse gas emissions.

The Council started by examining the implications for adding generating resources outside the region. Like the scenario work on organized and limited markets, this scenario looked at what resources would be built if limitations on new natural gas generation were removed. The scenario showed the addition of almost 60 gigawatts of natural gas generation by 2040 when the scenario was not constrained by resource options.

The Council also looked at the implications of explicit emissions pricing included in the dispatch of all resources in the West. In this case, renewable resource additions increased by just over 13 percent in 2040.

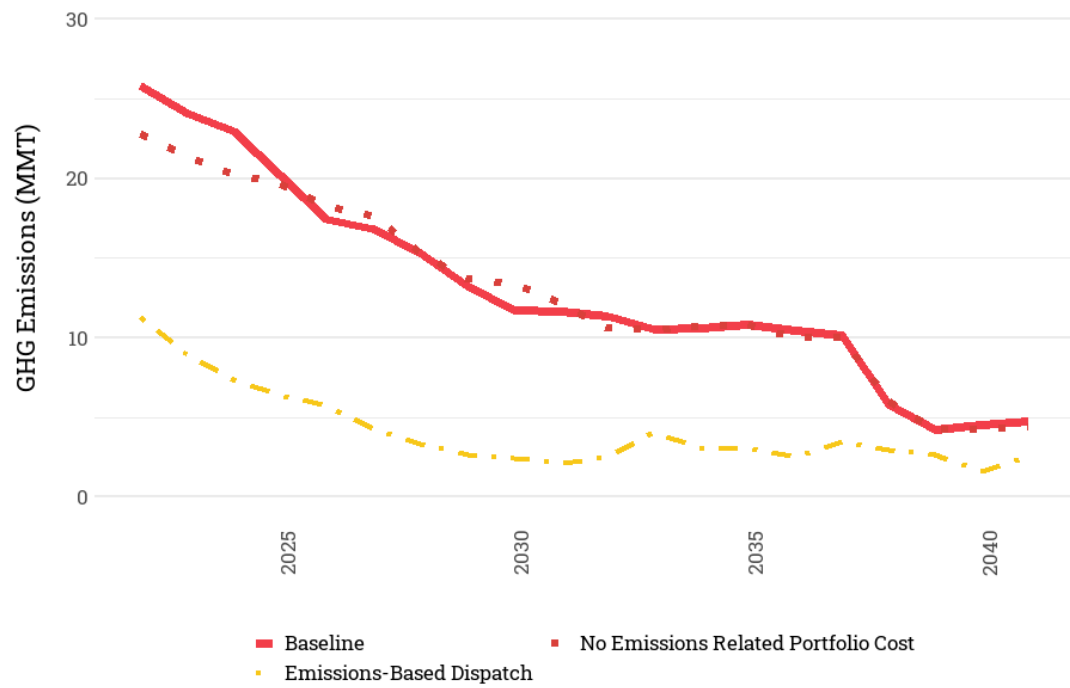
The Council's analysis shows that emissions regulation has a substantial impact on the resource strategy. While the Council does not set emissions-related policies either in the region or outside the region, the Council considers the impacts of these policies when making recommendations for a resource strategy. The analysis showed that both including the price of emissions in resource dispatch and removing emissions-related portfolio costs reduced the energy efficiency acquired.

73 nwcouncil.org/reports/1991-northwest-conservation-and-electric-power-plan



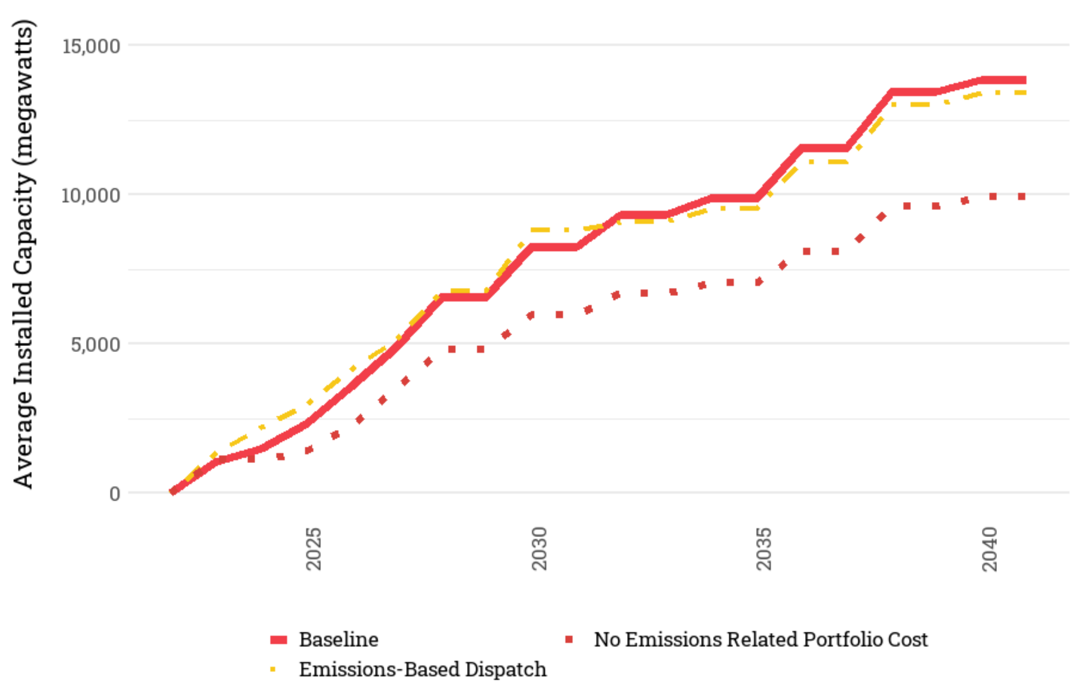
While implementing an emissions-based dispatch slightly increased the number of renewable resources built, removing emissions-related portfolio costs decreased the amount of renewable resources built to around 3,500 megawatts of nameplate capacity by 2027.

Average Emissions by Greenhouse Gas Scenario



There was little impact on regional emissions when removing the emissions-related portfolio costs, but changing how regional resources dispatch to include an emissions-based price substantially reduced the amount of emissions in the region.

Average Renewable Build by Greenhouse Gas Scenario



Pathways to Decarbonization

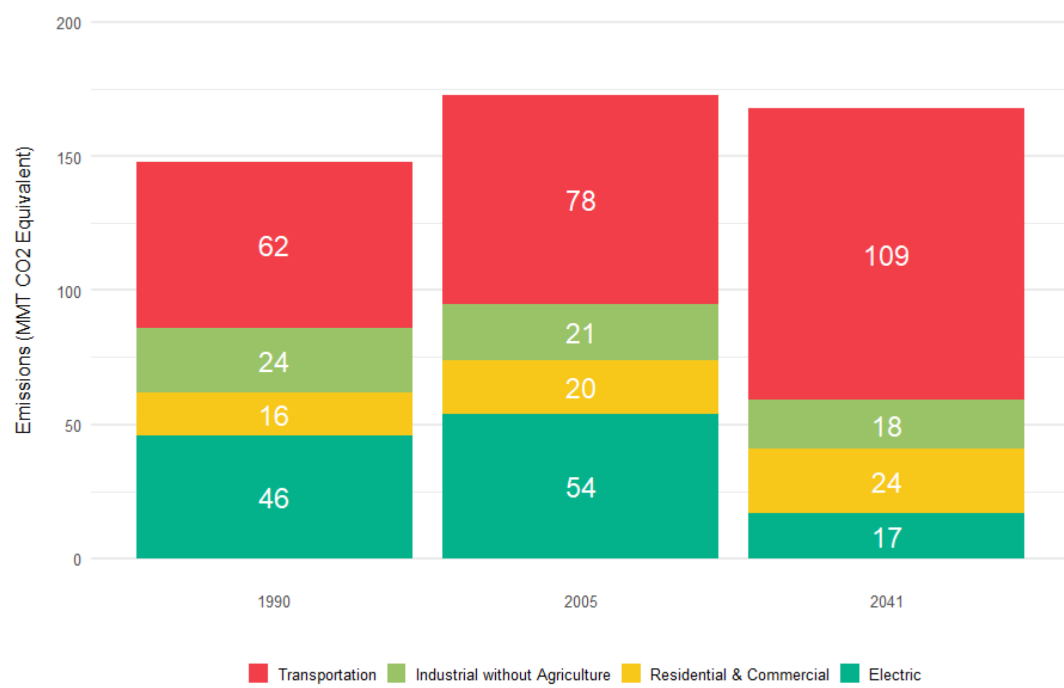
The states of Oregon and Washington have set goals and limits on future greenhouse gas emissions. Oregon's goal is to reduce emissions 80 percent below 1990 levels by 2050. Washington's goal is to reduce emissions 95 percent below 1990 levels and be at net-zero emissions by 2050.

These goals include the electricity sector in a broad range of emissions. To analyze the impacts on the electric system in this scenario, the Council forecast the region's demand for natural gas, as well as transportation fuels. Including the impact of emissions from the use of these fuels, the resulting estimates show that regional emissions will rise compared to 1990 levels in our baseline conditions.

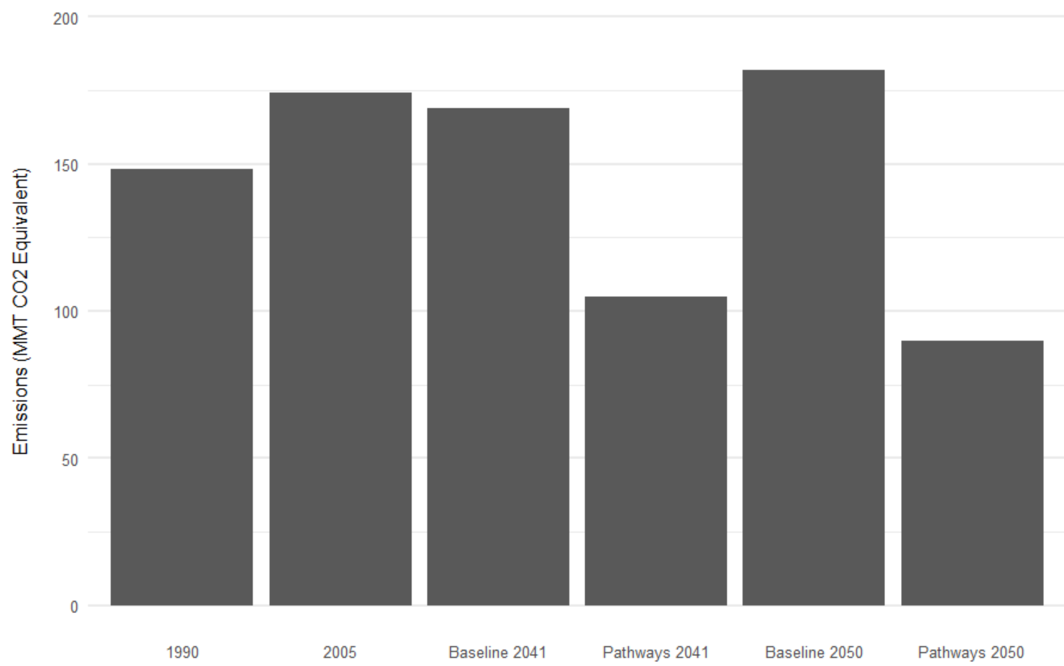
By 2041 under baseline conditions for the analysis, most regional emissions will be associated with the use of fuel for transportation. One potential approach to reducing emissions in the transportation sector would be the electrification of transport and potentially the production of hydrogen through electrolysis as a non-greenhouse-gas-emitting fuel for use in vehicles or other applications. The analysis shows it would be possible to reduce emissions by almost 27 percent by 2040, but it would require more than 12 gigawatts of additional electricity to meet the demand that new transportation technologies would place on the electricity grid.

However, even adding the reduction from aggressive electrification of transportation

Expected Sector Emissions Based on Baseline Conditions



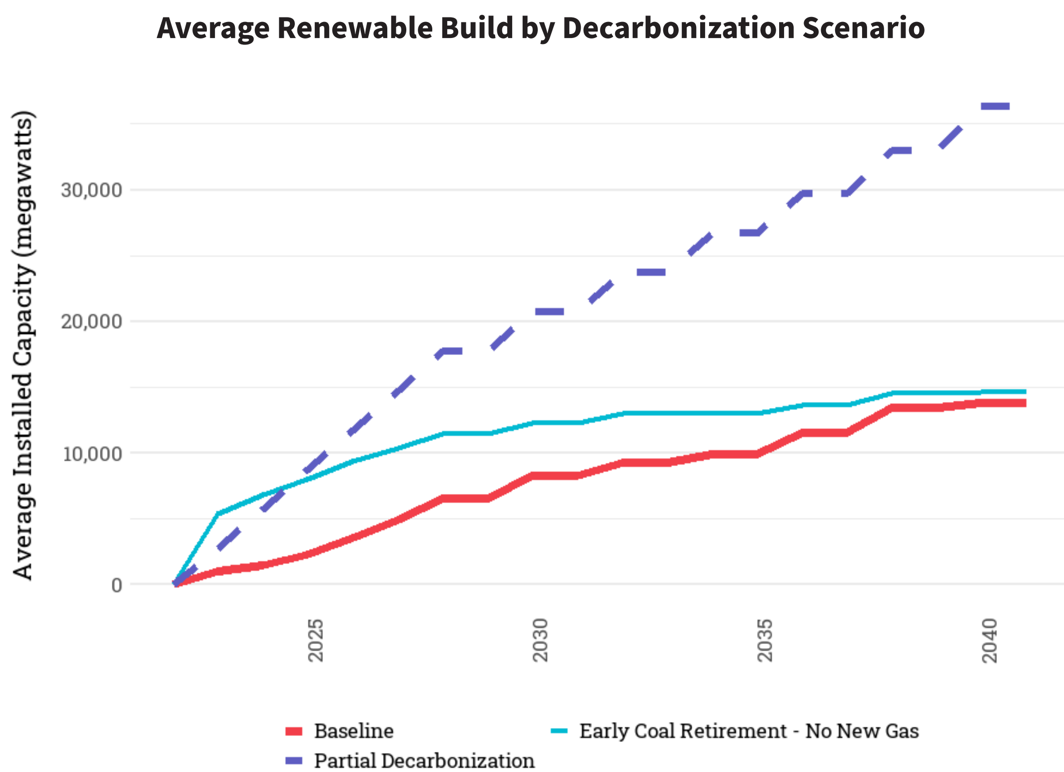
Regional Emissions from Energy Used in Residential, Commercial, Industrial, Agriculture, and Electric Utilities



with a collection of equally aggressive policies to reduce other emissions in the broader regional energy sector, the analysis does not show a path to getting to the targeted reductions within the energy sectors using the current technologies. The policies the Council tested include replacing vehicles and appliances and equipment in homes, businesses, and manufacturing at an accelerated but possibly obtainable pace.

Looking at the scope of change in this analysis, the Council decided the incremental demand to the electric system was beyond the resource expansion that could be supported by the structure of our analysis. To test the impact on the resource strategy, the Council removed a substantial proportion of the demand associated with the production of hydrogen by electrolysis. While this reduced the likelihood of reaching the Oregon and Washington targets for reducing greenhouse gas emissions, it provided a directional analysis of the possible impacts to resource additions. It also still represents aggressive emissions reductions relative to baseline conditions in the analysis. By 2040, this more moderate but still aggressive emission reduction increased the demand for electricity by just over 52 percent.

In response to this increased demand, the analysis showed a substantial increase in the addition of renewable resources relative to other scenarios the Council explored.

