# BOARD OF DIRECTORS

## Work Session and Board Meeting

## May 15-16, 2019

## Eastsound OPALCO Office

**TRAVEL**

# Wednesday May 15th – Work Session

| | | | | | | |
|---|---|---|---|---|---|---|
| **Via Island Air** | **To:** | | | | | |
| **(378-2376)** | Leave | Lopez | 7:30 a.m. | Arrive | ES | 7:45 a.m. |
| | | | | | | |
| **Via Ferry:** | **To:** | | | | | |
| | Leave | Lopez | 6:55 a.m. | Arrive | ES | 7:35 a.m. |
| | | FH | 6:10 a.m. | | | 7:35 a.m. |
| | | Shaw | 7:15 a.m. | | | 7:35 a.m. |

# Thursday May 16th – Regular Board Meeting

| | | | | | | |
|---|---|---|---|---|---|---|
| **Via Island Air** | **Return:** | | | | | |
| **(378-2376)** | Leave | ES | 12:00 | Arrive | Lopez | 12:15p.m. |
| | | | | | | |
| **Via Ferry:** | **Return:** | | | | | |
| | Leave | ES | 3:10 p.m. | Arrive | Shaw | 3:25 p.m. |
| | | | . | | Lopez | 3:45 p.m. |
| | | | 4:30 p.m. | | FH | 5:10 p.m. |

**Sequence of Events**

Wednesday

- 8:30 a.m. – 12:00 p.m.: RIC Q1 Review
- 12:00 p.m. – 4:00 p.m.: PNCG Discussion with Roger Gray

Thursday

- 8:00 AM – 12:00 p.m.: Regular Board Meeting (Lopez departing at 11:30 a.m.)

# Orcas Power & Light Cooperative
# Board of Directors
# Regular Board Meeting
### Eastsound
## May 16, 2019 8:00 A.M.*

**Time is approximate; meetings are scheduled around the ferry schedule; if all Board members are present, the meeting may begin earlier or later than advertised.*

**WELCOME GUESTS/MEMBERS**

*Member attending the board meeting acknowledge that they may be recorded, and the recording posted to OPALCO's website.*

- Member Comment Period
  - *Members are expected to conduct themselves with civility and decorum, consistent with Member Service Policy 17. If you would like answers to specific questions, please fill out Q&A card for post-meeting follow-up.*
- Olga Darlington, Business Assurance Partner, Moss Adams LLP
- Roger Gray, CEO PNGC

**ACTION ITEMS**

- Consent Agenda
- Bylaw Revision – 10% Member Threshold
- Member Service Policy 14 – *Interconnection of Member Generators and Storage* – 2$^{nd}$ reading
- 2018 Audit Presentation – Olga Darlington, Business Assurance Partner, Moss Adams LLP (subsequent to review in Executive Session)

**DISCUSSION ITEMS**

- Two-day Power Resource Discussion – Roger Gray, CEO PNGC
    - PNGC Talking Points – Wednesday
    - Closing Discussion – Thursday
- Transmission Redundancy – Review of system map

**REPORTS**

- 2019 Q1 Financial Statements
- General Manager
- Rock Island Snapshot

**COMMUNICATION**

- PNUCC Information – Homework to Inform PNGC Talking Points
  - Press Release
  - 2019 Forecast
  - Capacity Whitepaper
- PNGC Power Pulse
- WRECA Update

**ADJOURNMENT**

MEMORANDUM

May 10, 2019

TO: Board of Directors

FROM: Foster Hildreth

RE: Consent Agenda

All matters listed with the Consent Agenda are considered routine and will be enacted by one motion of the Board with no separate discussion. If separate discussion is desired, that item may be removed from the Consent Agenda and placed as an Action Item by request of a Board member. The minutes will reflect the approved consent agenda.

The Consent Agenda includes:

- **Minutes** of the previous meeting – attached.
- **Approval of New Members** – attached {as required by Bylaws Article I Section 2 (d)}

## NEW MEMBERS – April 2019

**District 1** (San Juan, Pearl, Henry, Brown, Spieden)

1. Barrios, Valerie
2. Bower, John
3. Bower, Sheelin
4. Burford, Ivan
5. Callahan, Lindsey & Stewart, Marlin
6. Curley, Devin
7. Dresch, Joseph & Gates, Melissa A
8. Elben Electric Inc
9. Ferris, Hugh
10. Finley, Beverly
11. Flack, Kim
12. Gilfillan, Tyler
13. Gonzalez, Jaime
14. Halcomb, Erin
15. Hunt, Judith A
16. Johnson, Deneen
17. Mason, Lenny
18. McCallum, Robert
19. Norton, Isaac
20. O'Connell, Sean
21. Schafenacker, Jenene & Steven
22. Sept, Jeanne M
23. Tylenda, Tyler
24. Worthington, John

**District 2** (Orcas, Armitage, Blakely, Obstruction, Big Double, Little Double, Fawn)

25. Anderson, Laura
26. Balcomb, Mallory, and Tyson
27. Banks, Jayne & Todd
28. Baron, Glen & Voinot-Baron, Margrett
29. Cheatwood, John
30. Clark, John & Ridenour, Lynn
31. Dundas, Glenn & Terri
32. Enriquez, Mario
33. Gimbert, Karen
34. Hamilton, Linda
35. Lee, Steve & Alanna
36. Matia Contractors
37. NAGA LLC
38. Ricketts, Roberta A
39. Risko, Joshua & Stephanie
40. Shima, Peter & Bridgette
41. Stannarb, Janet
42. Sutton, Parker

43. Tucker, Roberta & Aaron
44. Zimliich, Amanda

**District 3** (Lopez, Center, Decatur, Center, Charles)
45. Anderson, Steven T
46. Bastien, Lonny & Sarah E
47. Colombo, Gian & Ivy, Justine
48. Coover, Merv & June
49. Marmion, Darrell & Leslie H
50. Viscon, Ben
51. Weeks, Pamela

**District 4** (Shaw, Crane, Canoe, Bell)
52. Black, Bryn & Michael
53. Sutton, Helen

- **Capital Credit** payments to estates of deceased members and/or organizations no longer in business as shown below:

| May | | |
|---|---|---|
| Customer # | | Amount |
| 70207 | | $ 1,290.40 |
| 66656 | | 331.57 |
| 29640 | | 1,388.71 |
| 26576 | | 1,054.55 |
| 6765 | | 1,130.35 |
| **Total** | | **$ 5,195.58** |
| | | |

- **RUS 219s** *Inventory of Work Orders* of projects completed from the Construction Work Plan totaling $428,775.04. These forms are submitted to RUS for approval of loan funds.

  Inventory 201903 - $423,012.82 for URD replacement, OH to UG Conversion (Removal of OH on Mt. Constitution and installation on Buck Mountain in rocky terrain in concert with our URD replace schedule. This was due to the fire hazard, unreliable OH and UG circuits.)
  Inventory AS1903 - $5,762.22 for Minor Projects

Staff requests a motion to approve the Consent Agenda.

**Orcas Power & Light Cooperative**

**Minutes of the Board of Directors Meeting**

**Thursday, Thursday, April 25, 2019**

President Vince Dauciunas called the meeting to order at 8:25 a.m. in the OPALCO Eastsound conference room. Board members present were Vince Dauciunas, Mark Madsen, Jerry Whitfield, Jeffrey Struthers, Rick Christmas, Peter Garlock (via Zoom) and Brian Silverstein. Staff present were General Manager Foster Hildreth, Manager of Engineering and Operations Russell Guerry, Manager of Finance and Member Services Nancy Loomis, Attorney Joel Paisner, Head Accountant Travis Neal, Assistant Manager of Member Services Jon Orr (during the Policy 14 discussion), Public Relations Administrator Suzanne Olson and Executive Assistant Kelly Koral (serving as recording secretary). Consultant Jay Kimball was also in attendance.

**Member/Guests**

Chris Greacen (via Zoom)

**CONSENT AGENDA**

- **Motion** was made and seconded to approve Consent Agenda, including March 15, 2019 minutes, new members as listed with the Board materials, capital credit payments totaling $15,130.67 and RUS 219s totaling $34,004.31. Motion carried by voice vote.

**MEMBER COMMENTS**

No comments were made.

**NRECA DIRECTOR ELECTION**

Staff requested the Board make a motion to approve the primary and secondary voting delegates for the NRECA Director Election (at the WRECA Annual Meeting) on June 10th.

- **Motion** to approve Foster Hildreth as the voting delegate and Jerry Whitfield as alternate was made and seconded. Motion carried by voice vote.

**EASEMENT RELINQUISHMENTS**

Easement relinquishments for Thomas (tax parcel numbers 351190334000 and 351190335000) and Krajack (tax parcel number 251042001000) were discussed. Staff requested Board make a motion to approve the relinquishments.

- **Motion** to approve easement relinquishments was made and seconded. Motion carried by voice vote.

**ELECTRIFYING SCHOOL BUSSES**

Chris Greacen was available (via Zoom) for discussion of applying for a Department of Commerce grant for electrifying school busses in San Juan County. Staff was requested to assist San Juan County Conservation District with information needed for the grant application which was due by May 1st.

**BOARD OFFICER ELECTIONS**

As required by OPALCO bylaws, officers were elected for President, Vice President, Secretary and Treasurer positions. After nominations and voting by written ballot, the results were tallied. The results are as follows: President, Vince Dauciunas, Vice-President Jerry Whitfield and Secretary-Treasurer Brian Silverstein.

**ANNUAL MEETING RECAP**

The 2019 annual meeting was held on the interisland ferry with 231 attendees, which included 145 members. Processes were reviewed and discussion held about future meeting possibilities. The Board expressed a strong preference for the next annual meeting should be held on the interisland ferry in the month of April.

**MEMBER SERVICE POLICY 14 REVISIONS**

First read and discussion was held for Member Service Policy 14 revisions to include modernization of the policy. Staff will present this policy for a second reading at the May 16th board meeting.

**CANDIDATE FORUMS**
Discussion was held regarding the effectiveness, participation and cost of holding candidate forums for future elections. The forum will be conducted as follows:

- One live official forum in Eastsound
- Allow interactive video streaming (if possible)
- Video recording of bios and Q&A to be posted online
- Encourage candidates to participate in non-OPALCO sponsored forums

**CLEAN ENERGY BILL**
Board discussed the impact of SB5116, which the Governor is expected to sign, to become law. Kent Lopez of WRECA will be requested to attend a future meeting and discuss the bill's implications.

**EXECUTIVE SESSION 10:10 AM**

**RETURN TO REGULAR SESSION 12:50 PM**
Our bylaws Article III Section 2.3 states that board of director member cannot remain a director if they currently hold public office or serve on a governmental appointment or commission whose charter or scope of influence intersects with the business of the Cooperative. Christmas disclosed he currently holds an Orcas Island District Fire Commissioner position and questioned whether there is a potential or perceived confict of interest. The board and legal counsel discussed the matter and determined that the charters of the two organization do not intersect. Christmas stated he would recuse himself should such an occasion arise.

**REPORTS**
**GENERAL MANGER**
Hildreth review the General Manager's Report and Rock Island Snapshot

**PNGC Update**
Staff will reach out to the new PNGC CEO Roger Gray and request that he join the May Board meeting to lead a power resource discussion.

**ADJOURNMENT**
Meeting adjournment at 2:00 PM.

___________________________________ ___________________________________

Vince Dauciunas, President Brian Silverstein, Secretary-Treasurer

04/25/2019 1:18:25 pm

# RUS Form 219 Inventory Of Work Orders



## Period: MAR 2019 System Designation: WA AH O9

Inventory: 201903

| Loan Project | Loan Year | Work Order Construction (1) | Work Order Retirement (2) | Bdgt (3) | Gross Funds Required: Cost Of Construction: New Constr Or Replacements (4) | Gross Funds Required: Cost Of Removal: New Constr Or Replacements (5) | Deductions: Salvage Relating To New Construction Or Replacements (6) | Deductions: Salvage Relating To Retirements Without Replacements (7) | Deductions: Contrib In Aid Of Constr and Previous Advances (8) | Loan Funds Subject To Advance By RUS (9) |
|---|---|---|---|---|---|---|---|---|---|---|
| 324 | 2018 | 2444 | 2444 | 1 | 470,492.02 | 1,486.85 | 0.00 | 0.00<br>AFUDC: 16,681.54 | 39,516.34 | 415,780.99 |
| | | | | | 470,492.02 | 1,486.85 | 0.00 | 0.00 | 39,516.34 | 415,780.99 |
| 608 | 2018 | 2878 | | 1 | 7,363.50 | 0.00 | 0.00 | 0.00<br>AFUDC: 131.67 | 0.00 | 7,231.83 |
| | | | | | 7,363.50 | 0.00 | 0.00 | 0.00 | 0.00 | 7,231.83 |
| **Grand Totals:** | | | | | $ 477,855.52 | $ 1,486.85 | $ 0.00 | $ 0.00 | $ 39,516.34 | $ 423,012.82 |

04/25/2019 1:18:25 pm

# RUS Form 219 Inventory Of Work Orders



Period: MAR 2019 System Designation: WA AH O9

Inventory : 201903

| Budget Loan | Project | Amount |
|---|---|---|
| 1 | 324 | 415,780.99 |
| 1 | 608 | 7,231.83 |
| | **Total:** | 423,012.82 |

## BORROWER CERTIFICATION

WE CERTIFY THAT THE COSTS OF CONSTRUCTION SHOWN ARE THE ACTUAL COSTS AND ARE REFLECTED IN THE GENERAL ACCOUNTING RECORDS. WE FURTHER CERTIFY THAT FUNDS REPRESENTED BY ADVANCES REQUESTED HAVE BEEN EXPENDED IN ACCORDANCE WITH THE PURPOSES ON THE LOAN, THE PROVISIONS OF THE LOAN CONTRACT AND MORTGAGE, RUS BULLETINS, AND THE CODE OF FEDERAL REGULATIONS RELATIVE TO THE ADVANCE OF FUNDS FOR WORK ORDER PURPOSES. WE CERTIFY THAT NO FUNDS ARE BEING REQUESTED FOR REIMBURSEMENT OF CONSTRUCTION WORK IN A CBRA AREA.

SIGNATURE (MANAGER) DATE

SIGNATURE (BOARD APPROVAL) DATE

## ENGINEERING CERTIFICATION

I HEREBY CERTIFY THAT SUFFICIENT INSPECTION HAS BEEN MADE OF THE CONSTRUCTION REPORTED BY THIS INVENTORY TO GIVE ME REASONABLE ASSURANCE THAT THE CONSTRUCTION COMPLIES WITH APPLICABLE SPECIFICATIONS AND STANDARDS AND MEETS APPROPRIATE CODE REQUIREMENTS AS TO STRENGTH AND SAFETY. THIS CERTIFICATION IS IN ACCORDANCE WITH ACCEPTABLE ENGINEERING PRACTICE.

INSPECTION PERFORMED BY FIRM

LICENSE NUMBER DATE SIGNATURE OF LICENSED ENGINEER

04/25/2019 1:18:25 pm

# RUS Form 219 Inventory Of Work Orders



## Period: MAR 2019 System Designation: WA AH O9

Inventory: AS1903

| Loan Project | Loan Year | Work Order Construction (1) | Work Order Retirement (2) | Bdgt (3) | Gross Funds Required: Cost Of Construction: New Constr Or Replacements (4) | Gross Funds Required: Cost Of Removal: New Constr Or Replacements (5) | Deductions: Salvage Relating To New Construction Or Replacements (6) | Deductions: Salvage Relating To Retirements Without Replacements (7) | Deductions: Contrib In Aid Of Constr and Previous Advances (8) | Loan Funds Subject To Advance By RUS (9) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1600 | 2018 | 3063 | | 1 | 5,793.23 | 0.00 | 0.00 | 0.00<br>AFUDC: 31.01 | 0.00 | 5,762.22 |
| | | | | | 5,793.23 | 0.00 | 0.00 | 0.00 | 0.00 | 5,762.22 |
| **Grand Totals:** | | | | | $ 5,793.23 | $ 0.00 | $ 0.00 | $ 0.00 | $ 0.00 | $ 5,762.22 |

Minor Construction Work Orders

Work Order: 3063 - INSTALL CONDUIT IN SHARED TRENCH WITH WATER SYSTEM

04/25/2019 1:18:25 pm

# RUS Form 219 Inventory Of Work Orders



Period: MAR 2019 System Designation: WA AH O9

Inventory : AS1903

| Budget Loan | Project | Amount |
|---|---|---|
| 1 | 1600 | 5,762.22 |
| | **Total:** | 5,762.22 |

## ENVIRONMENTAL CERTIFICATION

1 ☐ WE CERTIFY THAT CONSTRUCTION REPORTED ON THE LISTED WORK ORDERS (EXCEPT CERTIFICATION "2" BELOW), IS A CATEGORICAL EXCLUSION OF A TYPE DESCRIBED IN 7 CFR 1970 WHICH NORMALLY DOES NOT REQUIRE PREPARATION OF A BORROWER'S ENVIRONMENTAL REPORT.

2 ☐ WE CERTIFY THAT CONSTRUCTION REPORTED ON WORK ORDERS________________________, IS A CATEGORICAL EXCLUSION OF A TYPE THAT NORMALLY REQUIRES A BORROWER'S ENVIRONMENTAL REPORT WHICH IS ATTACHED.

SIGNATURE (MANAGER) DATE

## BORROWER CERTIFICATION

WE CERTIFY THAT THE COSTS OF CONSTRUCTION SHOWN ARE THE ACTUAL COSTS AND ARE REFLECTED IN THE GENERAL ACCOUNTING RECORDS. WE FURTHER CERTIFY THAT FUNDS REPRESENTED BY ADVANCES REQUESTED HAVE BEEN EXPENDED IN ACCORDANCE WITH THE PURPOSES ON THE LOAN, THE PROVISIONS OF THE LOAN CONTRACT AND MORTGAGE, RUS BULLETINS, AND THE CODE OF FEDERAL REGULATIONS RELATIVE TO THE ADVANCE OF FUNDS FOR WORK ORDER PURPOSES. WE CERTIFY THAT NO FUNDS ARE BEING REQUESTED FOR REIMBURSEMENT OF CONSTRUCTION WORK IN A CBRA AREA.

SIGNATURE (MANAGER) DATE

SIGNATURE (BOARD APPROVAL) DATE

## ENGINEERING CERTIFICATION

I HEREBY CERTIFY THAT SUFFICIENT INSPECTION HAS BEEN MADE OF THE CONSTRUCTION REPORTED BY THIS INVENTORY TO GIVE ME REASONABLE ASSURANCE THAT THE CONSTRUCTION COMPLIES WITH APPLICABLE SPECIFICATIONS AND STANDARDS AND MEETS APPROPRIATE CODE REQUIREMENTS AS TO STRENGTH AND SAFETY. THIS CERTIFICATION IS IN ACCORDANCE WITH ACCEPTABLE ENGINEERING PRACTICE.

INSPECTION PERFORMED BY FIRM

LICENSE NUMBER DATE SIGNATURE OF LICENSED ENGINEER

MEMORANDUM

May 10, 2019

TO: Board of Directors

FROM: Foster Hildreth, General Manager

RE: Bylaw Revisions

The purpose of the revision is to update the number of members required to propose a bylaw amendment. Since the bylaws were originally drafted, the number of active members has grown substantially. As a point of reference, in 1938 OPALCO had 172 active members, as compared to 11,351 today. The current bylaws require only 50 members which is less than one half of one percent. Similar to how a quorum is determined (10% of active members), staff proposes the below bylaw revision (requiring 10% of active members) to bring this section up to date.

**Section 2. Energy Member Initiated Amendments.**

Energy ~~Voting~~ ~~m~~Members may propose changes to the bylaws as follows:

a) Bylaw Amendments Proposed by Energy Members. ~~Any group of fifty (50) or more~~ Consistent with the Articles of Incorporation and State Law, at least ten percent (10%) of the active Energy ~~voting~~ ~~m~~Members may propose, in writing, a resolution to make, alter, amend or repeal a bylaw or to adopt new bylaws. Each Energy Member proposed resolution shall be limited to a single subject. Any such proposed resolution must be submitted to the Board of Directors no less than ninety (90) and no greater than one hundred twenty (120) days prior to the date of the next annual meeting of the Energy ~~m~~Members, and consistent with Article II.

b) Review by Directors. After review by the directors, with the advice of legal counsel, the proposed amendment to the bylaws shall be placed upon the agenda of the annual meeting of the ~~e~~Energy ~~m~~Members, so long as consistent with law or the articles of incorporation, and notice of the proposed amendment shall be provided to the ~~e~~Energy ~~m~~Members in accordance with the notice provisions contained in Article II, Section 3 of the Bylaws.

c) Voting on Proposed Amendment. Any proposed amendment shall be voted upon at the annual meeting of the ~~e~~Energy ~~m~~Members. Voting shall be in accordance with Article II, Sections 5 and 6 of the Bylaws. Any proposed amendment receiving a simple majority of votes from the ~~e~~Energy ~~m~~Members shall be approved.

Staff requests the Board make a motion for approval of the bylaw revisions above.

MEMORANDUM

May 10, 2019

TO: Board of Directors

FROM: Foster Hildreth

RE: Member Service Policy 14 – Interconnection of Member Generators and Storage

Please find attached revisions to Member Service Policies 14 – *Interconnection of Member Generators and Storage*. This is the second reading for revisions to the policy based on the Board discussion at the April 25th board meeting

Staff requests the Board make a motion to approve the Member Service Policy 14 – *Interconnection of Member Generators and Storage* revisions.

# ORCAS POWER & LIGHT COOPERATIVE

## MEMBER SERVICE POLICY 14

## INTERCONNECTION OF MEMBER GENERATORS AND STORAGE

This policy covers interconnection of any member owned generating facility, herein referred to as distributed energy resource (DER), to the OPALCO distribution grid. Any DER energized prior to December 17, 2003 will continue to be covered under Member Services Policy 13. The member may select from the following options:

(1) Net Metering allows the member to consume energy generated by their system which will offset the amount of energy purchased from OPALCO; OR
(2) Buy/Sell allows the member the option to consume a portion of the energy produced.

### 14.1 AVAILABILITY

14.1.1 Energy must be generated from small scale renewable resources such as, but not limited to, solar, wind, and to micro-hydro;

14.1.2 All power is considered non-firm, (this means power that is not available 24 hours per day, seven days per week);

14.1.3 Facilities with nameplate capability no greater than 200 kilowatts (kW). Facilities over 200 kW must go through BPA's generation interconnection process;

14.1.4 Requests for interconnection will be processed on a first-come, first-served basis. Engineering will review applications and determine maximum generation capacities as it pertains to maintaining system reliability and safety;

14.1.5 OPALCO shall reserve the right to apply a fixed fee for administrative costs. The member shall be given reasonable notice before fixed fees are applied.

### 14.2 SERVICE CHARACTERISTICS

Single phase 120/240 or three phase 277/480 or 120/208 service, at 60 Hz are available. Any service upgrades necessary must comply with MS Policy 5 – Line Extension.

### 14.3 GENERAL PROVISIONS

14.3.1 Design Requirements

The DER shall be built and operated to comply with *Interconnection Standards for Member Generators with nameplate capability no greater than 200 kW*.

14.3.2 Interruption or Reduction of Deliveries

14.3.2.1 OPALCO shall not be obligated to accept delivery of DER's energy and may require member DER to interrupt or reduce such delivery:

14.3.2.1.1 In order to construct, or maintain any of OPALCO's equipment or system;

14.3.2.1.2 If curtailment is necessary because of emergencies, forced outages, or compliance with prudent electrical practices.

14.3.3 The members proposed facility must be pre-approved by the OPALCO Engineering Department prior to construction.

14.3.3.1 Member shall provide a detailed interconnection diagram showing disconnecting device(s) as well as any associated protection as required by applicable standards/practice and codes.

14.3.3.2 The member may be required to install additional protective equipment for the DER installation. OPALCO shall have the right to have representatives present at the initial testing of member's protective apparatus.

14.3.3.3 The DER shall not commence parallel operation of the facility until OPALCO has authorized the start up.

14.3.3.4 Smart inverter ride through is required for all new inverters after the September 8$^{th}$, 2017 and shall be certified to Underwriters Laboratories UL-1741 SA (Supplement A)

14.3.3.5 OPALCO may require the member to operate the DER for various power factor (PF) ranges within its specification and either enable or disable the dynamic Volt/VAR ability.

14.3.3.6 OPALCO may determine that additional anti-islanding protection is required and will be installed at the expense of the member.

14.3.4 The member shall complete, sign and submit an *Interconnection Application* and an *Agreement for Interconnection of Member Generators* prior to beginning construction.

14.3.5 Member shall pay for designing, installing, operating and maintaining the DER in accordance with OPALCO standards and agreements that apply at the time of installation. OPALCO's standards and agreements are detailed in OPALCO's *Agreement for Interconnection of Member Generators* and *Interconnection Standards for Installation of Member Generators*, which may be amended from time to time.

14.3.6 OPALCO reserves the right to designate the metering type, location, and method of interconnection. The member shall be required to pay a contribution in aid of construction for all equipment and upgrades necessary to OPALCO's distribution system in order to accommodate the facility.

14.3.7 Member shall obtain any governmental authorizations and permits required for the construction and operation of the DER. Member shall reimburse OPALCO for any and all losses, damages, claims, penalties or liability it incurs as a result of member's failure to obtain or maintain any governmental authorizations and permits required for construction and operation of DER or failure to properly maintain member's facility.

14.3.8 The DER shall comply with all requirements standards of all local, state, and federal rules and regulations or codes which may be applicable.

14.3.9 Notwithstanding any other provision of this policy, if at any time OPALCO determines that either (1) the facility may endanger OPALCO personnel or (2) the continued operation of member's facility may endanger the integrity of OPALCO's electrical system, OPALCO shall have the right to enact MS Policy 3.5 – Immediate Disconnection.

14.3.11 The owner of the DER shall install, at no cost to OPALCO, a disconnect device that is manually operated, accessible, visible, and lockable. OPALCO reserves the right to lock this device in the "open" position. This protective switching equipment may be operated without notice or liability by OPALCO or an OPALCO representative if, in the opinion of OPALCO or its representatives, continued operation of the DER in connection with OPALCO's system may create or contribute to a system emergency or safety hazard. OPALCO shall endeavor to minimize any adverse effects of such operation on the DER.

14.3.11.1 Single phase customers with inverter based generation less than 15 kW are not required by OPALCO to have a lockable AC Disconnect Switch so long as the installation meets all applicable local/national codes and standards. However, if the customer does not install a lockable AC Disconnect Switch, the revenue meter may be removed to isolate the customers generator from the electric distribution system. The removal of the revenue meter will result in the loss of electrical services.

