Benton PUD Rate Information

August 21, 2019

Staff Preliminary Recommendation
## Agenda

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<tbody>
<tr>
<td>1</td>
<td><strong>Overview</strong></td>
<td>Chad Bartram</td>
</tr>
<tr>
<td>2</td>
<td><strong>Net Power Costs &amp; Reserves</strong></td>
<td>Jon Meyer</td>
</tr>
<tr>
<td>3</td>
<td><strong>Questions/Comments</strong></td>
<td></td>
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<td>4</td>
<td><strong>Financial Metrics</strong></td>
<td>Jon Meyer</td>
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<td>5</td>
<td><strong>Cost of Service Analysis (COSA)</strong></td>
<td>Tony Georgis</td>
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<td>6</td>
<td><strong>Questions/Comments (Short Break)</strong></td>
<td></td>
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<td>7</td>
<td><strong>Power Market Volatility</strong></td>
<td>Rick Dunn</td>
</tr>
<tr>
<td>8</td>
<td><strong>Questions/Comments</strong></td>
<td></td>
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</tbody>
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Staff Proposal

- 2.9% average revenue increase effective October 1, 2019
  - Applied “across-the-board” to all rate classes (except unmetered)
- Applied evenly to all rate components
  - Base charge, kilowatt-hour charge, demand charge, etc.
- Remove seasonal rates from Medium/Large General Service
  - Effective January 1, 2020
- Last increase was two years ago: October 2017 (1.9%)
Key Driver – Power Costs

- Bonneville Power Administration (BPA) Contract
  - Costs heading up
    - BPA rate increase October 1, 2019
  - Generation heading down
    - Warmer weather impacting timing of run-off
    - Court-ordered spill

- Energy Independence Act
  - Must buy 15% of retail load from qualifying renewables
    - Wind, solar, and biomass (hydro not a qualifying renewable)
  - Up from 9%

- BPUD total power costs up $10.6 million in 2019
  - Water year significantly below average (less generation)
  - February/March weather event & price excursion
### Average Retail Rates\(^1\) per kWh

**APPA\(^2\) 2017 Report on Average Revenue (Cents per kWh)**

<table>
<thead>
<tr>
<th></th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Benton PUD</td>
<td>8.3</td>
<td>6.7</td>
<td>5.3</td>
<td>7.0</td>
</tr>
<tr>
<td>WA Publicly Owned</td>
<td>8.9</td>
<td>7.8</td>
<td>5.0</td>
<td>7.4</td>
</tr>
<tr>
<td>WA Investor Owned</td>
<td>10.8</td>
<td>9.8</td>
<td>7.8</td>
<td>10.1</td>
</tr>
<tr>
<td>WA Cooperatives</td>
<td>8.9</td>
<td>7.8</td>
<td>6.3</td>
<td>8.1</td>
</tr>
<tr>
<td>National Average</td>
<td>12.9</td>
<td>10.7</td>
<td>6.9</td>
<td>10.5</td>
</tr>
<tr>
<td>California</td>
<td>18.3</td>
<td>15.8</td>
<td>12.7</td>
<td>16.1</td>
</tr>
</tbody>
</table>

\(^1\) Revenues - includes all charges to customer

\(^2\) American Public Power Association
Average Monthly Bill Comparison

Residential

Average Monthly Bill at 1,350 kWh

Energy Independence Act (EIA) estimated impact on Benton PUD rates $≈$3.00 per month

2.9% increase: $119 avg. bill

Benton PUD has been at or below the median since 2005

Average bill information has been calculated by Benton PUD staff from publicly available information from other utilities’ websites. Calculation is Benton PUD’s best effort to provide comparable information.


Snohomish PUD has a monthly minimum bill in lieu of a monthly base charge. The monthly minimum bill is currently $0.53 per day or ~$15.90 per month.

Base Charge information has been calculated by Benton PUD staff from publicly available information from other utilities' websites. Calculation is Benton PUD's best effort to provide comparable information.
Average bill information has been calculated by Benton PUD staff from publicly available information from other utilities’ websites. Calculation is Benton PUD’s best effort to provide comparable information.