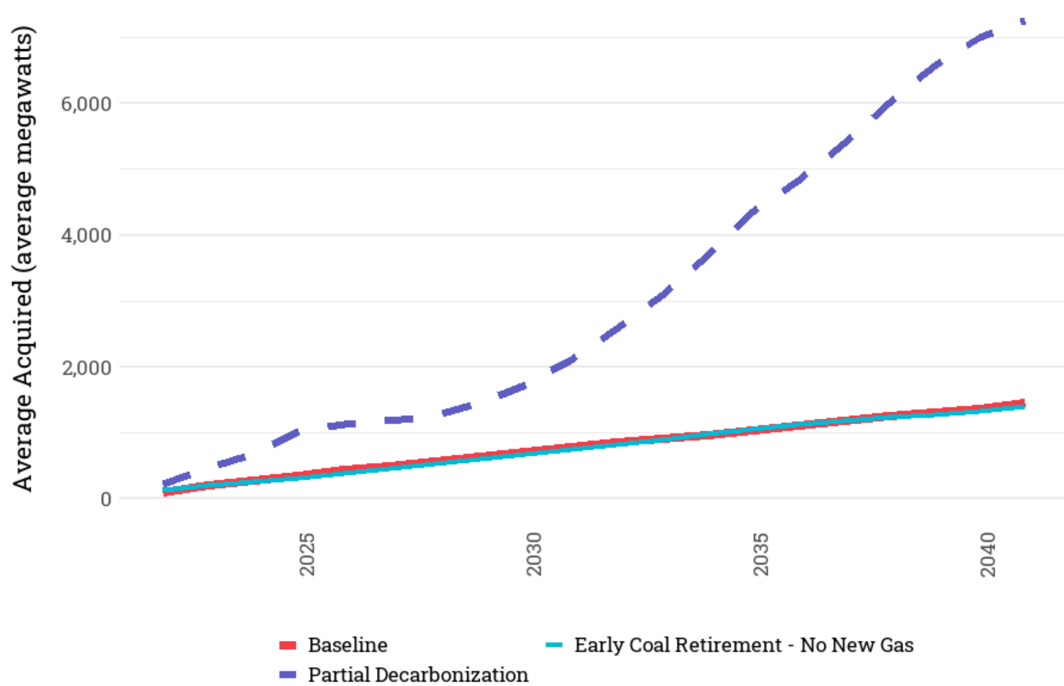


The Council also altered the supply of energy efficiency and demand response to incorporate the additional anticipated demand for electricity. This analysis showed substantial increases in energy efficiency.

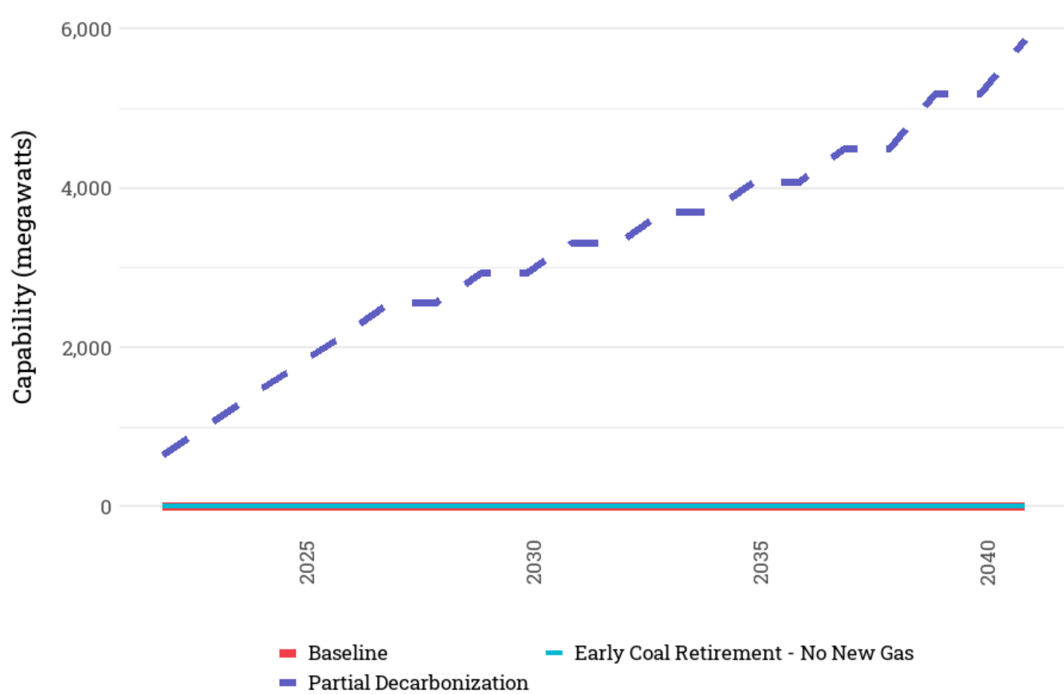
The analysis also showed a substantial uptake of demand response to support system adequacy (next figures).

The resource addition also included an expected 800 megawatts of battery storage capacity. Part of the renewable resource addition included an expected 2,100 megawatts of solar generation nameplate capacity with on-site batteries. In addition, there were some conditions where the increased demand resulted in a conventional geothermal power plant being part of the least-cost resource addition for this scenario.

Average Energy Efficiency Acquired by Decarbonization Scenario



Average Demand Response Acquired by Decarbonization Scenario



Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity

What the Northwest Power Act Requires of the Council Regarding Bonneville's Resource Acquisition

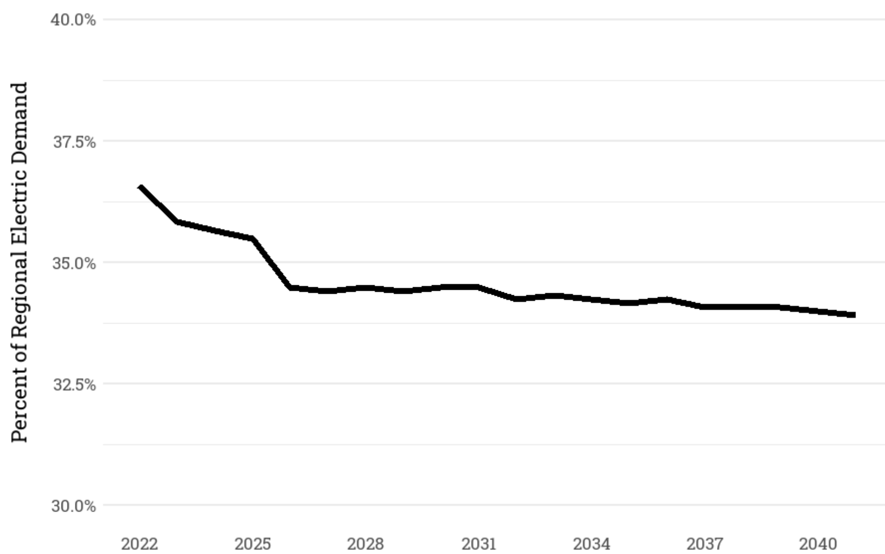
The Northwest Power Act directs the Council to "set forth a general scheme for implementing conservation measures and developing resources […] to reduce or meet the Administrator's obligations." The Council also is required to prepare a demand forecast of at least 20 years and "a forecast of power resources estimated by the Council to be required to meet the Administrator's obligations." Further, the Council is required to include, to the extent practicable, an estimate of the types of resources from which such power should be acquired.

To accomplish these requirements, the Council forecasts both demand for electricity from the Bonneville Power Administration and the electricity currently produced by the Federal Columbia River Power System, which is marketed by Bonneville. Further, the Council is required to make a recommendation to the Bonneville administrator on the amount of power needed to meet or reduce the agency's obligation and what types of resources that power should be acquired from. Our recommendation is included in *Section 8 Recommendation for the Amount of Power and Resources Bonneville Should Acquire to Meet or Reduce the Administrator's Obligation*.

Forecast of Demand for Electricity from the Bonneville Power Administration

The Council estimates[74] that the proportion of the regional demand for electricity that Bonneville is obligated to supply[75] with the federal power resources starts at just under 37 percent in the first year of the 20-year power plan forecast period and falls to just above 32 percent by the end. Through 2028, this estimate is based on the current Bonneville Regional Dialogue contracts.[76] After 2028 the Council assumes the contracts will be substantially similar, but in our scenario analysis we test the implications of both, adding to and subtracting from Bonneville's obligation. That is, in our

Estimated Bonneville Obligation as a Percentage of Annual Regional Electric Demand



This graph shows that Bonneville's obligation decreases as a proportion of the total regional demand for electricity through 2026. After 2026, Bonneville's obligation increases slightly.

74 The Council greatly appreciates Bonneville supplying data and supporting our analysis, which enabled the estimates included in this section. However, these estimates do not correspond to any publicly released forecast from Bonneville, nor are they intended to represent the forecasts Bonneville uses for its various functions and purposes.

75 While Bonneville has broad obligations under the Northwest Power Act, we use "obligation" to refer to the amount of electricity that will be requested from Bonneville by entities that have a statutory right to have Bonneville supply electricity to them.

76 www.bpa.gov/p/Power-Contracts/Regional-Dialogue/Pages/Regional-Dialogue.aspx

analysis we anticipate that Bonneville and its customers will sign new contracts, but we also acknowledge there is uncertainty about any contracts that may follow the current Regional Dialogue.

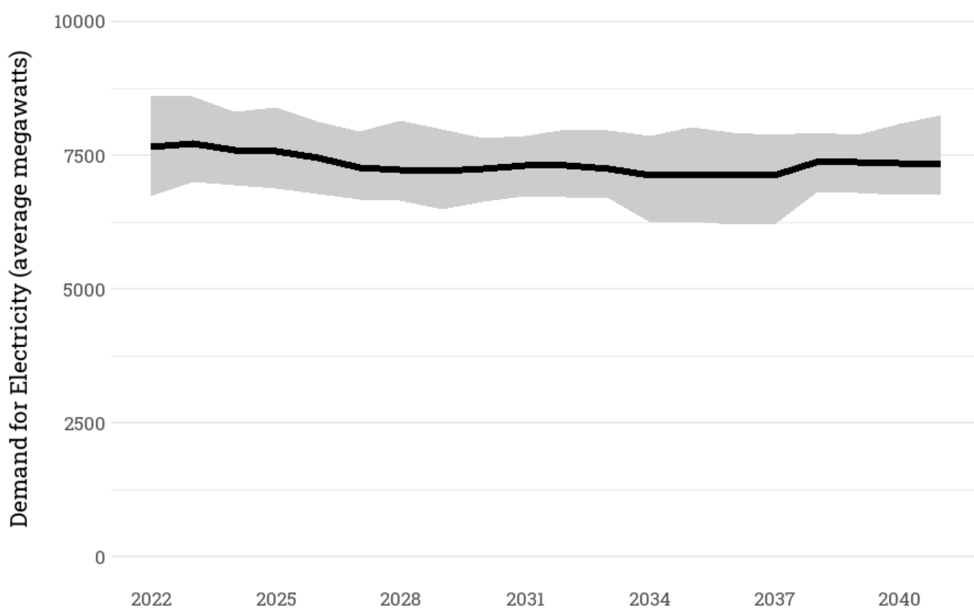
The Council's forecast includes estimates of climate-change impacts. However, Bonneville is less affected by temperature than is the region. To incorporate the impacts of temperature, we partitioned Bonneville's obligation into three categories: contract obligations, subscription obligations, and temperature-sensitive obligations.

Contract obligations are fixed amounts of electricity that Bonneville is obligated to deliver. These amounts do not increase or decrease based on temperatures in the region.

Subscription obligations are driven by the amount of power the federal resources generate. Temperature does not impact the total amount of power Bonneville is obligated to deliver in this category, but it may impact the timing of when that power is delivered.

Temperature-sensitive obligations are deliveries that respond to weather extremes and generally are less than half of Bonneville's obligation, but that changes between different quarters of the year and between forecast years.

Forecast Electric Demand Bonneville Is Obligated to Supply



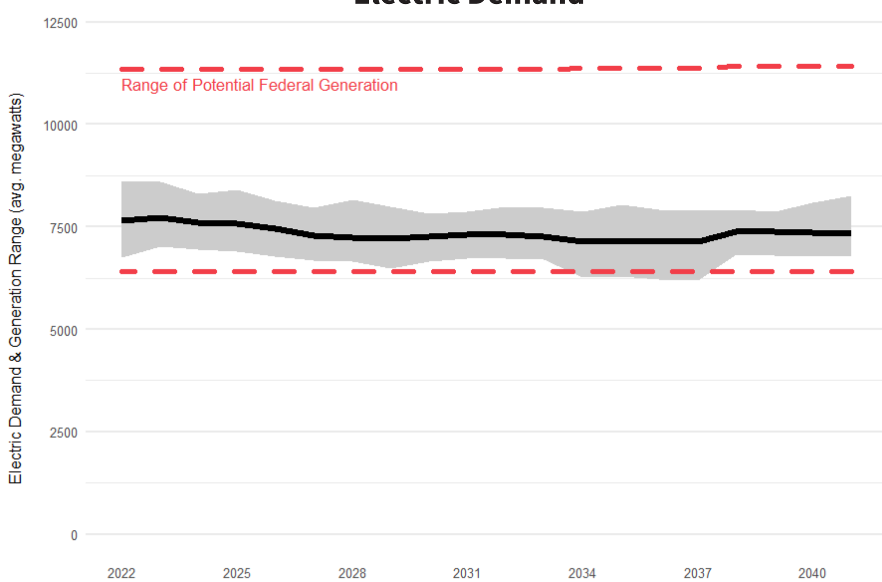
Percentage of Bonneville's Obligation Categorized as Temperature-Sensitive

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4[77]	43.2%	42.5%	43.0%	42.8%
Q1	41.8%	41.5%	42.2%	41.9%
Q2	46.4%	45.9%	47.4%	47.7%
Q3	45.3%	45.1%	46.2%	46.6%

Forecast of Electricity Produced by Federal Resources and Marketed by Bonneville

The Council estimates that generation from the Federal Columbia River Power System generally varies from a minimum of just over 6,400 average megawatts to a maximum of over 11,000 average megawatts. This range is mostly a function of the change in hydroelectric generation from year-to-year. In a year with plentiful water from regional rain and snowpack, the amount of generation from the system far exceeds Bonneville's obligations. In these situations, the excess

Electricity Produced by Federal Resources Compared to Electric Demand



77 The Bonneville and Council fiscal year is October 1 to September 30. The quarters indicated are the calendar year quarters. Thus, Q4 is the first quarter of the fiscal year and contains the months of October, November, and December. The first month of the 2023 fiscal year is October 2022.

electricity would either be sold, scheduled[78] in the secondary markets, or spilled at the federal dams without generating electricity.

Estimated Bonneville Need for Electricity

While under many circumstances Bonneville has surplus electricity relative to its obligation, there are some infrequent circumstances where the electricity produced by the federal system is less than the amount of power Bonneville is obligated to supply. For this analysis, the Council worked with Bonneville staff to adapt the approach taken in the Bonneville Needs Assessment.[79] This approach uses a "critical" energy amount[80] from the federal hydroelectric system to establish a risk preference on the amount of energy from that system set aside to meet the Bonneville obligation. This is added to the non-hydro-based resources in the federal system, and contracts and transmission losses are subtracted to determine the federal system's capability to supply electricity under critical circumstances.

Bonneville, in coordination with the Council, ran simulations using models tuned to estimate the federal system output. These simulations were adapted to the methods the Council uses in its regional modeling. Four years were run through the simulation, as detailed in the following table.

Expected Federal System Generation Under Critical Circumstances in Average Megawatts

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4	7157	7107	6995	7233
Q1	7000	6991	6845	7348
Q2	6007	6037	5843	5521
Q3	7086	7205	7091	6222

The Council's estimate of Bonneville's need for electricity is based on the difference between the Council's forecast of the electricity demand Bonneville is obligated to serve and the expected federal system generation under critical-energy circumstances. The analysis assumes limited market purchases to meet load variation in

78 There are times when the generation from the federal system is not sold in the secondary market but is still scheduled to be exported. See Bonneville's Oversupply Management Protocol, www.bpa.gov/Projects/Initiatives/Oversupply/Pages/default.aspx.

79 The Bonneville Needs Assessment is included in the BPA Pacific Northwest Loads and Resources Study, commonly referenced as the White Book. www.bpa.gov/p/Generation/White-Book/Pages/White-Book.aspx.

80 In this case, "critical" is defined by looking over the range of simulated generation when using regulated flows defined by the climate-change-based precipitation estimates for each of 14 periods, corresponding to the calendar months except April and August are split at the end of the 15th day to form two periods each. In each of these periods, we take an amount of generation that only one out of every 30 simulations would be below (or the 3.33 percentile of the simulated generation for each period).

a particular quarter or season. This results in an estimated margin between critical-energy generation and electricity demand.