14.3.12 The member must provide OPALCO a written notice of sale or transfer of the DER or the premises upon which the facility is located within thirty (30) calendar days. To continue interconnection service to the new member, a new interconnection agreement, signed by the new member, is required within thirty (30) calendar days. The net metering rate will cease to the departing member, but will transfer to new member upon receipt of signed documents.

14.3.13 Members must notify OPALCO if any significant changes (beyond general maintenance) are made to the interconnected system. This may include, but is not limited to, altering the AC inverter capacity, changing inverter types, increasing DC capacity before the inverters, or otherwise altering the system's one-line diagram initially submitted to OPALCO.

14.3.14 OPALCO may enter member's premises or property:

14.3.14.1 To inspect the member's protective devices during reasonable hours with prior notice;

14.3.14.2 To disconnect at OPALCO's meter or transformer, without notice, the DER (or the entire service if the DER cannot be disconnected at or near the meter) if, in OPALCO's opinion, a hazardous condition exists.

## 14.4 NET METERING

14.4.1 Net Metering is the connection method in which the DER may consume the energy generated by their system in order to offset the amount of energy purchased from

OPALCO. In the event the energy generated exceeds the energy consumed by the DER, the excess may be distributed to OPALCO's grid.

14.4.2 In no case will a credit be issued for excess energy generated. A bill for zero usage will be issued and excess kWhs will be "banked" for usage by the member in a subsequent month. Payment for any banked kWhs remaining on April 30th of each year shall be made based on OPALCO's yearly average of wholesale power purchased from ~~BPA~~ PNGC. The yearly average shall be determined each year on March 31st using OPALCO's year-end Rural Utilities Service (RUS) Form 7, Part K, Section (e) *Average Cost*. In addition, a green power premium shall be paid at one cent ($.01) per kWh.

14.4.3 The Net Metering billing adjustment applies to charges for energy consumed only. A member participating in the Net Metering Program is subject to the OPALCO tariff under which the member receives service. Banked kWhs shall be applied only to energy usage and not the service access charge. In all cases, the service access charge will apply.

14.4.4 OPALCO shall provide meter aggregation for members who are participating under the Net Metering section of this policy. If a member's interconnection under Net Metering is known to produce more energy than the member's premises can consume on a yearly basis, then OPALCO shall allow the member to apply the excess energy to any other of the member's account(s) that are under exactly the same name as the member's interconnected facility. Members may only aggregate up to 5 meters. The member shall provide OPALCO with the account information for which they wish meter aggregation at the time application is made. Members can change the accounts which are being aggregated one time each year, on or before April 30th. Requests must be in writing and the change shall take effect in the next billing period.

## 14.5 BUY/SELL

14.5.1 Energy delivered into the OPALCO system will be reimbursed on a monthly basis by OPALCO. The established rate at which OPALCO will purchase all energy flowing out of the DER and delivered to OPALCO's distribution grid for non-firm power shall be based on OPALCO's yearly average of wholesale power purchased from ~~BPA~~ PNGC. The yearly average shall be determined each year on March 31st using OPALCO's year-end Rural Utilities Service (RUS) Form 7, Part K, Section (e) *Average Cost*. In addition, a green power premium shall be paid at one cent ($.01) per kWh.

14.5.2 The Buy/Sell option applies to charges for energy consumed only. In all cases the basic charge will apply. OPALCO reserves the right to limit purchases that exceed OPALCO's ability to resell the power to its members.

## 14.6 MEMBER OWNED RENEWABLE ENERGY (MORE) FUND/PRODUCTION INCENTIVES

All MORE incentives will be funded through voluntary contributions; OPALCO offers no guaranteed incentive payments. New DERs will be admitted into the MORE Incentive Program on a first come, first served basis after July 1, 2010. MORE installations will follow the Net Metering Section 14.4 of this policy.

14.6.1 Production meter: Member will install, at their expense, a meter base which will accommodate an OPALCO meter. The production meter is a separate meter from the OPALCO billing meter and is required to record all energy produced from the DER.

14.6.2 Incentives will be administered through an independent committee of OPALCO members following approved MORE committee guidelines. See MORE guidelines for more details.

## 14.7 INDEMNITY AND LIABILITY

Member shall hold harmless and indemnify OPALCO, its other members, employees, and its agents, from any damage, loss, claim or expense arising out of member's actions or inaction in connection with this policy. OPALCO shall hold harmless and indemnify member for any loss, claim or expense arising out of the actions or inaction of OPALCO, its employees, or its agents in implementing this policy. This section shall not relieve any insurer of its obligation to pay claims in accordance with the provisions of any valid insurance policy.

| | |
|---|---|
| ______________________________ | ___May 16, 2019_______ |
| Foster Hildreth, General Manager | Effective Date |

MEMORANDUM

May 10, 2019

TO: Board of Directors

FROM: Foster Hildreth, General Manager

RE: 2018 Financial Statement Audit Report

Orcas Power & Light Cooperative and Subsidiary Report of Independent Auditors and Financial Statements for December 31, 2018 and 2017, as audited by Moss Adams LLP, will be presented and discussed at the May 16th board meeting. A draft of the findings will be sent separately from the regular Board packet, with the final report presented at the regular Board meeting in May. Please note the 2018 year-end financial information was previously reviewed at the March 2019 Board meeting and no material changes have occurred since the March financial presentation. Once approved by the board, the audit report will be posted in OPALCO's online resource library.

Representatives of Moss Adams were on-site in the Eastsound office the week of April 1st to April 5th. Olga Darlington, Business Assurance Partner, will be attending the May 16th board meeting to review the firm's audit findings and answer questions posed by the Board.

**Understanding the Consolidated Financial Statements of both OPALCO and its subsidiary, Rock Island Communications:**
Separate company financial statements were presented at the March meeting and the final consolidated audited financial statements are being presented to the Board at the June board meeting. Below is a narrative that describes some of the main comparisons between the OPALCO and Rock Island separate company financial statements and the consolidated statements.

Key takeaways:

- OPALCO and Rock Island received an "Unmodified" opinion, which is the highest level of opinion.

Consolidation methodology:

- At the March board meeting, OPALCO and RIC presented their year-end financials separately. As OPALCO owns 100% of Rock Island, accounting standards require that our audited financial statements be on a consolidated basis.
    - The first statements presented in the audit report (Income Statement, Balance Sheet and Cash Flows) and the associated notes to the financial statements combine both OPALCO and Rock Island.
    - The 'Supplementary Information' section of the statements (starting on page 21 of the audit report) is the consolidation where you can see the companies broken out individually and the related consolidating entries.
    - Note that for 2018 and each year, the margin to be allocated to members is equal to the OPALCO only margin, not the consolidated amount that includes Rock Island.

Upon the conclusion of the audit review and board discussion, staff requests that the board make a motion to approve OPALCO's Independent Auditors' Report and Financial Statements for December 31, 2018 and 2017, as audited by Moss Adams LLP.

MEMORANDUM

May 10, 2019

TO: Board of Directors

FROM: Foster Hildreth

RE: PNGC Talking Points

PNGC's new CEO, Roger Gray, will be attending the May Board meeting to discuss the future of power industry. The utility industry is changing dramatically. The reason staff has enlisted our partner PNGC is to navigate these resource pooling, power supply planning, regulatory compliance, legislative affairs, BPA policy, etc. This discussion will take place on Wednesday upon completion of the Rock Island meeting. Please refresh your memory with the following documents:

- Integrated Resource Plan (IRP) – *most important*
  https://www.opalco.com/wp-content/uploads/2015/12/Integrated-Resource-Plan-IRP.pdf
- Mission Statement
  https://www.opalco.com/about-us/mission-and-values/
- Strategic Directives
  https://www.opalco.com/wp-content/uploads/2015/12/board-strategic-directives-jan-2015.pdf
- PNUCC Forecast
  Attached to this report.

The following talking points will be touched upon:

1. PNGC's role is to meet the Members' future energy needs in the most prudent manner.
2. How the world around the industry is changing?
   - Technology
   - Electrification
   - Environmental (e.g. impacts on BPA hydro, resource operations and siting, etc.)
   - Policy and social values: carbon, customer control/choice, etc.
   - Changes due to renewable generation
   - Role of transmission (more important or irrelevant?)
   - Political and other shifts, etc.
3. Capacity horizon and power cost risk
   - Seventh Power plan assumptions
   - Generation plant closures
   - Regional capacity shortfall exposure
4. BPA Contract
   - Existing structure
   - What has changed since execution and what is happening in the near future?
   - What is it that is really valued?
5. Role of BPA in the future and contract(s)
   - What BPA might provide
   - BPA competitiveness and products:
     - commodity product (kwh) vs. load following construct
   - What is desired of a new contract and when?
   - What if BPA is not competitive? What is "Plan B"?
   - Can BPA (Plan A) and Plan B co-exist? Do they conflict or compliment?

- The federal system today and possible changes in the future
- Timeframes, BPA “roadmap” and trigger dates
    - BPA New Contract (existing expires 2028)
    - Wait for BPA to propose new contract vs. propose new contract to BPA

6. OPALCO’s IRP and Strategic Direction
    - What are the key take-aways?
    - What is clear and confident?
    - What is less clear or uncertain?
7. OPALCO and other PNGC 14 Member Cooperatives
    - What is needed from PNGC now?
    - What is unique and specific to OPALCO vs. other PNGC utilities in general?
    - What does our future power contract look like?
    - What is less clear or uncertain?
8. How to make good decisions in the face of uncertainty
    - Needs of PNGC’s other 14 member cooperatives?
    - Rely on market to meet future resource and capacity needs
    - Procurement of advanced purchase power contracts
    - Need for new “bricks and mortar” generation?
    - Planning for new generation (land acquisition, permitting, financing, equity plan for PNGC members)

MEMORANDUM

May 10, 2019

TO: Board of Directors

FROM: Foster Hildreth, General Manager

RE: Transmission Redundancy

**Transmission System Overview**

Staff wanted to inform the Board of our transmission setup, the redundancy currently in place and give an overview of our transmission system. Below are two examples showing the need for redundancy in the system. Staff will be available to discuss the transmission redundancy options we have for our BPA sources, substations, and other critical loads in Executive Session.

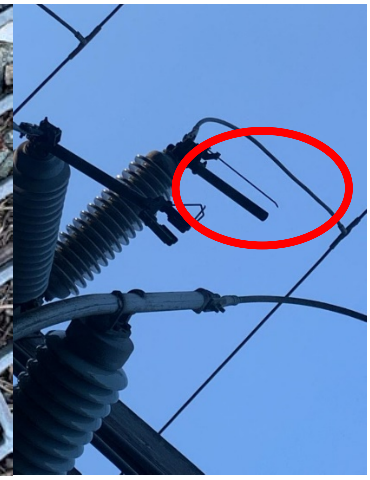
**Orcas/Shaw - April 26th Outage Recap (Most restored in 2.5 hours!)**

At ~7:20 PM, BPA sustained an outage on Decatur island on the overhead 69kV line feeding our Decatur Tap (Decatur, Blakely, and Olga Substations) and our Shaw/Orcas Tap (Shaw, Orcas, and Eastsound Substations). Engineering and operations staff assessed the issue and informed BPA of the suspected fault location and began operations to switch onto the 115kV feed to Lopez feeding the Lopez and San Juan areas. Operations staff, following BPA switching protocol, completed this at ~9:40 PM and re-energized the Orcas Substation and Eastsound Substations. Engineering and operation staff continued to switch load from the Decatur Tap to the Eastsound Substation as load allowed. All services were re-energized by ~12:30 AM.

**West Lopez Submarine Cable Terminal – May 9th Switch Failure**

At ~6:00 PM, a member who lives close to the West Lopez Submarine Cable Terminal called to report a loud buzzing sound. Our on-call crew responded and found the air-break switch was arcing. This switch was closed to keep the Furukawa submarine cable, installed in ~1990, energized. San Juan Island was fed from George, our new submarine cable, yet due to the capacitive load on the backup cable, this switch could not be opened without placing the cable in service. Operations closed the breaker on San Juan paralleling the two submarine cables. Once paralleled, the crew on site manually opened the air-break switch. While opening, a switch arm fell to the ground on one phase. The switch is out of service. Engineering and Operations have a plan to bypass if needed and will replace in the next three months pending material availability.

**Staff will be reviewing a one-line drawing in executive session. Note, for security reasons the transmission system one line drawing is not included in the Board packet.**



MEMORANDUM

May 10, 2019

To: Board of Directors

From: Foster Hildreth, General Manager

Re: 2019 First Quarter Financial Report

Please see attached the full 2019 1st quarter financial report. Included in the report package are the Statement of Revenues and Margins (along with a notable driver analysis), Balance Sheet, Statement of Cash Flows (GAAP), and capital projects budget tracking.

The colder weather experienced in Q1 of 2019 was the primary driver of the overall revenue variance of 7% ($682k) higher than budgeted. This was partially offset by the related increase in purchased power of 4% ($111k). All combined resulted in an increased margin of $507k.

| **Income Statement Summary** (in thousands) | Q1 2019 | | |
|---|---|---|---|
| | **Budget** | **Actual** | **Variance** |
| Gross Revenue | $ 9,691 | $ 10,528 | $ 837 |
| ECA Surcharge / (Credit) | - | (155) | (155) |
| Net Revenue | 9,691 | 10,373 | 682 |
| Expenses: | | | |
| Cost of Power | 2,994 | 3,105 | 111 |
| Transmission & Distribution Expense | 1,645 | 1,592 | (53) |
| General & Administrative Expense | 1,238 | 1,287 | 49 |
| Depreciation, Tax, Interest & Other | 2,029 | 2,097 | 68 |
| Total Expenses | 7,907 | 8,082 | 175 |
| Margin | $ 1,784 | $ 2,291 | $ 507 |
| TIER | 4.67 | 5.73 | 1.06 |

For more detail, please note the following key points:

- Through Q1, YTD Heating Degree Days (HDD) were up ~61% above normal budgeted levels (Actual of 797 vs. budget of 496)

- Actual kWh sales were 12.1M kWh above budget (73.9M vs. budget of 61.8M). We expect weather and heating fluctuations to produce dramatic sales revenue volatility and have budgeted based on those assumptions. We will continue to monitor revenue and expenses closely.

- Q1 YTD power purchases were up $111k due to higher kWh consumption. Actual kWh purchases were 9.3M kWh above budget (75.4M vs. budget of 66.1M).

- Excluding purchased power, Q1 YTD operating expenses were approximately $67k over budgeted amounts.

- The YTD Energy Cost Adjustment (ECA) through March billing period was a credit to members (and reduction to operating revenue) of $155,166, or $5.87 for a member using 1000 kWh/month.

- Borrowings were accelerated in 2019 due primarily to concerns surrounding the government shutdown December 22, 2018 until January 25, 2019 RUS had been on furlough during this period and upon re-opening for what was known as temporary, OPALCO borrowed $2.9M to ensure funding if the shutdown continued or occurred later in the year.

- Rock Island Communications Q1 Financials included in separate packet.

# GENERAL MANAGER'S REPORT
## April 2019

## DASHBOARDS

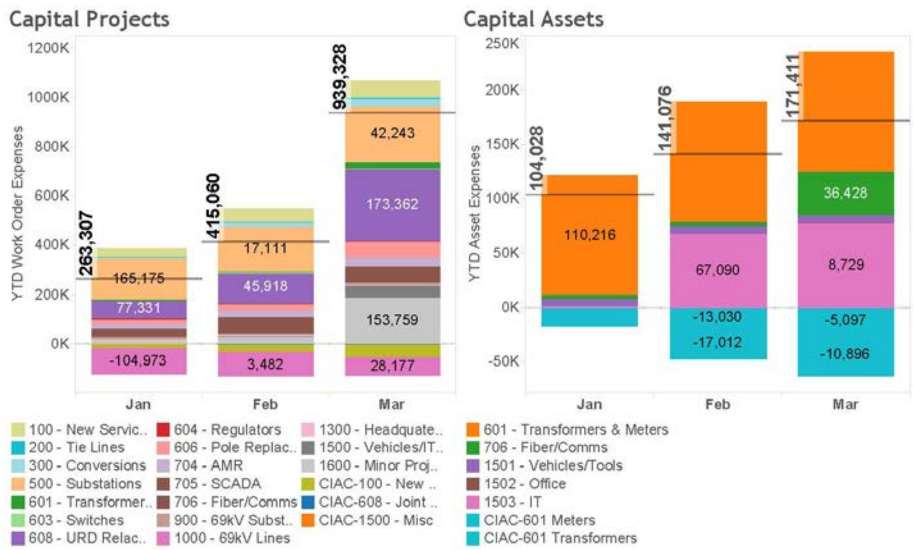
Please review the dashboards at https://www.opalco.com/dashboards. Note that all the dashboards are within board approved strategic parameters.

Existing

| Finance | Member Services | Outage |
|---|---|---|
| Cash | Service Additions | Historical SAIDI - Graph |
| Power Cost | PAL | Historical SAIDI - Figures |
| TIER/Margin | MORE | Outage Statistics - Monthly |
| Debt/Equity | Energy Assist | SAIDI by Category |
| Budget Variance | | Outage Summary |

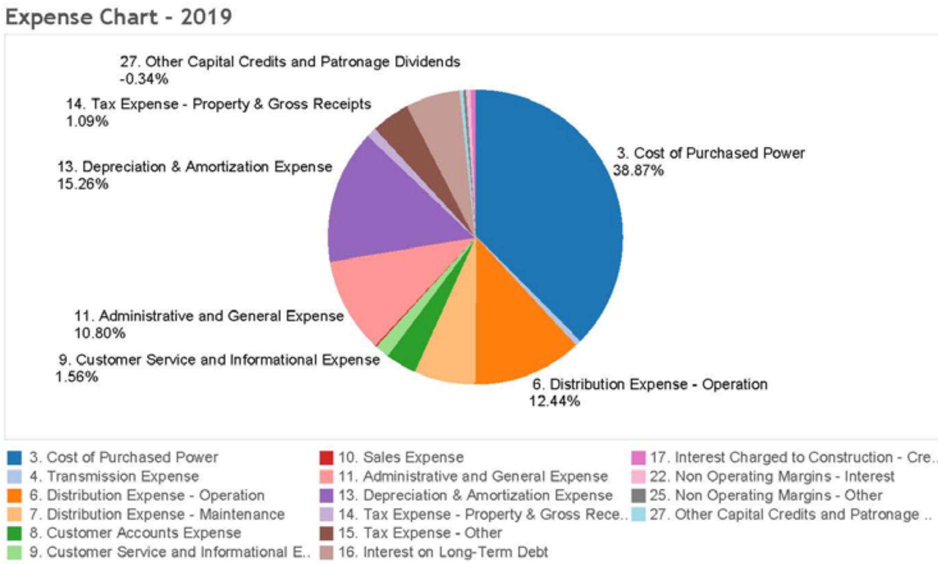
New

Finance: Capital

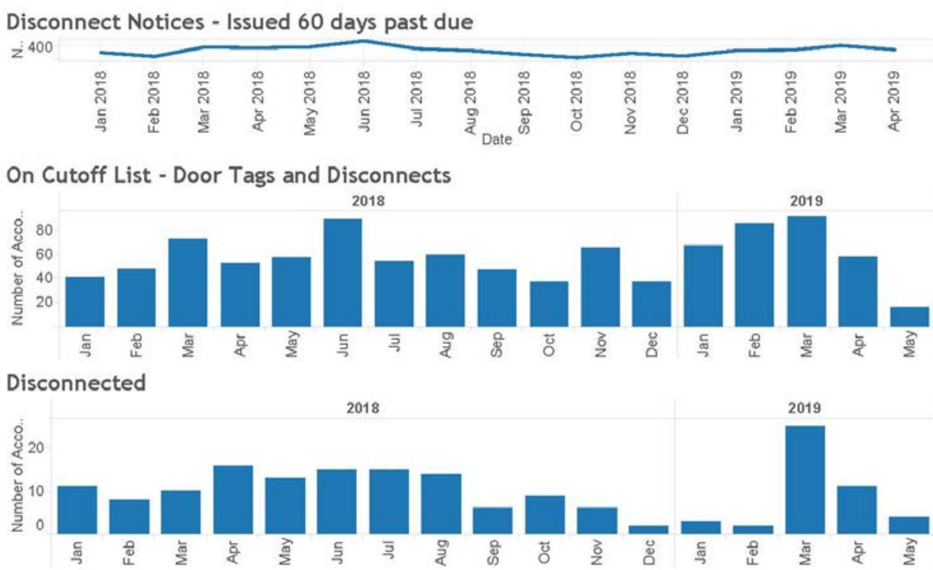



Finance: Expense

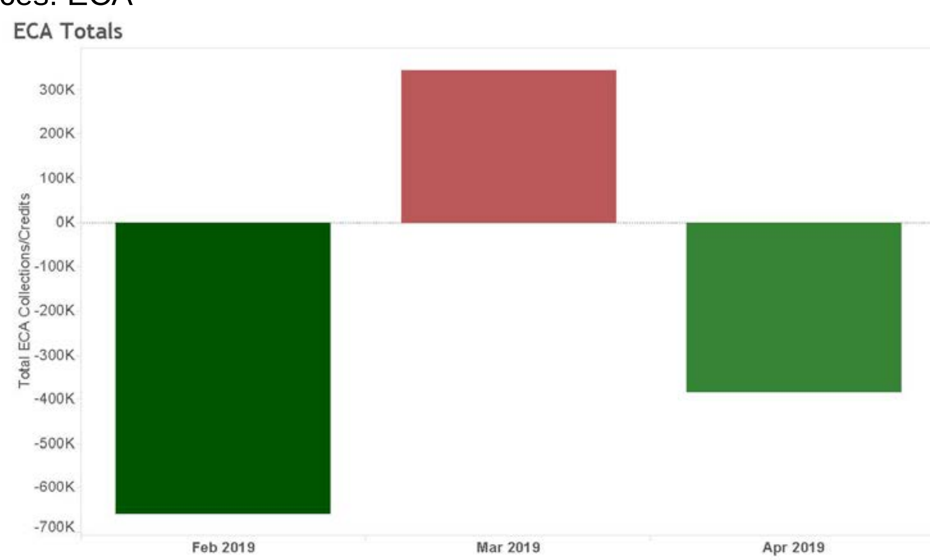
## Finance: Expense



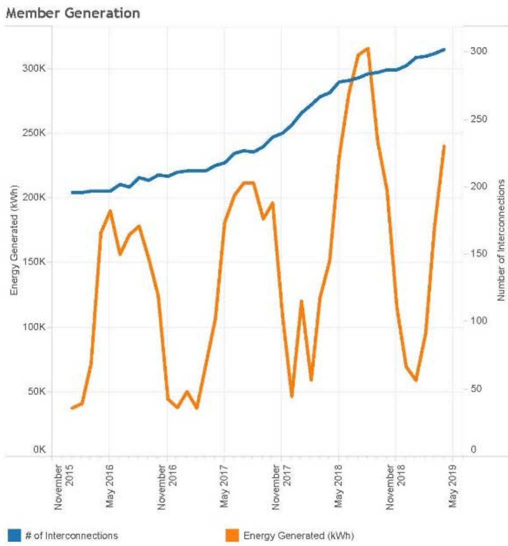

## Member Services: Disconnects



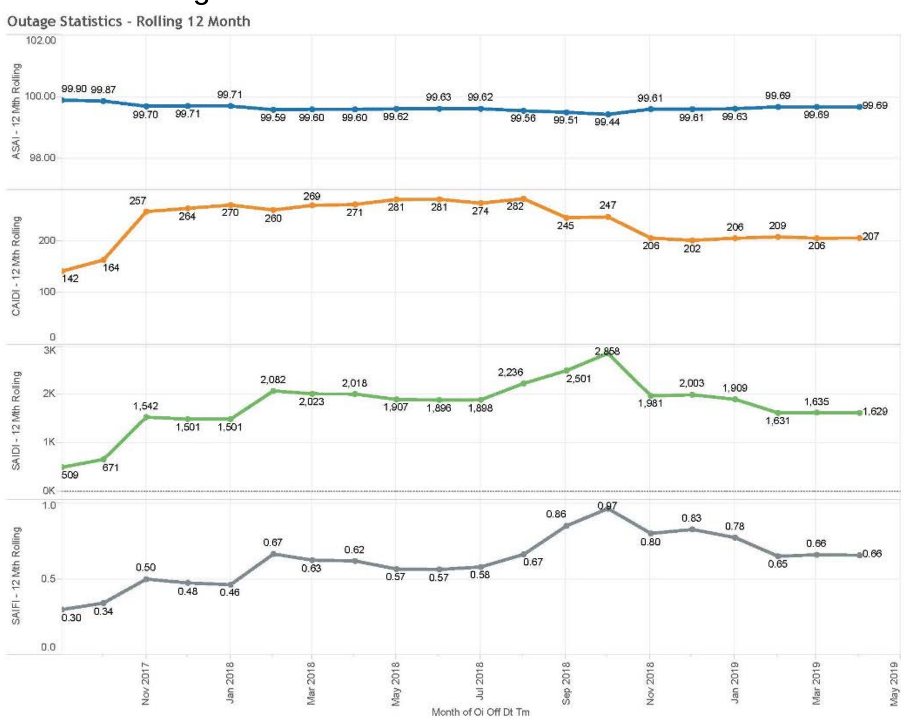

## Member Services: ECA



Member Services: Member Generation




Outage: Outage Stat – Rolling 12 Month




## ENGINEERING, OPERATIONS, AND INFORMATION TECHNOLOGIES

### WIP

As of May 8, 2019, there are 376 work orders open totaling $6.33M. Operations has completed construction on 109 work orders, totaling $2.35M.

### Safety

The total hours worked without a loss time accident: 151,710

### Grid Modernization Projects

WA DOC CEF 2 – Decatur Battery Energy Storage System

Staff is nearing completion of the final contract negotiations with the winning bidder.

WA DOC CEF 3 – Lopez Microgrid
Staff is continuing site evaluation and contract negotiation.