Monthly Bill Comparison

Medium General Service

Average Monthly Bill at 19,000 kWh and 75 KW

June 30, 2019

Average bill information has been calculated by Benton PUD staff from publicly available information from other utilities’ websites. Calculation is Benton PUD’s best effort to provide comparable information.

Average bill information has been calculated by Benton PUD staff from publicly available information from other utilities’ websites. Calculation is Benton PUD’s best effort to provide comparable information.

Low Income Programs

- **Low Income Discount - $603 thousand**
  - Assisted 1,900 customers per month (average) in 2018
  - Discounts range from 10% to 25% of monthly bill
  - Discount is greater of daily system charge or percentage of billed charges
  - Available to senior and disabled customers/members of household
  - Extended to Veterans/Active Military effective March 2019

- **BPUD Low Income Energy Efficiency - $180 thousand**
  - Assisted 44 households in 2018
  - Administered by BPUD and Community Action Committee

- **Helping Hands (customer donations) - $48 thousand**
  - Assisted 334 households in 2018
Net Power Costs & Reserves
Overview

- The District plans conservatively
  - Power costs budgeted at 25th percentile using statistical modeling
  - Typically, actual results are better than planned three out of four years
  - Reserves (cash) generated in good years used to defer/mitigate rate actions in subsequent years

- Last several rate increases did not keep up with rising power costs
  - Reserves were used to fill the gap

- The District budgeted a draw down of reserves $8.5M in 2019
- 2019 has been a challenging year (more later)
  - Draw down of reserves now forecasted to be $12.6M

- Rate increase necessary to keep up with net power costs

\(^1\)Does not include potential changes in timing of completion of major capital projects sooner than originally planned.

2019 Costs
Expenditures by Major Category

Net Power Supply 64%

O&M 17%

Taxes less Other Revenue 3%

Debt Service 4%

Net Capital 12%

2019 Total Net Expenditures $141.9 million*

* Amount needed to collect through electric rates

### Net Power Costs vs. Retail Rate Increases

<table>
<thead>
<tr>
<th>Line</th>
<th>Annual Change</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Net Power Cost ($ increase in millions)</td>
<td>$6.4</td>
<td>$1.9</td>
<td>$3.4</td>
<td>$1.3</td>
<td>$2.4</td>
<td>$(0.8)</td>
</tr>
<tr>
<td>2</td>
<td>Net Power Cost (% increase)</td>
<td>9.8%</td>
<td>2.6%</td>
<td>4.6%</td>
<td>1.7%</td>
<td>3.1%</td>
<td>(1.0)%</td>
</tr>
<tr>
<td>3</td>
<td>Retail Revenue Increase (%)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>3.9%</td>
<td>4.9%</td>
<td>1.9%</td>
<td>0.0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Line</th>
<th>Cumulative Change since 2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Net Power Cost ($ increase in millions)</td>
<td>$6.4</td>
<td>$8.3</td>
<td>$11.7</td>
<td>$13.0</td>
<td>$15.4</td>
<td>$14.6</td>
</tr>
<tr>
<td>2</td>
<td>Net Power Cost (% increase)</td>
<td>9.8%</td>
<td>12.7%</td>
<td>17.9%</td>
<td>19.8%</td>
<td>23.5%</td>
<td>22.3%</td>
</tr>
<tr>
<td>3</td>
<td>Retail Revenue Increase (%)</td>
<td>0.0%</td>
<td>0.0%</td>
<td>3.9%</td>
<td>9.0%</td>
<td>11.1%</td>
<td>11.1%</td>
</tr>
</tbody>
</table>

- For illustrative purposes only
  - 22.3% net power cost increase
  - x 60% power cost percentage of total costs*
  - 13.4% equivalent retail rate impact (approximation only)

* Costs or revenue requirement

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Water Volume by Year

January thru July Runoff at The Dalles Dam

More Water = More surplus power

2017-2018 back to back good water years

Average water 101.4 MAF

2019 water year is in the bottom third since 1961

Variables Impacting Net Power Costs

- BPA cost increases and generation decreases
- Energy Independence Act 2020
- Power market volatility
# BPA Costs Increases