For example, in the first quarter of the 2023 fiscal year (October to December of 2022), the Council estimates Bonneville would have sufficient electricity as long as the federal generation under critical circumstances (estimated at 7,157 average megawatts) can meet 88.5 percent or more of Bonneville's need for electricity.

Margin of Critical Resource to Electric Demand

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4	88.5%	88.8%	93.7%	98.0%
Q1	81.6%	83.3%	86.6%	94.0%
Q2	86.6%	88.3%	89.8%	84.1%
Q3	94.6%	96.8%	98.8%	86.6%

When the available federal generation is less than the estimated margin, we project Bonneville would need electricity.

Using this approach, the Council forecasts Bonneville will have a minimal need for electricity. The average expected need is under 7 average megawatts for the first decade of the forecast and under 28 average megawatts for the second decade.[81] However, those expected loads reflect a range of simulations. Within this range, there are some circumstances where the need could be larger than 60 average megawatts in the first decade and almost 145 average megawatts in the second decade. Seasonally these needs are more likely to occur in the summer, with the upper end of the range of forecast being around 300 average megawatts.

81 Assuming Bonneville customer utilities sign substantially similar contracts.

Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation

Resource Recommendations

Energy Efficiency

Public power has played an important role in the Northwest energy efficiency achievements over the last 40 years. Since 2008, Bonneville utility customers have acquired roughly 36 percent of the region's energy efficiency savings. Looking forward, the Council estimates that 36 percent of the remaining available energy efficiency is within the Bonneville utility customer service territories. Bonneville's energy efficiency program will continue to be an important piece of our regional power system infrastructure.

To support both Bonneville's and the regional power system's needs, the Council recommends that Bonneville acquire between 270 and 360 average megawatts of cost-effective energy efficiency by the end of 2027 and at least 865 average megawatts by the end of 2041. Aligning with the Council's analysis of remaining potential and historical achievements, this level represents 36 percent of the overall regional target.[82]

Within the first six years, the Council recommends that Bonneville plan to acquire a minimum of 243 average megawatts of cost-effective efficiency from programmatic savings. This includes savings currently funded through Bonneville's program, whether via the Energy Efficiency Incentive or self-fund utility contributions, as well as the Northwest Energy Efficiency Alliance (NEEA) market transformation initiatives. The remaining efficiency may come through additional programmatic activity, market change, or codes and standards.

Bonneville should use the Council's methodology and associated parameters for cost-effectiveness to identify efficiency opportunities at levels that are cost-effective for the region.[83] This target recognizes the value that Bonneville can provide the region to ensure a reliable power system and achieve decarbonization goals. Additionally, it can mitigate some of the risk associated with potential changes in obligations post-2028 when the current contracts expire.

The Council understands that although Bonneville produces an annual budget, it forecasts its revenues and expenditures on a biennial basis as part of its rate setting process. For the first two years of the 2021 Power Plan, the Council assumes that Bonneville has budgeted appropriately for the agency to successfully achieve the energy efficiency target in this plan. For the remaining years of the 2021 Plan, Bonneville should work with the Council to ensure that a budget is established to successfully meet the plan's energy efficiency targets.

If evaluation of the energy efficiency achievements through the Council's annual Regional Conservation Progress report indicates that Bonneville's achievements fall short of the Council's recommendation, Bonneville and the Council should work cooperatively to understand and address the underlying cause of this shortfall. The Council will continue to work with Bonneville, the NEEA, and the regional utility community to ensure the Regional Conservation Progress report that the Council was directed by Congress to produce annually accurately reflects the regional energy efficiency achievement.

The Council's recommendation for acquiring energy efficiency does not distinguish between energy efficiency

82 The determination of 36 percent as the Bonneville portion of the regional target represents the portion of cost-effective energy efficiency potential located within the Bonneville customer utilities territory. More information on this assessment can be found in the supporting material here: nwcouncil.org/2021powerplan_BPA-CE-Potential-Share

83 The cost-effectiveness methodology can be found here: nwcouncil.org/2021powerplan_cost-effective-methodology

funded through money collected by Bonneville and energy efficiency funded directly by customer utilities. Nor should the Council's recommendation be seen as a recommendation for maintaining or changing the structure of how energy efficiency is funded between Bonneville and its customer utilities. Further, this recommendation is not intended to be proportional to the customer utilities, based on load or potential or any other manner. Our intent is that this recommendation assists individual utilities in determining for their service territory how they can best structure their programs to acquire energy efficiency. Our recommendation is not prescriptive on how individual utilities should run their energy efficiency programs.

The Council recognizes that there are diverse challenges to acquiring energy efficiency across Bonneville's customer utilities. Achieving the efficiency targets will require that Bonneville work to meet each of those utility challenges within the cost-effectiveness considerations. Many of the public utilities with a rural–and primarily residential and agricultural–customer base have fewer energy efficiency opportunities. Additionally, these utilities may lack resources–such as staff, contractors, retailers–and thus have significant challenges implementing cost-effective efficiency programs. To meet its programmatic efficiency goals, Bonneville must work with these utilities and provide territory-wide programmatic opportunities to enhance the infrastructure for small and rural utilities. Continued funding of NEEA initiatives will also provide necessary support for training and other infrastructure to address implementation barriers across its customer utility footprint.

To help ensure the necessary levels of cost-effective conservation are acquired, the Council recommends that Bonneville contribute to all aspects of the regional conservation program, as described in *Section 5: Energy Conservation Program*. This includes continued funding and support in the following areas at levels commensurate with 2020 levels or greater: NEEA; research including regional market research, stock assessments, evaluation, and related analysis; and codes and standards development.

The Council's conservation program also identifies two key opportunities to ensure equitable distribution of energy efficiency. The Council recommends Bonneville continue to invest in weatherization programs, targeting those homes that are leaky (in need of duct or air sealing) and/or have zero or limited insulation. We recognize that these measures, while historically cost-effective, may not be cost-effective under our current paradigm. Nevertheless, the Council believes they are critical to provide livable homes for all people. Bonneville and its customers should consider coordinating with other agencies (such as community action agencies, state agencies, and/or nonprofits) and explore co-funding options to best serve these homes. Additionally, the Council recommends Bonneville work with its utilities with large commercial loads to utilize energy-use intensity data to identify those buildings with significantly higher consumption than comparable buildings. The Council believes leveraging this data will provide a way to identify those commercial consumers in the greatest need of efficiency measures that were previously missed by programs.

Demand Response

In *Section 6: Resource Development Plan,* the Council recommends that utilities pursue demand response that can be frequently deployed and obtained at a low cost. We identified that demand voltage regulation (DVR) and time-of-use (TOU) rates can help substantially in ramping and peak periods. Additional value may also be obtained to relieve transmission constraints and defer transmission and distribution system upgrades.

Bonneville should work to enable and encourage its customer utilities to pursue these and other low-cost and high-value demand response measures in an equitable manner.

Market Purchases

The Council anticipates that regional wholesale electricity prices will have substantial downward pressure from expanded renewable generation additions throughout the West. We recommend that Bonneville, when it has needs beyond the recommended energy efficiency and demand response resources, look to mid-term and long-term market resources for additional energy.

When Bonneville has needs for electricity in specific locations where the ability to deliver power from the federal system is limited, the Council still anticipates the mid-term and long-term market resources will likely be the low-cost resource alternatives.

Renewable Resources

Costs for renewable resources have substantially fallen. While the Council recommends purchasing market resources to meet Bonneville's needs for additional energy, we recognize that there may be situations where a more general market resource may be more expensive than a direct power purchase agreement, or similar arrangement, tied to a specific renewable resource. The Council recommends that Bonneville compare power purchased in this manner to alternative market products, both in price and capability, to ensure that the lowest-cost product that suffices to meet any need identified is purchased on behalf of the region's electricity consumers.

Supporting Recommendations

Regional Hydro Generation System

The Council's analysis shows a rapidly shifting market dynamic in the Western electricity grid. The impacts, both challenges and opportunities, need to be better understood and explored by all regional entities that have a role in operating the hydro system.

The Council recommends Bonneville play a central role in these future efforts. Bonneville can do this by both incorporating these impacts into its analyses and supporting broader regional efforts, at the Council and other organizations, to study and understand these impacts.

Future Contracts

The Council's recommendations to the Administrator on what power to acquire depend on the obligation placed on Bonneville. Current contracts allow customer utilities to reduce or abandon service from Bonneville at the end of the contract. Currently all contracts end at the same time, leaving an acute risk that could be aggravated by the Council's recommendations. Our analysis shows the lowest-cost strategy for the Bonneville portfolio changes within the action plan period based on whether regional utilities contract for power from Bonneville in the future.

Further, Bonneville's resource decisions may be limited based on this risk. When all the contracts expire at the same time, decisions made close to the end of the contract period are less likely to favor long-term commitments. This could disadvantage lower cost but longer duration power acquisition.

Bonneville should consider in its next contract negotiations how to mitigate the financial risk of acquiring power that may be least-cost but longer duration. Further, it should explore how a wide range of potential future Council recommendations on resource acquisition could be contractually accommodated without substantial risk of shifting costs among regional consumers of electricity at the end of contract periods.

Additionally, in the current contracts, many Bonneville customer utilities see little value in pursuing demand response and are limited in the ability to provide a demand response resource to another utility, both within and external to the pool of Bonneville customer utilities. In future contracts, Bonneville should consider provisions supporting its customer utilities' development and export of demand response resources.

Section 9: Cost Effective Methodology for Providing Reserves

Reserves in the Act

The Power Act indicates the power plan should include an analysis of reserve and reliability requirements and cost-effective methods of providing reserves designed to ensure adequate electric power at the lowest possible cost. Additionally, the Power Act explicitly recognizes that reserves can come either from generating resources or non-generation alternatives, including conservation measures and contract rights to curtail or interrupt power supplied to customers.

Reserves on the power system are held to account for the uncertainty about the expected amount of electricity demand and power generation. The wholesale power market can help address a significant amount of uncertainty in generation and load. However, most often individual utilities or collections of utilities take actions like holding back some existing resources from the market or adding additional generating resources or non-generation alternatives to address these uncertainties on a second-to-second, hour-to-hour, and year-to-year basis.

Types of Reserves

The growth of electricity demand due to changes in the economy or amount of water available for hydro generation in a year based on precipitation are forecast, but due to the uncertainty of those forecasts, reserve power generation capability is held on a planning basis. These types of reserves are often called planning reserves.

Uncertainty in the forecast speed and direction of the wind hitting turbines or the forecast of households who will have their lights on or air conditioning running at any certain time are examples of shorter-term uncertainties that may cause an imbalance between power scheduled to be delivered to demand. Additional power system capability to meet these schedule imbalances are often referred to as balancing reserves.[84]

While having less fuel uncertainty than solar, wind or hydropower, coal or gas plant generators have the possibility that some aspect of the controlled combustion that creates the power in those plants will go wrong and the entire plant will shut down unexpectedly. Additional power system capability to address these unexpected plant outages are often called contingency reserves.[85]

Since planning for future resource strategies in the power system must explicitly account for these uncertainties, the discussion of the methodology for including reserves in the analytical framework of the resource strategy started with a description of the types of reserves considered: planning, balancing, and contingency reserves. Balancing reserves are held by generating resources that are positioned to ensure that if any errors are made in forecasting load and generation on an hour to hour basis that there is enough of a buffer within the region to make sure generation matches load at all times by increasing or decreasing the amount of electricity being generated.

Contingency reserves are held back to make sure if events like large unexpected forced outages on generators happen that there are enough reserves to match load by increasing electricity generation to replace electricity that becomes unavailable.[86] These operational reserves are part of what makes up planning reserves. The rest of planning reserves account for year-to-year variation in generation and load, such as planning to be able to keep the lights on even during low hydro conditions. All these reserves are incorporated into the calculation of additional resource requirements to maintain the Council's adequacy standard[87] throughout the planning period. The following chart identifies the balancing and contingency reserve requirements that the Council included as inputs into the modeling analysis. The sources of these values are described in the supporting materials.[88]

84 Used maximum of the regional sum of balancing reserves in any hour in the Northwest Power Pool Energy Imbalance Market work as planning assumption for the region.

85 Northwest Power Pool reserve sharing group for contingency reserves

86 Increases in load require increases in generation, called *balancing up reserves* often referenced in the electric industry as *INCs*. Conversely, decreases in load require decreases in generation, called *balancing down reserves* often referenced as *DECs.*

87 5% Loss of Load Probability

88 nwcouncil.org/2021powerplan_reserve-input-assumptions

Operating Reserves

Type	Amount Held
Balancing Up	2,900 megawatts
Balancing Down	3,345 megawatts
Contingency Reserves	3% of load and 3% of generation

Providing Reserves Using New and Existing Resources

Traditionally, additional reserve requirements have more directly translated into needs for additional generating resources, energy efficiency or demand response, but the current analysis indicates that the operations of existing regional generators may play a larger role. In the past, in our region, coal and natural gas generators have complemented regional hydro generation by providing a significant amount of system flexibility. Since the wholesale market electricity price was set by coal or gas generation near times of scarcity, the expectation that those plants would operate if available was a decent assumption.

More Conservative Operation of Existing System to Provide Reserves

In the current and predicted future power system, significant amounts of solar generation throughout the Western grid contributes to very low prices for power midday. These low midday prices can be low enough that coal and gas plants can appear uneconomic to run during the day and plan to shut down to lower overall system cost.

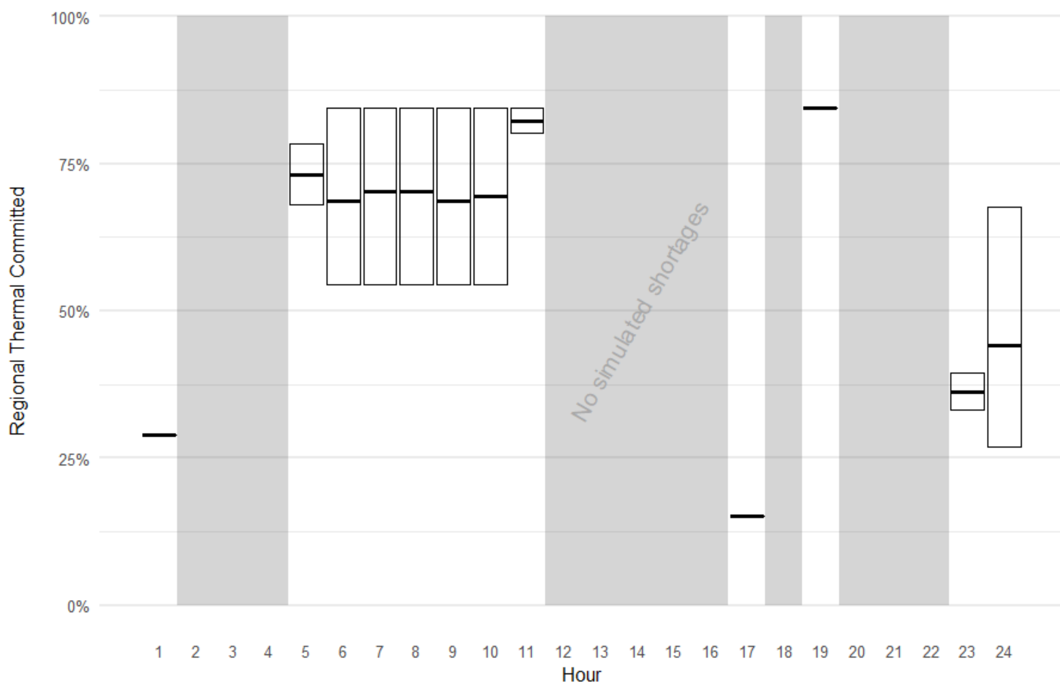
However, when demand for power ramps up in the morning and down at night, there is now significant uncertainty about available generation, along with the uncertainty associated with electricity demand, and that uncertainty introduces some operational challenges.