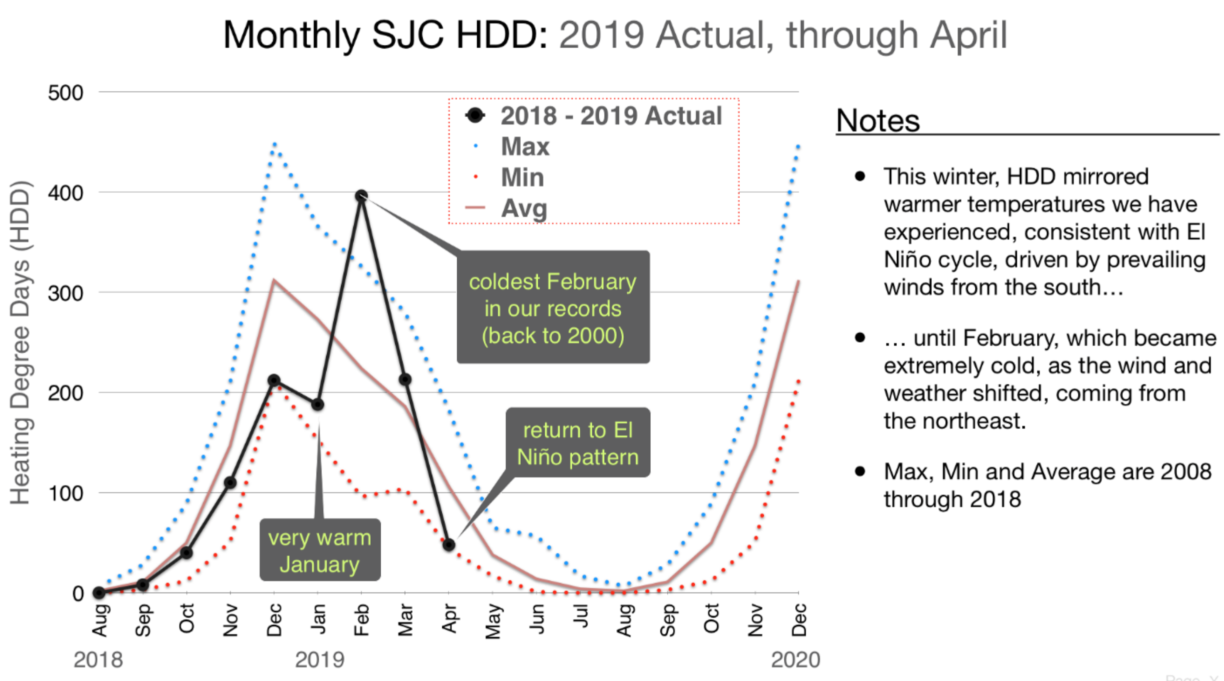
## FINANCE

### 2019 Budget Tracking

Kilowatt hour (kWh) purchases, sales were higher than budgeted through April 2019. This was primarily due to a record-breaking February as reported during the March regular meeting.

| Income Statement Summary (in thousands) | YTD | | |
|---|---|---|---|
| | Budget | Actual | Variance |
| Gross Operating Revenue | $ 12,149 | $ 12,421 | $ 271 |
| ECA Surcharge / (Credit) | - | (347) | (347) |
| Cost of Power* | 3,789 | 3,821 | 32 |
| Net Revenue | $ 8,360 | $ 8,252 | $ (108) |
| TIER | 3.94 | 6.09 | 2.15 |
| | | | |
| HDD | 565 | 845 | 280 |
| kWh Purchases | 83,636 | 92,106 | 8,470 |
| kWh Sales | 78,200 | 86,571 | 8,372 |

*April power cost is estimated & does not account for unknown BPA surcharges




### Monthly ECA

The calculated amount for the April ECA was a credit of $0.012022 per kWh which returned $191,919 to the membership in April, or $12.02 per 1,000 kWh. The YTD ECA through the April billing period is a credit to members (and reduction to operating revenue) of $347,084, or $17.89 for a member using 1000 kWh/month. The May billing period ECA will be a surcharge of +$0.008047.

**2019 Q1 Financial Statement Review**

Staff will be presenting the 2019 1st quarter financial results and analysis for discussion with the board at the May board meeting.

**2018 Financial Statement Audit**

Representatives of Moss Adams were on-site in the Eastsound office the week of April 1st to April 5th. Olga Darlington, Business Assurance Partner, will be attending the May 16th board meeting to review the firm's audit findings and answer questions posed by the Board. Once the Board has formally approved the final consolidated audit report, the 2018 audit report will be available on the website.

## MEMBER SERVICES

**Energy Assistance**

During April 2019, 355 members received ~$12.4k form the Energy Assist program, compared to 307 members receiving ~$9k worth of assistance in April 2018. In April 2019, there were 41 members that received ~$7.7k in PAL awards, compared to 51 members and ~$8.9k in April 2018.

**Energy Savings**

Members applied for 25 rebates and received ~ $15.5k in incentives in April 2019, which included five rebates for beneficial electrification projects totaling $5k.

**Community Solar**

During the April 2019 billing cycle the Decatur Community Solar array produced 46,880 kWh, and 7 kWh per solar unit was credited to member participants. A total of ~$4.7k was distributed to 274 accounts, including an additional ~$500 for the PAL and Energy Assist programs.

## COMMUNICATIONS

**Switch it Up**

Members are responding well to our Switch it Up! launch. 17 applications have been received to date and 5 projects have already been completed. Our turn-around time on applications is about a week and the process is running smoothly. The communications team are scheduling talks at civic clubs, HOAs and community meetings – and scheduled the first Switch it Up pop-up event at Island Hoppin' Brewery on Friday, May 10th.

**Scholarship Program**

The member selection committee interviewed seven out of the nine applicants (two were no-shows). Five fantastic students were selected: Lichen Johnson and Jose Raya (Lopez), Tashi Litch (Orcas), Anne Marie Ryan and Presley Clark (San Juan). Two of the four who were not selected are sophomores and will be encouraged to apply again next year. Staffers Krista Bouchey and Ed Lago will travel with the group to the Youth Rally at the College of Idaho July 14-20th.

**County Fair**

Plans are underway for our County Fair booth, August 14-17th. The main themes are safety and Switch it Up! The crew will do safety demonstrations and staff will promote Switch it Up! and rebates. We are coordinating with Rock Island to have a RIC staff member in the booth as often as possible to promote connections and co-op member ownership of the company. The Fair's theme is "A wheel in time – cultivating roots." We will tie into that theme with a t-shirt that shows the circle of ownership for the critical infrastructure in San Juan County, since 1937, and encourages pride of ownership.

**San Juan County Economic Development Council**

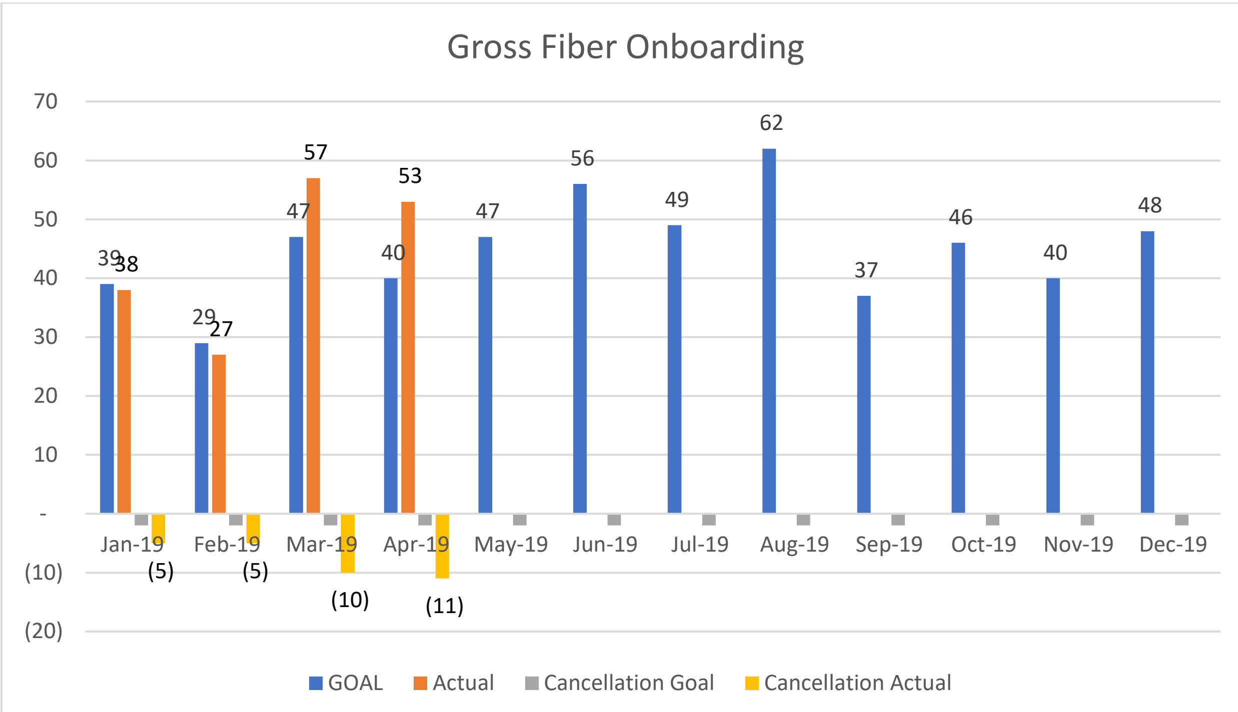
The San Juan Economic Development Council Luncheon had a presentation from the Department of Commerce. OPALCO was highlighted as an innovative utility benefitting from the Clean Energy Fund with our Decatur Solar Project, the Decatur Battery Project and the Lopez Microgrid. The luncheon was attended by ~100 attendees including business owners, county council, and other community leaders. It was a great third party endorsement.

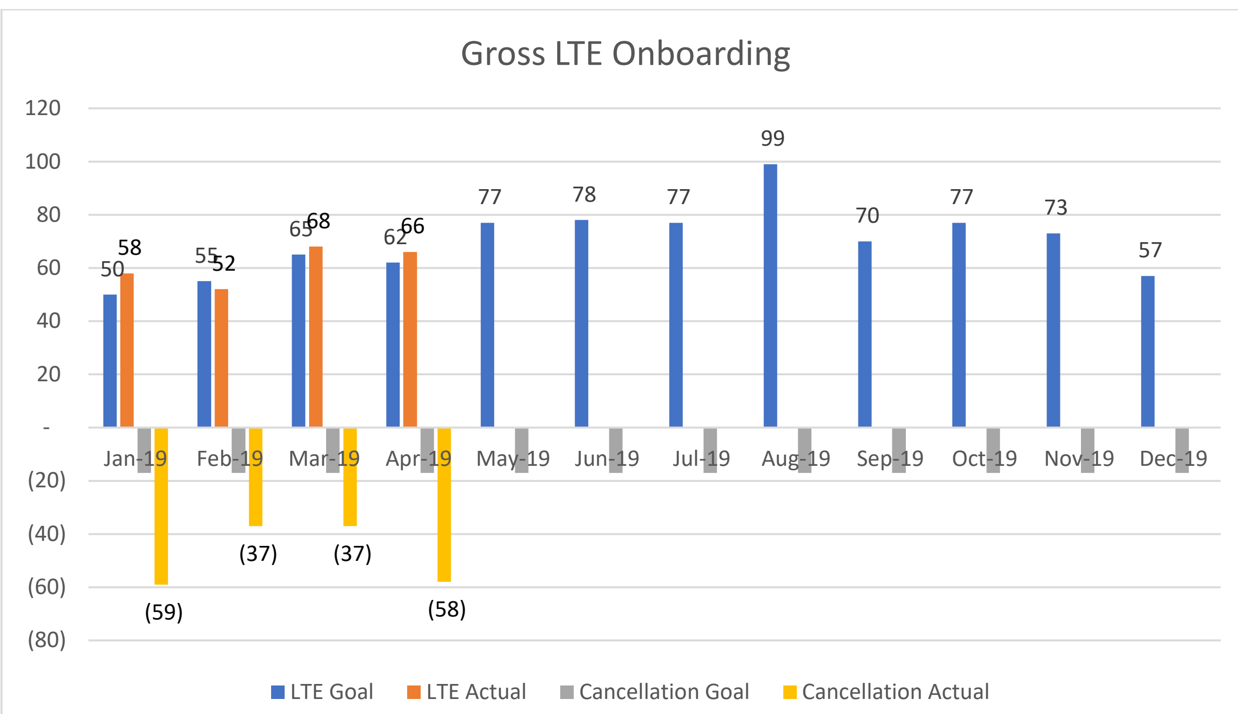
**NRECA**

NRECA is using OPALCO's new member experience (www.opalco.com/hello-new-member) as a prime example of best practices in their idea bank for engaging younger co-op members (https://www.cooperative.com/programs-services/communications/young-adult-member-engagement/Pages/Secure/default.aspx). This a new initiative from NRECA to prioritize communications with the young adult segment. They feel our new member experience is a good way to engage new co-op members especially in that demographic (https://www.cooperative.com/programs-services/communications/young-adult-member-engagement/engagement-resources/Pages/Secure/idea-bank.aspx).

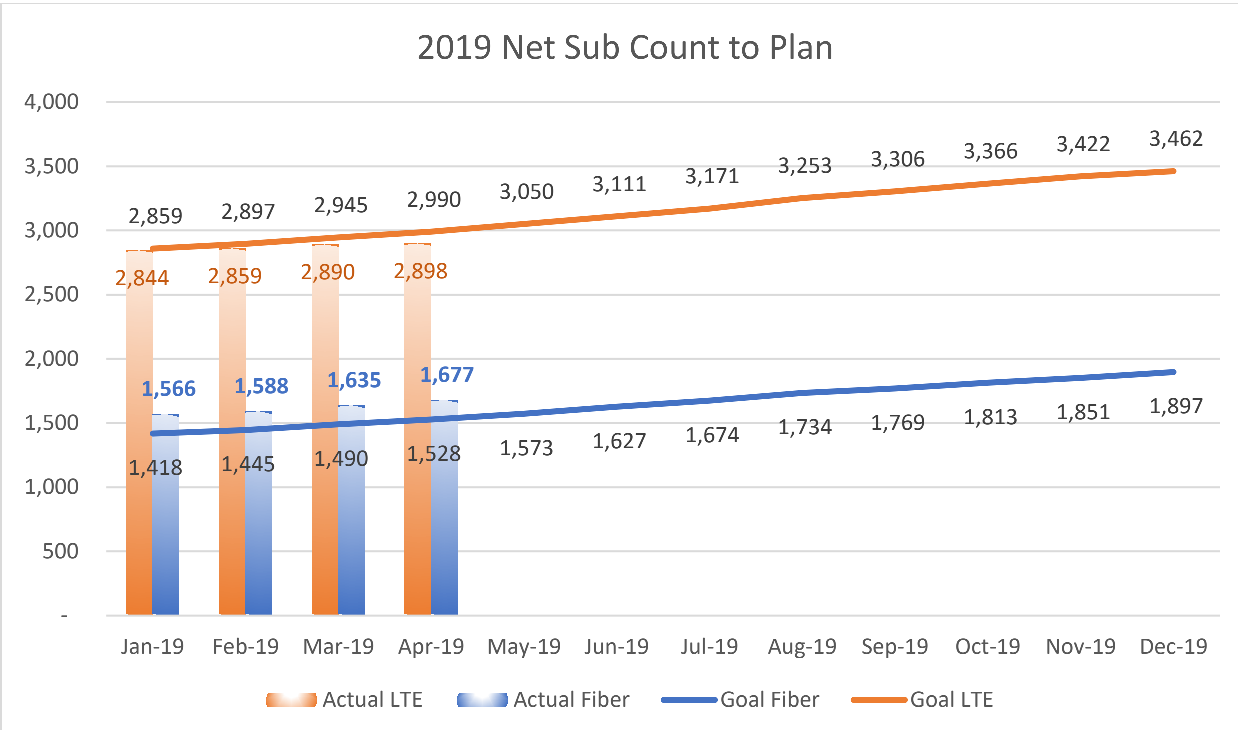
# Snapshot May 2019

## Gross Subscribers TD 2019

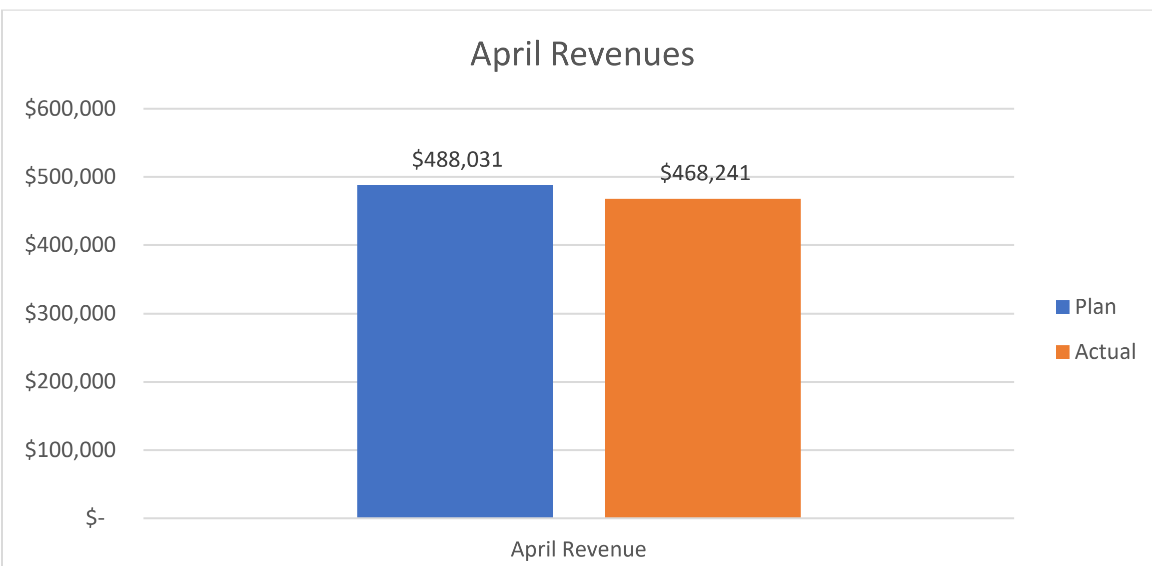


## Net Subscribers TD 2019




## Revenues TD




- Please note that without officially closing April business, this number can fluctuate by ~$2-3k

# Communications

1) **Pacific Northwest Utilities Conference Committee (PNUCC)**
   PNUCC plays a valuable role in bringing together a diversity of members and perspectives. It provides a venue to ensure our future electricity supply is cost-effective, mindful of the environment, and meets consumer expectations.
   a. Press Release
   b. 2019 Forecast
   c. Capacity Whitepaper

2) **PNGC Power Pulse**

3) **WRECA Update**

Date: April 23, 2019 at 3:08:46 PM PDT
Subject: PNUCC 2019 Northwest Regional Forecast
Dear PNUCC Members and Friends:

I'd like to call your attention to the newly released 2019 Northwest Regional Forecast, which provides the only utility view of the Pacific Northwest's future electric power landscape and demand for electricity and generating resources, as well as trends impacting utilities across the region.

For several years, the Forecast has outlined a predicted gap in the amount of electricity available during peak periods in winter with summer growing as a result of numerous factors – most notably the retirement of several coal-fired power plants. That future is now upon us, as the first facility will go off line at the end of this year.

While hydropower remains the backbone of the region's energy supply, the number of wind, solar and other new resources currently planned cannot be expected to make up for the loss of 3,600 megawatts of dispatchable generation. Last month's spike in prices underscores the region's need to examine resources closely to ensure the Pacific Northwest remains a reliable system. And while energy efficiency continues to do its job, these trends will impact utilities' planning and their customers.

I urge you to take a look at the attached news release along with the Forecast and become more familiar with the trends outlined in the Forecast as your utility moves forward. Familiarizing yourself with the Forecast's trends also can help you communicate to any local media about how your utility is meeting the challenges and opportunities ahead.

The Executive Summary and full report are also available at www.pnucc.org/system-planning/northwest-regional-forecast.

Attachments:
PNUCC 2019 Forecast
PNUCC Press Release

# Northwest Regional Forecast

of Power Loads and Resources

2020 through 2029

PNUCC

April 2019

Special thanks to PNUCC System Planning Committee members and utility staff that provided us with this information.

Electronic copies of this report are available on the

PNUCC website

**www.PNUCC.org**

**101 SW Main Street, Suite 1605**

**Portland, OR 97204**

**503.294.1259**

# Table of Contents

# 2019 Northwest Regional Forecast Executive Summary

## The One Certainty is Change

This annual analysis of Northwest utilities' data predicts the region's electric power need based on a look at supply and demand over the next 10 years, recognizing the unpredictability of weather and water conditions. This *Northwest Regional Forecast* has been a valuable tool to help inform utilities, decision-makers and others facing important decisions about the resource investments needed to ensure that the region has adequate supplies of electricity to meet the requirements of a growing region with a changing power supply picture.

This year's report, published on the heels of a recent record-setting wholesale energy price event in March, underscores the region's need for generating and demand-side resources that match up with characteristics of consumers' demand for electricity. It may also be a sign that traditional resource planning cannot fully capture the abilities and inabilities of our more dynamic, diverse power system.

This report largely shows a continuation of several compounding trends impacting the electric power industry's planning and operations. With the hydropower system as a backbone and a heavy reliance on future energy efficiency savings, utilities continue to operate – and make decisions about future power supply and demand – within a changing and sometimes chaotic economic, political, technological and social environment. The one certain thing is that the utility landscape continues to change and evolve.

Most notably, these are the key trends worth watching:

- Northwest utilities are achieving carbon-reduction goals and many are seeking opportunities to do more, while policymakers seem eager to enact more aggressive decarbonization legislation.
- Although the winter period shows improvement, serving winter peak demand remains a concern. And summertime peak demand continues to increase, focusing planners on peak capacity needs.
- The loss of several coal-fired power plants over the next decade will contribute to the challenges of maintaining an adequate, reliable power supply. In the Northwest, nearly 2,100 MW will be retired by 2022 with another 1,500 MW by 2029. Similarly, many more retirements are anticipated across the west, adding to regional adequacy concerns.
- Current planned construction of new wind and other renewable resources cannot be expected to fully offset the anticipated loss of generation from coal-fired power plant retirements.
- The use of new technologies, such as large-scale batteries, is being explored to confirm a greater role in utilities' resource plans.
- Growth in demand for electricity is not consistent across the region. On average, load growth is forecast under one percent annually. Some utilities are experiencing declining or flat loads, while a few expect well over three percent annual growth in demand through time.

These and other data-based perspectives are outlined in more detail on the following pages.

## Decarbonization is Happening

Decarbonization of electric power supply is the conversion of fossil fuel-based energy to lower-carbon electricity sources. Utilities are taking action to transition their power supply, and states' legislatures are considering additional action aimed at reducing carbon emissions more aggressively, including both Oregon and Washington. California already has very aggressive carbon-reduction goals in place that will also impact the Northwest.

Utilities have taken the decarbonization goal to heart. To meet policy directives and consumers' desires, they are setting corporate carbon reduction goals to reduce greenhouse gasses that contribute to climate change. Customers are expecting that their utility will invest more in wind, solar and other renewables.

Programs to accommodate electric-powered vehicles with charging stations and incentives are also top-of-mind among electric utilities across the region as they move to decarbonize. In addition, utilities continue to encourage more homes and businesses to pursue efficient heat pumps while pursuing more non-carbon generation. The success of these electrification efforts will influence future power supply and demand forecasts, but just how much is yet to be determined.

## Coal Retirements Underscore Reliability Challenges

Plans to retire eight coal-fired power units that serve the region will reduce the almost 6,800 megawatts of coal-fired generation available today to below 3,200 megawatts by 2028. This loss of more than 3,600 megawatts of dispatchable generation (both utility and non-utility owned) will be most notable during peak-demand periods in the winter and summer.

The committed and planned new generation facilities on the drawing board for the next five years are renewables projects. Then almost 950 MW of natural gas-fired generation are penciled in between 2025 and 2028. Utilities also continue to pursue aggressive energy-efficiency along with demand side-management programs designed to reduce energy use during peak periods. They are looking to capacity contracts and seeking to prove new technologies such as batteries, to also help fill the void created by the closure of the coal units.

Taken together, this is presenting the region with new challenges for reliably meeting demand under certain conditions. There is plenty of work ahead to identify and develop resources that meet the desire of customers and provide the supply attributes to ensure an adequate power system in the years ahead.

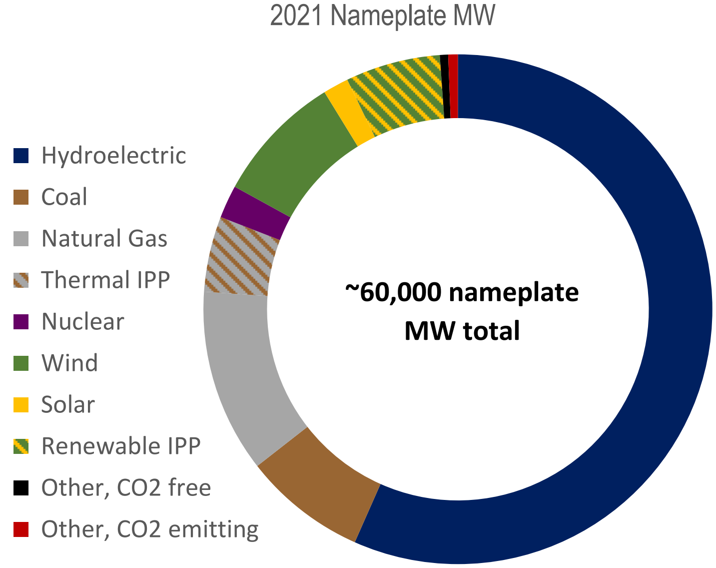
Figure 1: Northwest Planned Coal Unit Retirements

| Project | Nameplate MW | Schedule |
|---|---|---|
| Valmy Unit 1 | 254 | End of 2019 |
| Centralia Unit 1 | 670 | End of 2020 |
| Boardman | 585 | End of 2020 |
| Colstrip Unit 1 & 2 | 660 | July 2022 |
| Centralia Unit 2 | 670 | End of 2025 |
| Valmy Unit 2 | 267 | End of 2025 |
| Jim Bridger 2 | 540 | End of 2028 |
| **Total** | **3,646 MW** | |

## Hydropower Still Dominates

Utilities in the Northwest depend on a reliable, low-carbon fleet of resources to ensure that we meet the energy needs of customers. Since the 1930s, hydroelectric power has been the centerpiece of the Northwest's low-carbon energy portfolio, making up nearly 60 percent of the total electricity supply built in the region today. Even in low water conditions, hydropower makes up more than 60 percent of the region's winter peak capacity supply. Of course, the more abundant the water supply in a year, the greater the share of the Northwest's electric generation hydro provides.