## 2020 Adopted Rates

<table>
<thead>
<tr>
<th>BPA Power &amp; Transmission</th>
<th>Description</th>
<th>BP-20</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power – Base</td>
<td></td>
<td>0.0%</td>
</tr>
<tr>
<td>Power – FRP* Surcharge</td>
<td></td>
<td>1.5%</td>
</tr>
<tr>
<td>Transmission</td>
<td></td>
<td>3.6%</td>
</tr>
</tbody>
</table>

As applied to Benton PUD

<table>
<thead>
<tr>
<th>Annual $ Increase</th>
<th>$0.8M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual % Increase</td>
<td>1.2%</td>
</tr>
</tbody>
</table>

*Financial Reserve Policy

BPA Generation Decreases

Benton PUD receives a “slice” or 1.37% of this generation

BPA Forecasted 2020 Annual Generation

<table>
<thead>
<tr>
<th></th>
<th>BPA WY19 Study</th>
<th>BPA WY20 Study</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>9,124</td>
<td>9,124</td>
</tr>
<tr>
<td>Feb</td>
<td>8,802</td>
<td>8,802</td>
</tr>
</tbody>
</table>

BPA Forecasted 2020 Monthly Generation Shaping

Two Factors:
1) Climate
2) Court Ordered Spill

Net Cost Impact: $500k - $1.3M per year
Energy Independence Act (EIA)
2020 Renewable Energy Requirement

- **EIA applicable to utilities with more than 25,000 customers**
  - Currently, 17 utilities in the state subject to the EIA
  - Benton PUD is the only local utility fully subject to the EIA

- **Must purchase percentage of retail load from qualifying resources**
  - Wind, solar, biomass (hydro not a qualifying resource)
  - 2012 (3%) ............... 2016 (9%) ...............2020 (15%)
  - Can be energy or renewable energy credits

- **Impact of EIA on Benton PUD**
  - Currently spending $2.6M annually to meet the 9% EIA requirement
  - Rising to $3.2M in 2020 to meet the 15% EIA requirement

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Power Market Volatility

- The District buys and sells power in the power market
  - Typically a net seller
- Low prices reduce surplus sales revenues
- High prices increase purchased power cost
- Major Event - Feb/Mar 2019
  - Customer loads significantly higher than projected
  - Market prices significantly higher than expected
  - Effects of event felt throughout the Northwest (including BPA)
Power Market Volatility

2019 Net Power Cost Monthly Actual vs Budget


Purchases of wholesale power at extreme prices to meet customer load $6M over budget

Total 2019 forecasted to be $4.6M over budget
Power Market Volatility
Net Power Cost History and Projection

Primary cost drivers since 2007
• BPA increases every two years
• Lower surplus power sales
• Energy Independence Act (EIA)

Forecast: August 2019
$90.7
$81.5
$80.9
$81.6
$84.0

2019 Budget: $86.1M

Primary cost drivers - future
• BPA increases every two years
• Less stable wholesale market

(1) Net power costs (NPC) = gross power costs (including power and transmission) less secondary market sales.

Reserves - Days Cash on Hand

Historical and 2019 Original Forecast

1. Estimated ending balance
2. Budget included a proposed 2.4% increase effective May 1, 2019

Source - Moody’s Investors Service Public Power Electric Utility Medians and Methodology, September 2016

1. Estimated ending balance
2. Budget included a proposed 2.4% increase effective May 1, 2019
3. Actual ending balance $56.3M less $1.8M timing (revenue received in 2018 for a 2019 capital project and 2018 expenses paid in 2019)
4. Forecast includes a proposed 2.9% increase effective October 1, 2019. Does not include potential changes in timing of capital projects

Days Cash on Hand (Reserves)

WPUDA\(^1\) Survey – December 2017 (Distribution Systems Only)

\(^1\)Washington PUD Association

Source: WPUDA Source Book (July 2018)

Measures the number of days utility can cover its operating expenses using unrestricted reserves and assuming no additional revenue.
Projected Revenue Increases