For example, much of the regional fleet of coal and gas generation need a few hours to ramp up or ramp down from full generation, and fueling larger gas plants requires significant notice ahead of time to order the fuel. Depending on overnight pricing of wholesale power, this could mean that some of these plants might not be seeing an economic signal[89] to stay online or start up with enough time to respond to a potential shortage during those early morning or evening hours where there is significant uncertainty about the amount of electricity demand and generation available.

89 In general, most power plants generate when the cost of producing power is below the price they can receive on the wholesale market for selling power.

These types of operational issues appear to account for almost all the simulated system shortages in the analysis. These issues are not due to a shortage of resources, but in having enough information to operate the existing system economically and adequately.

Maximum Available Thermal Generation During Simulated Shortages[90]



One way to mitigate some of these challenges is to create a signal, in the form of additional reserves, to operate more of these plants to maintain adequacy. This effectively utilizes the existing generators in a way that results in higher overall system cost but less risk of being short generation at a critical time. Plan analysis showed that holding additional reserves overnight does seem to address most of the issues at a slightly higher cost merely by operating the existing system[91] more conservatively.

Additional Resources as a Reserve

Another way to address this issue is to add additional power generation, demand response or energy efficiency. Since reserves are accounted for implicitly in the

90 This graph shows the maximum and average percentage of total thermal generation online during the shortfalls in winter by hour of the day.

91 The existing system providing more reserves is referring mostly to regional hydro, coal and gas generation operated more conservatively

resource strategy analysis,[92] this approach is considered along with all the other reasons to make further investments in the regional power system. Generation resources like wind and solar tend to need more reserves. Generating resources like combined-cycle gas plants have some of the same operational challenges as the existing fleet. Demand response, batteries, and pumped storage can contribute to a solution, but without an explicit reserve signal, are often imperfectly positioned to address adequacy issues. Energy efficiency is the most effective resource at creating more reserve capability in the region; however, it is more expensive than in the past.

Additional Market Reliance

The wholesale electricity market is a valuable tool to take advantage of the diversity of the pool of resources in the Western power grid. Currently, the region has chosen to only rely on resources outside the region on a limited basis (2,500 megawatts per hour in the winter and fall and 1,250 megawatts per hour in the spring and summer). Since Northwest utilities have a limited say in the governance and planning in other regions in the West and due to recent historical events,[93] there has been reluctance on a planning basis to rely more heavily on other region's generation as a hedge against uncertainty, despite the cost advantages.

Cost Effective Reserves as Part of the Resource Strategy

Similar operational issues seen in the analysis have occurred in California power system operations for the last ten years or so, and the market operator in California[94] has multiple strategies[95] to address this issue. One is a more conservative operation of existing system power generators, incentivized by paying extra money to plants with flexibility to stay online. The Pacific Northwest currently has no such market operator,[96] and leveraging off regional collaborations[97] such as the Northwest Power Pool Resource Adequacy effort to achieve a similar mitigation strategy may be advantageous.

92 See Section 6: Resource Development Plan for more details on how these investment decisions are approached.

93 2001 Western Power Crisis

94 California Independent System Operator

95 Market mechanisms to hold more reserves and procure more resources.

96 Other than the limited volume of market trades that are governed within the Western Energy Imbalance market structure

97 Other options include leveraging the current Western Energy Imbalance Market structure and/or further coordinating throughout the West for the day-ahead market via the Enhanced Day-Ahead Market.

Additionally, a slightly more expensive, but effective alternative to this would be to invest more in resources like energy efficiency, beyond what was identified in the resource strategy analysis. A riskier but less expensive mitigation method would be to rely more on the market outside the region.

Major takeaways from the analysis:

1. The least-cost option to maintain an adequate, cost-effective regional system is to couple the investment recommendations (the listed amounts of renewable generation, energy efficiency, and demand response) in the resource development plan with some sort of reserve pooling effort via an organized market or regional collaboration to ensure that sufficient reserves[98] can be held to mitigate the increasing uncertainty from increased investment in renewable generation. Part of the reason this method is recommended as the most cost-effective is that the amount of reserves to maintain an adequate system could be changed to match needs over time.

2. A more expensive, but effective, alternative is to invest in more energy efficiency than identified in the resource strategy analysis. This will increase the fixed cost investments required by the region but may be necessary to maintain adequacy should regional coordination to provide additional reserves proves unsuccessful.

3. A less expensive, but riskier alternative is to plan on more external generation to support the region in times of need. Other regions have varying policies, requirements, and Northwest regional stakeholders have less say in their planning processes. Without a more formalized collaborative process like an organized market, this strategy, while taking advantage of the diversity of a large pool of existing resources, would likely expose the region to significantly more risk.

98 Analysis showed that over 3,000 megawatts of additional reserves may be required by 2023 to sufficiently incentivize enough generation to be online in order to have enough fuel to meet morning and evening ramps.

Section 10: Recommendations for Research and Development

The Northwest Power Act directs the Council to include within the plan a "recommendation for research and development." Given the vastly different and rapidly evolving power system, it is important that the Council reflect not only on what we know today, but on what we need to continue to understand to ensure we meet the needs of all the region's consumers. To that end, the Council recommends additional research and development in four key areas:

1. Research to support effective implementation of the conservation program
2. Exploration into alternative approaches to power system operation
3. Research of emerging technologies to support development of future resource options
4. Development of data and tools to enhance future power planning analysis

These recommendations are for entities across the region, with the Council at times providing a supporting role.

Implementing the Conservation Program

The Council is recommending 2,400 average megawatts of energy efficiency be acquired by 2041. Energy efficiency is a slow-building resource. Achieving this goal requires ongoing research to ensure that it is available, reliable, and acquired at the lowest cost.

It requires steady investment to identify opportunities, design programs to deliver efficiency to consumers, evaluate effectiveness, and then refine and repeat. Therefore, the Council recommends that the region continue to invest in research in the areas of evaluation, market research, regional stock assessments, and end-use load research.

In addition to supporting the *Section 5 Energy Conservation Program*, we believe this research provides important insights for identifying demand response opportunities and ensuring effective delivery of those products. The Council recommends the region consider these wider benefits when determining appropriate investment levels for research.

Evaluation

Evaluation is a critical component of understanding the impacts of energy efficiency measures and demand response products. It conveys whether the planned savings were realized, and it can provide insights on how to improve program effectiveness.

Many of the region's efficiency programs–including the Bonneville Power Administration's on behalf of its customer utilities–have robust evaluation efforts. The Council recommends continued investment in energy efficiency evaluation, at levels commensurate with today's investment. This research should include collecting all measure information required to support cost-effective and equitable application of ratepayer funds. Additionally, we recommend that efficiency programs develop evaluations in accordance with the Regional Technical Forum's guidelines, which support consistent and reliable determination of energy efficiency across all measure types.

Market Research

Market research provides thoughtful insights on efficient products available in the market, the availability of contractors and other experts needed to install efficient products (including those with controls that could be used in demand response programs), and where the largest gaps in efficiency adoption exist.

Over the past several years, the region has increased its investment in market research, providing the information needed to refine and focus efficiency programs on the most promising opportunities. NEEA plays a critical role in market research, using its market expertise to take advantage of economies of scale as a regional entity.

Bonneville, the Energy Trust of Oregon, and the region's utility programs also have an important role, particularly in gathering information to address specific local questions or needs. The Council recommends that NEEA, Bonneville, and the region's efficiency programs continue to invest in market research.

Regional Stock Assessments

Through NEEA, regional stock assessments have been conducted that provide snapshots of the existing building stock. This includes information on numbers of buildings, size, use, types of equipment installed, availability of products with controls, and more.

Stock assessments are an important complement to market research, providing another lens for identifying efficiency opportunities and tracking regional progress. The Council recommends that the region's utilities, through NEEA, continue to invest in regular stock assessments for the residential and commercial sectors. Ideally, these would be completed at least once every five years. As part of this effort, NEEA should explore new data techniques for providing more timely information about fast-evolving changes in the stock.

For commercial buildings, the Council recommends that NEEA, with support from Bonneville, Energy Trust of Oregon, and regional utilities, develop a reliable commercial building energy use intensity dataset. The starting point should be the commercial building stock assessment and other publicly available data sources. This dataset will enable efficiency programs to identify buildings that provide the greatest opportunity for significant investment.

The Council also recommends the region's utilities invest in another stock assessment for the industrial sector (including water and wastewater), with particular focus on motors and motor-driven systems. To the extent practical, data gathered on motor and motor-driven systems should also include the agricultural sector, as the region has a long-standing gap of information on this sector. For this work, we recommend that the region build on existing utility data and leverage efficiency program experts knowledgeable with these facilities as a starting point for this assessment.

End Use Load Research

Understanding the timing of energy use, as well as the timing of energy savings, is critical for identifying measures that provide more value for the power system. Today, the region continues to rely heavily on the results from the End-Use Load and Consumer Assessment Program (ELCAP), which was conducted in the late 1980s to characterize the timing of energy use.

Recently, through coordination at NEEA, the region has undertaken a new effort to meter and characterize energy use in residential and commercial buildings. The findings from this research shine light on how we use energy today and provide insights on how new technologies might shift and reduce the timing of energy use.

With the recent Covid-19 pandemic changing how people live and work, this research will answer questions around how energy use has shifted and whether any of those shifts will continue as the new normal. The Council recommends the region continue to fully fund this research and ensure that the knowledge gained is shared broadly for effective investment in all demand-side opportunities. Additionally, the Council recommends that the Regional Technical

Forum use this data to create load shapes for efficiency measures that can be used by the region's utilities to understand the timing of energy efficiency savings.

Exploring Alternative Approaches to Power System Operation

The rapidly decreasing cost of renewable resources, coupled with various state and utility clean policies and emissions goals, are driving large renewable builds across the West. The result: A very different power system. The system requires flexibility, with resource options that can fill in those valleys when renewable energy is not available and support ramping needs when the sun goes down and the lights come on.

Our modeling suggests that we need to rethink power system operations to ensure not only an adequate, efficient, economical, and reliable power supply, but one that continues to protect, mitigate, and enhance the important fish and wildlife in the region. To that end, the Council recommends the region undertake the following explorations aimed at broadening our thinking of power system operation.

Renewable Generation Impacts on Regional Hydropower Operations

The substantial increases in renewable generation across the West shifts power system generation and transforms power markets. The oversupply of renewable generation during the day rapidly shifts to a need for other resources during the evening when the sun is down. Since hydropower has a low variable cost and is flexible, our analysis shows that it is well positioned to help the region absorb increasing renewable generation and ensure adequacy in the region.

However, it is unclear how these daily river flow fluctuations will affect environmental conditions for fish in the river, particularly for juvenile and adult salmon and steelhead migration and for mainstem spawning and rearing habitat. The Council's 2014 Columbia River Basin Fish and Wildlife Program contains measures recommended by the state and tribal fish managers calling on the system operators to minimize or reduce daily flow fluctuations, and yet the analysis suggests a need for increasing fluctuations for adequacy.

The Council intends to organize and support an investigation into the implications of these changing river flows. This effort will bring together Bonneville, system operators, the federal and state fish and wildlife agencies, and the region's tribes. The goal will be to explore the possible benefits and consequences of different hydropower system operations to identify a path forward that provides greater benefit to both power and fish.

Alternative Approaches to Support Renewable Integration

Our analysis suggests other approaches might provide low-cost solutions to support integrating renewables into the existing system. One example is the role of holding reserves. Plan analysis shows that more regional collaboration on holding reserves can provide a lower cost approach to system adequacy.

When a utility holds more reserves, it has more of its existing generation ready if needed to address unexpected loads. Alternatively, with lower reserve amounts, the market prices diluted by the influx of renewables might not provide a sufficient signal to ensure those existing resources are otherwise available if needed. To better understand the tradeoffs around holding more or less reserves, the Council recommends that the region's utilities, regulators, and Bonneville conduct a study to explore how market liquidity by season and time of day can create price barriers for flexible resources, and the cost of mitigating those barriers through greater reserves. This analysis should take into account different hydro conditions.

Another approach to supporting adequacy is demand response. Balancing the system requires that resources are available to quickly meet loads as they come onto the system and can be curtailed as those loads go away. Demand response is a resource that can shift loads away from those high peaks to other times of the day when loads are otherwise low. The Council recommends that Bonneville and utilities research opportunities to use demand response to support system balancing. This effort should provide insight on how to improve modeling these opportunities for future regional and utility power planning efforts.

Transmission and Non-Wires Alternatives

With a potential significant deployment of cheap, new resources vying for access to the transmission system and competing with established, oftentimes more expensive, resources for dispatch to the grid, it is time for the region to reconsider how we contract, reserve, and schedule transmission access.

It is common for a given transmission path to be fully contractually encumbered on a long-term firm basis while still having substantial available physical capacity most or all hours of the year. New resources may face transmission access queues up to several years, creating a barrier to, or slowing, development. While any unused transmission capacity must be marketed for short-term utilization, this can have limited value to project developers who require deliverability guarantees in order to receive financing.

The Council recommends that the region's transmission providers work with utilities, load-serving entities, NorthernGrid, and others to develop a comprehensive review of the existing state of the transmission system; research potential short-term and long-term solutions to alleviate new resource development barriers, while balancing existing long-term contracts and compensation to transmission providers; and explore the potential benefits of implementing a regional transmission operator in the Pacific Northwest.

Additionally, the region should continue to explore non-wires alternatives to address transmission and distribution constraints. Battery storage and targeted demand response, for example, can provide significant value to deferring the need for adding transmission. The Council recommends that the region consider the role of battery storage, targeted demand response, and other demand-side resources to address existing transmission capacity challenges.

This research should speak to the role of these resources in alleviating some of the new resource development described earlier. Additionally, the Council recommends that utilities and Bonneville consider the value of these opportunities on a case-by-case basis to address local needs.

The Council's planning work will require a working knowledge of the impact of new and existing transmission on the region's access to market power and the region's ability to interconnect new generators. The Council is committed to engaging with the region's transmission planners and working alongside them to encourage better coordination on all aspects of long-term planning for the regional power system.

Role of Hydrogen and Fuel Cell Technology

Finally, the 2021 Power Plan is the first to explore the use of hydrogen fuel cell technology as a potential clean energy resource. Hydrogen may be especially promising as a replacement for diesel fuel in heavy duty freight transportation[99] and for some high-heat industrial uses. Currently there is limited demand and production in the region, however this may change in the future with the various clean electricity grid and emission reduction goals.

The Council recommends study of the impacts, benefits, and challenges that large-scale demand and production of hydrogen in the region might have on the power system overall, and in particular, hydro and renewable power. For instance, one hydrogen production method–electrolysis–can be turned on and off, which maybe be useful for balancing load and soaking up excess renewable generation.

99 nwcouncil.org/energy/energy-advisory-committees/demand-forecast-advisory-committee

Emerging Technology

In developing the recommended resource strategy, the Northwest Power Act requires the Council to give priority to resources that are cost-effective. This includes resources that are "reliable and available within the time [they are] needed, and to meet or reduce the electric power demand […] at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource."

We recognize that while the resource strategy must focus on those resources available today, there are many potential opportunities that might meet future power system needs at lower costs. To this end, the Council recommends that the region continue to invest in researching emerging opportunities.

As states and utilities progress toward clean, non-carbon emitting energy portfolios, there are opportunities for new, emerging supply-side technologies to compete with established renewable resources–such as onshore wind and solar photovoltaic–and that will play a critical role in the future power system.

The Council recommends that national labs, research institutions, trade allies, and utilities continue to work with developers and manufacturers to research and explore the regional resource potential of supply-side emerging technologies such as offshore wind, small modular nuclear, enhanced geothermal systems, energy storage, carbon sequestration technologies, and other carbon-free resources. In addition, the Council urges the region to identify potential barriers to deployment, including costs, transmission, siting, etc., and work together toward solutions when it is in the best interest of the region.

On the demand-side, new innovations in efficient technologies provide paths to lower cost energy efficiency. To ensure that efficiency measures are readily available and reliable, research is needed to understand the efficacy and applicability of potential technologies.

The Council recommends that efficiency programs, through NEEA, regional universities, national labs, and others should continue to invest in emerging technology research for efficiency measures. This effort includes scanning for emerging technologies, pilot studies to provide case studies for program opportunities, and field research to verify real-world savings.