Figure 2: Northwest Generating Resources

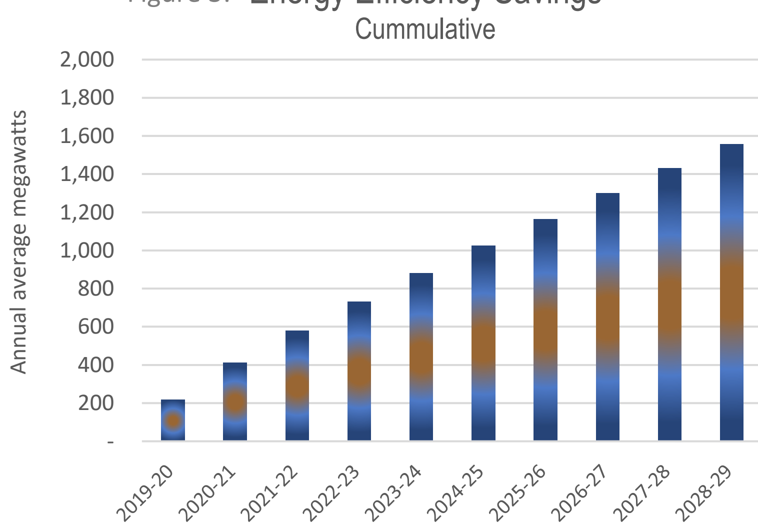



Our reliance on hydropower means the average carbon footprint of the Northwest's generating resources is less than half of the rest of the nation. It also means that the Northwest, in aggregate, has a head start in meeting national, regional, statewide and local goals that may be established for decarbonization.

## One Constant: Energy Efficiency

Northwest utilities' steady and long-term commitment to offering energy-efficiency programs and incentives to customers has saved thousands of average megawatts, reducing the need to invest in new and expensive power plants. According to the Northwest Power & Conservation Council, a multi-state planning agency, the Northwest has saved more than 6,600 average annual megawatts since 1978 thanks to energy efficiency.

Figure 3: Energy Efficiency Savings

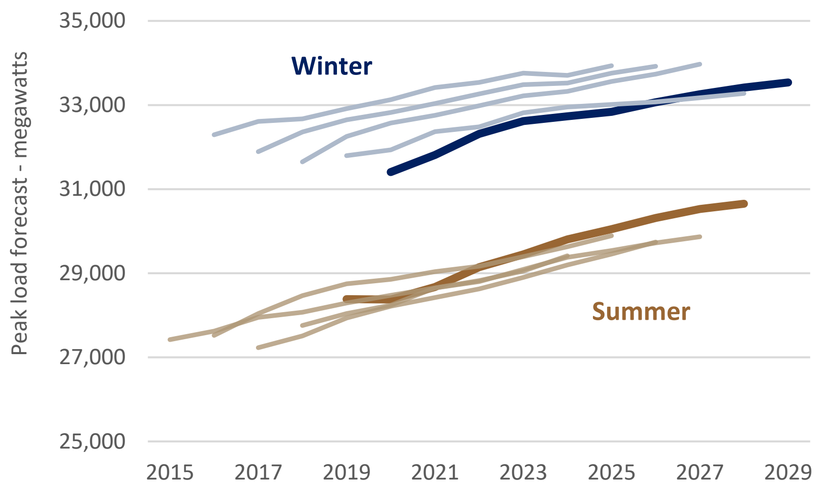



Based on utility data the Northwest has consistently exceeded its goals. The story remains constant. Utilities continue to invest heavily into energy efficiency, forecasting savings of almost 160 average megawatts per year. These numbers don't include the added savings from federal building and construction codes and standards, nor any market transformation efforts. The *Forecast* continues to predict significant energy efficiency acquisitions over the next decade.

## Peak Demand Remains a Concern

The trends for meeting the region's demand for power, especially during peak periods, might be as different as summer and winter – literally. Summer demand for electricity continues to stay on track. Multiple factors are likely contributing to this upward trend, including increased air conditioning. The projection for winter peak demand has slipped year over year. This is likely due to more energy efficiency, use of natural gas for heating, lost industrial load, among other drivers.

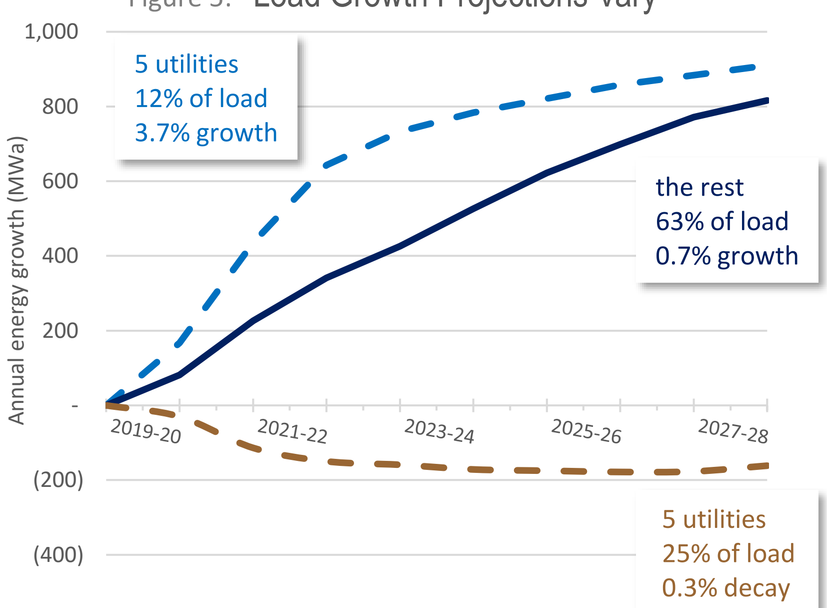
Figure 4: Summer Growth Outpacing Winter




## Growth Varies Across the Region

The overall growth in demand is not consistent across the Northwest. Some utilities are experiencing significant growth, due largely to anticipated new industrial customers. Many of these utilities are located east of the Cascades in Oregon and Washington, where lower electricity costs, cheaper land prices and other factors are attracting new, large customers – particularly high-tech companies that need large amounts of electricity for data centers.

Figure 5: Load Growth Projections Vary




The annual average load growth for the region is less than 1 percent – 0.8 percent over the ten-year horizon. Yet, demand for electricity for just five utilities is growing at an average rate of 3.7 percent per year, while five other utilities are anticipating decaying loads on average of 0.3 percent per year. The region's remaining utilities (over 60 percent of total demand) are expecting to grow on average at 0.7 percent annually.

Typically, the utilities with declining loads expect no new industrial customers to locate within their service territories. And while the number of residential customers is ticking up, energy use per customer is declining due to energy efficiency and federal codes and standards for new construction, use of natural gas for heating purposes or other factors.

## Winter Need Remains, Summer Need Coming

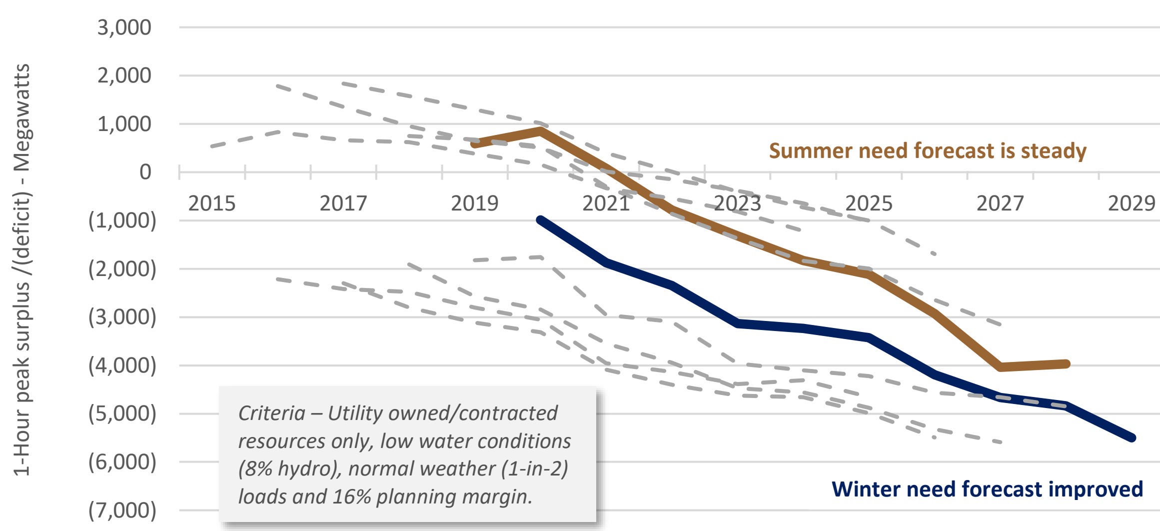
The Northwest has adequate generation to meet customer demand during most times of the year. However, the winter peak need still exists under this forecast's planning criteria. Although the picture has improved (in part due to the loss of large industrial load), the peak deficit grows through time if no future actions are taken.

The steady trend of a growing summer peak need is also drawing attention. Planning projections continue to indicate that within the *Forecast* horizon, summer peak requirements will outpace utilities' firm generation, challenging utility planners to consider actions to address both winter and summer peak capacity need. This is underscored with the planned coal unit retirements (See Figure 1 above) and periodic experiences of tighter power supply throughout the west in the last few years.

This increasing sense of concern regarding winter and summer resource adequacy seems counterintuitive to the *Need for Power* pictured here. Summer need is similar to past reports and the winter picture is improving. However, we cannot look at the Northwest utilities' load/resource balance picture in isolation.

Northwest utilities have leaned on better than low hydro generation, power from independent power producers, and imports from outside the region to ease adequacy concerns. Looking ahead, those same opportunities may not exist. Hydro generation, depending on water supply, varies and can continue to provide non-firm power. However, as large thermal resources are retired throughout the Western Interconnection, the availability of non-firm power (the market) is shrinking, especially during hours of low renewable production. The retirements, along with the growing uncertainty of a utility or developer's ability to build gas turbines to replace that lost generation, have triggered efforts to examine Northwest resource adequacy in a greater context.

Figure 6: Need for Power

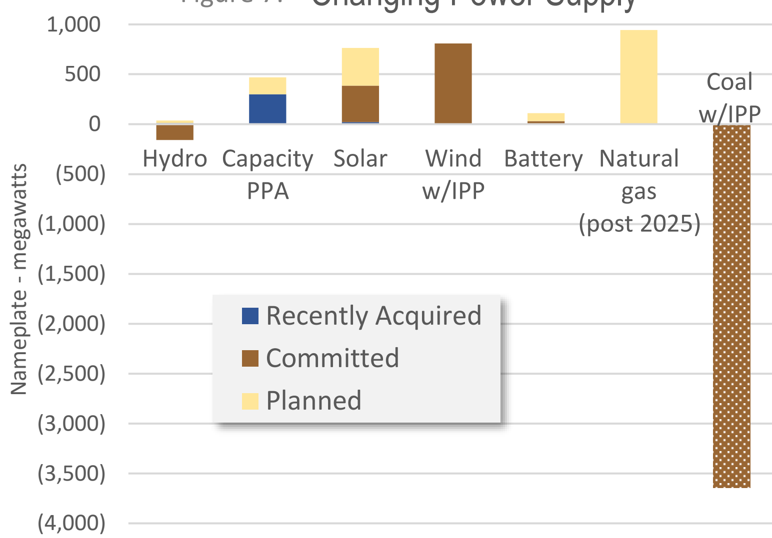


## New Resource Plans Dynamic

This year's *Forecast* reflects a quickening pace-of-change for utilities' plans for acquiring new resources. New renewables are jumping in as committed, and planned new resources often show up one year and then fall away in another as utilities refine their plans to account for changing circumstances. Since last year's *Forecast*, another coal unit closure has shown up in our planning horizon and been added to our tally for a total of over 3,600 MW of dispatchable capacity leaving the picture. In addition, the first large-scale battery (30 MW) will be integrated with a combined 350 MW wind and solar project in Eastern Oregon that has been committed to the Northwest.

The changes are stacking up. We expect more in next year's report as utilities announce new goals for developing renewable generation and further decarbonizing their resource portfolios. Utilities have added 300 megawatts of contracts and 34 MW of new generation since last year. Nearly 900 megawatts of new generating resource, all wind and solar, are committed to be built in the next few years, as well as 200 MW of non-utility wind. Committed resources are included in the need for power assessment.

Figure 7: Changing Power Supply




Utilities reported nearly 1,600 megawatts of nameplate capacity in the planning stage – mostly wind, batteries and solar power from 2019 to 2025. Starting in 2025, planned natural gas plants begin to appear, totaling over 900 MW by 2027. On the outgoing side, as mentioned earlier, are almost 3,600 MW of coal (including coal units owned by Independent Power Producers).

## The Future is Here

This year's *Northwest Regional Forecast* continues a trend that is relatively new in its 70-year history. Over the past two decades, the region has transformed into a more diverse mix of resources and customers. Stepping up to meet this challenge, utilities are carefully navigating a path for a reliable, adequate, affordable future.

Changes in customer desires have impacted energy usage and future supply. We have met the challenge to integrate new wind and solar resources into our existing hydropower dominate system. We are looking at how to achieve new, more aggressive carbon-reduction goals at the state and national level, in a region that already leads the country in a low carbon power supply. And we are paying careful attention to resolving the impact of the retiring dispatchable resources in this changing power supply landscape.

As always, we will keep our collective eyes on emerging trends and developments as new technologies for power supply evolve and the desires of consumers change.

# Overview

Each year the *Northwest Regional Forecast* compiles utilities' 10-year projections of electric loads and resources which provide information about the region's need to acquire new power supply. The Forecast is a comprehensive look at the capability of existing and new electric generation resources, long-term firm contracts, expected savings from demand side management programs and other components of electric demand for the Northwest.

This report presents estimates of annual average energy, seasonal energy and winter and summer peak capability in Tables 1 through 4 of the Northwest Region Requirements and Resources section. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

Northwest generating resources are shown by fuel type. Existing resources include those resources listed in Tables 5, 6, 10 and 11. Table 5, Recently Acquired Resources, highlights projects and supply that became available most recently. Table 6, Committed New Supply, lists those generating projects where construction has started, as well as contractual arrangements that have been made for providing power at a future time. Table 10, Northwest Utility Generating Resources, is a comprehensive list of generating resources that make up the electric power supply for the Pacific Northwest that are utility-owned or utility contracted. Table 11, Independent Owned Generating Resources, lists generating projects owned by independent power producers and located in the Northwest.

In addition, utilities have demand side management programs in place to reduce the need for generating resources. Table 7, Demand-Side Management Programs, provides a snapshot of expected savings from these programs for the next ten years. Table 8, Planned Resources, is a compilation of what utilities have reported in their individual integrated resource plans to meet future need.

## Planning Area

The Northwest Regional Planning Area is the area defined by the *Pacific Northwest Electric Power Planning and Conservation Act*. It includes: the states of Oregon, Washington, and Idaho; Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin; and any rural electric cooperative customer not in the geographic area described above, but served by BPA on the effective date of the *Act*.

# Northwest Region Requirements and Resources

**Table 1. Northwest Region Requirements and Resources – Annual Energy** shows the sum of the individual utilities' requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

| Average Megawatts | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Firm Requirements** | | | | | | | | | | |
| Load [1/] | 20,472 | 20,691 | 21,026 | 21,314 | 21,482 | 21,623 | 21,755 | 21,867 | 21,969 | 22,051 |
| Exports | 476 | 465 | 467 | 467 | 467 | 467 | 467 | 467 | 467 | 467 |
| **Total** | 20,947 | 21,157 | 21,493 | 21,781 | 21,949 | 22,090 | 22,222 | 22,334 | 22,436 | 22,518 |
| **Firm Resources** | | | | | | | | | | |
| Hydro [2/] | 11,117 | 11,117 | 11,097 | 11,079 | 11,080 | 11,080 | 11,080 | 11,080 | 11,080 | 11,080 |
| Natural Gas3/ | 4,637 | 4,627 | 4,586 | 4,481 | 4,462 | 4,359 | 4,340 | 4,136 | 4,137 | 4,094 |
| Renewables-Other | 235 | 233 | 230 | 227 | 227 | 227 | 224 | 214 | 215 | 216 |
| Solar | 189 | 254 | 269 | 268 | 268 | 267 | 268 | 268 | 268 | 268 |
| Wind | 1,308 | 1,397 | 1,378 | 1,337 | 1,322 | 1,314 | 1,314 | 1,299 | 1,261 | 1,258 |
| Cogeneration | 45 | 45 | 27 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Imports | 706 | 709 | 711 | 713 | 716 | 671 | 640 | 338 | 339 | 339 |
| Nuclear | 1,100 | 937 | 1,100 | 937 | 1,100 | 937 | 1,100 | 937 | 1,100 | 937 |
| Coal | 3,621 | 3,664 | 3,111 | 3,108 | 2,912 | 2,847 | 2,741 | 2,796 | 2,732 | 2,248 |
| **Total** | 22,958 | 22,984 | 22,509 | 22,160 | 22,094 | 21,711 | 21,713 | 21,076 | 21,140 | 20,448 |
| **Surplus (Deficit)** | **2,011** | **1,827** | **1,017** | **379** | **145** | **(379)** | **(509)** | **(1,258)** | **(1,296)** | **(2,070)** |

[1/] Loads net of energy efficiency
[2/] Firm hydro for energy is the generation expected assuming 1936-37 water conditions
[3/] There is likely more energy available from thermal units whose data shows only planned generation

**Table 2. Northwest Region Requirements and Resources – Monthly Energy** shows the monthly energy values for the 2019-2020 operating year.

| Average Megawatts | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Firm Requirements** | | | | | | | | | | | | |
| Load [1/] | 20,346 | 18,609 | 18,709 | 20,767 | 23,536 | 23,213 | 21,649 | 20,459 | 19,129 | 18,848 | 19,737 | 20,977 |
| Exports | 613 | 521 | 521 | 521 | 521 | 491 | 491 | 491 | 491 | 491 | 491 | 506 |
| **Total** | 20,959 | 19,130 | 19,230 | 21,288 | 24,056 | 23,704 | 22,140 | 20,950 | 19,620 | 19,339 | 20,227 | 21,483 |
| **Firm Resources** | | | | | | | | | | | | |
| Hydro [2/] | 11,715 | 9,136 | 9,526 | 10,863 | 11,595 | 11,202 | 9,144 | 9,581 | 9,412 | 11,341 | 14,633 | 13,512 |
| Natural Gas [3/] | 4,733 | 4,553 | 4,378 | 4,736 | 4,998 | 5,030 | 4,740 | 4,524 | 4,208 | 3,917 | 4,523 | 4,739 |
| Renewables-Other | 228 | 232 | 240 | 245 | 244 | 240 | 238 | 240 | 228 | 219 | 224 | 227 |
| Solar | 226 | 181 | 132 | 67 | 50 | 82 | 152 | 210 | 291 | 341 | 382 | 401 |
| Wind | 1,199 | 1,196 | 1,143 | 1,185 | 1,198 | 1,038 | 1,298 | 1,486 | 1,524 | 1,455 | 1,536 | 1,439 |
| Cogeneration | 43 | 45 | 47 | 47 | 55 | 55 | 51 | 54 | 46 | 40 | 28 | 43 |
| Imports | 701 | 659 | 671 | 705 | 744 | 762 | 729 | 736 | 674 | 677 | 697 | 721 |
| Nuclear | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 |
| Coal | 3,852 | 3,852 | 3,852 | 3,852 | 3,852 | 3,737 | 3,737 | 3,647 | 3,220 | 2,966 | 2,876 | 3,737 |
| **Total** | 23,798 | 20,953 | 21,088 | 22,799 | 23,835 | 23,247 | 21,190 | 21,577 | 20,703 | 22,056 | 25,998 | 25,918 |
| **Surplus (Deficit)** | **2,839** | **1,823** | **1,858** | **1,511** | **(222)** | **(457)** | **(950)** | **627** | **1,083** | **2,717** | **5,771** | **4,435** |

[1/] Loads net of energy efficiency
[2/] Firm hydro for energy is the generation expected assuming 1936-37 water conditions
[3/] There is likely more energy available from thermal units whose data shows only planned generation

## Table 3. Northwest Region Requirements and Resources – Winter Peak

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

| Megawatts | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Firm Requirements** | | | | | | | | | | |
| Load [1/] | 31,405 | 31,811 | 32,317 | 32,620 | 32,732 | 32,839 | 33,069 | 33,255 | 33,418 | 33,537 |
| Exports | 1,150 | 1,174 | 1,003 | 1,000 | 998 | 1,009 | 1,017 | 1,017 | 1,001 | 997 |
| Planning Margin [2/] | 5,025 | 5,090 | 5,171 | 5,219 | 5,237 | 5,254 | 5,291 | 5,321 | 5,347 | 5,366 |
| **Total** | 37,580 | 38,075 | 38,490 | 38,840 | 38,967 | 39,102 | 39,378 | 39,593 | 39,766 | 39,900 |
| **Firm Resources** | | | | | | | | | | |
| Hydro [3/] | 22,549 | 22,549 | 22,549 | 22,546 | 22,546 | 22,546 | 22,546 | 22,546 | 22,546 | 22,546 |
| Demand Response | 42 | 86 | 92 | 120 | 146 | 169 | 206 | 224 | 228 | 228 |
| Small Thermal & Misc. | 167 | 167 | 167 | 167 | 167 | 167 | 167 | 167 | 165 | 165 |
| Natural Gas | 6,546 | 6,556 | 6,556 | 6,418 | 6,417 | 6,417 | 6,417 | 6,157 | 6,157 | 6,157 |
| Renewables-Other | 250 | 248 | 241 | 241 | 241 | 241 | 241 | 223 | 223 | 223 |
| Solar | 10 | 13 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Wind | 289 | 309 | 297 | 276 | 271 | 271 | 271 | 271 | 270 | 270 |
| Cogeneration | 59 | 59 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Imports | 1,367 | 1,471 | 1,475 | 1,479 | 1,483 | 1,407 | 1,010 | 1,013 | 1,016 | 1,016 |
| Nuclear | 1,144 | 1,144 | 1,144 | 1,144 | 1,144 | 1,144 | 1,144 | 1,144 | 1,144 | 1,144 |
| Coal | 4,168 | 3,598 | 3,598 | 3,291 | 3,291 | 3,291 | 3,157 | 3,157 | 3,157 | 2,627 |
| **Total** | 36,592 | 36,200 | 36,143 | 35,706 | 35,730 | 35,676 | 35,183 | 34,926 | 34,931 | 34,400 |
| **Surplus (Need)** | **(988)** | **(1,875)** | **(2,348)** | **(3,134)** | **(3,237)** | **(3,426)** | **(4,195)** | **(4,667)** | **(4,835)** | **(5,500)** |

[1/] Expected (1-in-2) loads net of energy efficiency
[2/] Planning margin is 16% of load in every year (this is a change since 2018)
[3/] Firm hydro for capacity is the generation expected assuming critical (8%) water condition

## Table 4. Northwest Region Requirements and Resources – Summer Peak

The sum of the individual utilities' firm requirements and resources for a peak hour in August for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

| Megawatts | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Firm Requirements** | | | | | | | | | | |
| Load [1/] | 28,380 | 28,375 | 28,674 | 29,140 | 29,450 | 29,805 | 30,051 | 30,315 | 30,529 | 30,652 |
| Exports | 1,726 | 1,491 | 1,504 | 1,510 | 1,580 | 1,689 | 1,637 | 1,619 | 2,250 | 2,037 |
| Planning Margin [2/] | 4,541 | 4,540 | 4,588 | 4,662 | 4,712 | 4,769 | 4,808 | 4,850 | 4,885 | 4,904 |
| **Total** | 34,647 | 34,405 | 34,766 | 35,312 | 35,742 | 36,263 | 36,496 | 36,785 | 37,664 | 37,594 |
| **Firm Resources** | | | | | | | | | | |
| Hydro [3/] | 21,267 | 21,267 | 21,267 | 21,264 | 21,264 | 21,264 | 21,264 | 21,264 | 21,264 | 21,264 |
| Demand Response | 381 | 415 | 425 | 451 | 471 | 486 | 506 | 536 | 542 | 542 |
| Small Thermal & Misc. | 165 | 167 | 167 | 167 | 167 | 167 | 167 | 167 | 165 | 165 |
| Natural Gas | 6,084 | 6,095 | 6,095 | 6,097 | 5,962 | 5,962 | 5,961 | 5,957 | 5,720 | 5,720 |
| Renewables-Other | 253 | 251 | 249 | 243 | 243 | 243 | 243 | 225 | 225 | 225 |
| Solar | 249 | 336 | 389 | 406 | 406 | 406 | 406 | 406 | 406 | 406 |
| Wind | 298 | 306 | 325 | 293 | 293 | 284 | 284 | 284 | 280 | 280 |
| Cogeneration | 50 | 50 | 26 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Imports | 1,066 | 1,072 | 1,178 | 1,184 | 1,189 | 1,194 | 1,120 | 725 | 730 | 730 |
| Nuclear | 1,128 | 1,128 | 1,128 | 1,128 | 1,128 | 1,128 | 1,128 | 1,128 | 1,128 | 1,128 |
| Coal | 4,295 | 4,168 | 3,598 | 3,291 | 3,291 | 3,291 | 3,291 | 3,157 | 3,157 | 3,157 |
| **Total** | 35,235 | 35,254 | 34,846 | 34,532 | 34,423 | 34,435 | 34,379 | 33,859 | 33,625 | 33,625 |
| **Surplus (Need)** | **588** | **849** | **81** | **(781)** | **(1,320)** | **(1,828)** | **(2,117)** | **(2,926)** | **(4,039)** | **(3,969)** |

[1/] Expected (1-in-2) loads net of energy efficiency

[2/] Planning margin is 16% of load in every year (this is a change since 2018)

[3/] Firm hydro for capacity is the generation expected assuming critical (8%) water condition

# Northwest New and Existing Resources

**Table 5. Recently Acquired Resources** highlights projects that have recently become available.

| Project | Fuel/Tech | Nameplate (MW) | Winter Peak (MW) | Summer Peak (MW) | Energy (MWa) | Utility/Owner |
|---|---|---|---|---|---|---|
| Calligan Creek | Hydro | 6 | 6 | 2 | | Snohomish PUD |
| Hancock Creek | Hydro | 6 | 6 | 3 | | Snohomish PUD |
| Adams Neilson PPA | Solar | 22 (AC) | | | | Avista/Strata Solar |
| BPA capacity PPA | PPA | 200 | 200 | 200 | | PGE |
| AvanGrid capacity PPA | PPA | 100 | 100 | 100 | | PGE |
| **Total** | | **334** | | | | |

**Table 6. Committed New Supply** details contracts and generating projects where construction has started and that utilities are counting on to meet need. All supply listed in this table is included in the regional analysis of power needs.