- **Primary Driver:** Rising Power Costs

<table>
<thead>
<tr>
<th>Year</th>
<th>Revenue Increase %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oct 2017</td>
<td>1.9%</td>
</tr>
<tr>
<td>Jan 2018</td>
<td>0.0%</td>
</tr>
<tr>
<td>Oct 2019</td>
<td>2.9%</td>
</tr>
<tr>
<td>2020</td>
<td>Likely 0%</td>
</tr>
<tr>
<td>2021</td>
<td>Projected 2% - 4%</td>
</tr>
</tbody>
</table>

Pause for Questions / Comments
Financial Metrics
Operations and Maintenance (O&M)

APPA\(^2\) Survey – 2017 Median for West utilities

O&M(1) Cost per Customer – APPA(2) Benchmark

O&M Cost per Customer has declined after factoring in the effects of inflation\(^{3}\)

Benton PUD continues to be below APPA benchmark

(1) O&M = non-power operations & maintenance cost (distribution, transmission, customer accounts, and administrative and general). Excludes Broadband.

(2) American Public Power Association - 2017 median for West utilities.

(3) Inflation rate utilized comes from a producer price index for electric utilities, which on average has been slightly under 3%.

Customers per District Employee

Definition of Customer per American Public Power Association

Debt Per Customer
WPUDA¹ Survey – December 2017 (Distribution Systems Only)

¹Washington PUD Association

Source: WPUDA Source Book (July 2018)

District below the median and average of Washington PUDs

Median for survey respondents ($1,419)
Benton PUD 2018 Debt Per Customer ($985)

$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0

Chelan
Ferry
Wahkiakum
Pacific
Lewis
Skamania
Clallam
Benton
Clark
Pend Oreille
Okanogan
Mason 1
Douglas
Average
Mason 3
Franklin
Kittitas
Cowlitz
Grays Harbor
Grant
Klickitat

Benton PUD

District below the median and average of Washington PUDs

Credit Ratings History
Independent Credit Rating Agencies

<table>
<thead>
<tr>
<th>Date</th>
<th>Moody's</th>
<th>S &amp; P</th>
<th>Fitch</th>
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<tbody>
<tr>
<td>July 2019(1)</td>
<td>Aa3</td>
<td>A+ (affirmed)</td>
<td>AA-</td>
</tr>
<tr>
<td>May 2019(2)</td>
<td>Aa3</td>
<td>A+</td>
<td>AA- upgrade</td>
</tr>
<tr>
<td>Sept 2016(3)</td>
<td>Aa3</td>
<td>A+</td>
<td>A+</td>
</tr>
<tr>
<td>July 2010</td>
<td>Aa3</td>
<td>A+</td>
<td>A+</td>
</tr>
<tr>
<td>Feb 2010</td>
<td>A2</td>
<td>A+</td>
<td>A</td>
</tr>
<tr>
<td>Oct 2009</td>
<td>A2</td>
<td>A</td>
<td>A</td>
</tr>
<tr>
<td>Sept 2006</td>
<td>A3</td>
<td>A-</td>
<td>A-</td>
</tr>
<tr>
<td>March 2005</td>
<td>A3</td>
<td>A-</td>
<td>A-</td>
</tr>
<tr>
<td>Sept 2004</td>
<td>A3</td>
<td>BBB+ Positive</td>
<td>A- Stable</td>
</tr>
<tr>
<td>Oct 2003</td>
<td>A3</td>
<td>BBB+ Stable</td>
<td>BBB+ Positive</td>
</tr>
<tr>
<td>Nov 2002</td>
<td>A3</td>
<td>BBB Neg.</td>
<td>-</td>
</tr>
<tr>
<td>Nov 2001</td>
<td>A3</td>
<td>A- Stable</td>
<td>-</td>
</tr>
</tbody>
</table>

Number of rating levels we have improved since Nov. 2002:

- S&P affirmed District’s A+ rating
- Fitch upgraded the District’s rating to AA- from A+
- Moody’s, S&P, and Fitch ratings affirmed with the 2016 series bond issue

2019 S&P/Fitch Reports:
- Low Rates
- Low Debt
- Solid Reserves
- Strong Economy

Cost of Service
Overview of Rate Making Process

**Financial Forecast**
Multi-year financial forecast to project total utility costs and initial revenue requirement for average rate impacts.