With less lower cost energy efficiency potential than in prior years, and greater competition with generating resources, this research should also explore opportunities for cost reduction and paths forward that provide the most efficiency benefit at the lowest costs.

The Council also recommends the Regional Technical Forum increase the rigor of its measure cost analysis to support improved comparison with alternative resources in future resource planning. Further, the Council recommends additional research around demand response opportunities.

Our analysis for the plan demonstrates that demand response products that can be frequently deployed at low cost provide significant value to the power system to maintain adequacy and reduce emissions. As utilities and Bonneville explore the value of demand response, the Council recommends that the region continue to develop these non-traditional applications that may provide more value than the standard peak-reducing product.

Development in Support of Future Power Planning

The Council recognizes that power planning is an ongoing effort. The power plan reflects our recommendations based on our understanding of the system today, the availability and costs and benefits of new resources, and existing modeling tools. We recognize, however, that there are enhancements needed to continue to improve our power planning in the future. To that end, the Council recommends developing data and tools in the areas of equity, the valuation of model inputs, and enhanced metrics and tools for improved modeling.

Equity

Through its development of the power plan, and in particular discussions in the System Integration Forum[100] on diversity, equity, and inclusion in the power planning process, the Council identified a gap in equity data that informs equitable representation and accountability in regional and utility resource plans.

The Council recommends that the region convene a series of workshops to investigate existing equity data–encompassing generation, transmission and distribution, and demand-side resources–share publicly available data sources, and perform a gap analysis to identify areas where further research and data are needed.

The goal of this workshop is to develop a regional framework to improve future power planning analysis, including future Council power plans and regional utility integrated resource plans. The workshop participants will need to identify the appropriate entities to manage these efforts long-term. Regional

100 The System Integration Forum brings together multiple Council advisory committees to explore cross-cutting topics. The Forum on diversity, equity, and inclusion was held on February 19, 2021: nwcouncil.org/meeting/sif-2021-power-plan-and-dei-february-19-2021

cooperation and collaboration–broad representation across the region, including many agencies and utility groups–is crucial to the success of this effort. The Council will use its role as convener to assist in launching the first workshop.

Improved Valuation of Model Inputs

Upstream Methane

Despite the focus on renewables, natural gas continues to play an important role in providing energy to the Northwest. Methane, the primary component of natural gas, is an especially potent greenhouse gas, and measures of atmospheric levels have been rising significantly in recent years.[101,102]

The 2021 Power Plan is the first to include an estimate of upstream methane emissions from the natural gas system directly in the planning process. For this plan, the Council–with the expertise of the Natural Gas Advisory Committee–developed an estimate for methane release rate of the natural gas consumed in the Northwest, which is drawn from Western Canada and the Western United States. While we are confident in the approach and assumptions for this analysis, we recognize that there are gaps in our understanding.

Assessing the upstream methane emissions related to the extraction, processing, transportation, and storage of natural gas is a complex undertaking. This has emerged as an important topic, spurring a number of studies that use new methods to assess the overall emissions from natural gas activities in the United States. However, the level of methane releases can vary among specific gas basins. To add a further level of complexity, estimates for the same gas basin can vary depending on the methods and tools that were used to develop the estimate.

The Council recommends working with the Northwest Gas Association and other interested regional bodies to design a study and define a course of action with the goal to more fully quantify the upstream methane emissions related to the natural gas consumed within our region. We also recommend a follow-up study on how best to limit the intended and unintended methane releases related to natural gas consumed in the region.

Valuation of Resilience and Flexibility

Energy efficiency provides values to the power system not readily captured in today's modeling. Two important attributes are resiliency and flexibility. In these terms, resiliency is focused on home and building resilience. For example, some energy efficiency measures provide the ability to ride-through extended power outages or

101 gml.noaa.gov/ccgg/trends_ch4
102 research.noaa.gov/article/ArtMID/587/ArticleID/2742/Despite-pandemic-shutdowns-carbon-dioxide-and-methane-surged-in-2020

extreme weather events. Recent events, like the historic wildfires across the West and the Texas freeze, have demonstrated the importance for home and building resilience during extended outages.

Energy efficiency can also support flexibility. While energy efficiency itself is not a flexible resource, there are many measures that support load management for grid flexibility, whether through integrated control or reducing the impacts on end-users from other load-management efforts.

For both resiliency and flexibility, the Council considered proxy values in the cost-effectiveness valuation to highlight those beneficial measures. The Council recognizes the need to improve this valuation for future efforts. The Council recommends that the Regional Technical Forum investigate methods for quantifying the value of flexibility and resiliency for energy efficiency measures. To ensure symmetrical treatment of energy efficiency with other demand-side and supply-side resources, the Regional Technical Forum should work with other regional experts in developing these values.

Efficacy of Voltage Regulation

The Council recommends that Bonneville, the national labs, NEEA, and regional utilities study the impacts of voltage regulation under current conditions and explore how these results might change with future expected loads.

Utilities may regulate the voltage along the distribution system as a way of changing total energy demand. Reducing the line voltage will reduce the resistive losses in the system, resulting in energy or peak demand savings. The efficacy of voltage regulation is determined by the amount of resistive load on the system. New technological advances and efficiency gains–for example compressor-based equipment replacing electric resistance technologies–have the potential to change the amount of savings from voltage regulation.

Current data for voltage regulation effectiveness are based on older studies that do not represent today’s technology mix, nor do they reflect future load sources such as electric vehicles. As the Council and regional utilities base estimates of energy efficiency (conservation voltage regulation or CVR) and demand response (demand voltage regulation or DVR) potential on these studies, updated research will provide more accurate assessments of potential.[103] The analysis for this plan demonstrates the importance of this regulation, particularly DVR as a non-

103 Demand voltage regulation is a product that allows utilities to reduce voltage during peak periods of need and increase it for periods of load building as a way of balancing the system. Alternatively, a consistent reduction in voltage throughout the year can serve as a conservation measure, also known as conservation voltage regulation.

intrusive and regularly available demand response product, for addressing future power system needs.

Valuation of Non-Energy Based Emissions, and Potential Regional Emissions, Sinks, or Offsets

This plan attempts to explore paths toward meeting various economy-wide decarbonization goals. While not in the direct purview of the Council, understanding non-energy sector emissions and viable paths for reducing emissions is important for understanding the interaction between the power sector and these other sources. The Council estimated rough targets in the pathways to decarbonization scenario to explore the tradeoffs between the power sector and other emissions sources in meeting economy-wide emissions goals, but more data would improve future modeling. The Council recommends that the region–including national labs, universities, and state agencies–analyze emissions sources and sinks that may have implications for future power system planning. This data and analysis should be made available to regional stakeholders to support future analysis.

Improved Modeling

Adequacy Metrics for Power Systems With High Renewable Penetration

The Council, and others in the region, have historically used the annual loss of load probability as a measure of power supply adequacy. The changing power system with more prominent seasonal issues requires that the region rethink its assessment of adequacy. Specifically, the Council believes that a set of more detailed adequacy metrics is warranted.

Therefore, the Council recommends that Bonneville and the region's utilities investigate adequacy standards that capture the frequency, duration, and magnitude of potential shortfall events to better understand issues that occur in a system with high renewable generation penetration.

The Council should also investigate underlying system conditions during shortfall events and how adding resources or changing reserves impacts these events. The Council commits to working with Bonneville and the regional utilities on this important issue, with a goal of incorporating improved metrics into future power planning.

Broaden Regional Extreme Event Analysis

In addition to working on how adequacy is assessed, it is important for the region to understand the impact of extreme events on the power system. Major heat waves and cold spells in the Northwest and across the country have emphasized the need for investigation and utility cooperation in estimating the impact and frequency of such events.

The Council recommends that Bonneville and regional utilities, working with the

Council, coordinate in developing methods to estimate their frequency, magnitude, and duration. Further, the Council recommends adapting these methods to allow investigating their impact in the full range of power system models, including those used by the Council in its power planning processes.

Revisit Analytical Approaches to Planning for the Electric System

The models and analytical approaches used by the Council and regional utilities for power planning reflect standard industry practice. These standard industry practices are based on a historic electric system that is different than our present-day electric grid. Furthermore, we expect a substantial transformation of the grid that will diverge even more from the electric system these models and approaches were designed to simulate.

While the timing and extent of this transformation is unclear, the Council recommends the region, including national labs, universities, and other experts, research how effective the current models are at forecasting or simulating system operation and at projecting the future drivers of electricity demand. This research should focus on production-cost models, load-forecasting models, and capacity-expansion models.

Production-cost models, the computer programs most often used to estimate electricity prices, use the marginal pricing theory from economics, which in the current electric system means electricity prices are largely forecast and formed based on what it costs to operate fossil-fuel-based generation.

However, fossil-fuel-fired generation is rapidly being retired and will likely make up a smaller portion of the future electric system. With fewer fossil-fuel power plants in the system there will be fewer power plants ready to respond to market prices and more generators that have minimal or even negative operating costs, such as wind and solar plants.

This shift in generation results in prices being more volatile, likely leading to inefficiencies in the market and possibly a breakdown in the economic theory on how electricity market prices are formed. This impacts the accuracy and efficacy of widely used production-cost models. Since forecasting future electricity prices is fundamental to the Council's analysis, we recommend the next generation of production-cost models directly address this challenge.

In load-forecasting models, we have made progress toward incorporating climate change into our analysis but would also encourage a broader regional conversation on methods that adapt our forecasts to a changing climate. We also see that future demand for electricity depends on the interaction of the electric system with purposes that have historically been served by other forms of energy, such as electric vehicles replacing those previously powered by gasoline.

The interaction between the different forms of energy used in our region or in the broader Western electric grid could have wide-ranging impacts on our future power plans. In this plan, we have shown the range of potential future electric loads is extremely large, depending on the extent of electrification of transportation and buildings that occurs. We recommend the next generation of load-forecasting models focus on improving estimates of these interactive effects.

Capacity-expansion models generally assume a static demand for electricity is met by adding differing types of generating technologies, while minimizing the capital cost and fixed and variable costs of operating the resulting system. The next generation of capacity-expansion models will likely need to assess trade-offs between different technologies on the demand-side, particularly hydrogen produced by electrolysis, an energy-intensive process.

Also, in using models to test capacity expansion, it's important to capture the impacts on the existing system from dynamically adjusting reserves and storage deployment for different generating technologies. Finally, capacity-expansion models are computationally intensive, therefore we recommend that future models focus on those questions that result in a meaningful difference, recognizing that these may be different questions than in the past.

The Council recommends that analysis of the current generation of models should both address these concerns and explore further implications of how transformation of the electric system will affect our ability to appropriately capture future risks and requirements for power planning.

Section 11: Methodology for Determining Quantifiable Environmental Costs and Benefits and Due Consideration for Environmental Quality, Fish and Wildlife, and Compatibility with the Existing Regional Power System

The production, generation, and distribution of electricity affects the environment, and environmental effects will vary based on several factors, including the resource type and technology, fuel use and extraction processes, the facility size and footprint, and location. Pursuant to the Northwest Power Act, in its power planning, the Council must consider environmental effects related to the power system and integrate these considerations into its analysis through various statutory vehicles. For example, perhaps reflecting the time when the Act was drafted, when natural resource policymaking shifted to recognize the importance of internalizing environmental externalities, Section 4(e)(3)(C) of the Act requires the Council to include as an element of the power plan a “methodology for determining [the] quantifiable environmental cost and benefits” of new generating and conservation resources.

Further, Section 4(e)(1) of the Northwest Power Act requires that the Council’s regional power plan give “priority to resources which the Council determines to be cost-effective.” The definition of cost-effective, found in Section 3(4) of the Act, requires that the Council estimate and compare the incremental system costs of different generating and conservation resources, with system cost defined as:

> “an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and *such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource.”*

Consequently, the methodology for determining environmental costs and benefits not only represents one of the vehicles available to the Council to analyze and integrate environmental effects into its planning, it is also a significant component of the Council’s work to estimate and compare the system costs of a particular resource and ultimately determine those resources that are most cost-effective for the region.

In addition, Section 4(e)(2) of the Act requires that the Council set forth a general scheme for implementing conservation measures and developing resources with due consideration for, among other things, environmental quality, and the protection, mitigation and enhancement of fish and wildlife. Therefore, this statutory vehicle introduces a broader set of environmental considerations for the Council to deliberate on as it analyzes new generating and conservation resources, and, importantly, as it assembles those new resources into a regional resource strategy.

The first part of this section describes the Council’s methodology for determining environmental costs and benefits for the 2021 Power Plan. Implementation of this methodology is then reflected in the resource strategy discussed in Section 6, with the supporting materials providing additional analysis regarding the resource cost assumptions and analysis (See the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials).

The second half of this section describes how the Council, in developing its resource scheme, gave due consideration for environmental quality, compatibility with the existing regional power system, protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and other criteria as set forth in this plan. This last part of the section, describing how the Council gave due consideration to each of these listed factors, captures how the Council grappled with and used these considerations to shape its final resource strategy and planning decisions.

Methodology for Determining Quantifiable Environmental Costs and Benefits

Section 4(e)(3)(C) requires the Council develop and include as an element of the power plan "a methodology for determining quantifiable environmental costs and benefits" of new generating and conservation resources.

The Act does not prescribe a particular procedure or method that the Council must undertake in developing its methodology. However, the sum of the provisions of the Act addressing the methodology, Section 4(e)(3)(C) and Section 3(4)(B), are specific in that the methodology is to consider costs and benefits to the *environment*, not to any other type or category of costs and benefits, and that those environmental costs and benefits must be *quantifiable* and *directly attributable* to the new resource. These terms, "environmental," "directly attributable," and "quantifiable," are not defined in the Act; therefore, the Council has used a common-sense understanding of the terms, guided by the context in the Act, discussions included in the legislative history, and at times, the Council has exercised its judgment on a reasoned basis in making determinations as to what these terms mean and how they apply for purposes of the methodology.

For the 2021 Power Plan, and consistent with previous plans, the Council has identified four primary components to serve as the base of the methodology: 1) compliance with existing regulations; 2) environmental effects beyond regulatory controls, including both residual and unregulated; 3) compliance with proposed environmental regulations; and, 4) environmental benefits.

Each component is discussed in detail below. However, before discussing each component, it should be understood that Section 3(4)(B) of the Act requires a back and forth between the Council and the Bonneville Power Administration's administrator to develop and then apply the methodology that is not workable in practice for development of the power plan. Under the precise language of the Act, as part of the plan, the Council must develop a methodology for determining quantifiable environmental costs and benefits, then on the basis of that methodology, Bonneville's administrator is to determine such quantifiable environmental costs and benefits directly attributable to each resource, and then the Council is to incorporate the administrator's determinations into the estimated system cost of each new measure or resource to determine the cost-effective resource strategy for the power plan.

Following this specific direction does not work, as the Council cannot issue a power plan that includes the cost-effective resource strategy without first estimating and comparing the resource system costs, which requires considering quantifiable environmental costs and benefits. To make these provisions work together, the Council provides Bonneville, and others, including various advisory committees, the opportunity to examine and comment on the Council's methodology and the environmental costs and benefits attributed to each resource both prior to and following issuance of the draft plan. Any concerns identified in comments on the draft plan will be considered and addressed in the final plan.

Components of the Methodology

Cost of Compliance with Existing Regulations

The Council's planning assumes that all new (and existing) generating and conservation resources will comply with existing federal, state, tribal, and local environmental regulations. This includes, for example, compliance with environmental regulations governing air and water emissions, siting and licensing, waste disposal, fuel use (extraction and production), and fish and wildlife protection and mitigation requirements.

Existing regulations reflect policy decisions already agreed upon regarding the environmental costs and the appropriate level of protections to redress that harm, the costs are directly attributable to the resource, and largely quantifiable as a component of capital installment costs and fixed and operating costs.

Therefore, the estimated cost of compliance with existing environmental regulations is the primary method the Council has used to quantify environmental costs of generating and conservation resources in past plans, and it is again the primary method for the 2021 Power Plan.