| Project | Year | Fuel/Tech | Name plate (MW) | Winter Peak (MW) | Summer Peak (MW) | Energy (MWa) | Utility/Owner |
|---|---|---|---|---|---|---|---|
| Vale 1 Solar | 2019 | Solar | 3 | | 5 | 2 | Idaho Power |
| Brush Solar | 2019 | Solar | 3 | | 1 | 1 | Idaho Power |
| Morgan Solar | 2019 | Solar | 3 | | 2 | 2 | Idaho Power |
| Baker Solar Center | 2019 | Solar | 15 | | 8 | | Idaho Power |
| PacifiCorp Wind Repower | 2019 | Wind | 25 | | | | PacifiCorp |
| Rattlesnake Flat | 2020 | Wind | 144 | | | 50 | Avista/Clearway |
| Skookumchuck | 2020 | Wind | 139 | | | | PSE |
| Montauge Wind (IPP) | 2020 | Wind | 200 | | | | Avangrid |
| Wheatfield Wind | 2020 | Wind | 300 | 49 | 49 | 100 | PGE/NextEra |
| Wheatfield Battery | 2021 | Battery | 30 | | | | PGE/NextEra |
| East. WA. Solar | 2021 | Solar | 150 | | | | PSE/Avangrid |
| Wheatfield Solar | 2021 | Solar | 50 | | | | PGE/NextEra |
| Idaho/Twin Falls Solar | 2022 | Solar | 120 | | | | Idaho Power/Jackpot |
| **Total** | | | **1,182** | | | | |

**Table 7. Demand-Side Management Programs** is a snapshot of the regional utilities' efforts to manage demand. The majority of the energy efficiency savings are from utility programs and included in the regional analysis of power needs. This table also shows cumulative existing plus new demand response programs reported by utilities.

| | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Energy Efficiency (MWa)** | | | | | | | | | | |
| Incremental | 218 | 194 | 166 | 152 | 150 | 143 | 141 | 135 | 130 | 128 |
| Cumulative | 218 | 413 | 579 | 731 | 881 | 1,023 | 1,165 | 1,299 | 1,429 | 1,558 |
| **Demand Response (MW)** | | | | | | | | | | |
| Winter (exist.+ forecast) | 42 | 86 | 92 | 120 | 146 | 169 | 206 | 224 | 228 | 228 |
| Summer (exist. + forecast) | 381 | 415 | 425 | 451 | 471 | 486 | 506 | 536 | 542 | 542 |

**Table 8. Planned Resources** catalogues potential resources that utilities have identified to meet their own needs. These resources are not included in the regional analysis of power needs.

| Project | Date | Fuel/Tech | Nameplate (MW) | Winter Peak (MW) | Summer Peak (MW) | Energy (MWa) | Utility |
|---|---|---|---|---|---|---|---|
| Generator Replacement | 2019 | Hydro | 9 | 9 | 9 | | Grant County PUD |
| Generator Replacement | 2019 | Hydro | 9 | 9 | 9 | | Grant County PUD |
| Generator Rebuild | 2019 | Hydro | 9 | 9 | 9 | | Grant County PUD |
| Capacity PPA | 2019 | Unknown | 50 | 50 | - | 5 | Snohomish PUD |
| Hydro Upgrade | 2020 | Hydro | 3 | - | 3 | | Idaho Power |
| Solar | 2022 | Solar | 266 | 0 | | | PSE |
| Battery | 2023 | Battery | 50 | 38 | | | PSE |
| Battery | 2024 | Battery | 25 | 15 | | | PSE |
| Solar | 2024 | Solar | 112 | 0 | | | PSE |
| Natural Gas Peaker | 2025 | Natural Gas | 239 | 239 | | | PSE |
| Natural Gas Peaker | 2026 | Natural Gas | 192 | 204 | 177 | 178 | Avista |
| Natural Gas Peaker | 2026 | Natural Gas | 239 | 239 | | | PSE |
| Thermal Upgrades | 2026-2029 | Natural Gas | 34 | 34 | 35 | 31 | Avista |
| Natural Gas Peaker | 2027 | Natural Gas | 239 | 239 | | | PSE |
| Capacity Resource | 2028 | Unknown | 120 | 116 | 116 | 12 | Snohomish PUD |
| Storage | 2029 | Unknown | 5 | 5 | 5 | 0 | Avista |
| **Total** | | | **1,599** | | | | |

**Table 9. Committed and *Planned* Dispatchable Resources Timeline** provides an expected schedule for new resource additions for both the committed resources already included in the load/resource picture, and planned resources that are not as far along in the acquisition/build process.

| Nameplate MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hydro | *26* | (160) | | | | | | | | | | (134) |
| Capacity | *50* | | | | | | | | | *120* | | 170 |
| Solar | 24 | | 200 | *266* | | *112* | | | | | | 741 |
| Wind (inc. IPP) | 25 | 783 | | | | | | | | | | 808 |
| Battery | | | 30 | | *50* | *25* | | | | | *5* | 110 |
| Natural gas | | | | | | | *239* | *431* | *273* | | | 943 |
| Demand Response | | | 44 | 6 | 28 | 26 | 23 | 37 | 17 | 5 | | 186 |
| Coal (inc. IPP) | (254) | (1,255) | | (660) | | | (937) | | | (540) | | (3,646) |
| **Total incremental** | **(129)** | **(632)** | **274** | **(248)** | **78** | **163** | **(675)** | **468** | **290** | **(416)** | **5** | |
| **Total cumulative** | **(129)** | **(761)** | **(487)** | **(735)** | **(657)** | **(494)** | **(1,169)** | **(701)** | **(411)** | **(827)** | **(823)** | |

**Table 10. Northwest Utility Generating Resources** is a comprehensive list of utility-owned and utility contracted generating resources that make up those utilities electric power supply.

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| **HYDRO** | | | **33,344** |
| Albeni Falls | US Corps of Engineers | Federal System (BPA) | 43 |
| Alder | Tacoma Power | Tacoma Power | 50 |
| American Falls | Idaho Power | Idaho Power | 92 |
| Anderson Ranch | US Bureau of Reclamation | Federal System (BPA) | 40 |
| Arena Drop | PURPA | Idaho Power | 0 |
| Arrowrock Dam | Clatskanie PUD/Irrigation Dist. | Clatskanie PUD | 18 |
| B. Smith | PacifiCorp | PacifiCorp | 0 |
| Baker City Hydro | | Idaho Power | |
| Barber Dam | | Idaho Power | 4 |
| Bell Mountain | PacifiCorp | PacifiCorp | 1 |
| Big Sheep Creek | Everand Jensen | Avista Corp. | 0 |
| Big Cliff | US Corps of Engineers | Federal System (BPA) | 18 |
| Birch Creek | PURPA | Idaho Power | 0 |
| Birch Creek | PacifiCorp | PacifiCorp | 3 |
| Black Canyon # 3 | PURPA | Idaho Power | 0 |
| Black Canyon | US Bureau of Reclamation | Federal System (BPA) | 10 |
| Black Canyon Bliss Dam | PURPA | Idaho Power | - |
| Black Creek Hydro | Black Creek Hydro, Inc. | Puget Sound Energy | 4 |
| Blind Canyon | PURPA | Idaho Power | 2 |
| Boston Power | | PacifiCorp | |
| Bliss | Idaho Power | Idaho Power | 75 |
| Boise River Diversion | US Bureau of Reclamation | Federal System (BPA) | 2 |
| Bonneville | US Corps of Engineers | Federal System (BPA) | 1,102 |
| Box Canyon-Idaho | PURPA | Idaho Power | 0 |
| Boundary | Seattle City Light | Seattle City Light | 1,119 |
| Box Canyon | Pend Oreille County PUD | Pend Oreille County PUD | 70 |
| Briggs Creek | PURPA | Idaho Power | 1 |
| Brownlee | Idaho Power | Idaho Power | 585 |
| Bypass | PURPA | Idaho Power | 10 |
| Cabinet Gorge | Avista Corp. | Avista Corp. | 265 |
| Calligan Creek | Snohomish County PUD | Snohomish County PUD | 6 |
| Calispel Creek | Pend Oreille County PUD | Pend Oreille County PUD | 1 |
| Canyon Springs | PURPA | Idaho Power | 0 |
| Carmen-Smith | Eugene Water & Electric Board | Eugene Water & Electric Board | 105 |
| Cascade | US Bureau of Reclamation | Idaho Power | 12 |
| CDM Hydro | PacifiCorp | PacifiCorp | 6 |
| Cedar Falls, Newhalem | PURPA | Seattle City Light | 33 |
| Central Oregon Siphon | | PacifiCorp | 5 |
| Chandler | US Bureau of Reclamation | Federal System (BPA) | 12 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Chelan | Chelan County PUD | Chelan County PUD | 59 |
| Chief Joseph | US Corps of Engineers | Federal System (BPA) | 2,457 |
| C. J. Strike | Idaho Power | Idaho Power | 83 |
| Clark Canyon Dam | PURPA | Idaho Power | 8 |
| Clear Lake | Idaho Power | Idaho Power | 3 |
| Clear Springs Trout | PURPA | Idaho Power | 1 |
| Clearwater #1 | PacifiCorp | PacifiCorp | 15 |
| Clearwater #2 | PacifiCorp | PacifiCorp | 26 |
| Cline Falls | COID | PacifiCorp | 1 |
| COID | PacifiCorp | PacifiCorp | 7 |
| Copco #1 | PacifiCorp | PacifiCorp | 20 |
| Copco #2 | PacifiCorp | PacifiCorp | 27 |
| Cougar | US Corps of Engineers | Federal System (BPA) | 25 |
| Cowlitz Falls | Lewis County PUD | Federal System (BPA) | 70 |
| Crystal Springs | PURPA | Idaho Power | 2 |
| Curry Cattle Company | PURPA | Idaho Power | 0 |
| Curtis Livestock | PacifiCorp | PacifiCorp | 0 |
| Cushman 1 | Tacoma Power | Tacoma Power | 43 |
| Cushman 2 | Tacoma Power | Tacoma Power | 81 |
| Deep Creek | Gordon Foster | Avista Corp. | 0 |
| Derr Creek | Jim White | Avista Corp. | 0 |
| Detroit | US Corps of Engineers | Federal System (BPA) | 100 |
| Dexter | US Corps of Engineers | Federal System (BPA) | 15 |
| Diablo Canyon | Seattle City Light | Seattle City Light | 182 |
| Dietrich Drop | PURPA | Idaho Power | 5 |
| Dry Creek | | PacifiCorp | 4 |
| D. Wiggins | | PacifiCorp | |
| Dworshak | US Corps of Engineers | Federal System (BPA) | 400 |
| Dworshak/ Clearwater | | Federal System (BPA) | |
| Eagle Point | PacifiCorp | PacifiCorp | 3 |
| East Side | PacifiCorp | PacifiCorp | 3 |
| Eight Mile Hydro | PURPA | Idaho Power | 0 |
| Electron | Electron Hydro, LLC | Puget Sound Energy | 23 |
| Elk Creek | PURPA | Idaho Power | 2 |
| Eltopia Branch Canal | SEQCBID | Seattle City Light | 2 |
| Esquatzel Small Hydro | Green Energy Today, LLC | Franklin County PUD | 1 |
| Fall Creek | PacifiCorp | PacifiCorp | 3 |
| Falls Creek | Clallam PUD | Other Public (BPA) | 0 |
| Falls River | PURPA | Idaho Power | 9 |
| Faraday | Portland General Electric | Portland General Electric | 37 |
| Fargo Drop Hydro | PURPA | Idaho Power | 1 |
| Farmers Irrigation | PacifiCorp | PacifiCorp | 3 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Faulkner Ranch | PURPA | Idaho Power | 1 |
| Fish Creek | PacifiCorp | PacifiCorp | 11 |
| Fisheries Development Co. | PURPA | Idaho Power | 0 |
| Foster | US Corps of Engineers | Federal System (BPA) | 20 |
| Frontier Technologies | PacifiCorp | PacifiCorp | 4 |
| Galesville Dam | PacifiCorp | PacifiCorp | 2 |
| Gem State Hydro | | Other Publics (BPA) | 23 |
| Geo-Bon No 2 | PURPA | Idaho Power | 1 |
| Georgetown Power | PacifiCorp | PacifiCorp | 0 |
| Gorge | Seattle City Light | Seattle City Light | 207 |
| Grand Coulee | US Bureau of Reclamation | Federal System (BPA) | 6,494 |
| Green Peter | US Corps of Engineers | Federal System (BPA) | 80 |
| Green Springs | US Bureau of Reclamation | Federal System (BPA) | 16 |
| Hailey CSPP | PURPA | Idaho Power | 0 |
| Hancock Creek | Snohomish County PUD | Snohomish County PUD | 6 |
| Hazelton A | PURPA | Idaho Power | 8 |
| Hazelton B | PURPA | Idaho Power | 8 |
| Head of U Canal | PURPA | Idaho Power | 1 |
| Hells Canyon | Idaho Power | Idaho Power | 392 |
| Hills Creek | US Corps of Engineers | Federal System (BPA) | 30 |
| Hood Street Reservoir | Tacoma Power | Tacoma Power | 1 |
| Horseshoe Bend | PURPA | Idaho Power | 10 |
| Hungry Horse | US Bureau of Reclamation | Federal System (BPA) | 428 |
| Hutchinson Creek | STS Hydro | Puget Sound Energy | 1 |
| Ice Harbor | US Corps of Engineers | Federal System (BPA) | 603 |
| Idaho Falls - City Plant | | Federal System (BPA) | 8 |
| Idaho Falls - Lower Plant | | Federal System (BPA) | 8 |
| Idaho Falls - Upper Plant | | Federal System (BPA) | 8 |
| Ingram Warm Springs | PacifiCorp | PacifiCorp | 1 |
| Iron Gate | PacifiCorp | PacifiCorp | 18 |
| Island Park | | Fall River Rural Electric Cooperative | 5 |
| Jackson (Sultan) | Snohomish County PUD | Snohomish County PUD | 112 |
| James Boyd | | PacifiCorp | |
| Jim Ford Creek | Ford Hydro | Avista Corp. | 2 |
| Jim Knight | PURPA | Idaho Power | 0 |
| John C. Boyle | PacifiCorp | PacifiCorp | 90 |
| John Day | US Corps of Engineers | Federal System (BPA) | 2,160 |
| John Day Creek | Dave Cereghino | Avista Corp. | 1 |
| John H Koyle | PURPA | Idaho Power | 1 |
| Joseph Hydro | | PacifiCorp | |
| Kasel-Witherspoon | PURPA | Idaho Power | 1 |
| Kerr | NorthWestern Corporation | NorthWestern Energy | 194 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Koma Kulshan | Koma Kulshan Associates | Puget Sound Energy | 11 |
| La Grande | Tacoma Power | Tacoma Power | 64 |
| Lacomb Irrigation | PacifiCorp | PacifiCorp | 1 |
| Lake Creek | | Other Publics (BPA) | |
| Lake Oswego Corp. | | Portland General Electric | 1 |
| Lateral No. 10 | PURPA | Idaho Power | 2 |
| Leaburg | Eugene Water & Electric Board | Eugene Water & Electric Board | 16 |
| Lemolo #1 | PacifiCorp | PacifiCorp | 32 |
| Lemolo #2 | PacifiCorp | PacifiCorp | 33 |
| Lemoyne | PURPA | Idaho Power | 0 |
| Libby | US Corps of Engineers | Federal System (BPA) | 525 |
| Lilliwaup Falls | | Other Public (BPA) | 1 |
| Little Falls | Avista Corp. | Avista Corp. | 32 |
| Little Goose | US Corps of Engineers | Federal System (BPA) | 810 |
| Little Wood | PURPA | Idaho Power | 3 |
| Little Wood/Arkoosh | PURPA | Idaho Power | 1 |
| Little Wood River Ranch II | PURPA | Idaho Power | 1 |
| Lloyd Fery | PacifiCorp | PacifiCorp | 0 |
| Long Lake | Avista Corp. | Avista Corp. | 70 |
| Lookout Point | US Corps of Engineers | Federal System (BPA) | 120 |
| Lost Creek | US Corps of Engineers | Federal System (BPA) | 49 |
| Lower Baker | Puget Sound Energy | Puget Sound Energy | 115 |
| Lower Granite | US Corps of Engineers | Federal System (BPA) | 810 |
| Lower Malad | Idaho Power | Idaho Power | 14 |
| Lower Monumental | US Corps of Engineers | Federal System (BPA) | 810 |
| Lower Salmon | Idaho Power | Idaho Power | 60 |
| Lowline #2 | PURPA | Idaho Power | 3 |
| Lowline Canal | PURPA | Idaho Power | 3 |
| Lowline Midway | Idaho Power | Idaho Power | 8 |
| Lucky Peak | US Corps of Engineers | Seattle City Light | 113 |
| Magic Reservoir | PURPA | Idaho Power | 9 |
| Main Canal Headworks | SEQCBID | Seattle City Light | 26 |
| Malad River | PURPA | Idaho Power | 1 |
| Mayfield | Tacoma Power | Tacoma Power | 162 |
| McNary | US Corps of Engineers | Federal System (BPA) | 980 |
| McNary Fishway | US Corps of Engineers | Other Publics (BPA) | 10 |
| Merwin | PacifiCorp | PacifiCorp | 136 |
| Meyers Falls | Hydro Technology Systems | Avista Corp. | 1 |
| Middlefork Irrigation | PacifiCorp | PacifiCorp | 3 |
| Mile 28 | PURPA | Idaho Power | 2 |
| Mill Creek (Cove) | | Idaho Power | 1 |
| Mill Creek | | Other Publics (BPA) | 1 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Milner | Idaho Power | Idaho Power | 59 |
| Minidoka | US Bureau of Reclamation | Federal System (BPA) | 28 |
| Mink Creek | PacifiCorp | PacifiCorp | 3 |
| Mitchell Butte | PURPA | Idaho Power | 2 |
| Monroe Street | Avista | Avista Corp. | 15 |
| Mora Drop | PURPA | Idaho Power | 2 |
| Morse Creek | | Port Angeles | 1 |
| Mossyrock | Tacoma Power | Tacoma Power | 300 |
| Mountain Energy | PacifiCorp | PacifiCorp | 0 |
| Mount Tabor | City of Portland | Portland General Electric | 0 |
| Moyie Springs | City of Bonners Ferry | Other Publics (BPA) | 4 |
| Mud Creek/S&S | PURPA | Idaho Power | 1 |
| Mud Creek/White | Mud Creek Hydro | Idaho Power | 0 |
| N-32 Canal (Marco Ranches) | Ranchers Irrigation Inc. | Idaho Power | 1 |
| Nicols Gap | PacifiCorp | PacifiCorp | 1 |
| Nicolson SunnyBar | PacifiCorp | PacifiCorp | 0 |
| Nine Mile | Avista Corp. | Avista Corp. | 26 |
| Nooksack | Puget Sound Hydro, LLC | Puget Sound Energy | 2 |
| North Gooding | | Idaho Power | |
| North Fork | Portland General Electric | Portland General Electric | 41 |
| North Fork Sprague | PacifiCorp | PacifiCorp | 1 |
| N.R. Rousch | PacifiCorp | PacifiCorp | 0 |
| Noxon Rapids | Avista Corp. | Avista Corp. | 466 |
| Odell Creek | PacifiCorp | PacifiCorp | 0 |
| Oak Grove | Portland General Electric | Portland General Electric | 51 |
| O.J. Power | PacifiCorp | PacifiCorp | 0 |
| Opal Springs | PacifiCorp | PacifiCorp | 5 |
| Ormsby | | PacifiCorp | |
| Owyhee Dam | PURPA | Idaho Power | 5 |
| Oxbow | Idaho Power Company | Idaho Power | 190 |
| Packwood | Energy Northwest | Multiple Utilities | 26 |
| Palisades | US Bureau of Reclamation | Federal System (BPA) | 177 |
| PEC Headworks | SEQCBID | Grant County PUD | 7 |
| Pelton Reregulation | Warm Springs Tribe | Portland General Electric | 19 |
| Pelton | Portland General Electric | Multiple Utilities | 110 |
| Phillips Ranch | Glen Phillips | Avista Corp. | 0 |
| Pigeon Cove | PURPA | Idaho Power | 2 |
| Portland Hydro-Project | City of Portland | Portland General Electric | 36 |
| Portneuf River | | PacifiCorp | 1 |
| Potholes East Canal 66 Headworks | SEQCBID | Seattle City Light | 2 |
| Post Falls | Avista Corp. | Avista Corp. | 15 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Preston City | PacifiCorp | PacifiCorp | 0 |
| Powerdale | PacifiCorp | PacifiCorp | 6 |
| Pristine Springs | PURPA | Idaho Power | 0 |
| Priest Rapids | Grant County PUD | Multiple Utilities | 956 |
| Pristine Springs #3 | PURPA | Idaho Power | 0 |
| Prospect projects | PacifiCorp | PacifiCorp | 44 |
| Quincy Chute | SEQCBID | Grant County PUD | 9 |
| R.D. Smith | SEQCBID | Seattle City Light | 6 |
| Reynolds Irrigation | PURPA | Idaho Power | 0 |
| Reeder Gulch | City of Ashland | Other Publics (BPA) | 0 |
| Rock Creek No. 1 | PURPA | Idaho Power | 2 |
| River Mill | Portland General Electric | Portland General Electric | 19 |
| Rock Creek No. 2 | PURPA | Idaho Power | 2 |
| Rocky Brook | Mason County PUD #3 | Other Public (BPA) | 2 |
| Sagebrush | PURPA | Idaho Power | 0 |
| Rock Island | Chelan County PUD | Multiple Utilities | 629 |
| Rocky Reach | Chelan County PUD | Multiple Utilities | 1,300 |
| Ross | Seattle City Light | Seattle City Light | 450 |
| Round Butte | Portland General Electric | Multiple Utilities | 247 |
| Roza | US Bureau of Reclamation | Federal System (BPA) | 13 |
| Sahko | PURPA | Idaho Power | 1 |
| Santiam | PacifiCorp | PacifiCorp | 0 |
| Schaffner | PURPA | Idaho Power | 1 |
| Sheep Creek | Glen Phillips | Avista Corp. | 2 |
| Shingle Creek | PURPA | Idaho Power | 0 |
| Shoshone II | PURPA | Idaho Power | 1 |
| Shoshone CSPP | PURPA | Idaho Power | 0 |
| Slide Creek | PacifiCorp | PacifiCorp | 18 |
| Shoshone Falls | Idaho Power | Idaho Power | 13 |
| Soda Springs | PacifiCorp | PacifiCorp | 11 |
| Smith Creek | Smith Creek Hydro, LLC | Eugene Water & Electric Board | 38 |
| Snedigar Ranch | PURPA | Idaho Power | 1 |
| Snoqualmie Falls | Puget Sound Energy | Puget Sound Energy | 54 |
| Spokane Upriver | City of Spokane | Avista Corp. | 16 |
| Soda Creek | City of Soda Springs | Other Publics (BPA) | 1 |
| Snake River Pottery | PURPA | Idaho Power | |
| South Fork Tolt | Seattle City Light | Seattle City Light | 17 |
| Stauffer Dry Creek | | PacifiCorp | |
| Summer Falls | SEQCBID | Seattle City Light | 92 |
| Stone Creek | Eugene Water & Electric Board | Eugene Water & Electric Board | 12 |
| Strawberry Creek | South Idaho Public Agency | Other Publics (BPA) | |
| Sygitowicz | Cascade Clean Energy | Puget Sound Energy | 0 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Swan Falls | Idaho Power | Idaho Power | 25 |
| Swift 1 | PacifiCorp | Multiple Utilities | 219 |
| Swift 2 | Cowlitz County PUD | Multiple Utilities | - |
| TGS/Briggs | | PacifiCorp | |
| Tiber Dam | PURPA | Idaho Power | 8 |
| The Dalles | US Corps of Engineers | Federal System (BPA) | 1,807 |
| The Dalles Fishway | Northern Wasco Co. PUD | Northern Wasco Co. PUD | 5 |
| Thompson Falls | NorthWestern Corporation | NorthWestern Energy | 94 |
| Thousand Springs | Idaho Power | Idaho Power | 9 |
| Toketee | PacifiCorp | PacifiCorp | 43 |
| Trout Company | PURPA | Idaho Power | 0 |
| Trail Bridge | Eugene Water & Electric Board | Eugene Water & Electric Board | 10 |
| Tunnel #1 | PURPA | Idaho Power | 7 |
| Twin Falls | PURPA | Puget Sound Energy | 20 |
| Twin Falls | Idaho Power | Idaho Power | 53 |
| Walla Walla | PacifiCorp | PacifiCorp | 2 |
| TW Sullivan | Portland General Electric | Portland General Electric | 15 |
| Upper Baker | Puget Sound Energy | Puget Sound Energy | 105 |
| Upper Falls | Avista Corp. | Avista Corp. | 10 |
| Upper Malad | Idaho Power | Idaho Power | 8 |
| Upper Salmon 1 & 2 | Idaho Power | Idaho Power | 18 |
| Upper Salmon 3 & 4 | Idaho Power | Idaho Power | 17 |
| Weeks Falls | So. Fork II Assoc. LP | Puget Sound Energy | 5 |
| Wallowa Falls | PacifiCorp | PacifiCorp | 1 |
| Walterville | Eugene Water & Electric Board | Eugene Water & Electric Board | 8 |
| Wanapum | Grant County PUD | Multiple Utilities | 934 |
| West Side | PacifiCorp | PacifiCorp | 1 |
| Wells | Douglas County PUD | Multiple Utilities | 774 |
| White Water Ranch | PURPA | Idaho Power | 0 |
| Wilson Lake Hydro | PURPA | Idaho Power | 8 |
| Woods Creek | Snohomish County PUD | Snohomish County PUD | 1 |
| Yakima-Tieton | PacifiCorp | PacifiCorp | 3 |
| Wynoochee | Tacoma Power | Tacoma Power | 13 |
| Yale | PacifiCorp | PacifiCorp | 134 |
| Yelm | | Other Publics (BPA) | 12 |
| Young's Creek | Snohomish County PUD | Snohomish County PUD | 8 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| **COAL** | | | **5,429** |
| Boardman | Portland General Electric | Multiple Utilities | 575 |
| Colstrip #1 | PP&L Montana, LLC | Multiple Utilities | 330 |
| Colstrip #2 | PP&L Montana, LLC | Multiple Utilities | 330 |
| Colstrip #3 | PP&L Montana, LLC | Multiple Utilities | 740 |
| Colstrip #4 | NorthWestern Energy | Multiple Utilities | 805 |
| Jim Bridger #1 | PacifiCorp / Idaho Power | Multiple Utilities | 540 |
| Jim Bridger #2 | PacifiCorp / Idaho Power | Multiple Utilities | 540 |
| Jim Bridger #3 | PacifiCorp / Idaho Power | Multiple Utilities | 540 |
| Jim Bridger #4 | PacifiCorp / Idaho Power | Multiple Utilities | 508 |
| Valmy #1 | NV Energy / Idaho Power | Multiple Utilities | 254 |
| Valmy #2 | NV Energy / Idaho Power | Multiple Utilities | 267 |
| **NUCLEAR** | | | **1,230** |
| Columbia Generating Station | Energy Northwest | Federal System (BPA) | 1,230 |
| **NATURAL GAS** | | | **6,878** |
| Alden Bailey | Clatskanie PUD | Clatskanie PUD | 11 |
| Beaver | Portland General Electric | Portland General Electric | 516 |
| Beaver 8 | Portland General Electric | Portland General Electric | 25 |
| Bennett Mountain | Idaho Power | Idaho Power | 173 |
| Boulder Park | Avista Corp. | Avista Corp. | 25 |
| Carty | Portland General Electric | Portland General Electric | 440 |
| Chehalis Generating Facility | PacifiCorp | PacifiCorp | 517 |
| Coyote Springs I | Portland General Electric | Portland General Electric | 266 |
| Coyote Springs II | Avista Corp. | Avista Corp. | 287 |
| Danskin | Idaho Power | Idaho Power | 92 |
| Danskin 1 | Idaho Power | Idaho Power | 179 |
| Dave Gates | NorthWestern Energy | NorthWestern Energy | 150 |
| Encogen | Puget Sound Energy | Puget Sound Energy | 159 |
| Ferndale Cogen Station | Puget Sound Energy | Puget Sound Energy | 245 |
| Frederickson | EPCOR Power L.P./PSE | Multiple Utilities | 258 |
| Fredonia 1 & 2 | Puget Sound Energy | Puget Sound Energy | 208 |
| Fredonia 3 & 4 | Puget Sound Energy | Puget Sound Energy | 108 |
| Fredrickson 1 & 2 | Puget Sound Energy | Puget Sound Energy | 149 |
| Goldendale | Puget Sound Energy | Puget Sound Energy | 298 |
| Hermiston Generating P. | PacifiCorp/Hermiston Gen. Comp. | PacifiCorp | 469 |
| Kettle Falls CT | Avista Corp. | Avista Corp. | 7 |
| Lancaster Power Project | Avista Corp. | Avista Corp. | 270 |
| Langley Gulch | Idaho Power | Idaho Power | 319 |
| Mint Farm Energy Center | Puget Sound Energy | Puget Sound Energy | 312 |
| Northeast A&B | Avista Corp. | Avista Corp. | 62 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Port Westward | Portland General Electric | Portland General Electric | 415 |
| Port Westward Unit 2 | Portland General Electric | Portland General Electric | 220 |
| Rathdrum 1 & 2 | Avista Corp. | Avista Corp. | 167 |
| River Road | Clark Public Utilities | Clark Public Utilities | 248 |
| Rupert (Magic Valley) | Rupert Illinois Holdings | Idaho Power | 10 |
| Sumas Energy | Puget Sound Energy | Puget Sound Energy | 127 |
| Whitehorn #2 & 3 | Puget Sound Energy | Puget Sound Energy | 149 |
| **COGENERATION** | | | **147** |
| Billings Cogeneration | Billings Generation, Inc. | NorthWestern Energy | 64 |
| Hampton Lumber | | Snohomish County PUD | 5 |
| International Paper Energy | Eugene Water & Electric Board | Eugene Water & Electric Board | 26 |
| Simplot-Pocatello | PURPA | Idaho Power | 12 |
| Tasco-Nampa | Tasco | Idaho Power | 2 |
| Tasco-Twin Falls | Tasco | Idaho Power | 3 |
| Wauna (James River) | Western Generation Agency | Multiple Utilities | 36 |
| **RENEWABLES-OTHER** | | | **307** |
| Bannock County Landfill | PURPA | Idaho Power | 3 |
| Bettencourt B6 | PURPA | Idaho Power | 2 |
| Bettencourt Dry Creek | PURPA | Idaho Power | 2 |
| Big Sky West Dairy | PURPA | Idaho Power | 2 |
| Bio Energy | | Puget Sound Energy | 1 |
| Bio Fuels, WA | | Puget Sound Energy | 5 |
| Biomass One | PacifiCorp | PacifiCorp | 25 |
| City of Spokane Waste to E. | City of Spokane | Avista Corp. | 26 |
| Coffin Butte Resource | Power Resources Cooperative | | 6 |
| Cogen Company | Prairie Wood Products Co-Gen Co. | Oregon Trail Coop | 8 |
| Co-Gen II - DR Johnson | PacifiCorp | PacifiCorp | 8 |
| Columbia Ridge Landfill Gas | Waste Management | Seattle City Light | 13 |
| Convanta Marion | Portland General Electric | Portland General Electric | 16 |
| Double A Digestor | PURPA | Idaho Power | 5 |
| Dry Creek Landfill | Dry Creek Landfill Inc. | PacifiCorp | 3 |
| Edaleen Dairy | | Puget Sound Energy | 1 |
| Farm Power Tillamook | Tillamook | Tillamook | 1 |
| Fighting Creek | PURPA | Idaho Power | 3 |
| Flathead County Landfill | Flathead Electric Cooperative | Flathead Electric Cooperative | 2 |
| Hidden Hollow Landfill | PURPA | Idaho Power | 3 |
| Hooley Digester | Tillamook PUD | Tillamook PUD | 1 |
| H. W. Hill Landfill | Allied Waste Companies | Multiple Utilities | 10.5 |
| Interfor Pacific-Gilchrist | Midstate Electric Co-op | Midstate Electric Co-op | 2 |
| Kettle Falls | Avista Corp. | Avista Corp. | 51 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Lynden | Farm Power | Puget Sound Energy | 1 |
| Mill Creek (Cove) | | Idaho Power | 1 |
| Neal Hot Springs | U.S Geothermal | Idaho Power | 23 |
| Olympic View 1&2 | Mason County PUD #3 | Mason County PUD #3 | 5 |
| Pine Products | PacifiCorp | PacifiCorp | 6 |
| Plum Creek NLSL | Plum Creek MDF | Flathead Electric Cooperative | 6 |
| Pocatello Wastewater | PURPA | Idaho Power | 0 |
| Portland Wastewater | City of Portland | Portland General Electric | 1.7 |
| Qualco Dairy Digester | | Snohomish PUD | 1 |
| Raft River 1 | US Geothermal | Idaho Power | 16 |
| Rainier Biogas | | Puget Sound Energy | 1 |
| Rexville | Farm Power | Puget Sound Energy | 1 |
| River Bend Landfill | McMinnville Water & Light | McMinnville Water & Light | 5 |
| Rock Creek Dairy | PURPA | Idaho Power | 4 |
| Seneca | Seneca Sustainable Energy, LLC | Eugene Water & Electric Board | 20 |
| Short Mountain | | Emerald PUD | 3 |
| Skookumchuck | | Puget Sound Energy | 1 |
| Smith Creek | | Puget Sound Energy | 0 |
| Stimson Lumber | Stimson Lumber | Avista Corp. | 7 |
| Stoltze Biomass | F.H. Stoltze Land & Lumber | Flathead Electric Coop | 3 |
| Tamarack | PURPA | Idaho Power | 5 |
| Van Dyk | | Puget Sound Energy | 0 |
| VanderHaak Dairy | VanderHaak Dairy, LLC | Puget Sound Energy | 1 |
| Whitefish Hydro | City of Whitefish | Flatthead Electric Cooperative | 0 |
| **SOLAR** | | | **956** |
| Ashland Solar Project | | BPA | 0 |
| American Falls Solar | PURPA | Idaho Power | 20 |
| American Falls Solar II | PURPA | Idaho Power | 20 |
| Baker Solar | PURPA | Idaho Power | 10 |
| Bellevue Solar | EDF Renewable Energy | Portland General Electric | 2 |
| Boise City Solar (ID Solar 1) | PURPA | Idaho Power | 40 |
| Brush Solar | PURPA | Idaho Power | 3 |
| Finn Hill Solar | | Puget Sound Energy | 0 |
| Grand View Solar | PURPA | Idaho Power | 80 |
| Grove Solar | PURPA | Idaho Power | 10 |
| Hyline Solar Center | PURPA | Idaho Power | 10 |
| Island Solar | | Puget Sound Energy | 0 |
| King Estate Solar | Lane County Electric Coop | Lane County Electric Coop | - |
| Morgan Solar | PURPA | Idaho Power | 3 |
| Mountain Home Solar | PURPA | Idaho Power | 20 |
| Moyer-Tolles Solar | Umatilla Electric Coop | | 1 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Murphy Flat Power | PURPA | Idaho Power | 20 |
| Neilson Solar | | Avista | 19 |
| Open Range Solar Center | PURPA | Idaho Power | 10 |
| Orchard Ranch Solar | PURPA | Idaho Power | 10 |
| PacifiCorp Solar Bundle | | PacifiCorp | 193 |
| PGE QF Solar | | Portland General Electric | 230 |
| Puget Eastern WA | | Puget Sound Energy | 150 |
| Railroad Solar Center | PURPA | Idaho Power | 10 |
| Simco Solar | PURPA | Idaho Power | 20 |
| Thunderegg Solar Center | PURPA | Idaho Power | 10 |
| Vale I Solar | PURPA | Idaho Power | 3 |
| Vale Air Solar | PURPA | Idaho Power | 10 |
| Wheatridge Solar | NextEra | PGE | 50 |
| Wild Horse Solar Project | Puget Sound Energy | Puget Sound Energy | 1 |
| Yamhill Solar | EDF Renewable Energy | Portland General Electric | 1 |
| **WIND** | | | **4,992** |
| 3Bar-G Wind | | Puget Sound Energy | 0 |
| Bennett Creek | PURPA | Idaho Power | 21 |
| Benson Creek Wind | PURPA | Idaho Power | 10 |
| Big Top | Big Top LLC (QF) | PacifiCorp | 2 |
| Biglow Canyon - 1 | Portland General Electric | Portland General Electric | 125 |
| Biglow Canyon - 2 | Portland General Electric | Portland General Electric | 150 |
| Biglow Canyon - 3 | Portland General Electric | Portland General Electric | 174 |
| Burley Butte Wind Farm | PURPA | Idaho Power | 21 |
| Butter Creek Power | Butter Creek Power LLC | PacifiCorp | 5 |
| Camp Reed Wind Park | PURPA | Idaho Power | 23 |
| Cassia Wind Farm | PURPA | Idaho Power | 11 |
| Coastal Energy | CCAP | Grays Harbor PUD | 6 |
| Cold Springs | PURPA | Idaho Power | 23 |
| Combine Hills I | Eurus Energy of America | PacifiCorp | 41 |
| Combine Hills II | Eurus Energy of America | Clark Public Utilities | 63 |
| Condon Wind | Goldman Sachs /SeaWest NW | Federal System (BPA) | 25 |
| Desert Meadow Windfarm | PURPA | Idaho Power | 23 |
| Durbin Creek | PURPA | Idaho Power | 10 |
| Elkhorn Wind | Telocaset Wind Power Partners | Idaho Power | 101 |
| Foote Creek Rim 1 | PacifiCorp & EWEB | Multiple Utilities | 41 |
| Foote Creek Rim 2 | PPM Energy | Federal System (BPA) | 2 |
| Foote Creek Rim 4 | PPM Energy | Federal System (BPA) | 17 |
| Fossil Gulch Wind | PURPA | Idaho Power | 11 |
| Four Corners Windfarm | Four Corners Windfarm LLC | PacifiCorp | 10 |
| Four Mile Canyon Windfarm | Four Mile Canyon Windfarm LLC | PacifiCorp | 10 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Golden Valley Wind Farm | PURPA | Idaho Power | 12 |
| Goodnoe Hills | PacifiCorp | PacifiCorp | 94 |
| Hammett Hill Windfarm | PURPA | Idaho Power | 23 |
| Harvest Wind | Summit Power | Multiple Utilities | 99 |
| Hay Canyon Wind | Hay Canyon Wind Project LLC | Snohomish County PUD | 101 |
| High Mesa Wind | PURPA | Idaho Power | 40 |
| Hopkins Ridge | Puget Sound Energy | Puget Sound Energy | 157 |
| Horseshoe Bend | PURPA | Idaho Power | 9 |
| Horseshoe Bend | PURPA | Idaho Power | 9 |
| Jett Creek | PURPA | Idaho Power | 10 |
| Judith Gap | Invenergy Wind, LLC | NorthWestern Energy | 135 |
| Klondike I | PPM Energy | Federal System (BPA) | 24 |
| Klondike II | PPM Energy | Portland General Electric | 75 |
| Klondike III | PPM Energy | Multiple Utilities | 221 |
| Knudson Wind | | Puget Sound Energy | 0 |
| Leaning Juniper 1 | PPM Energy | PacifiCorp | 101 |
| Lime Wind Energy | PURPA | Idaho Power | 3 |
| Lower Snake River 1 | Puget Sound Energy | Puget Sound Energy | 342 |
| Lime Wind Energy | PURPA | Idaho Power | 3 |
| Marengo | Renewable Energy America | PacifiCorp | 140 |
| Marengo II | PacifiCorp | PacifiCorp | 70 |
| Milner Dam Wind Farm | PURPA | Idaho Power | 20 |
| Moe Wind | Two Dot Wind | NorthWestern Energy | 1 |
| Nine Canyon | Energy Northwest | Multiple Utilities | 96 |
| Oregon Trail Windfarm | Oregon Trail Windfarm LLC | PacifiCorp | 10 |
| Oregon Trails Wind Farm | PURPA | Idaho Power | 14 |
| Pa Tu Wind Farm | Pa Tu Wind Farm, LLC | Portland General Electric | 9 |
| Pacific Canyon Windfarm | Pacific Canyon Windfarm LLC | PacifiCorp | 8 |
| Palouse Wind | Palouse Wind, LLC | Avista Corp. | 105 |
| Paynes Ferry Wind Park | PURPA | Idaho Power | 21 |
| Pilgrim Stage Station Wind | PURPA | Idaho Power | 11 |
| Prospector Wind | PURPA | Idaho Power | 10 |
| Rattlesnake Flats | | Avista Corp. | 144 |
| Rockland Wind | PURPA | Idaho Power | 80 |
| Ryegrass Windfarm | PURPA | Idaho Power | 23 |
| Salmon Falls Wind Farm | PURPA | Idaho Power | 22 |
| Sand Ranch Windfarm | Sand Ranch Windfarm LLC | PacifiCorp | 10 |
| Sawtooth Wind | PURPA | Idaho Power | 21 |
| Sheep Valley Ranch | Two Dot Wind | NorthWestern Energy | 1 |
| Skookumchuck | | Puget Sound Energy | 131 |
| Stateline Wind | NextEra | Multiple Utilities | 300 |
| Swauk Wind | | Puget Sound Energy | 4 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---|---|---|---|
| Thousand Springs Wind | PURPA | Idaho Power | 12 |
| Three Mile Canyon | Momentum RE | PacifiCorp | 10 |
| Tuana Gulch Wind Farm | PURPA | Idaho Power | 11 |
| Tuana Springs Expansion | PURPA | Idaho Power | 36 |
| Tucannon | Portland General Electric | Portland General Electric | 267 |
| Two Ponds Windfarm | PURPA | Idaho Power | 23 |
| Vansycle Ridge | ESI Vansycle Partners | Portland General Electric | 25 |
| Wagon Trail Windfarm | Wagon Trail Windfarm LLC | PacifiCorp | 3 |
| Ward Butte Windfarm | Ward Butte Windfarm LLC | PacifiCorp | 7 |
| Wheat Field Wind Project | Wheat Field Wind LLC | Snohomish County PUD | 97 |
| Wheatridge | PGE/NextEra | PGE/NextEra | 300 |
| White Creek | White Creek Wind I LLC | Multiple Utilities | 205 |
| Wild Horse | Puget Sound Energy | Puget Sound Energy | 273 |
| Willow Spring Windfarm | PURPA | Idaho Power | 10 |
| Wolverine Creek | Invenergy | PacifiCorp | 65 |
| Yahoo Creek Wind Park | PURPA | Idaho Power | 21 |
| **SMALL THERMAL AND MISCELLANEOUS** | | | **130** |
| Crystal Mountain | Puget Sound Energy | Puget Sound Energy | 3 |
| PGE DSG | | Portland General Electric | 127 |
| Wheatridge battery | PGE/NextEra | PGE/NextEra | 30 |
| | **Total** | | **53,502** |