**Test Year Revenue Requirement**
Total costs and allocations to customers to be recovered through the COSA process and rate making.

**Cost of Service Analysis**
Unbundling, classification and allocation of Revenue Requirement to be recovered from customer classes.

**Rate Design**
Use the cost of service results and Rate Strategy to guide rate design. Rates should fully recover all costs not funded by reserves and/or debt.

COSA Model Components

Functionalize Costs

Allocate Costs

Classify Costs

Utility Total Costs

Generation
Transmission
Distribution
Customer

Energy
Demand
Customer

Residential
Commercial
Industrial
Irrigation

COSA vs. Rate Making

- COSA is a quantitative tool to guide setting rates for each class
- COSA results for each class can vary from year-to-year
- Policy goals/decisions can influence how rates are set
- Benchmarking rates is another tool to guide rate setting
2019 COSA Results Comparison to Target

Rate Strategy Policy: Move rate classes to +/- 10% of COSA over the long-term

2019 COSA Results (% of COSA) +/− 10% Targeted Range

- Residential: 91.3%
- General Service: 97.7%
- Large Industrial: 89.5%
- Small Irrigation: 86.6%
- Large Irrigation w/o MLC: 84.3%
- Large Irrigation w/ MLC: 87.6%
- Street Lighting: 91.0%
- Security Lighting: 96.3%
- Unmetered: 74.1%
- Total: 92.2%

Summary and Next Steps

- **Staff proposal: 2.9% average revenue increase**
  - Key Driver: Power Costs
  - Applied across the board to all rate classes (except unmetered)
  - Applied evenly to all rate components
- Draft rates presented to Commission at August 27 meeting
- Consider adoption of new rates at September 10 meeting
  - New rates would be effective October 1, 2019
Pause for Questions / Comments

Then 5 Minute Break
Power Market Volatility

Maintaining Grid Reliability and Affordability in a Clean Energy Era
Agenda

- Benton PUD Power Supply Portfolio
- Northwest Power Market Capacity Concerns
- Washington State’s 100% Clean Legislation
Benton PUD
Power Supply Portfolio

Generation Resources

- **Natural Gas CCCT**
  - Capacity: 50 MW
  - Dispatched as Needed

- **Small Hydroelectric**
  - Capacity: 3.7 MW
  - 0.92 aMW

- **Wind Power**
  - Capacity: 18 MW
  - 5.4 aMW

- **Columbia Generating Station**
  - Capacity: 1,100 MW
  - In Service: 1984
  - Decommissioning: 2050

- **Federico Creek**
  - Capacity: 250 MW
  - In Service: 2002
  - Decommissioning: 2022

- **White Creek**
  - Capacity: 205 MW
  - In Service: 2007

- **Nine Canyon**
  - Capacity: 96 MW
  - In Service: 2007

- **BPA Slice/Block Contract**
  - 2.85% of FCRPS
  - 198 aMW

- **BPUD Load**
  - Capacity: 430 MW Peak
  - 210 aMW

- **Federal Columbia River Power System Dams**
  - Capacity: 22,000+ MW
  - In Service: Various, beginning 1936

- **Columbia Generating Station**
  - Capacity: 1,100 MW
  - In Service: 1984
  - Decommissioning: 2050

- **Net Power Cost Annual Budget**
  - $80 to $90 Million

Load/Resource Balance
2018 Block and Critical/Average Slice

- Market Purchases Required to Meet Load
- Frederickson Generates When Economic

Surplus Energy Sold to Market

Block/Slice Generation observed over the last 3 years
Frederickson available as energy call option through August 2022

Peak Hour Net Position

without Frederickson

Electrical Energy & Generation Capacity

- Electrical Energy
  - Amount of electricity generated or consumed over a period of time

- Generation Capacity
  - Ability to generate electricity during peak demand periods
    - Coldest hours on the coldest days in Winter
    - Hottest hours on the hottest days in Summer
  - Capacity resources are required for stable and reliable power grid operations
Benton PUD – Summer Load Profile


Benton PUD Load
7/1/2018 - 7/31/2018

Capacity
Generation required to precisely follow and meet peak load

Energy
Area under the Power curve

July 2018 Hour Ending
Northwest Power Market Capacity Concerns
Electricity is Simultaneously...