While the cost of compliance may seem most obvious for generating resources, the costs of compliance also factor into the total system cost of new conservation measures, to the extent there are applicable environmental compliance costs quantifiable and directly attributable to the measure.

The generating resource reference plant section of the new generating resource supporting materials describes the environmental effects of generating resources, with existing systems and policies supporting materials providing additional information on the environmental effects of generating resources and outlining the existing environmental regulations to address those effects.

In addition, the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials, describe and assess resource system costs, including costs of compliance. The supporting materials for the methodology also expound on how the Council applies this method using an existing regulation as an example.

Cost of Compliance with Proposed Environmental Regulations

The Council has typically dealt with the cost of compliance with proposed environmental regulations on a case-by-case basis depending on the proposal, the effects the proposal addresses, and the quantitative data available. The Council is again deciding to address costs of compliance with proposed regulations on a case-by-case basis for the 2021 Power Plan. However, at the time of drafting this plan, there were no environmental regulations proposed that set stricter standards than those previously established for new resources. Consequently, there were no costs of compliance with proposed regulations added to any new resource system costs.

Environmental Effects Beyond Regulatory Controls

Existing environmental regulations control or mitigate for some amount of the targeted environmental effects from generating or conservation resources, but existing regulations do not control or mitigate for all environmental effects of resources–including residual. Residual effects remain after compliance with current regulations. For example, not all discharges from an electric generating facility, whether to the air or water, are controlled or prevented by the limitations and standards established pursuant to the Clean Water Act or the Clean Air Act, nor are all bird kills from wind turbines prevented by current regulations.

In addition, there are unregulated effects, which are environmental effects not yet regulated or not currently under regulation. The social cost of carbon emissions is an example of an associated environmental effect of a resource that is currently beyond regulation.

The Council acknowledges there are environmental effects beyond regulatory control that should be considered in the Council's planning. However, quantifying costs for these effects in a resource's system cost is difficult, if not impossible, due to the persistent lack of adequate data and methods to determine reasonable quantitative costs.

Moreover, while sufficient data is available for a few effects (e.g., the social cost of carbon) data largely remains deficient for most other residual or unregulated environmental effects. Adding the determined costs of some effects to some resource costs, but not the costs of all known effects to all resources due to an inability to reasonably quantify them could lead to an inappropriately skewed resource cost comparison.

Further, when estimating and comparing resource system costs, it is most useful for the Council to consider costs reasonably anticipated or appropriate to be borne by the power system. Considering social or damage costs in the direct costs of a few resources could lead to potentially applying costs to some resources that are extraneous to the power system, resulting in inconsistent resource cost comparisons.

Therefore, consistent with previous power plans, for the 2021 Power Plan, the Council is continuing to acknowledge and examine residual and unregulated effects qualitatively in the resource analysis and in developing the resource strategy because it remains infeasible for the Council to develop quantitative cost estimates for these effects, especially in a systematic or consistent way across resources, and then add them to the new resource system costs.

The methodology supporting materials provides additional detail regarding the data insufficiency and the hinderance it presents to the Council in estimating the costs of these environmental effects beyond regulation. The Council's qualitative assessment of these effects is described in the generating resource reference plant section of the new generating resource supporting materials, with the environmental effects of generating resources found in the existing systems and policies supporting materials providing additional information.

The Council integrates environmental effects into its power planning, and considers unregulated environmental damages, through the lens of Section 4(e)(2)–the provision requiring that the Council give due consideration to, among other factors, environmental quality and the protection and mitigation of fish and wildlife.

A prime example of this is the continued implementation of protected areas. Protected areas were first adopted by the Council in 1988 as an element of the Council's fish and wildlife program. They are river reaches where the Council believes new hydroelectric facilities would have unacceptable risks of loss to fish and wildlife species of concern or their habitat.

Their designation, and continued implementation and enforcement, is an explicit expression of the Council's due consideration of the effects of new energy resources on environmental quality and fish and wildlife resources.

In the power plan, the Council has included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation, with upstream methane emissions factored into that cost calculation as well. While these environmental effects are not added as a direct cost of the resource via the methodology, these effects are considered and integrated into the Council's planning, and their impact is reflected in the Council's resource decisions detailed in the resource strategy (Section 6).

For additional details regarding how the social cost of carbon was incorporated into the Council's planning including in scenario analysis and as one component of the net present value of the total portfolio cost in the regional portfolio model, see the Global Assumptions[104] in the supporting materials

Quantifiable Environmental Benefits

In addition to quantifiable environmental costs, the Act also requires the methodology address quantifiable environmental benefits of new generating and conservation resources. When considering environmental benefits, a key issue for the Council is whether and how to factor into the system cost of a new resource the benefit of being able to reduce an existing activity that has an environmental cost.

The Council acknowledges that the environmental benefit of a resource should be recognized and considered within the resource analysis in some capacity. However, the question for the Council is whether these environmental benefits can be quantified and determined to be directly attributable to the new resource. The Council is deciding to not attempt to include quantified environmental benefits in new resource costs beyond a few historic examples and will instead emphasize in the resource strategy how certain resource choices help to mitigate harmful environmental effects.

Except for a few minor exceptions, the Council has not been able to quantify environmental benefits of new resources because information and data on environmental benefits is not available,

104 nwcouncil.org/2021powerplan_global-assumptions-power-plan

sufficient, or well understood. Quantifying financial aspects of reducing environmental harm is also often missing or quite speculative in the data that is available.

It is also difficult to determine that a reduction in environmental harm (or an environmental benefit) is directly attributable to the new resource and not simply incidental or indirect. And, as noted earlier regarding the effects beyond regulatory control, while it may be possible to capture quantified environmental benefits for a few resources, the Council is reluctant to engage in a piecemeal quantification of benefits, which could result in a skewed resource cost comparison.

To use a familiar example, installing an efficient washing machine saves energy and reduces water consumption, which is an environmental benefit. The reduction in water consumption is a direct benefit of installing the efficient clothes washer and the Council is able to quantify this direct environmental benefit by utilizing consumer water and wastewater bills as data to support the quantification.

The Council can do a similar analysis for other water-saving measures, such as dishwashers, showerheads, and aerators. However, to walk through another familiar example, installing a ductless heat pump in the main living area of a house may result in burning less wood. With less wood burned, particulate emissions are reduced, which is a benefit to the environment (air quality) as well as a benefit to human health.

However, in this example, it is more challenging for the Council to say whether the environmental benefit (reduced particulate emissions) is directly attributable to the installation of the ductless heat pump, or a result of a behavior choice and incidental to the installation of the measure. Also, this environmental benefit is more difficult to reasonably quantify due to a lack of appropriate data and tools for quantification. Therefore, the Council has not added this benefit to the cost of the measure.

Since the Seventh Power Plan, more information on quantifying environmental benefits has been developed, but not enough to enable the Council to quantify environmental benefits to a broader degree. Specifically, the U.S. Environmental Protection Agency issued a report in July 2019, *Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report,* addressing the public health benefits associated with conservation and renewable resources, and Washington investor-owned utilities (IOU) issued studies analyzing how to monetize the benefits of reduced wood smoke from the installation of ductless heat pumps. The Washington IOU studies did provide new location-specific information for quantifying the environmental benefits of reduced wood smoke. However, they do not resolve the

Council's concerns since it's difficult to say to what extent reductions in particulate emissions are directly attributable to the installation of the efficiency measure. And, this additional data does not address lingering concerns regarding piecemeal quantification leading to a skewed resource cost comparison.

To be clear, the Council recognizes that particulate emissions from wood burning are a well-documented health concern, and the installation of a new electrical measure in the right circumstances may lead to reduced emissions. The Council will continue to exercise its discretion on the basis of the data currently available and not apply these benefits to the cost of new conservation resources. Nonetheless, state and local government, regulatory commissions, and utilities are more than justified in continuing to pursue these measures based on the health and societal benefits.

The EPA's report recognized energy efficiency and renewable resources reduce emissions. The report quantified near-term benefits of reduced emissions using avoided emissions rates based on 2017 electricity generation, which resulted in dollars per kilowatt values for conservation and renewable resources.

EPA advised, however, that the values should not be used to estimate benefits beyond 2022 given the emission rates underpinning the values.[105] Thus, capturing these benefits in new resource system costs for the 2021 Power Plan, would require significant analysis by staff to extend the values through the 20-year planning period.

More importantly, however, is the transformation occurring in the region and broader Western electric grid as significant amounts of renewable resources are added. This is spurred by lower resource costs, coal retirements, and clean energy policies. Emissions will be changing over the next five to 10 years and beyond; with increased reliance on zero-emitting resources, the avoided emissions rate for the region will also be changing.

This will lead to an even lower dollars-per-kilowatt-hour benefit in future years. The potential for the benefit value to become less significant over the course of the planning period compounds the Council's concerns regarding: 1) applying these benefits piecemeal; and 2) the risk of inappropriately skewing the resource cost comparison.

Moreover, there are other vehicles under the Act enabling the Council to consider the environmental effects of resources; one is its due consideration of environmental quality. In developing the power plan, the Council considered greenhouse gas emissions, as well as climate change, and integrated each of these into its analysis. Climate change

105 EPA issued an update to the 2019 report in May 2021. However, data for the 2021 Power Plan was frozen in April 2020; moreover, the May 2021 update recommends its values not be used beyond 2024.

mpacts on temperature and precipitation, which affect loads and river flows, were integrated throughout our quantitative analysis and modeling, and the Council included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation in the regional portfolio model, with upstream methane emissions factored into that cost calculation as well.

While the environmental effects of carbon were not added as a direct cost or benefit of a new resource via the methodology, its effects were considered and integrated into the Council's planning, and the impact of that consideration is reflected in the Council's resource decisions, addressed in more detail below. Additional Information on how the social cost of carbon was incorporated into the power planning analysis is in the Global Assumptions[106] in the supporting materials.

Therefore, for these reasons and consistent with the Council's previous application in past power plans, the Council did not attempt to include quantified environmental benefits in new resource costs beyond the few historic examples, and instead recognizes and emphasizes in the resource analysis the value of certain resource choices to help mitigate other harmful environmental effects.

See the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials for additional information on benefits included in resource system costs. And the generating resource reference plant section of the new generating resource supporting materials describes the environmental effects of generating resources, with existing systems and policies supporting materials providing additional information regarding the environmental effects of generating resources.

Due Consideration for Environmental Quality, Fish and Wildlife Protection, Mitigation and Enhancement, and Compatibility with the Existing Regional Power System

The Power Act calls on the Council to develop the conservation and generation resource strategy for the plan "with due consideration by the Council for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat,

106 nwcouncil.org/2021powerplan_global-assumptions-power-plan

including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan."

The following documents how the Council provided "due consideration" for these matters in developing this Power Plan, with particular focus on considerations of environmental quality and fish and wildlife. There are certain matters the Council considers with every power plan that are relevant here, and other matters particular to this plan. Both are highlighted as follows:

Fish and Wildlife Program; Hydropower System Operations for Fish and Wildlife

The Act requires the Council to call for recommendations and amend the fish and wildlife program prior to the power plan. The Act then makes the fish and wildlife program a mandatory element of the power plan. See *Section 12: Fish and Wildlife Program.*

One of the reasons for this is so that the Council, in developing the power plan, can assess how dam operations to benefit fish affects hydropower generation, both in its amount and timing, and then design a regional resource strategy that accounts for any reduction in generation available.. The Council designs the strategy in part to facilitate reliable implementation of the system operations for fish, while continuing to assure the region an adequate, efficient, economical, and reliable power supply.

The Council's analytical models and scenario analyses for the power plan incorporated all the latest system operations recognized in the Council's fish and wildlife program. This includes reservoir operations, spill, and other passage operations, including the flexible spill operation for juvenile fish incorporated into the program from decisions external to the program, such as the most recent Columbia system biological opinions. These operations are all incorporated into the Council's modeling and analytical work on the scenarios, as well as the baseline conditions. The Council's resource strategy is developed in part to assure an adequate and reliable power supply that will also allow for reliable implementation of fish operations.[107]

107 In October 2021, after the Council published the draft power plan for public review and comment, the federal agencies operating the Columbia River System agreed to a slightly different set of spill and run-of-river reservoir operations for 2022, for one year only.
See: pweb.crohms.org/tmt/JointMotion_TermSheet_CourtOrder_OCT2021.pdf. Although a formal analysis is not available, Bonneville Power Administration staff publicly reported its estimate that the operations agreement for 2022 would reduce the federal system's average hydro output approximately 45 aMW compared to the operations that were to occur in 2022, as specified in the 2020 Columbia system biological opinion. See: newsdata.com/nw_fishletter/bpa-estimates-power-impact-of-additional-spill-in-agreement/article_5b341294-56c6-11ec-9028-e702aac7ae67.html. The Council decided for the final power plan not to revise the operations in

Environmental Effects From the Generation of Electricity and Conservation

The Council identifies the various environmental effects from the generation of electricity in all phases of the life cycle of a new generation resource. They include, for example, the effects on land, water, habitat, and fish and wildlife during construction; environmental effects of key parts in manufacturing; fuel development and transportation; operational effects, such as air and water emissions or harm to wildlife or fish; waste disposal; and end-of-life decommissioning and similar matters. The Council also identifies environmental effects to the extent possible for conservation measures and other non-generation alternatives.

The Council described these effects in a comprehensive way for the Seventh Power Plan, especially in Appendix I. The Council reviewed and updated this information as necessary for the 2021 Power Plan. See the supplemental material for generating resources, especially the discussion of environmental effects in the generating resource reference plant section and the environmental effects of generating resources.

To the extent these environmental effects can be quantified in dollar terms, the Council includes these resource costs for the new resource cost comparison, as part of in the environmental cost and benefit methodology described above. Environmental effects and damage that cannot be quantified in the same way are still recognized and considered in developing the resource strategy.

Unquantifiable environmental impacts and damage from utility-scale generating developments have always been an additional consideration for implementing conservation measures and for other power system efforts that avoid construction and operation of major facilities, including demand response measures, and in certain cases, more efficient use of existing generation facilities.

Protected Areas

Beginning in 1988, the Council adopted protected areas as an element of the Council's fish and wildlife program and power plans. In these provisions, the Council calls on the Federal Energy Regulatory Commission (FERC) to not license a new hydroelectric project in river reaches with valuable fish or wildlife resources that the Council identified and mapped in a protected areas database by the Council. The protected areas provisions also call on Bonneville to not acquire the output of, or provide transmission support for, such a project, assuming it were to receive a license. To date, FERC has not licensed a new hydroelectric

the baseline conditions and re-run the model analyses for all the scenarios. The size and duration of the change in generation is not of a magnitude to affect the resource strategy.

project in a protected area identified by the Council.

In the power plan context, protected areas represent a judgment by the Council that due to potential effects on habitat, flows, and passage, the adverse effects on, and environmental costs to, important fish and wildlife resources are too great to justify including new hydroelectric projects in these areas, except under certain limited conditions.

The existing power system is already bearing substantial costs to protect and mitigate for its impacts on fish and wildlife resources. The power plan context is also important in that the protected areas designation extends throughout the entire Pacific Northwest (essentially the same as the Bonneville service territory), not just within the Columbia River Basin. This is part of the resource strategy for the region's power system, as well as a comprehensive plan for the region's waterways and new hydroelectric development.

As the Council evaluates the potential and cost-effectiveness for new hydroelectric development in each power plan, it includes the effects of protected areas in limiting the extent of that potential. The Council also gives due consideration to fish and wildlife and the quality of their environment by including a set of development conditions to protect fish and wildlife as new hydroelectric projects are licensed and developed in areas outside of the protected areas.

Greenhouse Gas Emissions and Climate Change

The environmental quality topic of primary interest in this plan, as in the last two, was the issue of greenhouse gas emissions and climate change. The Council has considered this topic in several ways in formulating the plan's resource strategy, including:

- The Council closely tracked state and other legal and policy developments in the region and across the West that require retiring, or reduced emissions from, coal-fired generation; the scheduled retirements of coal plants; the addition of renewable resources through renewable portfolio standards; and clean energy standards and greenhouse gas reduction goals from the electrical power system. The Council designed a resource strategy for a power system consistent with the effects of these laws, policies, and commitments. Part of the Council's aim in the power plan is to help the region understand a least-cost way to make this transition and retain an adequate and reliable system.
- The Council included greenhouse gas emissions considerations in new resource costs whenever possible to quantify and also tracked emissions effects to the extent possible. This includes upstream

methane emissions from natural gas production.