**Table 11. Independent Owned Generating Resources** is a comprehensive list of independently owned electric power supply located in the region. The nameplate values listed below show full availability. Some of these units have partial contracts (reflected in the load/resource tables) with Northwest utilities.

| Project | Owner | Nameplate (MW) |
|---|---|---|
| **HYDRO** | | **15** |
| Big Creek (Hellroaring) | | - |
| PEC Headworks | SEQCBID | 7 |
| Soda Point Project | | - |
| Sygitowicz | Cascade Clean Energy | 0 |
| Owyhee Tunnel No.1 | Owyhee Irrigation District | 8 |
| **COAL** | | **1,340** |
| Centralia #1 | TransAlta | 670 |
| Centralia #2 | TransAlta | 670 |
| **NATURAL GAS** | | **2,081** |
| Grays Harbor (Satsop) | Invenergy | 650 |
| Hermiston Power Project | Hermiston Power Partners (Calpine) | 689 |
| Klamath Cogen Plant | Iberdrola Renewables | 502 |
| Klamath Peaking Units 1-4 | Iberdrola Renewables | 100 |
| March Point 1 | March Point Cogen | 80 |
| March Point 2 | March Point Cogen | 60 |
| **COGENERATION** | | **28** |
| Boise Cascade | | 9 |
| Freres Lumber | Evergreen BioPower | 10 |
| Rough & Ready Lumber | Rough & Ready | 1 |
| Warm Springs Forest | | 8 |
| **RENEWABLES-OTHER** | | **26** |
| Spokane MSW | City of Spokane | 23 |
| Treasure Valley | | 3 |
| **Solar** | | **56** |
| Gala Solar Farm | | **56** |

| Project | Owner | Nameplate (MW) |
|---|---|---|
| **WIND** | | **3,447** |
| Big Horn | Iberdrola Renewables | 199 |
| Big Horn-Phase 2 | Iberdrola Renewables | 50 |
| Cassia Gulch | John Deere | 21 |
| Glacier Wind - Phase 1 | Naturener | 107 |
| Glacier Wind - Phase 2 | Naturener | 104 |
| Goshen North | Ridgeline Energy | 125 |
| Juniper Canyon - Phase 1 | Iberdrola Renewables | 151 |
| Kittitas Valley | Horizon | 101 |
| Klondike IIIa | Iberdrola Renewables | 77 |
| Lava Beds Wind | | 18 |
| Leaning Juniper II-North | Iberdrola Renewables | 90 |
| Leaning Juniper II-South | Iberdrola Renewables | 109 |
| Linden Ranch | NW Wind Partners | 50 |
| Magic Wind Park | | 20 |
| Martinsdale Colony North | Two Dot Wind | 1 |
| Martinsdale Colony South | Two Dot Wind | 2 |
| Montague Wind | AvanGrid | 200 |
| Notch Butte Wind | | 18 |
| Pebble Springs Wind | Iberdrola Renewables | 99 |
| Rattlesnake Rd Wind (aka Arlington) | Horizon Wind | 103 |
| Shepards Flat Central | Caithness Energy | 290 |
| Shepards Flat North | Caithness Energy | 265 |
| Shepards Flat South | Caithness Energy | 290 |
| Stateline Wind | NextEra | 300 |
| Vancycle II (Stateline III) | NextEra | 99 |
| Vantage Wind | Invenergy | 90 |
| Willow Creek | Invenergy | 72 |
| Windy Flats | Cannon Power Group | 262 |
| Windy Point | Tuolumne Wind Project Authority | 137 |
| **SMALL THERMAL AND MISCELLANEOUS** | | **44** |
| Colstrip Energy LP Coal | Colstrip Energy Limited Partnership | 44 |
| **Total** | | **7,038** |

# Report Description

This report provides a regional firm needs assessment (Tables 1 - 4) using annual energy (August through July), monthly energy, winter peak-hour and summer peak-hour metrics. The monthly energy picture is provided to underscore the variability of the power need within an average year. A seasonal or weekly snapshot would tell a similar story. The peak need reflects information for January and August, as they present the greatest need for their respective seasons. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

This information reflects the summation of individual utilities' load forecasts and generating resources expected to meet their load, as well as the presents the total of utilities' planned resource acquisitions to meet future needs. The larger utilities, in most cases, prepared their own projections for their integrated resource plans. BPA provides much of the information for its smaller customers. This section includes procedures used in preparing the load resource comparisons, a list of definitions, and a list of the utilities summarized by this report (Table 12).

## Load Estimate

Regional loads are the sum of demand estimated by the Northwest utilities and BPA for its federal agency customers, certain non-generating public utilities, and direct service industrial customers (DSI – currently not a significant part of regional load). Load projections reflect network transmission and distribution losses, reductions in demand due to rising electricity prices, and the effects of appliance efficiency standards and energy building codes. Savings from demand-side management programs, such as energy efficiency, are also reflected in the regional load forecasts.

### Energy Loads

A ten-year forecast of monthly firm energy loads is provided. This forecast reflects normal (1-in-2) weather conditions. The tabulated information includes the annual average load for the year forecast period as well as the monthly load for the first year of the report.

### Peak Loads

Northwest regional peak loads are provided for each month of the ten-year forecast period. The tabulated loads for winter and summer peak are the highest estimated 60-minute clock-hour average demand for that month, assuming normal (1-in-2) weather conditions. The regional firm peak load is the sum of the individual utility peak loads, and does not account for the fact that each utility may experience its peak load at a different hour than other Northwest utilities. Hence the regional peak load is considered non-coincident. The federal system (BPA) firm peak load is adjusted to reflect a federal coincident peak among its many utility customers.

### Federal System Transmission Losses

Federal System (BPA) transmission losses for both firm loads and contractual obligations are embedded in federal load. These losses represent the difference between energy generated by the federal system (or delivered to a system interchange point) and the amount of energy sold to customers. System transmission losses are calculated by BPA for firm loads utilizing the federal transmission system.

### Planning Margin

In the derivation of regional peak requirements, a planning margin is added to the load. Like the *2018 Forecast*, this year's planning margin is different from past reports. The planning margin is set to 16 percent of the total peak load for every year of the planning horizon. In many *Forecast's* before 2018 the planning margin started at 12 percent for the first year and grew a percent a year until it reached 20 percent and remained at 20 percent thereafter. The justification for this change is three-fold.

- The purpose for the growing planning margin was in part to address uncertainty of planning for generating resources with long planning and construction lead times (coal and nuclear power plants). Utilities are not currently planning for these types of resources.
- The growing planning margin as a percent of load overstated the growing regional requirements and resulting need for power.
- A flat planning margin simplifies comparison analyzes of reports from different years.

This planning margin is intended to cover, for planning purposes, operating reserves and all elements of uncertainty not specifically accounted for in determining loads and resources. These include forced-outage reserves, unanticipated load growth, temperature variations, hydro maintenance and project construction delays.

## Demand-Side Management Programs

Savings from demand-side management efforts are reported in *Table 7. Demand-Side Management Programs*. These estimates are the savings for the ten-year study period and include expected future energy savings from existing and new programs in the areas of energy efficiency, distribution efficiency, some market transformation, fuel conversion, fuel switching, energy storage and other efforts that reduce the demand for electricity. These estimates reflect savings from programs that utilities fund directly, or through a third-party, such as the Northwest Energy Efficiency Alliance and Energy Trust of Oregon.

Demand response activity is reported in *Table 7* as well. The total load reduction reported is the cumulative sum of different utilities' agreements with their customers. Each program has its own characteristics and limitations.

# Generating Resources

This report catalogues existing resources, committed new supply (including resources under construction), as well as planned resources. For the assessment of need only the existing and committed resources are reflected in the regional tabulations. In addition, only those generating resources (or shares) that are firmly committed to meeting Northwest loads are included in the regional analysis.

## Hydro

Major hydro resource capabilities are estimated from a regional analysis using a computer model that simulates reservoir operation of past hydrologic conditions with today's operating constraints and requirements. The historical stream flow record used covers the 80-year period from August 1928 through July 2008. The bulk of the hydro modeling used in this report is provided by BPA, the US Army Corps of Engineers, and/or project owners.

### Energy

The firm energy capability of hydro plants is the amount of energy produced during the operating year with the lowest 12-month average generation. The lowest generation occurred in 1936-37 given today's river operating criteria. The firm energy capability is the average of 12 months, August 1936 to July 1937. Generation for projects that are influenced by downstream reservoirs reflects the reduction due to encroachment.

### Peak Capability

For this report the peak capability of the hydro system represents the maximum sustained hourly generation available to meet peak demand during the period of heavy load. Historically, a 50-hour sustained peak (10 hours/day for 5 days) has been reported.

The peaking capability of the hydro system maximizes available energy and capacity associated with the monthly distribution of streamflow. The peaking capability is the hydro system's ability to continuously produce power for a specific time period by utilizing the limited water supply while meeting power and non-power requirements, scheduled maintenance, and operating reserves (including wind reserves).

Computer models are used to estimate the operational hydro peaking capability of the major projects, based on their monthly average energy for 70 or 80 water conditions, depending on the source of information. The peaking capability used for this report is the 8th percentile of the resulting hourly peak capabilities for January and August to indicate winter and summer peak capability respectively. These models shape the monthly hydro energy to maximize generation in the heavy load hours.

### Columbia River Treaty

Since 1961 the United States has had a treaty with Canada that outlines the operation of U.S. and Canadian storage projects to increase the total combined generation. Hydropower generation in this analysis reflects the firm power generated by coordinating operation of three Canadian reservoirs, Duncan, Arrow and Mica with the Libby reservoirs and other power facilities in the region. Canada's share of the coordinated operation benefits is called Canadian Entitlement. BPA and each of the non-Federal mid-Columbia project owners are obligated to return their share of the downstream power benefits owed to Canada. The delivery of the Entitlement is reflected in this analysis.

### Downstream Fish Migration

Another requirement incorporated in the computer simulations is modified river operations to provide for the downstream migration of anadromous fish. These modifications include adhering to specific flow limits at some projects, spilling water at several projects, and augmenting flows in the spring and summer on the Columbia, Snake and Kootenai rivers. Specific requirements are defined by various federal, regional and state mandates, such as project licenses, biological opinions and state regulations.