Produced

Delivered

Consumed
Load & Resource Balance - BPA

Hydro-Generation Follows Load Maintains Load & Resource Balance (with surplus to sell)

Thermal Plants Produce Constant Generation

Wind Displaces Hydro (Effectively Negative Load)
Northwest Power Plant Retirements

- Retirement of NWPP baseload generation

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Capacity (MW)</th>
<th>Retirement Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Centralia Generation (1)</td>
<td>670</td>
<td>2020</td>
</tr>
<tr>
<td>Boardman</td>
<td>585</td>
<td>2021</td>
</tr>
<tr>
<td>Colstrip (1)</td>
<td>307</td>
<td>End of 2019</td>
</tr>
<tr>
<td>Colstrip (2)</td>
<td>307</td>
<td>End of 2019</td>
</tr>
<tr>
<td>Centralia Generation (2)</td>
<td>670</td>
<td>2025</td>
</tr>
<tr>
<td>Various Coal, NG, Hydro</td>
<td>1,769</td>
<td>2018-2025</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>4,308</strong></td>
<td></td>
</tr>
</tbody>
</table>

Regional Capacity Assessment

- **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 will be most notable during peak-demand periods in the winter and summer.”
Regional Capacity Assessment


Figure 6: Need for Power

Criteria – Utility owned/contracted resources only, low water conditions (8% hydro), normal weather (1-in-2) loads and 16% planning margin.

Winter Already Deficit

Summer Begins to be Deficit

2019 PNUCC Northwest Regional Forecast
Regional Capacity Assessment

- “...Northwest power supply is likely to become inadequate by 2021, primarily due to the retirement of the Centralia 1 and Boardman coal plants... The loss-of-load probability (LOLP) for that year is estimated to be over 6 percent, which exceeds the Council’s standard of 5 percent.”

- “By 2022 the LOLP is projected to rise to about 7 percent, due to the additional retirements of the North Valmy 1 coal plant, the Colstrip 1 and 2 coal plants...”
Capacity Assessment Update

2024 Monthly LOLP

2024 Reference Case LOLP = 8%
With coal retirements LOLP = 30%
(for reference 2001 LOLP was 24%)

Sum of monthly LOLP values is equal to or greater than the annual LOLP value because curtailments across multiple months can occur in the same year.

March 2019 Power Market Spike

Many Natural Gas Power Plants Idle
$160/MMBTU
>$1,000/MWh

2000 MW to Canada
Northwest Deep Freeze
1900 MW from Montana

2000 MW from California

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Capacity MW</th>
<th>March 1 to 6 Power Production</th>
<th>Retirement Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Centralia (1/2)</td>
<td>1,340</td>
<td>500 – 1,250</td>
<td>2020/2025</td>
</tr>
<tr>
<td>Boardman</td>
<td>585</td>
<td>475</td>
<td>2021</td>
</tr>
<tr>
<td>Colstrip</td>
<td>2,094</td>
<td>2,000</td>
<td>2019 (614 MW)</td>
</tr>
</tbody>
</table>

COAL-FIRED POWER PLANT STATUS

March 2019 Power Market Spike

BPA Loads and Resources
Rolling Average, 03/01 - 03/07

March 2019 Power Market Spike

Spikes in Alberta, Canada Real Time Power Market Price $800/MWh

Mid-C Day Ahead Price Spike >$800/MWh

The Black Swan Event that lasted less than three days cost the District ~$2.0M

$50/MWh

Mid-C Day Ahead Price Jump

Washington State’s 100% Clean Legislation
WA 100% Clean - Summary

- 100% carbon free energy by 2045
- Coal-fired electricity eliminated by 2025
- 100% greenhouse gas neutral by 2030
  - Up to 20% through alternative compliance
    - compliance payment
    - unbundled RECs
    - energy transformation projects
- Existing hydro & nuclear energy count
- Energy Independence Act (EIA) investments count
WA 100% Clean - Summary

- Compliance payment/penalty
  - Coal-fired: $150/MWh
  - Gas-fired peaking: $84/MWh
  - Gas-fired combined cycle: $60/MWh
  - Inflation factor after 2027