- The Council also integrated climate change effects into the baseline conditions and analyses, including climate change impacts on river flows for hydropower generation and on loads from changing temperatures.
- The Council included a cost of carbon in the baseline analyses as a damage cost on emissions from existing and new fossil-fueled generation. The Council also ran several scenarios or variants to test different aspects of this issue – removing the social cost of carbon; accelerating the retirement of coal plants; restricting the build of renewable resources; restricting the build of new natural gas plants; assessing the emissions reduction effects of a demand response sensitivity case; assessing in several different ways the power system effects of an economy-wide effort to decarbonize; and more. One result tracked for all model analyses was the resulting change in system emissions of greenhouse gases.

More details on how the Council considered this topic can be found in several different sections of the plan and supporting materials, including the resource development plan, the global assumptions in the power plan, the generating resource reference plants, and environmental effects of generating resources.

Protecting Environmental and Cultural Resources From the Impacts of New Generating Resource Development

The siting, construction, and operation of any generating facility has impacts on land uses; water resources; wildlife and wildlife habitat conditions; cultural resources; traditional uses; and local landowners and communities.

Environmental effects of any proposed development are analyzed as part of state energy siting processes (if on private land) or by state or federal land management agencies (if on public land) through an array of different criteria and procedures. State fish and wildlife agencies and tribes have commented throughout the last two the power planning processes, sharing concerns that energy siting decisions for renewable facilities are not or may not be as protective of wildlife, habitat, cultural resources, and traditional uses as optimally needed. As the scale of development increases, so do concerns about the impact of a host of individual decisions and about the cumulative impacts.

The Council's Fish and Wildlife Program has a set of standards and conditions for developing new hydroelectric projects outside of protected areas. The purpose is to "ensure that new hydroelectric development is carried out in a manner that protects the remaining fish and wildlife resources of the Columbia River Basin and the Pacific

Northwest and does not add to the region's and ratepayers' mitigation obligation."

The Council has been asked to consider including in the power plan a similar set of development conditions for renewable resources. While siting authorities have no obligations to the Council's power plan, unlike the Federal Energy Regulatory Commission and hydroelectric project licensing, the Council commits to working with stakeholders throughout the region to help guide the consideration of aggregated effects of new renewable resources.

The Council also recommends that siting authorities should work to ensure that new renewable resource development is carried out in a manner that protects wildlife and fish and cultural resources of the Pacific Northwest.

The emphasis should be to incorporate "least impact, less conflict" siting principles to push development away from high value lands; ensure deliberate, strategic outreach and engagement in siting processes with fish and wildlife agencies and tribes and communities directly affected by development; and ensure that tribes are consulted to understand and preserve cultural resources and traditional uses in the vicinity of developments.

Hydrosystem Flexibility and Possible Impacts to Fish

The substantial increases in renewable generation across the West shift power system generation and transform power markets. The increasing supply of solar generation during the day highlights the need for other resources when the sun goes down.

Since hydropower has a low variable cost and is flexible in its use (within certain established parameters noted earlier), the Council's analyses – and current actual practice – indicates that the hydropower system is well positioned to help the region absorb increasing renewable generation and ensure adequacy in the region.

However, it's unclear how these daily river flow fluctuations – which are already evident and will likely increase if power considerations drive river operations - will affect environmental conditions for fish, particularly for juvenile and adult salmon and steelhead migration and for mainstem spawning and rearing habitat.

The Council's 2014 Columbia River Basin Fish and Wildlife Program contains measures recommended by the state and tribal fish managers calling on system operators to minimize or reduce daily flow fluctuations, and yet the power system analyses indicate a system adequacy benefit from increasing generation and flow fluctuations.

As described in the research recommendations in *Section 10: Recommendations for Research and Development*, the Council intends to organize and support an investigation into the implications of these changing river flows. This effort will bring together the Council, Bonneville, system operators, the federal and state fish and wildlife agencies, the region's tribes, and others. The goal will be to explore the possible benefits and consequences of different hydropower system operations to try to identify a path forward that provides greater benefit to both power and fish.

Compatibility with Existing Power System: Retirement of Existing Coal Plants; Lower Snake River Dams

The Council's power plan, under the Northwest Power Act, is to analyze and recommend what new conservation and generation resources should be added to the region's power supply. The Council is to do so while taking into consideration not just matters of environmental quality and fish and wildlife impacts, but also the compatibility of new resources "with the existing regional power system."

The Council has done so in several ways, including analyzing how existing hydropower and gas plants have a valuable role in integrating additional significant amounts of renewable resources in a cost-effective manner while preserving an adequate system.

The Council's task is not to analyze or decide whether elements of the current system should remain or be retired for environmental or economic or other reasons. The Council does need to consider decisions made by others to retire or reduce the output of existing resources or constrain what types of new resources may be added.

This includes, for this power plan, the current set of decisions by utilities to retire coal-fired generating units for reasons of economics and state law, as well as the new state laws requiring the addition of renewable or clean resources, both part of a policy effort to reduce the output of greenhouse gas emissions from the existing system.

In this instance, the Council needs to analyze the effects of those plant retirements on the existing power system and decide what resources, and in what amounts, need to be added to assure the region retains an adequate, efficient, economical, and reliable power supply.

In this plan period, numerous comments have been submitted asking the Council to analyze or recommend the removal of the four federal dams on the lower Snake River. There are no planned retirement dates for any mainstem dams on the Snake and Columbia. So, the Act does not require that the Council analyze the effects of the retirement of those plants for this power plan in order to develop the power plan's new resource strategy and fit that strategy to the existing if changing power system. And it is not the Council's task under the Act, in the power planning process, to analyze or recommend the retirement of existing system resources.

However, there may be value to the region, following the completion of the power plan, in analyzing the power system effects if the output of the dams were no longer available sometime in the future, including what replacement resources would be needed to achieve similar levels of reliability. The Council will begin scoping and considering whether to undertake this analysis after the plan is adopted.

Section 12: Fish and Wildlife Program

The Council's *Columbia River Basin Fish and Wildlife Program* is one of the required elements of the power plan under the Northwest Power Act. The 2014 Fish and Wildlife Program, supplemented by a 2020 Addendum, is the Council's current version of the program. nwcouncil.org/reports/2014-columbia-river-basin-fish-and-wildlife-program

The Act requires the Council, prior to the review of the power plan, to call for recommendations to amend the fish and wildlife program and then follow the process described in the Act for deciding on program amendments. The Council did so, initiating a fish and wildlife program amendment process in 2018 that culminated in a final decision on the 2020 Addendum to the existing program toward the end of 2020. Section 11 includes a discussion of the role of the fish and wildlife program in the development of the 2021 Power Plan, as part of the required fish and wildlife and environmental considerations.

The Council's fish and wildlife program has evolved through time. Early programs focused largely on improving juvenile and adult fish survival at and through the mainstem Columbia and Snake river dams, including water management and fish passage provisions for anadromous fish and reservoir operations to benefit resident fish. Early program developments also included anadromous fish loss assessments and systemwide goals; wildlife loss assessments and the beginning of mitigation for those losses; and the designation of protected areas to protect the region's fish and wildlife resources from new hydroelectric development.

Over time, the Council built up other portions of the program, especially expanding the off-site mitigation activities of the program with habitat improvements and fish hatcheries in the tributaries off the mainstem and in the lower Columbia River and estuary.

The 2014 Program reflects work built over many years of program development and implementation, with a continued emphasis on mainstem water management, passage improvements and spill, and offsite habitat and hatchery mitigation improvements.

The 2014 Program also identified a set of emerging priorities and called on Bonneville, the other federal agencies, and the region to integrate these emerging priorities into program implementation. These included: Providing funding for long-term maintenance of program assets; integrating climate change considerations; expanding efforts to deal with predation and invasive species; increased focus on addressing the needs of sturgeon and lamprey; increased attention to toxic contaminants; investigating blocked area mitigation options through a number of activities; and continuing efforts to support ecosystem function through improved floodplain habitats.

When it came time under the Act to call for recommendations to amend the 2014 Program, the Council, in consultation with other program participants, concluded that a wholesale revision of the 2014 Program did not seem necessary. The Council asked the region to focus on two key program needs: 1) how to improve the way the Council and others assess and report on program performance and how to further develop and utilize the program's goals, objectives, and performance indicators to that end; and 2) a small set of near-term needs regarding program implementation. The Council worked, with public input, to focus the 2020 Addendum to the 2014 Program on those two topics.

Based on the recommendations received, the region's experience with implementation following the 2014 Program, and the development work with the region, the 2020 Addendum is structured in two parts. Part I focuses on program performance, reorganizing and supplementing the goals, objectives, and indicators provided in the 2014 Program to enable the Council and others to evaluate program performance in an effective manner. The Council granted requests to extend the scheduled conclusion of Part I for approximately six months to further engage the state and federal fish and wildlife agencies and the region's Indian tribes in a series of workshops on the program's goals, objectives, and performance indicators.

Part II of the 2020 Addendum covered a small set of program implementation needs consistent with the existing and emerging priorities identified in the 2014 Program. These included, among others, re-emphasizing the need to integrate climate change impacts into all areas of implementation; continuing the asset management effort; increasing the scope of mitigation in the blocked areas, especially the work to mitigate for the loss of anadromous fish and the losses to other fish and wildlife species in the areas of Grand Coulee and Chief Joseph dams; implementation of refinements in operations at Libby and Hungry Horse dams; restoring and sustaining the implementation of ocean research studies identified by the Council; sustaining ongoing efforts to reduce predation and increase or revise those efforts as necessary; research to assess benefits of estuarine use by salmon stocks from the interior Columbia River Basin; and more.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-134:
Overview of Power Council's Resource Adequacy Approach

Resource Adequacy

Electricity does more than keep the lights on in the Pacific Northwest. It literally powers our economy. The absence or presence of an adequate electricity supply can either curtail or facilitate economic growth. In the worst extreme, an inadequate electricity supply can affect public health and safety, as in a blackout. Fortunately, such events are rare and when they do happen are most often caused by a disruption in the delivery of electricity (transmission lines), not the supply. However, there have been times – during extreme cold spells or heat waves – when the supply has been tenuous.

Adequacy refers to having sufficient resources to serve loads. In determining adequacy, the Council uses sophisticated computer programs (such as GENESYS) that simulate the hourly operation of the power system over many different futures. Each future is simulated under a different set of unknown parameters, such as water supply, temperature, wind and solar generation and thermal resource performance.

Historically in the Pacific Northwest, the biggest risk for power system adequacy was having a bad water year coincide with high loads. That is no longer the case. Planning for the future grid is becoming more complex with the changing resource mix, increased load growth from electrification, periods of extreme weather, and additional uncertainties.

To better address these challenges, in FY 2023 the Council's Power Division staff adopted a new, more sophisticated way to test whether the region's power grid has adequate resources by using multiple metrics. The Council was among the first power planners in the U.S. to move to a multiple metric approach.

The Council's previous adequacy metric of Loss of Load Probability (LOLP) focused on identifying the probability of a year with one or more simulated shortfalls from modeling that tested a range of hydropower, load, and wind conditions. The LOLP metric was effective for a power system heavily reliant on hydropower, thermal plants, and energy efficiency, where generation uncertainty was minimal and revolved around the coincidence of high loads and low water.

The Council evaluates shortfalls as a signal for needing emergency measures, such as a utility buying amounts of power from wholesale markets that are above market-import caps to meet peak demand. A multi-metric adequacy framework provides insights into the frequency, duration, and magnitude of potential shortfall events. An adequate system means all metrics stay within their respective thresholds.

The previous LOLP approach didn't offer insights into how large the shortfall would be, how long it would last, or what month or season it would occur in.

With a multi-metric approach, it is now possible to fully understand the shape and size of adequacy issues. This is a major advancement in helping the Council and the region plan for needed solutions.

The process to develop the multi-metric adequacy standard featured working with utilities and energy providers, including Bonneville Power Administration, throughout the region. Staff consulted with regional organizations such as the Western Power Pool, Pacific Northwest Utilities Conference Committee, Pacific Northwest Generating Cooperative, and the Columbia River Inter-Tribal Fish Commission. Finally, staff interviewed representatives and technical staff from public utilities commissions in Idaho, Oregon, and Washington.

Multiple metrics

Following an extensive public engagement and research process, the Council adopted the following adequacy metrics in FY 2023:

- **Frequency – Loss of load events (LOLEV)** is used to prevent overly frequent use of emergency measures.

The next three metrics are designed to protect against extreme shortfall events 39 out of 40 years. It means adequacy events do not last too long or have large magnitudes.

- **Duration – Value at Risk** sets a limit to protect against prolonged use of emergency measures. This helps to capture the risk of a summer heatwave or a winter storm.
- **Magnitude – Peak Value at Risk** protects against large magnitude emergency measure use.
- **Magnitude – Energy Value at Risk** protect against large aggregate use of emergency measures during a year.

The Council continues to refine these metrics by developing provisional thresholds, and will further evaluate them in advance of the next power plan process.

See the Resource Adequacy Advisory Committee for all current work.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-135:
Overview of Power Council's Approach to Load Forecasting

Explaining how the Council forecasts load growth for the Pacific Northwest power system

At an April 29 meeting that will be hosted online, staff will present results from a new load forecast for the Northwest

MARCH 20, 2025 | PETER JENSEN

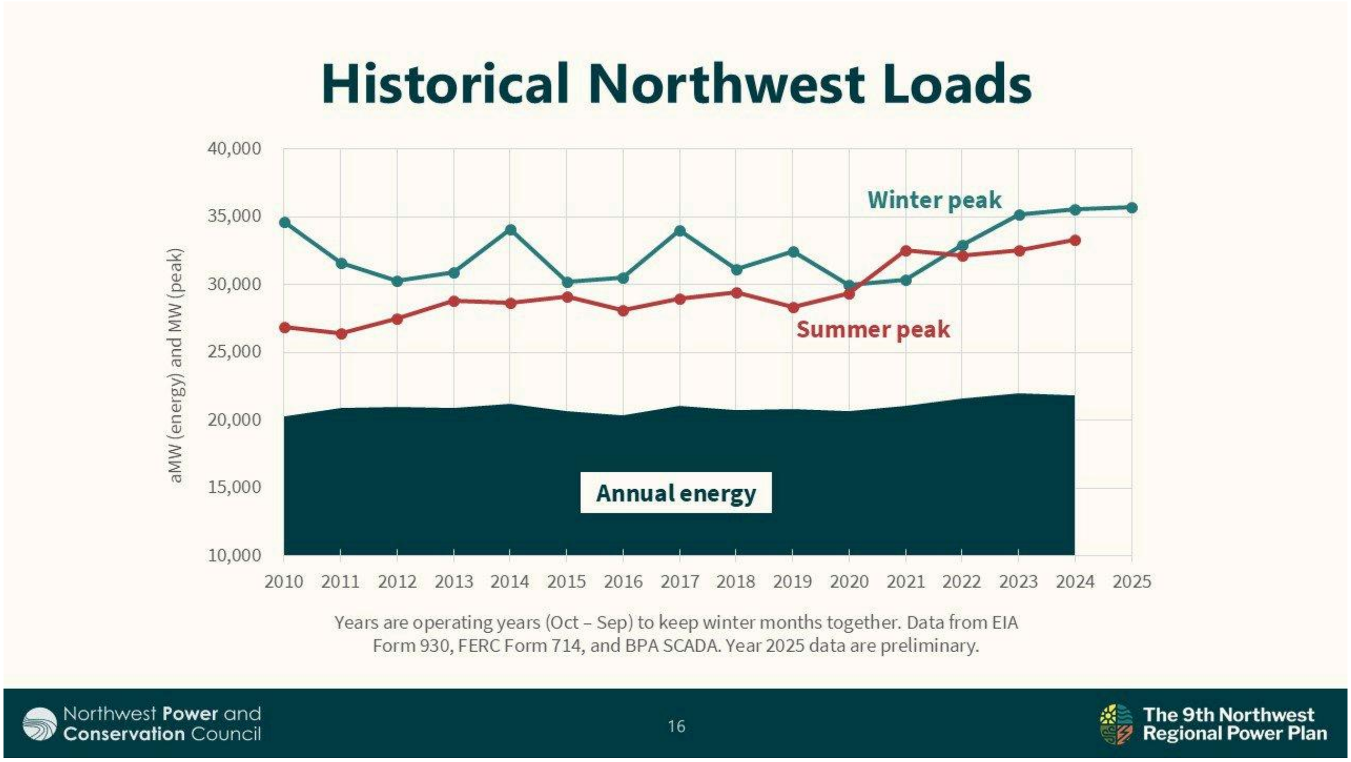
EVs are expected to be a significant source of load growth in the Northwest. Image credit: Department of Energy

When you need to see in the dark, which will illuminate the terrain better – a flashlight or an aerial flare? This spring, Council Power Division staff will be using the latter approach to produce a new 20-year load forecast for the future of the Pacific Northwest's power system.