## Thermal and Other Renewable Resources

Thermal resources are reported in a variety of categories. Coal, cogeneration, nuclear, and natural gas projects are each totaled and reported as individual categories.

Renewable resources other than hydropower are categorized as solar, wind and other renewables and are each totaled and reported separately. Other renewables include energy from biomass, geothermal, municipal solid waste projects and other miscellaneous projects.

All existing generating plants, regardless of size, are included in amounts submitted by each utility that owns or is purchasing the generation. The energy and peaking capabilities of plants are submitted by the sponsors of the projects and take into consideration scheduled maintenance (including refueling), forced outages and other expected operating constraints. Some small fossil-fuel plants and combustion turbines are included as peaking resources and their reported energy capabilities are only the amounts necessary for peaking operations. Additional energy may be available from these peaking resources but is not included in the regional load/resource balance.

## New and Future Resources

The latest activity with new and future resource developments, including expected savings from demand-side management, are tabulated in this report. These resources are reported as *Recently Acquired Resources, Committed New Supply* and *Planned Resources* to reflect the different stages of development.

### Recently Acquired Resources

*The Recently Acquired Resources* reported in *Table 5* have been acquired in the past year and are serving Northwest utility loads as of December 31, 2018. They are reflected as part of the regional firm needs assessment.

### Committed New Supply

*Committed New Supply* reported in *Table 6* includes those projects under construction or committed resources and supply to meet Northwest load that are not delivering power as of December 31, 2018. In this report, resources being built by utilities or resources where their output is firmly committed to utilities are included in the regional load-resource analysis. Future savings from committed demand-side management programs are reported in Table 7.

### Planned Resources

*Planned Resources* presented in *Table 8* include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans. Projects specifically named in *Planned Resources* are not yet under construction, are not part of the regional analysis, and are in some ways speculative.

## Contracts

Imports and exports include firm arrangements for interchanges with systems outside the region, as well as with third-party developers/owners within the region. These arrangements comprise firm contracts with utilities to the East, the Pacific Southwest and Canada. Contracts to and from these areas are amounts delivered at the area border and include any transmission losses associated with deliveries.

Short term purchases from Northwest independent power producers and other spot market purchases are not reflected in the tables that present the firm load resource comparisons.

## Non-Firm Resources

The *Forecast* omits from the load/resource comparisons non-firm power supply that may be available to utilities to meet needs. These non-firm sources include generation from uncommitted Northwest independent power producers, imports from power plants located outside the region, and hydro generation likely available when water supply is greater than the assumed critical water.

*Independent Owned Generating Resources*, presented in *Table 11*, include thermal independent power producers (IPP) located in the region. The table below shows the nameplate amount of dispatchable non-firm generation over the next five years. Due to maintenance, unplanned outages, fuel availability, unit commitments to out-of-region buyers, and other factors, the actual amount of resource available from these sources may be less. Note the decrease from 2020 to 2021 as Centralia Unit 1 retires.

| Thermal Northwest IPP Nameplate MW | | | | |
|---|---|---|---|---|
| **2019** | **2020** | **2021** | **2022** | **2023** |
| 3,095 | 3,095 | 2,425 | 2,425 | 2,425 |

Non-firm imports depend on several factors including availability of out-of-region resources, availability of transmission interties, and market friction. In their *2018 Resource Adequacy* study for year 2023, the Northwest Power and Conservation Council assumed 2,500 MW of available spot imports from California in the winter, and zero for summer (3,000 MW of generation was assumed to be available off-peak year-round in a day-ahead market). However, as noted earlier a trend of large thermal resource retirements in the Western Interconnection could impact power available for import into the Northwest in the coming years.

Looking at hydropower, the Forecast assumes critical water (8%) during peak hours. Most years the water supply for the hydro system is not at critical levels. During an average, the region could expect an additional 4,100 MW of sustained peaking generation in January and 2,200 MW in August.

## Table 12. Utilities included in the Northwest Regional Forecast

Albion, City of
Alder Mutual
Ashland, City of
Asotin County PUD #1
Avista Corp.
Bandon, City of
Benton PUD
Benton REA
Big Bend Electric Co-op
Blachly-Lane Electric Cooperative
Blaine, City of
Bonners Ferry, City of
Bonneville Power Administration
Burley, City of
Canby Utility
Cascade Locks, City of
Central Electric
Central Lincoln PUD
Centralia, City of
Chelan County PUD
Cheney, City of
Chewelah, City of
City of Port Angeles
Clallam County PUD #1
Clark Public Utilities
Clatskanie PUD
Clearwater Power Company
Columbia Basin Elec. Co-op
Columbia Power Co-op
Columbia REA
Columbia River PUD
Consolidated Irrigation Dist. #19
Consumers Power Inc.
Coos-Curry Electric Cooperative
Coulee Dam, City of
Cowlitz County PUD
Declo, City of
Douglas County PUD
Douglas Electric Cooperative
Drain, City of
East End Mutual Electric
Eatonville, City of
Ellensburg, City of
Elmhurst Mutual P & L
Emerald PUD
Energy Northwest
Eugene Water & Electric Board
Fall River Rural Electric Cooperative
Farmers Electric Co-op
Ferry County PUD #1
Fircrest, Town of
Flathead Electric Cooperative
Forest Grove Light & Power
Franklin County PUD
Glacier Electric
Grant County PUD
Grays Harbor PUD
Harney Electric
Hermiston, City of
Heyburn, City of
Hood River Electric
Idaho County L & P
Idaho Falls Power
Idaho Power
Inland Power & Light
Kittitas County PUD
Klickitat County PUD
Kootenai Electric Co-op
Lakeview L & P (WA)
Lane Electric Cooperative
Lewis County PUD
Lincoln Electric Cooperative
Lost River Electric Cooperative
Lower Valley Energy
Mason County PUD #1
Mason County PUD #3
McCleary, City of
McMinnville Water & Light
Midstate Electric Co-op
Milton, Town of
Milton-Freewater, City of
Minidoka, City of
Missoula Electric Co-op
Modern Electric Co-op
Monmouth, City of
Nespelem Valley Elec. Co-op
Northern Lights Inc.
Northern Wasco Co. PUD
NorthWestern Energy
Ohop Mutual Light Company
Okanogan Co. Electric Cooperative
Okanogan County PUD #1
Orcas Power & Light
Oregon Trail Co-op
Pacific County PUD #2
PacifiCorp
Parkland Light & Water
Pend Oreille County PUD
Peninsula Light Company
Plummer, City of
PNGC Power
Port of Seattle – SEATAC
Portland General Electric
Puget Sound Energy
Raft River Rural Electric
Ravalli Co. Electric Co-op
Richland, City of
Riverside Electric Co-op
Rupert, City of
Salem Electric Co-op
Salmon River Electric Cooperative
Seattle City Light
Skamania County PUD
Snohomish County PUD
Soda Springs, City of
Southside Electric Lines
Springfield Utility Board
Steilacoom, Town of
Sumas, City of
Surprise Valley Elec. Co-op
Tacoma Power
Tanner Electric Co-op
Tillamook PUD
Troy, City of
Umatilla Electric Cooperative
Umpqua Indian Utility Co-op
United Electric Cooperative
US Corps of Engineers
US Bureau of Reclamation
Vera Water & Power
Vigilante Electric Co-op
Wahkiakum County PUD #1
Wasco Electric Co-op
Weiser, City of
Wells Rural Electric Co.
West Oregon Electric Cooperative
Whatcom County PUD
Yakama Power

# Definitions

## Annual Energy

Energy value in megawatts that represents the average output over the period of one year. Expressed in average megawatts.

## Average Megawatts

(MWa) Unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period.

## Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.

## Canadian Entitlement

Canada is entitled to one-half the downstream power benefits resulting from Canadian storage as defined by the Columbia River Treaty. Canadian entitlement returns estimated by Bonneville Power Administration.

## Coal

This category of generating resources includes the region’s coal-fired plants.

## Cogeneration

Cogeneration is the technology of producing electric energy and other forms of useful energy (thermal or mechanical) for industrial and commercial heating or cooling purposes through sequential use of an energy source.

## Combustion Turbines

These are plants with combined-cycle or simple-cycle natural gas-fired combustion turbine technology for producing electricity.

## Committed Resources

These projects are under construction and/or committed resources and supply to meet Northwest load but not delivering power as of December 31, 2018.

### Conservation

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with energy efficiency.

### Demand Response

Control of load through customer/utility agreements that result in a temporary change in consumers' use of electricity.

### Demand-side Management

Peak and energy savings from conservation/energy efficiency measures, distribution efficiency, market transformation, demand response, fuel conversion, fuel switching, energy storage and other efforts that that serve to reduce electricity demand.

### Dispatchable Resource

A term referring to controllable generating resources that are able to be dispatched for a specific time and need.

### Direct Service Industries (DSI)

Large electricity-intensive industries such as aluminum smelters and metals-reduction plants that purchase power directly from the Bonneville Power Administration for their own use. Very few of these customers exist in the region today.

### Distribution Efficiency

Infrastructure upgrades to utilities' transmission and distribution systems that save energy by minimizing losses.

### Encroachment

A term used to describe a situation where the operation of a hydroelectric project causes an increase in the level of the tailwater of the project that is directly upstream.

### Energy Efficiency

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with conservation.

### Energy Load

The demand for power averaged over a specified period of time.

### Energy Storage

Technologies for storing energy in a form that is convenient for use at a later time when a specific energy demand is greater.

### Exports

Firm interchange arrangements where power flows from regional utilities to utilities outside the region or to non-specific, third-party purchasers within the region.

### Federal System (BPA)

The federal system is a combination of BPA's customer loads and contractual obligations, and resources from which BPA acquires the power it sells. The resources include plants operated by the U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (USBR) and Energy Northwest. BPA markets the thermal generation from Columbia Generating Station, operated by Energy Northwest.

### Federal Columbia River Power System (FCRPS)

Thirty federal hydroelectric projects constructed and operated by the Corps of Engineers and the Bureau of Reclamation, and the Bonneville Power Administration transmission facilities.

### Firm Energy

Electric energy intended to have assured availability to customers over a defined period.

### Firm Load

The sum of the estimated firm loads of private utility and public agency systems, federal agencies and BPA industrial customers.

### Firm Losses

Losses incurred on the transmission system of the Northwest region.

### Fuel Conversion

Consumers' efforts to make a permanent change from electricity to natural-gas or other fuel source to meet a specific energy need, such as heating.

### Fuel Switching

Consumers' efforts to make a temporary change from electricity to another fuel source to meet a specific energy need.

### Historical Streamflow Record

A database of unregulated streamflows for 80 years (July 1928 to June 2008). Data is modified to take into account adjustments due to irrigation depletions, evaporations, etc. for the particular operating year being studied.

### Hydro Maintenance

The amount of energy lost due to the estimated maintenance required during the critical period. Peak hydro maintenance is included in the peak planning margin calculations.

### Hydro Regulation

A study that utilizes a computer model to simulate the operation of the Pacific Northwest hydroelectric power system using the historical streamflows, monthly loads, thermal and other non-hydro resources, and other hydroelectric plant data for each project.

### Imports

Firm interchange arrangements where power flows to regional utilities from utilities outside the region or third-party developer/owners of generation within the region.

### Independent Power Producers (IPPs)

Non-utility entities owning generation that may be contracted (fully or partially) to meet regional load.

### Intermittent Resource (a.k.a. Variable Energy Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements.  Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

### Investor-Owned Utility (IOU)

A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

### Market Transformation

A strategic process of intervening in a market to accelerate the adoption of cost-effective energy efficiency.

### Megawatt (MW)

A unit of electrical power equal to 1 million watts or 1,000 kilowatts.

### Nameplate Capacity

A measure of the approximate generating capability of a project or unit as designated by the manufacturer.

### Natural Gas-Fired Resources

This category of resources includes the region's natural gas-fired plants, mostly single-cycle and combined-cycle combustion turbines. It may include projects that are considered cogeneration plants.

### Non-Firm Resources

Electric energy acquired through short term purchases of resources not committed as firm resources. This includes generation from hydropower in better than critical water conditions, independent power producers and imports from outside the region.

### Non-Utility Generation

Facilities that generate power whose percent of ownership by a sponsoring utility is 50 percent or less. These include PURPA-qualified facilities (QFs) or non-qualified facilities of independent power producers (IPPs).

### Nuclear Resources

The region's only nuclear plant, the Columbia Generating Station, is included in this category.

### Operating Year

Twelve-month period beginning on August 1 of any year and ending on July 31 of the following year. For example, operating year 2017 is August 1, 2016 through July 31, 2017.

### Other Publics (BPA)

Refers to the smaller, non-generating public utility customers whose load requirements are estimated and served by Bonneville Power Administration.

### Peak Load

In this report the peak load is defined as one-hour maximum demand for power.

### Planned Resources

These resources include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans. These projects are not yet under construction, are not part of the regional analysis, and are in some ways speculative.

## Planning Margin

A component of regional requirements that is included in the peak needs assessment to account for various planning uncertainties. In the 2018 *Forecast* the planning margin changed to a flat 16% of the regional load for each year of the study. Earlier reports included a growing planning margin that started at 12% of load, increasing 1% per year until it reached 20%.

## Private Utilities

Same as investor-owned utilities.

## Publicly-Owned Utilities

One of several types of not-for-profit utilities created by a group of voters and can be a municipal utility, a public utility district, or an electric cooperative.

## PURPA

Public Utility Regulatory Policies Act of 1978. The first federal legislation requiring utilities to buy power from qualifying independent power producers.

## Renewables - Other

A category of resources that includes projects that produce power from such fuel sources as geothermal, biomass (includes wood, municipal solid-waste facilities), and pilot level projects including tidal and wave energy.

## Requirements

For each year, a utility's projected loads, exports, and contracts out. Peak requirements also include the planning margin.

## Small Thermal & Miscellaneous Resources

This category of resources includes small thermal generating resources such as diesel generators used to meet peak and/or emergency loads.

## Solar Resources

Resources that produce power from solar exposure. This includes utility scale solar photovoltaic systems and other utility scale solar projects. This category does not include customer side distributed solar generation.

## Thermal Resources

Resources that burn coal, natural gas, oil, diesel or use nuclear fission to create heat which is converted into electricity.

### Variable Energy Resource (a.k.a. Intermittent Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements.  Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

### Wind Resources

This category of resources includes the region's wind powered projects.

APRIL 23, 2019

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# Northwest energy supply growing more dynamic and diverse

**PORTLAND, Ore. –** A newly released forecast of Pacific Northwest electric power loads and resources shows that a number of trends are impacting the electric power industry and utilities' plans for meeting future demand. Utilities are balancing customers and policymakers' interest in reducing carbon emissions with the need to ensure there is no shortage of electricity during high-demand summer and winter periods in the years to come, according to the *2019 Northwest Regional Forecast*.

PNUCC's annual *Forecast* illustrates how a number of compounding factors are accelerating the pace-of-change in the region's utility industry. New and anticipated policies are intensifying Northwest utilities' efforts to achieve carbon-reduction goals. The steady, long-term commitment to energy-efficiency has reduced the energy demand by thousands of megawatts. Yet, the regional picture shows an ongoing need as traditional power plants close with few resources confirmed to replace them.

"Although hydropower remains the backbone of the Northwest's electric power supply, the region's resource mix is rapidly becoming much more dynamic and diverse," said Shauna McReynolds, executive director of the PNUCC. "As a result, these trends will impact utilities' planning and their customers."

The *Forecast* found perhaps the most significant impact on supply will be the upcoming retirements of several coal-fired power plants. And it recognizes that the currently planned construction of new wind and solar cannot be expected to replace in-kind the loss of over 3,600 megawatts of dispatchable generation. In parallel, utilities are seeking opportunities for testing and proving out new technologies such as large-scale batteries and securing possible demand response programs to reduce power consumption in peak demand situations.

The gap in available power supply to meet demand can lead to spikes in prices as evidenced by a recent wholesale energy event. "Last month's event underscores the region's need even further as utilities look to accommodate consumers demands and carbon reduction goals, while maintaining a reliable system," McReynolds added.

The PNUCC's *Northwest Regional Forecast* serves as an on-the-ground view of the Pacific Northwest's electric power landscape providing an annual snapshot of the demand for electricity and the power-generation resources Northwest utilities need to provide customers with safe, reliable and affordable energy. The *Forecast* is intended to help utility leaders, decision-makers, the media and others gain a deeper understanding of the trends impacting the Northwest power system.

The Executive Summary of the Forecast, as well as the full report, can be found at: www.pnucc.org/system-planning/northwest-regional-forecast.

*PNUCC (Pacific Northwest Utilities Conference Committee) is a utility trade association providing a forum for investigating and working through a range of issues affecting electricity providers and large industrial electricity users in the Northwest.*

ISSUE #13

# PNGC Power Pulse

April 2019

Inside This Issue



## 'Tis the Season

It's springtime, and for the majority of PNGC Power cooperatives, that means it's annual meeting time.

Annual meetings provide the opportunity for cooperatives to bring a community together. "Annual meetings not only allow our members to hear industry updates and connect one-on-one with our leadership and employees, but they also give members the opportunity to see the connection between their co-op and the community," said Heather Anderson, Central Electric Cooperative's Executive Assistant, who plans their annual event. "The meeting also gives the cooperative a chance to educate members about important topics like safety, legislative issues, and advances in technology."

A lot of work goes into the planning and execution of annual meetings. From the logistics of where and when, to the content of the meeting itself, each cooperative seeks to bring value to their membership.

"While we kid about members showing up at the annual meeting for the door prizes and the food, it's a great opportunity to educate them looking back over the previous year as well as into the future," said Todd Munsey, Douglas Electric Cooperative's Director of Member Services. Douglas' service territory was recently hit with a major weather event, leaving some members without power for weeks as crews worked tirelessly to restore power. "On the heels of this storm, members appeared a little more interested in the financial picture, and that's a good story for us to tell," Munsey said. "It's also an opportunity for members to interact with their directors, and praise our crews and staff."

Beyond talking about the immediate issues of the cooperative, like major snow and subsequent outages, Munsey sees annual meetings as a possible way to bridge the gap in changing cooperative demographics. "Like everyone else, we have a tough time reaching the 24-44 year-old demographic. Before I retire, I would love to

**Meeting with a view:** OPALCO holds their annual meeting on the interisland Washington State Ferry, picking up members from around the various San Juan Islands, holding the meeting on board, and dropping members off along the way back home. Here's a shot from aboard the boat looking back at the ferry landing on Orcas Island.

transition this meeting into a family event where we can educate those younger members on the benefits of belonging to an electric cooperative."

Greg Mendonca, PNGC Power's Vice President of Power Supply, reflected on why he likes to visit a few cooperative annual meetings each year, "It's always nice to get out to our cooperatives and experience their community through their annual meetings. We get a real sense of what is driving our cooperatives back home."

Not all annual meetings happen in the spring. Some PNGC cooperatives have their annual meetings later in the year. PNGC's own annual meeting will be held September 30 and October 1, 2019 in Portland, Oregon.

## Employee Spotlight: Scott Russell

Scott Russell, PNGC Power's Vice President of Transmission, joined the team in August of 2016. In his role he covers all aspects of BPA Transmission Service, which is no small feat. "As BPA's largest Network Transmission Customer, with approximately 150 points of delivery with BPA, we can see significant bottom line impacts from seemingly minor changes to BPA's Open Access Transmission Tariff and/or Business Practices. As such, I pay special attention to what is happening in the policy arena."

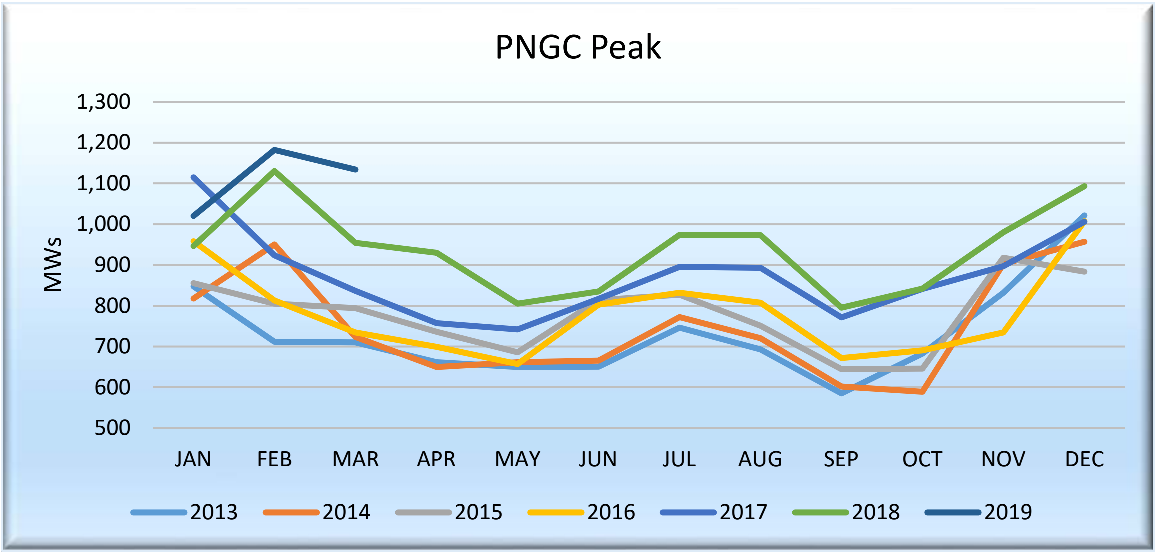
In addition to policy, Russell also wears an operational hat and helps other PNGC staff with energy purchases to make sure that they have access to as many generation resources as possible. And he finds some of his most rewarding work to be when he works directly with members on operational issues that face individual utilities, like facilitating new interconnect requests for new large loads, or integrating community renewable projects.

Russell previously worked for Portland General Electric in various capacities like financial analysis, corporate planning, power operations, and contract negotiation, and he enjoys the move from the investor owned utility to the cooperative world. "I really enjoy working in the energy industry and having been in the cooperative world for the past two years, believe that it is perhaps the best business model for what we are trying to achieve," Russell said. "The cooperative model of banding together and providing essential services 'at cost' to our members feels good at the end of the day. Being ranked the number one low cost wholesale provider out of all G&Ts is something I am professionally proud of."

Russell was born and raised in the Northwest, growing up in Boardman, Oregon. And after obtaining both his Bachelor of Science in Economics, and his Master of Science in Economics, from Oregon State University, he moved to the Portland area in 2005. He and his wife Cassie have been married for 13 years, and have two four-year-old twins, Abe and Nora. When he's not at work Russell enjoys family time in the great outdoors, and he and Cassie take the kids camping, fishing, and hiking every opportunity they get.

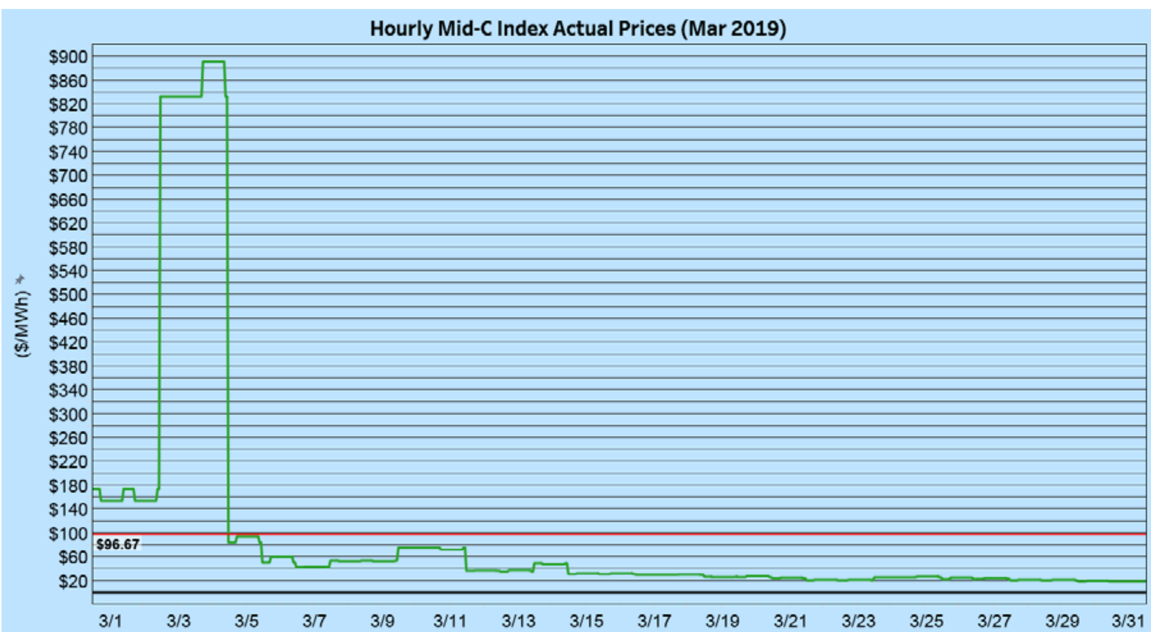
## PNGC Peak

The graph below shows PNGC Peak for the past 5 years




## Mid-C Pricing

The graph below shows Mid-C Pricing for the month of March 2019




## BPA Happenings

| | |
|---|---|
| April 30 | FY 2019 Q2 Quarterly Business Review |
| May 1 | Limited Hourly Firm Preparation Workshop |
| May 3 | May Finance Workshop |
| May 6 | Hourly Firm Customer Update |
| May 15 | Energy Imbalance Market Stakeholder Meeting |
| May 17 | Hourly Firm Webinar |

## Upcoming PNGC Events

| | |
|---|---|
| May 7 | PNGC Board Meeting |
| May 8 | PNGC Education Session |
| May 11 | Northern Lights Annual Meeting |
| May 27 | Memorial Day – PNGC Office Closed |
| May 28 | Lane Annual Meeting |
| June 3-5 | PNGC Strategic Planning Meeting – Eureka, Montana |

PNGC Power
Smart. Local. Connected.

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*About PNGC Power:*

*PNGC Power is a Portland-based electric generation and transmission (G & T) cooperative owned by 15 Northwest electric distribution cooperative utilities with service territory in seven western states (Oregon, Washington, Idaho, Montana, Utah, Nevada and Wyoming). The company creates value for its member systems by providing power supply, transmission, and other management services. PNGC Power is an aggregator of geographically diverse loads in the region.*

May 1, 2019
(revised version)

# FUTURE NORTHWEST CAPACITY SHORTAGES[1]

**By Randy Hardy and Larry Kitchen**

## I. Recent Events Affecting the Mid-Term Pacific Northwest (PNW) Capacity Outlook

Several developments which have occurred, or become apparent, in the last few months will have significant impacts on the PNW resource capacity outlook in the 2020-2030 timeframe. Such recent developments are described below. To provide some context for this issue, a short history of PNW capacity development is included as Appendix A.