- Considered compliant if investments meet or exceed 2% of prior year’s revenue requirement (limits rate increases)

- Attempts to address grid reliability risks
  - Technically and financially complex problems
  - Existing studies already indicate retirement of coal-fired generation will cause unacceptable increase in regional loss-of-load probability

- Significant increase in the amount and complexity of Utility reporting and planning
WA 100% Clean - Summary

Benton PUD 2018 Portfolio

Fuel Mix

- Hydro 82%
- Nuclear 8%
- Wind 7%
- Other 3%

Fuel Mix developed in accordance with Washington State Department of Commerce calculations based on data reported by Benton PUD.

97% Carbon Free

Benton PUD Challenges/Concerns

- **BPUD is long energy and short capacity**
  - Capacity resources being retired with no firm plans for replacement
    - WA 100% Clean chills potential investments in operationally proven and cost-effective capacity such as natural-gas power plants
  - Big $ risk increase in relying on market purchases
    - Too many utilities relying on market purchases to cover capacity deficits
    - Mid-C market volatility increasing during peak load periods

- **Grid reliability concerns**
  - Wind and solar power does not provide replacement capacity needed during poor water years and extreme temperatures
    - Energy gluts erode business case for capacity resources in current power markets (energy based payments)

Questions / Comments?
### Proposed Increase: Rate Components

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Current Rates</th>
<th>Proposed Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Energy</td>
<td>DSC</td>
</tr>
<tr>
<td>Residential</td>
<td>$0.0718</td>
<td>$18.60</td>
</tr>
<tr>
<td>Small General Service</td>
<td>$0.0644</td>
<td>$16.20</td>
</tr>
<tr>
<td>Medium General Service Jan – Mar &amp; Sept – Dec</td>
<td>$0.0597</td>
<td>$48.30</td>
</tr>
<tr>
<td>Medium General Service April – August</td>
<td>$0.0509</td>
<td>$48.30</td>
</tr>
<tr>
<td>Large General Service Jan – Mar &amp; Sept – Dec</td>
<td>$0.0492</td>
<td>$58.80</td>
</tr>
<tr>
<td>Large General Service April – August</td>
<td>$0.0411</td>
<td>$58.80</td>
</tr>
<tr>
<td>Large Industrial</td>
<td>$0.0384</td>
<td>$226.20</td>
</tr>
<tr>
<td>Small Irrigation</td>
<td>$0.0520</td>
<td>$5.40</td>
</tr>
<tr>
<td>Large Irrigation w/o MLC</td>
<td>$0.0441</td>
<td>$36.00</td>
</tr>
<tr>
<td>Large Irrigation w/MLC</td>
<td>$0.0414</td>
<td>MLC</td>
</tr>
</tbody>
</table>

1) Daily system charge: $ per month based on a 30-day month
   
   *Small General Service rates based on Single-Phase service*
   
   *Medium General Service rates based on Multi-Phase service*

2) Large irrigation w/MLC class has a Miles of Line Charge in lieu of a daily system charge

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# Medium/Large General Service

## Proposed Increase: Energy Component Only

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Current Rates</th>
<th>Proposed Rates</th>
<th>Proposed Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Energy</td>
<td>Energy¹</td>
<td>Energy²</td>
</tr>
<tr>
<td>Medium General Service</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan – Mar &amp; Sept – Dec</td>
<td>$0.0597</td>
<td>$0.0614</td>
<td>$0.0577</td>
</tr>
<tr>
<td>April – August</td>
<td>$0.0509</td>
<td>$0.0524</td>
<td>$0.0577</td>
</tr>
<tr>
<td>Large General Service</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan – Mar &amp; Sept – Dec</td>
<td>$0.0492</td>
<td>$0.0506</td>
<td>$0.0471</td>
</tr>
<tr>
<td>April – August</td>
<td>$0.0411</td>
<td>$0.0423</td>
<td>$0.0471</td>
</tr>
</tbody>
</table>

1) Rate effective October 1, 2019 through December 31, 2019

2) Rate effective January 1, 2020 through December 31, 2020 (Seasonality removed January 1, 2020)