At March's Council meeting, Senior Energy Forecasting Analyst Steve Simmons and Senior Power Analyst Tomás Morrissey explained their analytical approach and methodology to load forecasting (read presentation | watch video). "We're going to try to illuminate a pretty large area," Simmons said.

This was the first of a multi-part discussion on load forecasting this spring, which is a key component of the Ninth Northwest Power Plan. At a meeting on April 29 that will be hosted online, staff will present comprehensive results from the new load forecast for the Northwest.

The Council's approach to load forecasting



In Feb. 2025 during a cold snap, the Northwest power system peak load reached 35,700 MW, which sets a new post-Direct Service Industry record high for the region. The peak load during a January 2024 winter storm was 35,600 MW. However, the total energy needed in January 2024 was 2,000 aMW higher than what was needed in February 2025.

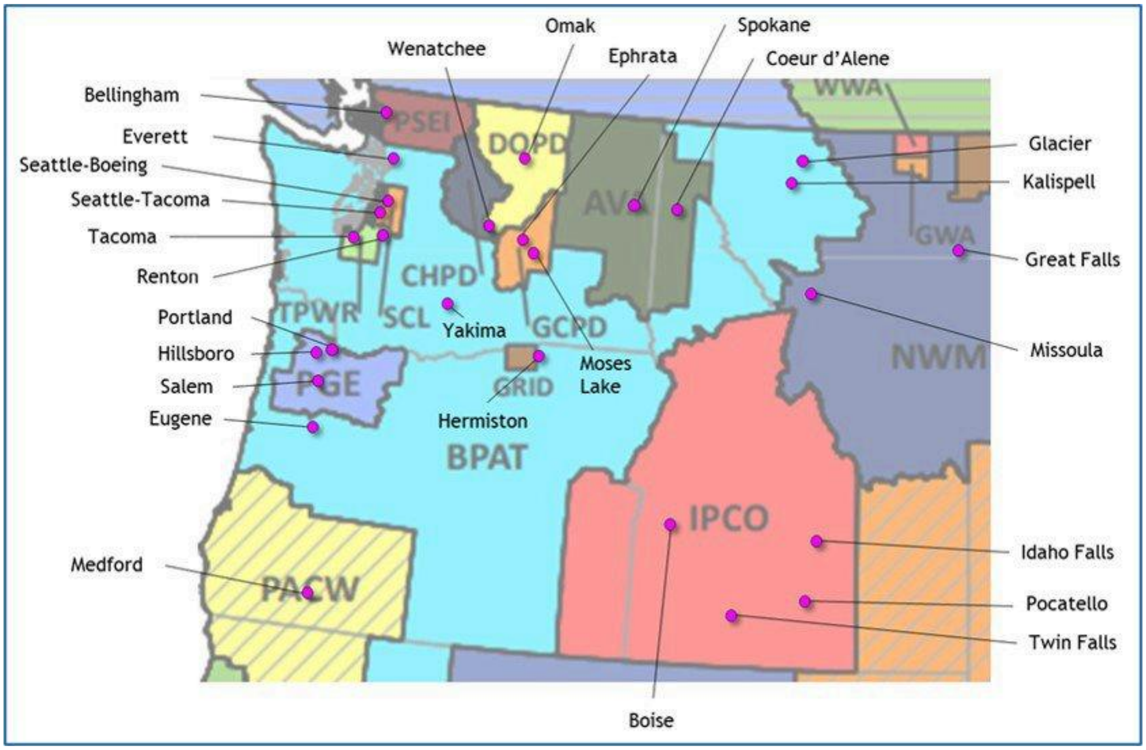
As the chart above shows, growth in electricity demand does not travel upward on a linear trajectory. It ebbs and flows over time. This is true for both annual energy and peak demand. This demonstrates the need for greater flexibility in forecasting, and to capture a range of possible futures rather than one future plotted precisely on a graph. This is why the Council uses forecast ranges instead of an exact "best guess" number. This has been the Council's approach ever since its first Power Plan in 1983. This method, innovative for the time, was developed at a moment when the Northwest's power system had veered badly off course due to errors in load forecasting in the 1960s and 1970s, resulting in disastrous over-building of the region's electricity generation resources.

While load forecasting computer modeling systems, analysis, and methodologies have all advanced tremendously since 1983, electricity demand growth still ebbs and flows over time in similar patterns. For the Ninth Plan, the Council's forecasts of the Northwest's power demand will consider several possible trajectories, which capture and reflect a range of future uncertainties for how much electricity demand materializes on the Northwest's power system, and by when. This range of uncertainty is core to successfully planning for the future.

Improvement in computer modeling, growing data complexity

At March's meeting, Simmons noted that the goal is to create an accurate and comprehensive forecast of demand for electricity in the region across 20 years. To do that, staff needs to analyze the region's current and historic energy use, which helps to gain an understanding of what might drive changes to future demand. That requires building a computer model. The demand forecast is an output from this model, which is highly input data driven and is getting more complex for the Ninth Plan.

In producing the 2021 Power Plan, staff continually bumped up against limitations to their old models' ability to do long-term load forecasting, among other essential tasks in power planning. In 2023 staff contracted with Itron, a company offering energy forecasting software tools, to upgrade the Council's long-term load forecasting.



The Council has upgraded its load forecasting capabilities for the Ninth Power Plan. Power system analysts will be able to produce annual, monthly, and hourly forecasts of load across 20+ years for the region as well as individual utilities' balancing authorities, shown on the map above. They'll also include data for 27 weather stations around the Northwest (noted with purple dots on the map).

Power system analysts now have the capability to produce annual, monthly, and hourly forecasts of load across 20+ years for the Northwest as well as for 13 individual utilities' balancing authorities. They'll also be able to include data from 27 weather stations in Oregon, Washington, Idaho, and Montana, which will allow staff to forecast changes related to weather conditions. Forecasts will represent residential, commercial, and industrial sectors, as well as for electric vehicles, data centers, electrification, and rooftop solar. Those added capabilities have made data inputs and management more complex and challenging, Simmons said. Staff is taking care to monitor quality and check for accuracy for all inputs going into the model to develop the load forecast.

Simmons reviewed data sources staff is working with for this load forecast:

Building stock – new and existing by type

- Units
- Square feet

End use technology, such as space heating or cooling in buildings

- Fuel type
- Unit saturation
- Energy efficiency
- Load shape

Economic conditions

- Population
- Employment income

Quantitative and qualitative data and analysis on industries and the tech sector, including data centers and chip fabrication facilities

Future weather

Electric Vehicles

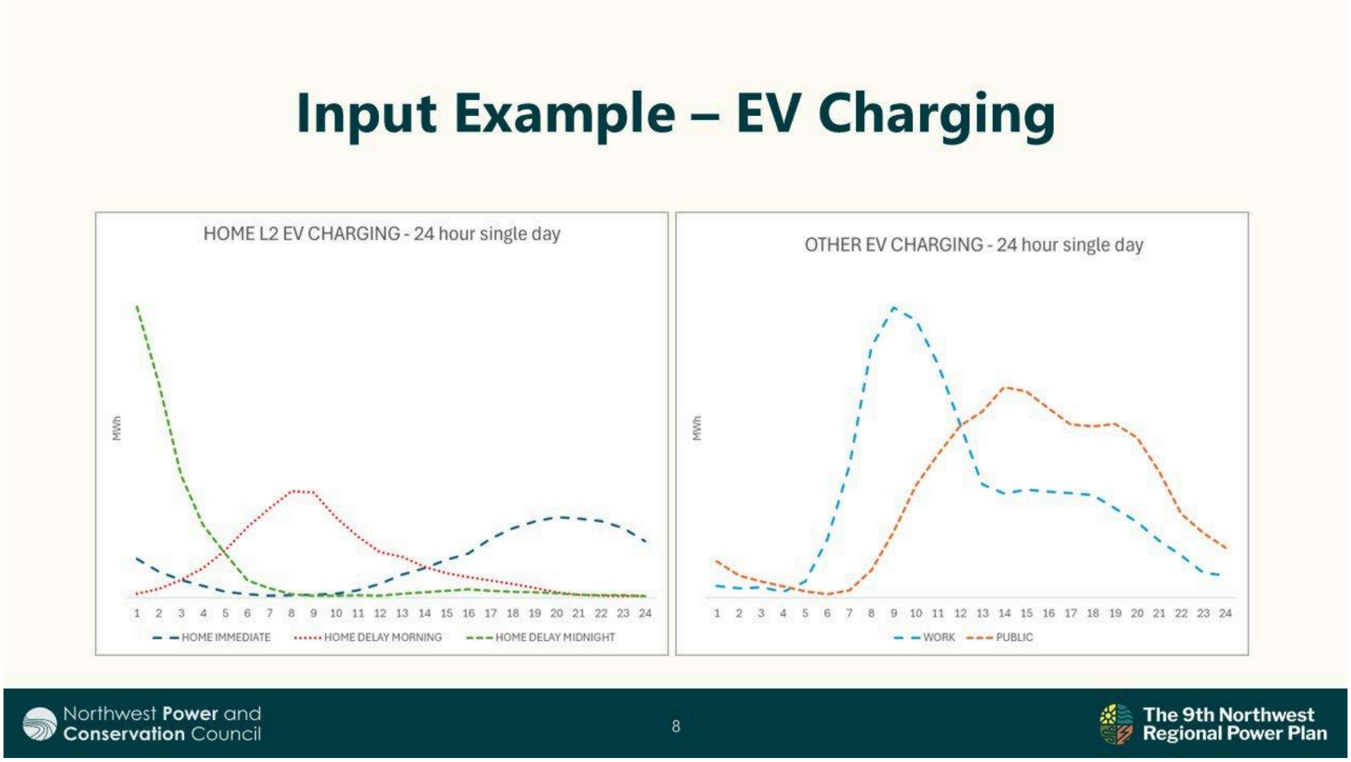
- Registration & Sales
- Usage
- Load shape

Rooftop Solar

- Installations and shape

Load shapes and future demand trajectories

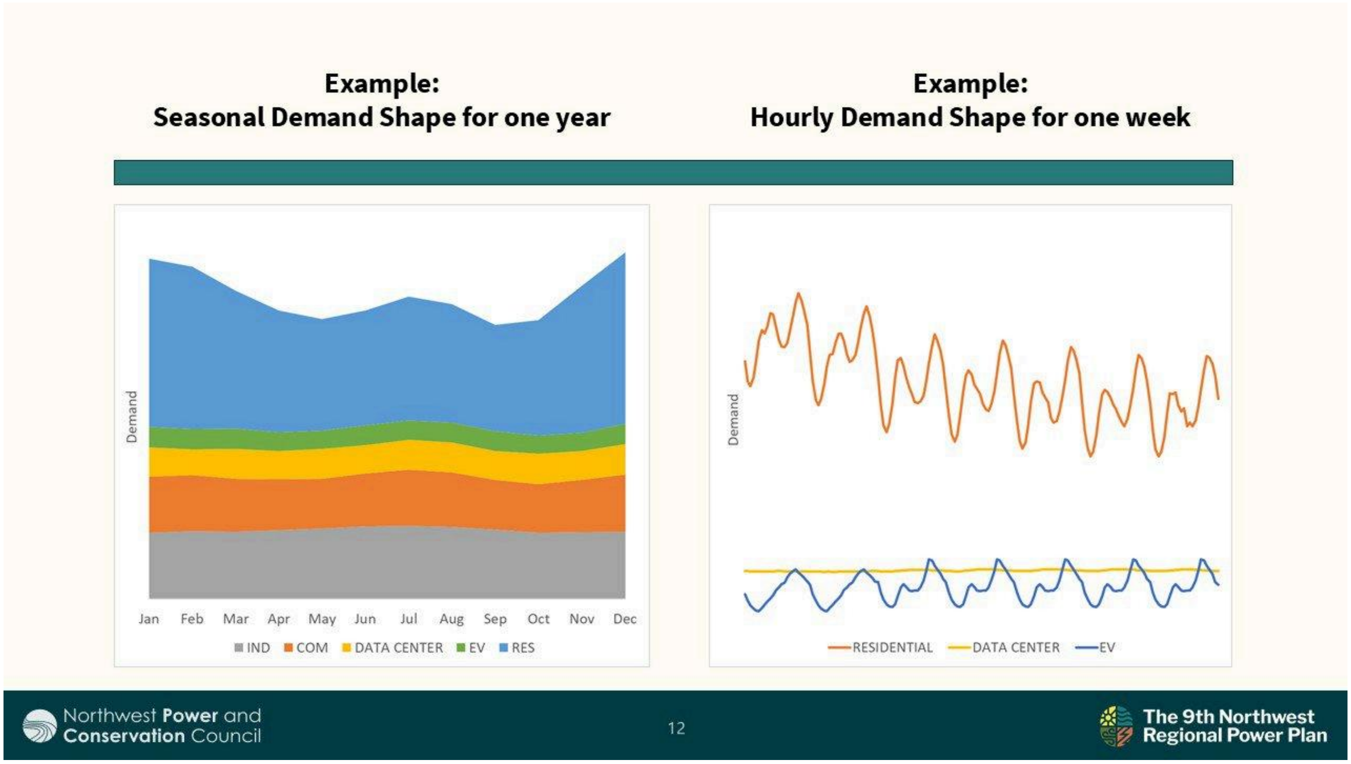
A vital part of the Ninth Power Plan will be to evaluate cost-effective energy efficiency and demand response potential and compare and contrast it with other resource options to meet future energy needs in the Northwest. Therefore, the initial load forecast will freeze efficiency at today's levels and assume no demand response. This will result in a forecast that might be higher than actual long-term loads, or have larger peaks. For example, unmanaged electric-vehicle charging that often occurs in after-work hours can coincide with other peak hour power needs. Utilities pursuing demand response could manage the charging in several different ways that have less impact on power system peaks – such as after midnight. The initial load forecast will assume unmanaged charging, leaving the demand response potential of managed charging as an option to the model.



Near the end of the power planning cycle, once the Council has made decisions on how much cost-effective efficiency, rooftop solar, and demand response should be included, staff will re-run the load forecast to get the final version to include in the Ninth Plan.

Staff will also be analyzing three demand characteristics – magnitude, timing, and shape – for six key futures: weather, economic growth or stagnation, electric vehicles, data centers, building electrification, and hydrogen production.

- Future weather affects summer loads' peaks and the timing will occur throughout the Ninth Plan's 20 year horizon.
- Electric vehicles affect residential loads' peaks and will have a large impact mid-way through the 20-year period. EVs will be a significant source of demand in some zones, such as Western Washington and Western Oregon, while not as much in others.
- Data centers will be single large loads that will come on early in the plan period. The profile will be flat. It will be significant in some zones but not others.
- Building electrification will affect winter loads' peaks, but will have a larger impact late in the 20-year period.
- Hydrogen production will be a single large load with a flat profile that will also be late in the 20-year period.



Understanding the differences between loads' magnitude, timing, and shape down to monthly, daily, and hourly levels will help the Council's power planners identify the right cost-effective suite of resources to add to the Northwest's power system so it continues to be adequate, efficient, economical, and reliable.