### A. E3 Study on PNW Resource Adequacy

E3, the consulting/analytical firm which has studied numerous West Coast power issues over the last several years, completed a comprehensive analysis of PNW capacity issues in January 2019. Among that study's conclusions was that, due to load growth and announced coal plant retirements, the PNW faces a potential eight-gigawatt (GW) capacity deficit by 2030 unless new dispatchable capacity is constructed. Absent such construction, the regional loss of load probability (LOLP) will grow to 48 percent by that date (five percent LOLP is the normal reliability standard used by WECC utilities). The Northwest Power Planning Council in its draft mid-term assessment of its Seventh Power Plan has also noted the PNW faces resource adequacy issues absent new construction.

### B. Washington (WA) State Zero Carbon Legislation

In addition to the PNW capacity deficits projected by E3 absent new construction, the WA state legislature has enacted legislation mandating that WA utilities achieve zero fossil fuels in their resource base by 2045. This legislation is modelled after California's zero carbon legislation passed in 2018. Its major near/mid-term provisions include a directive that no WA utility is supplied by coal by 2025. This provision will impact Puget Sound Energy (PSE), Avista and PacifiCorp (PAC), all of whom own shares of Colstrip 3 and 4, possibly causing those plants to close in 2025 rather than their current planned retirement in 2035.

Next, by 2030, all WA utilities must be 80 percent carbon free in terms of the power resources used to supply their load. This provision will not only require substantial renewable acquisition by PSE and others over the next ten years, but will also mean that those utilities, after 2030, will only be able to use their existing gas-fired resources for reliability emergencies (as opposed to economy energy transactions or normal load service).

Finally, the loss of Colstrip 3 and 4 will add another 1.5 GW to E3's projected 8 GW capacity deficit in 2030.

[1] The views in this paper are strictly our own, and do not necessarily reflect those of our clients.

### C. No New Gas Sentiment

Besides these developments, the current political climate in both WA and Oregon (OR) is strongly against development of any new gas-fired resources (e.g., combustion or combined cycle turbines – CTs/CCTs) to fill the projected 8 GW PNW capacity deficit. Not surprisingly, this posture in the PNW closely parallels the no new gas/retire existing gas sentiment which has existed in CA in recent years.

## II. Consequences of These Developments

Taken together, these actions, along with already projected PNW coal plant retirements, will create a substantially different set of resource acquisition and operating procedures in the Northwest.

### A. Renewables Only

From 2020 on, the most likely energy resources which can be acquired in the PNW will be wind and solar. In WA such resources will need to bring each utility's non-carbon emitting resource portfolio to 80 percent of load by 2030. Operationally, coal resources can still be used until 2025 and CTs/CCTs until 2030 (with limited use after 2030), but the WA renewables mandate will be a significant challenge for PSE and other in-state investor owned utilities (IOUs) to meet. Oregon's present 50 percent RPS and pending cap and trade system will provide similar renewable dominant incentives but with more flexibility than WA mandates.

### B. Capacity Needs – Batteries/Pumped Storage (PS)

As a result of these dynamics, the most likely <u>capacity</u> resources PNW entities will be able to develop are batteries and PS. There may be some limited carbon-free capacity from existing hydro providers (e.g., BPA, Seattle City Light, Powerex) but it is likely to be limited in both quantity and duration. With only batteries and PS available (in lieu of CTs), and an 8 GW projected capacity deficit by 2030, capacity acquisitions will be different and significantly more challenging than during the last 20 plus years. In addition, battery/PS resources will be needed, not just to meet cold snap winter reliability needs, but also to provide most of the renewable resource firming requirements as the region approaches 2030. The contrasts between these two types of capacity resources are notable: batteries can be installed quickly at points near load centers or other optimal locations; batteries, however, in aggregate are still quite expensive (e.g., probably two to three times cost of a CT) and have yet to have their performance characteristics (e.g., four-hour discharge cycle, 20-year life) tested at magnitudes needed to effectively help utilities manage the grid (e.g., greater than 50 MW capacity). While costs are decreasing and performance data will eventually be forthcoming, utilities will be taking significant operational risks that are inherent with any new technology (at least on the scale required here).

On the other hand, PS is a proven technology which has successfully operated in utility systems around the world for decades. It is capital intensive and has long lead times to become operational, but performance characteristics and costs for individual projects are well known. In addition, there are several PS sites, both in the PNW and CA, which are potentially viable.

Given the magnitude of the PNW's 2030 capacity deficit, it is likely that both substantial battery and PS installations will be needed. Other potential capacity resources that might be viable include small modular nuclear resources, cogeneration, biomass resources and demand side management, depending on future technical developments and availability.

### C. Impact on California (CA)

The magnitude of future PNW capacity requirements will also likely decrease capacity and energy available for export to CAISO/CA entities between 2020-2030. Specifically, significant PNW surplus capacity and energy has been readily available to CA since 2002, and, since the capacity has typically been embedded in energy deliveries, it has essentially been free to CA purchasers. Given the PNW's changing resource mix, such imported capacity will likely decrease substantially, unless the CAISO provides sufficient financial payments and associated market structure changes for existing surplus capacity to continue flowing south.

### D. Low Water

Another major uncertainty which further complicates this situation is the variation in generation in the PNW due to water availability. Low water conditions typically occur every five ($25^{th}$ percentile) to ten ($10^{th}$ percentile) years depending on severity. Severe PNW drought conditions such as 2001 removed 3500 to 7000 MW of supply during the months of January through August from the average year West Coast power supply. If we were to experience such low water in, for example, 2024-25, it would dramatically add to both energy and capacity problems in CA and the PNW with possibly severe reliability consequences.

### E. Recent Scarcity Events – Wake-Up Call

During July through September 2018, the Peak net load of the CAISO was 7% lower (46,000 to 50,000) than the peak load in 2017. Nevertheless, system marginal energy prices in the day-ahead market reached record highs on July 24, 2018, peaking at almost $980/MWh in hour ending 20. The frequency of high day-ahead prices increased significantly during the third quarter, largely concentrated between July 23 and August 10, driven by extreme temperatures across the western region and limited natural gas availability.

On March 1, 2019, the Midc index price for day ahead bilateral trades exceeded $900/MWh for heavy load hour energy and $160/MMbtu for natural gas. These prices were driven by a number of factors including cold temperatures, a pro-longed cold period prior to March 1 resulting in depletion of hydro generation and natural gas in storage, an inability of Los Angeles Department of Water and Power (LADWP) gas resources to support exports on the DC Intertie due to various system constraints, and limitations in supplies of Canadian natural gas impacting the ability of some U.S. natural gas generation to operate.

These high prices, and the capacity shortage that they reflected, occurred despite nearly all the soon-to-be retired PNW coal plants operating at maximum capacity. This occurrence should serve as a wake-up call to PNW entities.

## III. Possible Actions to Alleviate Capacity Shortfalls

Policy should address the problems likely to be caused by the changing PNW resource mix unless developing integrated resource plans (IRPs) direct the construction of more CTs/CCTs, which seems impossible given current West Coast political sentiment. Policy development needs to conscientiously assess the role of ratepayers taking risk through resources selected in IRPs and independent power producers (IPPs) taking risk based on their assessment of the competence of government plans. Some potential policies include:

### A. Ensure Robust Day Ahead Resource Sufficiency in the CAISO Expansion of its Day Ahead Market (EDAM) to EIM Entities

CAISO plans to launch EDAM in the near future. If successful, it would require resource sufficiency (as opposed to resource adequacy) demonstrations from all EDAM participants. The resource sufficiency metrics would be designed to ensure each EIM Entity has developed or purchased enough capacity to meet its own load without relying on neighboring EIM Entities beyond agreed estimates of resource sharing.

### B. Acquisition of Batteries/Pumped Storage

As mentioned earlier, batteries or PS appear to be the only new capacity resources currently able to be procured by West Coast utilities, either for reliability needs or renewables firming, in the foreseeable future. Both resources have their strengths and weaknesses, but WECC utilities will need to test their performance viability post-2020. Developing products that pay resources for offering ramping capability will assist in the construction of such resources.

### C. Review Fossil Fuel Era Planning and Operating Metrics

The changing PNW resource mix calls into question a number of habits that have become common wisdom over the last 15 years. Many PNW utilities have relied on short term 96 hour per week energy purchases from the bilateral wholesale market. These purchases were enabled by the ability to produce energy on demand from fossil fuel capacity resources and the surplus energy from hydroelectric resources. The 3-4.5 GW of retiring coal plants (and possibly the additional 5 GW of capacity due to 2020-2030 load growth) will likely be replaced/served in IRPs with energy limited capacity, not capacity capable of baseload or heavy load hour operation. IRPs will need to develop assessments of the necessary energy duration of the capacity needed for resource adequacy and should not rely on the metrics of the fossil fuel era.

Development of wide area markets was predicated on the diversity inherent from planning reserve margins for individual utilities based on the development of fossil fuel resources for capacity. Policy makers should be cautious in relying on further diversity benefits from wide area markets to cover upcoming capacity shortfalls. Assuming that energy limited resources will be available on the hour that capacity is needed requires additional study and will inject additional risk into the system during the upcoming rapid transition period. While the planning reserve margins of individual utilities may have been inefficient, they also covered the unplanned events that occur beyond the 95% thresholds commonly used for long term planning. These individual planning margins captured the diversity among utilities by reliance on short term capacity purchases for resource planning in the areas with surplus generation.

### D. Explore Development of PNW Resource Adequacy Agreement

Resource adequacy is a policy construct designed to ensure enough generation or demand side resources have been developed or procured to meet day ahead resource sufficiency and real time load and reserve requirements in a given area. All the resource adequacy programs developed in North America (other than plans of individual entities) have been developed by organized wholesale power markets run by independent system operators or regional transmission organizations. Absent the creation of an organized wholesale market for energy and reserves in a given area, development of a resource adequacy program for a given area requires the voluntary agreement of the utilities and other load serving entities in such area or an agreement of the States served in such area on a common set of metrics to measure resource adequacy and an enforcement mechanism. Given the complexity of the metrics involved in such an agreement, an organization would be needed to design and administer such program and such agreement would need to address the governance of such organization.

The PNW has attempted to develop an organized wholesale market several times over the last 25 years and has failed to reach agreement. The rapid transition of the PNW electric industry may provide the impetus to reach agreement on metrics for ensuring the reliability of PNW electricity markets.

### E. Possible Transmission (Tx) Solutions

As these capacity driven trends emerge, it is possible that a variety of tx solutions will also develop. For example, PNW utilities (in addition to PAC and Idaho Power) may decide to participate in PAC's Gateway West tx project. Such participation could enable PNW utilities both to acquire Wyoming wind (with its complementary load shape and higher capacity factor to Columbia Gorge wind) to meet their RPS goals and even access Wyoming/Utah thermal capacity for reliability emergencies. Somewhat similar dynamics might also exist for tx access to Montana wind.

## IV. Or Not

### A. Pray for Rain and Mild Weather

Murphy's law predicts that the next low water year in the PNW will arrive in 2025 as peak coal plant retirement occurs and the PNW IRPs defer decisions on construction of new resources waiting for the next cost reduction in carbon free capacity.

# Appendix A

## Short History of PNW Capacity Resource Development

### I. Development of the Federal Columbia River Power System (FCRPS)

Following initial development of hydroelectric generation on local rivers by PNW utilities, the Federal government began development of the Columbia River in the 1930s with the construction of Bonneville and Grand Coulee dams. Development of the Columbia River involved a reshaping of the natural hydrograph to better match the pattern of electric loads in the PNW. The hydroelectric system that developed only has the capability to store about a third of the annual runoff. Due to the large difference in hydroelectric power production between wet and dry years, it was economic to install turbines in the dams with capability far in excess of dry year energy production – installed turbine nameplate ratings are roughly three times dry year average energy production. The Bonneville Power Administration (BPA) was established to develop the transmission and market the power produced by the hydroelectric system,

The FCRPS as developed was able to move energy production to periods where it was most needed or most valuable. The system was planned and operated for a 42 ½ month period where energy was shaped not only day to day and month to month but over a 42 ½ month period based on the driest 42 ½ month period in the historical record. This planning construct allowed BPA to "borrow" as much as 1500MW from expected water availability in future years to serve loads in the current year.

### II. Development of the Columbia River Treaty (Treaty)

In the early 1960's, the United States and Canada negotiated a Treaty regarding flood control and development of storage reservoirs on the Columbia River. Among many aspects of the Treaty was a requirement to agree on a set of metrics measuring dry year assured hydroelectric production and a sharing of the increased production resulting from new storage reservoirs in Canada. As the Treaty approaches the end of its 60-year initial minimum term, the United States and Canada are now engaged in a process examining renegotiation of the Treaty including the metrics for determining benefits of the Treaty and how those benefits should be shared.

Development of the Treaty created a surplus of hydroelectric generation in the mid-60s that provided the impetus for development of the Pacific Northwest-Pacific Southwest Intertie transmission facilities (Intertie). These transmission facilities allowed PNW utilities to trade surplus PNW summer capacity needed by California utilities for surplus California winter capacity and energy needed by PNW utilities (i.e. seasonal exchanges).

### III. Development of the Hydro-Thermal Power Program

Continued growth of electric loads in the PNW during the 1960s led to development of the Hydro-Thermal Power program. Under this joint initiative of PNW utilities, the FCRPS would continue the installation of additional turbines at existing FCRPS dams while the utilities would construct coal and nuclear plants to meet growing energy loads in the PNW. Many of the coal plants scheduled for retirement were a result of this program.

## IV. Impacts of the Fish Measures on Energy Metrics

Congress passed the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) in 1980 establishing the Northwest Power Planning Council (Council) tasked with creating a long-term regional resource plan and a fish and wildlife program. The fish and wildlife program and biological opinions established under the Endangered Species Act have resulted in changes to the operations of the FCRPS. These changes in operations reversed a portion of the change in the hydrograph caused by development of the FCRPS. The metrics used for dry year energy planning changed from a 42 ½ month period to an eight-month period. This change in metrics eliminated the ability to borrow from expected water availability in future years to serve the load in the current year and measured energy availability on an annual basis instead of a monthly basis. In response, planners assumed that surplus energy from PNW and California thermal plants could be purchased and stored or purchased as necessary to serve a portion of electric loads in the summer and winter of a dry year. These changes in operations to mitigate impacts on salmon have also reduced the FCRPS capability to move energy production in shorter timeframes.

## V. Northwest Power Plan

Resource plans of the Council have primarily relied on several thousand MWs of conservation as described by the Regional Act to serve Pacific Northwest load growth over the last 40 years. The current power plan relies on conservation and increased development of demand response to serve PNW loads with the potential for a modest amount of natural gas resource development in the early 2020s. This plan was developed prior to the current legislative initiatives around carbon in the current Washington and Oregon legislatures.

## VI. Loss of Industrial Electric Load

Another factor impacting the need for capacity in the PNW has been the change in industrial loads over the last 30 years. The PNW has seen a significant reduction of the PNW aluminum industry resulting in the loss of several thousand MWs of electric load. Global competition in pulp and paper, steel, and other industries has also resulted in the closing of industrial facilities that once used several thousand MWs of electricity in the PNW.

## VII. Impact of the California Independent System Operator (CAISO) and the California Air Resources Board (CARB) on Seasonal Exchanges

Development of an organized market in California and the creation of the CAISO as well as the implementation of carbon cap and trade legislation by CARB has impacted the long-term marketing of surplus capacity over the Intertie.

Federal legislation passed prior to construction of the Intertie ensured that PNW energy in a dry year was reserved for use by PNW energy loads. This legislation enabled both short-term exchanges and long-term exchanges of energy that allowed the PNW to provide surplus capacity to serve peak loads in California if the California entity committed to return the energy in a specified timeframe.

Creation of the CAISO created a new method of charging California loads for transmission on a per use basis instead of a fixed annual fee. The California cap and trade legislation includes a requirement to pay CARB a fee for each amount of energy generated by a fossil fuel resource and exported from California.

The current market prices for capacity will not support either long term or short-term exchanges of energy due to the impact of these two fees or charges.

## VIII. Planning for Capacity

Most utility systems have historically planned to ensure they have generation capacity available to serve a few peak hours during the year leaving significant amounts of surplus energy during other periods. As the FCRPS faced reduced flexibility, BPA has reduced the amount of surplus capacity it sold long term and focused more of its sales in day to day and monthly markets. These PNW utilities, losing access to long-term surplus capacity sales from BPA, made the switch to capacity planning, however, many of them still rely on wholesale market purchases from other utilities in their planning.

BPA has primarily planned to ensure there was enough energy during a dry year. BPA has relied on planned amounts of purchases of wholesale energy during dry years instead of developing additional resources.

Development of renewable resources has created a new component of uncertainty in the system in addition to uncertainty in loads, resource outages, and availability of water. The metrics of planning for this uncertainty are still being developed.

## IX. Implications of this History

The first three items of this history – development of the FCRPS, negotiation of the Columbia River Treaty and implementation of the Hydro-Thermal program – are key to understanding why capacity was never an issue in PNW power planning until now. **Because the PNW initially developed a hydro baseload system with hydro generators sized at three times the critical period Columbia River runoff, the region always had sufficient capacity to handle winter peaks.**

Subsequent developments, such as loss of aluminum load and PNW conservation efforts, basically enabled the region to continue to meet growing loads with only modest generating resource additions (primarily combustion/combined cycle turbines) until today. While fish mitigation measures lessened this capacity cushion, the real "crunch" did not come until this year, when a combination of substantial renewable resource acquisitions, scheduled retirement of existing coal plants and a political environment which probably prevents construction of new gas-fired resources will likely create substantial capacity shortfalls for the first time in the region's 80-year electric power history.

**Washington Rural Electric Cooperative Association** **Update**

**To: WRECA Members** **May 9, 2019**

**From: Kent Lopez, General Manager**

**It's official. On Tuesday, the Governor signed SB 5116 –** officially known as the Clean Energy Transformation Act (CETA). This law changes the way the electric utility industry works in Washington State. An elite team is analyzing the new law and preparing reports for the WRECA membership. The reports will include a section-by-section outline of the bill, a timeline of implementation deadlines, and a listing of the rule-making that state agencies will be doing in the years ahead. Passage of CETA is just the beginning of a long and complicated process that will involve analysis and input from WRECA members.

**The CETA is only one bill that was passed during the 2019 legislative session that impacts WRECA members –** a quick look at the other bills is later in this UPDATE.

**We're in the final preparations for the 2019 WRECA Annual Meeting, June 11 & 12 at The Centennial Hotel in Spokane, WA –** The WRECA Annual Meeting is THE premier statewide meeting for the executive management and governing directors of Washington's electric cooperatives and mutual electric companies. Speakers scheduled include:

- State Rep. Bob McCaslin (R-4)
- Curtis Wynn – President, NRECA
- Lou Green – Executive VP, Electric Cooperatives of South Carolina
- Kurt Miller – Executive Director, Northwest RiverPartners
- Leigh Taylor – Director, Executive Search, NRECA
- Michael Shepard – CEO, Ruralite
- Scott Corwin – Executive Director, Northwest Public Power Association
- Taylor Smith – Washington Youth Leadership Council Representative
- Dan James – Deputy Administrator, Bonneville Power Administration

There is still time to register for the meeting and make your reservation at The Centennial Hotel. Registration information is on our website at www.wreca.coop or contact me and I'll send you the information.

**The Annual Meeting schedule includes fundraisers for WECPAC –** starting with the WECPAC Annual Golf Tournament on Monday, June 10, at The Creek at Qualchan Golf Course in Spokane. And we'll also have our annual WECPAC live auction following dinner (hosted again this year by Federated) on Tuesday evening, June 11.

**We had successful meetings with members of the Washington State Congressional Delegation the last week of April –** During the NRECA Legislative Conference in Washington, DC, representatives from Washington's electric cooperatives met with U.S. Reps. Rick Larsen (D-2), Denny Heck (D-10), Cathy McMorris Rodgers (R-5), Kim Schrier (D-8), and Dan Newhouse (R-4). We also met with legislative staff for Reps. Suzan DelBene (D-1), Jaime Herrera Beutler (R-3), Derek Kilmer (D-6), and Sen. Cantwell.

**Left to right: Steve Walter, general manager of Tanner EC; Randy Suess, director of Inland Power; Judi and Danny Lee, director of Inland Power; Rep. Cathy McMorris Rodgers; Troy Berglund, community development manager of Benton REA; Kent Lopez, general manager of WRECA.**

We had four primary messages that we discussed in the meetings:

- **A tax law change is needed to protect electric co-op tax-exempt status –** We asked for their support of H.R. 2147/S. 1032. Recent changes to the Internal Revenue Code created an unintended consequence for rural electric cooperatives. Government grants are now be considered non-member income. Electric cooperatives must comply with the 85 percent-15 percent income test. Congress should take action to amend Section 501(c)(12) to retain the tax-exempt status of rural electric co-ops and allow the full use of federal, state or local grants to benefit our members.


**Meeting with Rep. Dan Newhouse.**

- **Stop PBGC from overcharging low-risk co-op pension plans –** We asked for their support of H.R. 1994. More than 880 rural electric cooperatives participate in the defined-benefit "multiple-employer" pension plan sponsored by NRECA including 13 electric cooperatives in Washington State. Current rules are increasing volatility and cost pressures on participating electric cooperatives. The same facts that led Congress to adjust *funding* rules for cooperative and small employer charity (CSEC) plans in 2014 strongly support adjusting PBGC *premiums* charged to CSEC plans.

- **PMAs are a vital source of electricity for electric cooperatives –** We asked them to oppose the proposals in the Administration's 2020 budget to privatize the PMA assets and change the rate structure. The Power Marketing Administrations, including BPA, are federal agencies that market electric power used by 600 rural electric cooperatives in 34 states, including 15 co-ops in Washington State. Appropriations for the federal power program are repaid, with interest, to the U.S. Treasury by federal power customers. Reps. Newhouse, DelBene, Herrera Beutler, Heck, Kilmer, Larsen, and McMorris Rodgers signed a letter opposing the administration's proposal.

**Visiting with Rep. Denny Heck in his office.**

- Finally, we asked that the delegation members continue to assist BPA in its efforts to be more competitive. One suggestion we made was asking Congress to direct the Corps of Engineers to reconsider the cost allocation for the projects. When the federal hydropower projects were originally authorized, approximately 75 percent of the "joint use" of the Columbia and Snake River dams was assigned to power customers for repayment. Today, there are many other users of the river system who should take a greater role in the costs of operating the dams.

**And now a final wrap on the 2019 Washington State Legislative Session –** As expected, the action in the final hours was very hectic. But our lobbying efforts, led by Grant Nelson, paid big returns for WRECA members – mostly. Here's where we ended up.

**The governor's clean energy standard legislation is now law –** The Senate version of the bill (SB 5116) was passed by the legislature and the governor signed it into law on Tuesday. Every step of the way saw changes that mostly made the legislation more "doable" for WRECA members. As noted above, we're now working on legislative reports and preparing to work with state agencies as the rule-making process begins.

**Net metering –** SB 5223 increases the minimum requirement for a utility to net meter at the retail level from 0.5 percent of the utility's 1996 peak to 4.0 percent. It also changes how "aggregated" net metering is defined to be one "designated" meter and one "aggregated" meter.

**Distributed energy –** HB 1126 provides a methodology for electric utilities to determine the impacts that distributed energy resources have on the distribution system.

**Wildfires** –SB 5305 establishes a task force of utility representatives to work with DNR to develop policies and procedures for working together to fight wildfires on DNR-owned forest land.

**Utility workers –** HB 1380 makes the assaulting of a utility worker subject to aggravating circumstances in sentencing.

**Fuel source report –** HB 1428 updates the statute concerning a utility's fuel source mix report to include RECs and other energy product attributes.

**Telecommunications equipment –** HB 1594 clarifies that installation of telecommunications equipment in the electricity zone on a utility pole is covered by the NESC.

**Our CFC bill – well, we'll try again next year –** HB 1368 "*Reauthorizing the Business and Occupation Tax Deduction for Cooperative Finance Organizations"* provides a specific exemption from the Washington business and occupation tax related to gross receipts earned from nonprofit rural electric systems by a nonprofit cooperative lender. At the last minute, the bill was passed by the House unanimously and sent to the Senate where the Ways & Means Committee held a hearing on it. Grant testified on the bill. Several other entities signed in to support the measure and there was no public opposition to it. It was scheduled to be voted on by the committee, but was withdrawn from consideration at the last minute. The next day, Sen. Randi Becker brought it up as an amendment to another bill being considered by the full Senate, but it was ruled out of scope and withdrawn. So, we'll find out what the issues were that prevented a vote by the Ways & Means Committee and get those addressed before the 2020 session.

**Don't forget the director training being offered after the Annual Meeting –** NWPPA is presenting this NRECA credentialed director class CCD 2640 "Financial Decision Making" right after the WRECA Annual Meeting in Spokane. This is a really hard class to get on this side of the US. You do not have to be members of NWPPA to take advantage of this class, and the price, but you do need to register with NWPPA. The class will be held in The Centennial Hotel. The class begins on Thursday, June 13 and adjourns by noon on Friday.

To register for this course, go to www.nwppa.org. If you have any questions, contact Elaine Dixon, 360.816.1445 - Elaine@nwppa.org.

**Cooperative University (Co-op U®) is coming to our region in 2019 –** More than 1,200 employees from 400+ co-ops have taken advantage of the unique learning opportunities available at Co-op U® over the past nine years! With training courses offered across multiple subject areas over five days - including 15 courses from the popular **Supervisor and Manager Development Program** curriculum - 2019 Co-op U® provides a customizable learning experience. Your staff members can choose courses that are most beneficial to their job roles and responsibilities. And, by taking multiple courses on the same trip, your co-op can minimize costs. Join this year as we commemorate the **10th Anniversary of Co-op U®, May 13-17, 2019 at the Portland Marriott City Center, Portland, Ore.**

**Important dates –** please put the following on your calendars:

June 10 – 2019 WECPAC Golf Tournament, Spokane, WA
June 10 – WRECA Board of Directors, Spokane, WA
June 11-12 – 2019 WRECA Annual Meeting, Spokane, WA
Sept. 25-26 – NRECA Region 9 Meeting, Spokane, WA

Please let me know if you have any questions. – Kent